COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2018-00294**
ADJUSTMENT OF ITS ELECTRIC RATES	**)**	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
COMMISSION STAFF'S THIRD REQUEST FOR INFORMATION
DATED DECEMBER 13, 2018

FILED: JANUARY 2, 2019

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

K W Blake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Elizabeth J. McFarland

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

STATE OF NORTH CAROLINA)

COUNTY OF BUNCOMBE)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W. Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21 day of December 2018.

Ryan Ridenour (SEAL)
Notary Public

My Commission Expires:

7-29-23

Ryan Ridenour
NOTARY PUBLIC
BUNCOMBE COUNTY, NC
MY COMMISSION EXPIRES 7/29/23

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 1

Responding Witness: Robert M. Conroy / Elizabeth J. McFarland

Q-1. Refer to KU's Response to Commission Staff's Second Request for Information (Staff's Second Request), Item 1.

a. Refer to Item a. Provide a revised tariff sheet reflecting the text change included in this response.

b. Refer to Item b. Provide a revised tariff sheet reflecting the addition of a note stating that asterisks represent non-LED lights.

c. Refer to Item 1(2). Explain why the "Definitions" and "Rate" sections are no longer used for new and renewing franchise agreements.

d. Refer to Item m(1). Provide a revised tariff sheet reflecting this change.

e. Refer to Item n. Explain the reasoning for the proposed text changes to b. and c. of "5. Other Line Extensions" and b. of "6. Overhead Line Extensions for Subdivisions."

f. Refer to Item o(1). Identify the criteria used to determine eligibility for this credit and explain why it now rarely exists.

g. Refer to Attachment to Response to PSC-2 Question No. 1 (h), page 19 of 26. Under "19. Unauthorized Attachments," it states, "such Attachment shall be deemed an 'Unauthorized Attachment,' and shall be presumed to have been affixed to Company Structures for two years or since completion of the most recent audit, whichever is occurring earlier. Attachment Customer shall be liable for attachment charges for this time period." This language seems to indicate that if the most recent audit occurred four years ago, the Attachment Customer would be responsible for four years' worth of attachment charges. Explain how this would not be in violation of KRS 278.225. If the tariff language needs to be revised, provide a revised tariff sheet reflecting such revision.

A-1.

a. See attached.

b. See attached.

c. The language in these sections refers to the previous method for calculating franchise fee payments that is no longer used on newer franchise agreements. There are a limited number of active franchise agreements that are calculated based on the language in these sections with the last one due to expire in 2031. All franchise agreements signed since August 2012 are calculated based upon a standard methodology with the collection and payment applied uniformly to all customers in the franchise area. As a result, these sections are no longer needed for franchise agreements entered since August 2012.

d. See attached.

e. The process of issuing refunds every year for each contract is time consuming and labor intensive. Annually, KU will review contracts that are reaching their 10 year expiration and issue a refund due to the customer.

f. The criterion for the credit is for the customer to have the underground facilities installed by an entity other than the Company at the customer's expense. For most all underground extension efforts, customers have chosen to have the Company perform the underground work and pay for the estimated installed cost rather than contract with another entity to do the work and receive a credit from the Company. Therefore, the conditions have rarely existed for the Company to pay the credit and the language is being removed from the tariff.

g. KRS 278.225 limits a customer's liability for unbilled service to two years unless the service was obtained through fraud, theft, or deception. Term and Condition 19 is intended to recognize the practical and legal limits on billing an Attachment Customer for attachment charges following the discovery of an unauthorized attachment. To eliminate any confusion regarding the maximum period for which an Attachment Customer may be billed for an unauthorized attachment, the relevant section of Term and Condition 19 should be revised to read: "If Attachment Customer makes any Attachment that requires Company approval or advance notice under this Schedule or the Contract and has not obtained such approval or provided such advance notice, such Attachment shall be deemed an 'Unauthorized Attachment,' and shall be presumed to have been affixed to Company Structures for a period of two years or since completion of the most recent audit, if such audit was completed within that two year period." A substitute tariff page reflecting this revision is attached.

Standard Rate **GS**

General Service

APPLICABLE

In all territory served.

AVAILABILITY T

To general lighting and small power loads for secondary service.

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

RATE

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

ADJUSTMENT CLAUSES

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

Demand-Side Management Cost Recovery Mechanism	Sheet No. 86	T
Fuel Adjustment Clause	Sheet No. 85	T
Off-System Sales Adjustment Clause	Sheet No. 88	T
Environmental Cost Recovery Surcharge	Sheet No. 87	D/T
Franchise Fee	Sheet No. 90	T
School Tax	Sheet No. 91	

DETERMINATION OF LOAD

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

DATE OF ISSUE: September 28, 2018

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

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

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

RATE (continued) T

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

Units marked with an asterisk (*) are non-LED offerings. N

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

Pole Charges

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

CONVERSION FEE

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

Conversion Fee: $6.12 per month for 60 months

Terms and Conditions
Deposits

GENERAL

1. Company may require a cash deposit or other guaranty from Customers to secure payment of bills in accordance with 807 KAR 5:006, Section 8, except for Customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection.
2. Deposits may be required from all Customers not meeting satisfactory credit and payment criteria. Satisfactory credit for Customers will be determined by utilizing independent credit sources (primarily utilized with new Customers having no prior history with Company), as well as historic and ongoing payment and credit history with Company.
   a. Examples of independent credit scoring resources include credit scoring services, public record financial information, financial scoring and modeling services, and information provided by independent credit/financial watch services.
   b. Satisfactory payment criteria with Company may be established by paying all bills rendered, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments, having no meter diversion or theft of service.
3. Company may offer residential or general service Customers the option of paying all or a portion of their deposits in installments over a period not to exceed the first six (6) normal billing periods. Service may be refused or discontinued for failure to pay and/or maintain the requested deposit.
4. Interest on deposits will be calculated at the rate prescribed by law, from the date of deposit, and will be paid annually either by refund or credit to Customer's bills. 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. T

RESIDENTIAL

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

DATE OF ISSUE: September 28, 2018

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

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

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

T

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

19. UNAUTHORIZED ATTACHMENTS

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

20. DEFAULT

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

DATE OF ISSUE: September 28, 2018

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

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

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

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 2

Responding Witness: John K. Wolfe

Q-2. Refer to KU's Response to Staff's First Request for Information (Staff's First Request), Item 6.

a. Explain whether there are any governmental units that will see an increase in pole attachment charges.

b. Explain whether there are any educational units that will see an increase in pole attachment charges.

A-2.

a. KU has five Attachment Customers in this class, 13 of which are K-12 public school systems, and four of which are municipalities.

Of the 13 school systems, five pay an annual attachment charge that is higher than the proposed PSA rate. These five customers would see a decrease in pole attachment charges (a combined decrease of $237.50 for all five). Six school systems attached their facilities pursuant to license agreements providing for a one-time attachment charge for the entire agreement term. Those six agreements expire in 2026, 2027, and 2031, after which those customers would pay the annual fee of $7.25. The two remaining school systems would see an increase in pole attachment charges (a combined increase of $58.00 for both systems).

Of the four municipalities, two are currently paying an annual attachment fee at the rate proposed by Rate PSA. The other two municipalities would see an increase in pole attachment charges.

b. The Attachment Customer in this class is currently paying an annual attachment fee at the rate proposed by Rate PSA.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 3

Responding Witness: Robert M. Conroy

Q-3. Refer to KU's Response to Staff's Second Request, Item 2.c. Provide the compilation in Excel spreadsheet format.

A-3. See attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 4

Responding Witness: John K. Wolfe

Q-4. Refer to KU's Response to Staff Second Request, Item 5. Confirm that KU will no longer purchase non-LED lighting inventory. If this cannot be confirmed, provide the date that KU expects to no longer purchase non-LED lighting inventory.

A-4. The Company expects to no longer purchase non-LED lighting inventory (with the exception of the Victorian HPS fixtures that remain an LS offering) by May 2019.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 5

Responding Witness: Robert M. Conroy

Q-5. Refer to KU's Response to Staff's Second Request, Item 11 .b. Provide the benefits beyond net metering.

A-5. The meter would also allow the customer to participate in available time-of-day rates (e.g., RTOD-Demand and RTOD-Energy) and enable the customer to access more granular usage data through the MyMeter portal. These benefits would continue to be available as long as the meter was deployed, regardless of whether the customer (or a subsequent customer) served by the meter continued to participate in the Solar Share Program.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 6

Responding Witness: Daniel K. Arbough / Robert M. Conroy

Q-6. Refer to KU's Response to Staff's Second Request, Item 16.

a. Refer also to Schedule B-2.2, page 2 of 2, line 14. Provide the amount of the adjustment that relates to Advanced Metering Infrastructure (AMI) meters required by Solar Share participants.

b. Refer also to Schedule B-2.3, page 5 of 6, line 56. Provide the amount of the increase that relates to AMI meters required by Solar Share participants.

A-6.

a. $0.

b. See the response to part a.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 7

Responding Witness: William Steven Seelye

Q-7. Refer to KU's Response to Staff's Second Request, Item 24, Attachment–Costs Reference Tab.

a. Provide support for the Charge Point Annual Cost of $255.00 for a single port.

b. Provide support for the Charge Point Annual Cost of $510.00 for a double port.

A-7.

a. These costs are for the Chargepoint Network Service Plan that allows the Companies to monitor stations, collect usage data, and collect fees. Support for the costs can be found in the Companies' contract with Chargepoint. See pages 11-13 of the attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

b. See the response to part a.

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 8

Responding Witness: William Steven Seelye

Q-8. Refer to KU's Response to Staff's Second Request, Item 25.b.

a. Provide support for the monthly carrying charge percentage.

b. Provide the Attachment to this response in Excel spreadsheet format with all formulas unprotected and all rows and columns fully accessible.

A-8.

a. The monthly carrying charge percentage is calculated by dividing the annual carrying charge rate by 12 months (see factor highlighted in grey in the attachment being provided in Excel format). The support for the charge is also included in the Excel attachment.

b. See the attachment to part a.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 9

Responding Witness: Christopher M. Garrett

Q-9. Refer to KU's response to Staff's Second Request, Item 43, and the attachment thereto in which KU explained how it calculated changes to its accumulated deferred income taxes (ADIT) using the pro rata method.

a. Explain why KU applied the pro rata method by using the total change between April 30, 2019, and April 30, 2020, divided by 12 for the monthly increase and decrease amounts as opposed to actual projected monthly increase and decrease amounts.

b. Confirm that it would be consistent with the pro rata method described in 26 C.F.R. § 1.167(1)-1 to apply the pro rata method using the actual projected monthly changes instead of the total change between April 30, 2019, and April 30, 2020, divided by 12 as KU did in the attachment to Staff's Second Request, Item 43.

c. If KU contends that it would be inconsistent with 26 C.F.R. § 1.167(1)-1 to apply the pro rata method using the actual projected monthly changes, explain all bases for that contention with reference to the specific provisions of 26 C.F.R. § 1.167(1)-1 and any relevant interpretations thereof, including Example 2 and Example 3 in 26 C.F.R. § 1.167(1)-1 (h)(6)(iv).

A-9.

a. Deferred taxes are generally adjusted quarterly for budgeting purposes rather than monthly. Therefore, the Company believes it is more appropriate to spread the activity evenly when calculating the pro rata deferred tax balance. This is consistent with the core principles of ASC 740-270 which require companies to follow a general process for allocating an entity's annual tax provision to its interim financial statements.

b. The Company agrees that it would be consistent to apply the pro rata method using the actual projected monthly changes were the Company to have performed a detailed monthly deferred tax calculation as opposed to the annual tax provision calculations used by the Company.

c. See the response to part b.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 10

Responding Witness: David S. Sinclair

Q-10. Refer to KU's Response to Staff's Second Request, Item 45.a. Explain what factors caused projected market purchases to increase from the base period to the forecast period.

A-10. The increase in projected market purchases is largely a function of forecasted hourly market prices relative to the forecasted cost of energy being less than that of the Companies' generating units as compared to what occurred in the base period. The Companies participate in the hourly spot energy market every hour of the year and make energy purchase and sales when it was economically advantageous to do so and transmission is available. The forecasted data is a result of modeled conditions that attempt to mimic reality through simulating random outage events in conjunction with defined load, prices, and unit characteristics. The forecast period had lower average market prices than the base period, and the timing of planned unit outages during fall and spring maintenance seasons also impacted the unit availability relative to the base period. The model is a forecast based on a specific set of assumptions, and if the actual system, load, and market conditions mirror those in the model, the Companies would expect market purchases to be higher in the forecast period compared to the base period.

The forecast period also includes fewer generating units, as Brown units 1 and 2 are scheduled to be retired in February 2019, and LG&E's Capacity Purchase and Tolling Agreement with Bluegrass Power ends in April 2019. However, this reduction in generating capacity is partially offset by the loss of load from the departing municipal customers.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 11

Responding Witness: Elizabeth J. McFarland

Q-11. Refer to KU's Response to Staff's Second Request, Item 53. Explain whether the Advanced Meters identified are included in the AMI DSM program. If not, explain why not.

A-11. All of the advanced meters purchased in the base year for KU were included in the AMI DSM (AMS Opt-In) program.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 12

Responding Witness: Christopher M. Garrett

Q-12. Refer to KU's Response to Staff's Second Request, Item 55, in which KU explained that the adjustment amount for deferred income taxes in Att_KU_PSC_1- 53_Sch_B at tab "Sch-B-6" reflects the Environmental Cost Recovery (ECR) and Demand-Side Management (DSM) deferred income tax amounts.

a. State whether KU contends that it is reasonable to calculate the extent to which ECR and DSM deferred income tax amounts should be included in the total deferred income tax amount using the pro rata method while calculating the extent to which ECR and DSM deferred income tax amounts should be removed from the total deferred income tax amount using a 13-month average of the actual projected monthly amounts.

b. If KU contends that using the two different methods to calculate the ECR and DSM deferred income tax amounts is reasonable, identify and explain all bases for its contention that the practice is reasonable.

A-12.

a. The Company believes it is appropriate to remove rate mechanisms using a 13 month average rather than the pro rata method as explained in part b below.

b. The Company would not fully recover its prudently incurred cost were a mismatch to occur as a result of the forecasted mechanism revenue requirement calculations not using a pro rata method. The Company is utilizing Kentucky Jurisdictional Capitalization (13 month average) adjusted to remove other rate mechanisms (13 month average) in determining its valuation for ratemaking purposes.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 13

Responding Witness: Christopher M. Garrett

Q-13. State whether the ADIT amounts in Att_KU_PSC_1-53_Sch_B produced in KU's response to Staff's First Request were calculated based on KU's current, approved depreciation rates, or its proposed, accelerated depreciation rates.

A-13. The ADIT amounts were calculated based on KU's proposed depreciation rates.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 14

Responding Witness: Christopher M. Garrett

Q-14. Refer to KU's response to Staff's Second Request, Item 61, which states that KU "does not allocate NOLs to specific utility properties." If that is the case, explain how KU ensures that it treats deferred tax assets arising from accelerated tax depreciation, specifically those arising from Net Operating Loss (NOL) carryforwards, in the same manner as deferred tax liabilities arising from accelerated tax depreciation when it takes properties, the depreciation of which generated those assets and liabilities, out of service as indicated in KU's Response to Staff's Second Request, Item 63.

A-14. The reversal of NOL deferred tax assets are not dependent on whether the losses were the result of accelerated tax depreciation but rather are based solely on the extent to which the Company has future taxable income. As described in the response to PSC 2-59 the result of the "with or without" method was that the NOL carryforward balance was caused entirely by accelerated depreciation. Therefore, the Company treats excess ADIT on NOLs as protected and amortizes it over the same time period as property related excess ADIT using the ARAM.

The NOL excess ADIT is reversed by the same percentage that property related excess ADIT is reversed using the ARAM in aggregate. The Company first calculates its annual property related excess ADIT amortization using ARAM to determine the percentage of each year's amortization to the total. Once each year's percentages are calculated, these percentages are then applied to the NOL excess ADIT balance so that it will reverse by the same percentage as the property related excess ADIT.

The Company will recalculate its property related excess ADIT using the ARAM annually to incorporate any changes that occurred during the year. The adjusted percentages will then be applied to the NOL excess ADIT.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 15

Responding Witness: Kent W. Blake / Christopher M. Garrett

Q-15. In its September 28, 2018 Order in Case No. 2018-000341[1] at page 11, the Commission disallowed KU's capitalization adjustment for the Tax Cut and Jobs Act impact to current federal income tax expense, but allowed the adjustment to capitalization for amortization of excess ADIT. Explain if KU's forecasted capital includes both adjustments. If it does, identify the amounts included in the end-of-period and 13-month average capitalization.

A-15. The Company's forecasted capitalization in this proceeding was based on the Commission's Order dated March 20, 2018, in Case No. 2018-00034. The Company has also made no adjustments to capitalization on Schedule J-1 related to the effects of the TCJA and ratemaking treatment. See attached for the amounts included in the end-of-period and 13-month average capitalization.

The Company expressed its disagreement with the Commission's decision in its response to the September 28, 2018 Final Order but did not challenge the decision as there may arguably be some diversity in practice in terms of how utilities settle single-issue ratemaking proceedings like Case No. 2018-00034. The Companies believed the savings being provided to customers were sufficiently reasonable and that it was appropriate to bring that single issue ratemaking proceeding to a close.

However, the Companies did not and do not agree with the September 28, 2018 Order's disallowance of the capitalization adjustment in Case No. 2018-00034. That Order states: "KU/LG&E have been allowed to collect additional cash for FIT taxes without a corresponding cash expense, thereby increasing their cash position" and rejects the capitalization adjustment for the TCJA impact "because it is requiring the ratepayers to pay the increased cost of capitalization of the current FIT refund."[2] The Order's logic, in this regard, is flawed. It has been the longstanding and appropriate ratemaking methodology of the Commission to

[1] Case No. 2018-00034, Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company (Ky. PSC Sept. 28, 2018).

[2] *In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00034, Order at 11 (Ky. PSC Sept. 28, 2018).

calculate revenue requirements using expenses per books. With respect to income tax expense, this would incorporate permanent book versus tax differences. With respect to timing differences, customers benefit from favorable timing differences that reduce cash taxes paid to the Internal Revenue Service as those differences reduce rate base and capitalization through deferred income taxes and thus lower the cost of capital embedded in base rates and other rate mechanisms such as the environmental cost recovery surcharge mechanism. The TCJA and associated surcredit had the effect of reducing these timing difference benefits. The Order erred in refusing to recognize this reversal and the resulting increase in rate base and capitalization.

Because the Companies had a net operating loss carryforward when the TCJA was enacted, the tax benefits being returned to customers through reduced income tax rates and expense are not reducing *current* federal income tax. The tax benefits being returned to customers result in a reduction to *deferred* income tax expense with a corresponding reduction in net ADIT. Failure to recognize this reduction in net ADIT in this base rate proceeding is not only improper but could also lead to a normalization violation.

The Companies have fully reflected the impacts of the TCJA in this proceeding including the amortization of excess ADIT through April 30, 2020. Accordingly, the ADIT balance used for ratemaking purposes must also be adjusted through April 30, 2020.

TCJA Impact on Capitalization

	End-of-period Capitalization as of 4/30/19			
	LGEE	LGEG	KU	TOTAL
TCJA Credit to Customers	48.9	14.3	72.4	135.6
TCJA Amortization of Excess ADIT	9.2	2.2	12.3	23.7
TCJA Impact on other Rate Mechanisms	19.9	0.4	21.1	41.4
TCJA Impact on Federal Cash Taxes Paid	0.0	0.0	2.6	2.7
Subtotal - TCJA Impacts	78.0	16.8	108.5	203.4

	13-month Average Capitalization as of 4/30/20			
	LGEE	LGEG	KU	TOTAL
TCJA Credit to Customers	48.9	14.3	72.4	135.6
TCJA Amortization of Excess ADIT	12.7	3.1	19.9	35.7
TCJA Impact on other Rate Mechanisms	19.9	0.4	21.1	41.4
TCJA Impact on Federal Cash Taxes Paid	0.0	0.0	(0.1)	(0.0)
Subtotal - TCJA Impacts	81.6	17.8	113.4	212.7

	End-of-period Capitalization as of 4/30/20			
	LGEE	LGEG	KU	TOTAL
TCJA Credit to Customers	48.9	14.3	72.4	135.6
TCJA Amortization of Excess ADIT	16.2	4.0	26.8	47.0
TCJA Impact on other Rate Mechanisms	19.9	0.4	21.1	41.4
TCJA Impact on Federal Cash Taxes Paid	0.4	0.1	(4.0)	(3.6)
Subtotal - TCJA Impacts	85.4	18.8	116.3	220.5

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 16

Responding Witness: Lonnie E. Bellar

Q-16. Refer to the Responses to Staff's Second Request, Item 68.c.

a. KU explained in its response that it has contacted two surplus parts firms regarding the obsolete inventory at Brown Units 1 and 2. Explain if KU has attempted to identify and contact other surplus parts firms to buy the Brown Units 1 and 2 obsolete inventory.

b. Provide a detailed description of the process KU used to identify and contact the surplus parts firms.

c. Provide any correspondence or emails between KU and the surplus parts firms.

A-16.

a. The two firms KU reported in its initial response are Paragon Energy Solutions and Plant Closing Consultants LLC. KU has also contacted General Electric, Babcock and Wilcox, Envirocom Asset Recovery, and Surplus Industrial Supply to explore their interests in the Brown Units 1 and 2 inventory (Inventory).

Additionally, KU posted the Inventory on a power generation virtual inventory directory, RAPID. RAPID is accessible by other power generation utilities, parts suppliers, and surplus parts purchasers across the United States. There has been no interest in the Inventory by the members of RAPID to date.

The large number of coal fired plant closures across the country and the vintage of the Brown units are likely contributors to the lack of interest to date by the aforementioned entities. KU continues to pursue additional opportunities.

b. KU has been an active member of RAPID since 2012.

General Electric and Babcock and Wilcox are the current primary suppliers of turbine, boiler, and coal mill parts for Brown Units 1 and 2. Brown inventory management personnel reached out to General Electric by phone and Babcock and Wilcox via email in late 2017.

Paragon Energy Solutions currently provides KU a service that facilitates its surplus parts purchasing and sales transactions with other utilities through RAPID. They also buy surplus parts. KU made Paragon aware of the pending Brown Units 1 and 2 plant closure and associated Inventory availability via email in September 2018.

Plant Closing Consultants LLC (also known as Project Development Services or PDS) contacted KU via email in August 2018 and KU responded via email (the same email sent to Paragon) in September 2018.

Envirocom Asset Recovery submitted an email in August 2017 depicting the type of material they typically pursue and was contacted by KU via phone in September 2017.

Surplus Industrial Supply (SIS) was identified via Google search. A notification of the Inventory and request for contact was submitted to SIS via their website in December 2018.

c. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff’s Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 17

Responding Witness: Daniel K. Arbough

Q-17. Refer to KU's Response to Staff's Second Request, Item 69. Provide a copy of the schedule that was attached to this response in Excel spreadsheet format with formulas intact and unprotected, and all rows and columns fully accessible. Include in the Excel spreadsheet the percentage of each reported variance.

A-17. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 18

Responding Witness: Lonnie E. Bellar

Q-18. Refer to KU's Response to Attorney General's Initial Request for Information (Attorney General's Initial Request), Item 14. Explain how KU's existing price forecast scenarios compare to the market analysis software, PROMOD (used by PJM), which contain the LMP forecasting for selected nodes, user-defined hubs, or load-weighted or generator-weighted zone features.

A-18. Based on the information contained in PJM's presentation, "PJM PROMOD Overview," dated August 11, 2017,[3] it appears that PROMOD is similar in several ways to AURORA, which the Companies use to model RTO electricity prices. Both models include inputs for forecasted demand and energy levels and shapes, generating unit characteristics, transmission grid topology and constraints, fuel costs, and environmental costs. Both models perform a granular simulation of the system's commitment and dispatch and produce various outputs, including zonal or nodal electricity prices. As the system operator, PJM appears to use PROMOD in a more detailed fashion compared to the Companies' use of AURORA. However, the Companies expect that both models produce reasonable long-term forecasts of market electricity prices and recognize that neither PJM's PROMOD model nor the Companies' AURORA model include the complexity to produce theoretical LMPs for the Companies' generating units.

---

[3] See http://www.pjm.com/~/media/committees-groups/subcommittees/cs/20170811/20170811-item-02-pjm-promod-overview.ashx.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 19

Responding Witness: Daniel K. Arbough

Q-19. Refer to KU's Response to the Attorney General's Initial Request, Item 40. KU states that capitalization cannot be tracked to individual items. Provide a detailed explanation of the process KU used to forecast its monthly capitalization in the forecasted period.

A-19. For each month, the model calculates revenues, expenses, capital expenditures, and financing cash flows based on the assumptions input. The model then generates a complete set of financial statements based on the above items. The monthly capitalization is calculated from the balance sheet generated by the model. Capitalization is a total Company item that is impacted by all of the individual transactions, and therefore it is not possible to calculate the exact impact of individual items on capitalization unless the model is run each time a new project is added to isolate its impact.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 20

Responding Witness: Lonnie E. Bellar

Q-20. Refer to KU's Response to the Attorney General's Initial Request, Item 47.

a. Provide an itemized list of the distribution capital projects for each category in the chart.

b. Provide a comparison by category of the amounts in the chart to the actual amounts spent in each category for the prior three calendar years.

A-20.

a. See attached.

b. The table below shows the comparison to the calendar years 2015-2017.

KU	Calendar Years			Total	AG Initial Request Item 47
	2015	2016	2017	2015-2017	July 2018 - April 2020
Connect New Customer	$40	$40	$40	$120	$77
Enhance The Network					
Distribution Automation	*$0*	*$0*	*$5*	*$5*	*$22*
Circuit Hardening/Reliability	*$1*	*$1*	*$3*	*$5*	*$25*
Transformer Contingency	*$3*	*$8*	*$6*	*$17*	*$10*
Other	*$15*	*$14*	*$19*	*$48*	*$48*
Maintain The Network	$29	$26	$28	$83	$69
Repair The Network	$6	$5	$6	$17	$11
Miscellaneous	$1	$1	$1	$3	$4
Total	$95	$95	$108	$298	$266

Itemized List of Distribution Capital Projects by Category

DIST OPER-CONNECT NEW CUSTOMER

Barton Distillery Circuit Work
KU Barton Sub Expansion
KU Line Transformers
New Business Circuit 0101 UPGRADE (REYNOLDS)
New Business Commercial Overhead - 011560
New Business Commercial Overhead - 012160
New Business Commercial Overhead - 012360
New Business Commercial Overhead - 012460
New Business Commercial Overhead - 012560
New Business Commercial Overhead - 013150
New Business Commercial Overhead - 013660
New Business Commercial Overhead - 014160
New Business Commercial Overhead - 014260
New Business Commercial Overhead - 017660
New Business Commercial Underground - 011560
New Business Commercial Underground - 012160
New Business Commercial Underground - 012360
New Business Commercial Underground - 012460
New Business Commercial Underground - 012560
New Business Commercial Underground - 013150
New Business Commercial Underground - 013660
New Business Commercial Underground - 014160
New Business Commercial Underground - 014260
New Business Commercial Underground - 017660
New Business Electric Service Overhead - 011560
New Business Electric Service Overhead - 012160
New Business Electric Service Overhead - 012360
New Business Electric Service Overhead - 012460
New Business Electric Service Overhead - 012560
New Business Electric Service Overhead - 013150
New Business Electric Service Overhead - 013660
New Business Electric Service Overhead - 014160
New Business Electric Service Overhead - 014260
New Business Electric Service Overhead - 017660
New Business Electric Service Underground - 011560
New Business Electric Service Underground - 012160
New Business Electric Service Underground - 012360
New Business Electric Service Underground - 012460
New Business Electric Service Underground - 012560

New Business Electric Service Underground - 013150
New Business Electric Service Underground - 013660
New Business Electric Service Underground - 014160
New Business Electric Service Underground - 014260
New Business Electric Service Underground - 017660
New Business Residential Overhead - 011560
New Business Residential Overhead - 012160
New Business Residential Overhead - 012360
New Business Residential Overhead - 012460
New Business Residential Overhead - 012560
New Business Residential Overhead - 013150
New Business Residential Overhead - 013660
New Business Residential Overhead - 014160
New Business Residential Overhead - 014260
New Business Residential Overhead - 017660
New Business Residential Underground - 011560
New Business Residential Underground - 012160
New Business Residential Underground - 012360
New Business Residential Underground - 012460
New Business Residential Underground - 012560
New Business Residential Underground - 013150
New Business Residential Underground - 013660
New Business Residential Underground - 014160
New Business Residential Underground - 014260
New Business Residential Underground - 017660
New Business Street Lights - 011560
New Business Street Lights - 012160
New Business Street Lights - 012360
New Business Street Lights - 012460
New Business Street Lights - 012560
New Business Street Lights - 013150
New Business Street Lights - 013660
New Business Street Lights - 014160
New Business Street Lights - 014260
New Business Street Lights - 017660
New Business Transformers - 011560
New Business Transformers - 012160
New Business Transformers - 012360
New Business Transformers - 012460
New Business Transformers - 012560
New Business Transformers - 013150
New Business Transformers - 013660

New Business Transformers - 014160
New Business Transformers - 014260
New Business Transformers - 017660
Pineville Tower
TOYOTA SOUTH SUBSTATION

DIST OPER-ENHANCE THE NETWORK

Distribution Automation

Distribution Automation KU 2017
Distribution Automation KU 2019
Distribution Automation KU 2020
IT Distribution Automation KU

Circuit Hardening/Reliability

2017 Tap Line EAROC
2017 Tap Line LEXOC
2018 CEMI - Appalachia 4730
2018 CEMI - Burgin Circuit 2131
2018 CEMI - Clinch Valley 4646
2018 CEMI - Install TripSavers
2018 CEMI - Newtown 0431
2018 CEMI - Pineville Recl's
2018 CEMI - Taylorsville 2530
2018 CEMI - Totz 0468
2018 CEMI - Totz 0468 Sub
2018 CEMI - Winchester Water
2018 CH - Calloway 0312
2018 CIFI - Appalachia 4731
2018 CIFI - Cawood 0418
2018 CIFI - Cynthiana 0853
2018 CIFI - Detroit Harv 801
2018 CIFI - Evarts 4476
2018 CIFI - Fariston 0217
2018 CIFI - Hamblin 0757
2018 CIFI - Hopewell 0286
2018 CIFI - Poor Valley 0752
2018 CIFI - Richmond 3 2109
2018 CIFI - Versailles W 0512
2018 CIFI - Waitsboro 0533
2018 Circuit Hardening - Kenton 0924
2018 Circuit Hardening - Leb Junc 2402
2018 Circuit Hardening - Rice Ln Recond
2018 Circuit Hardening - Rogers Gap 451
2018 Circuit Hardening-Hodgenville 2430

Alexander 0515 CIFI 2017
Big Stone Gap 4702 CIFI 2017
Big Stone Gap 4704 CIFI 2017
Calloway 0311 CIFI 2017
Capital Reliability - 011560
Capital Reliability - 012160
Capital Reliability - 012360
Capital Reliability - 012460
Capital Reliability - 012560
Capital Reliability - 013150
Capital Reliability - 013660
Capital Reliability - 014160
Capital Reliability - 014260
Capital Reliability - 017660
CEMI 2018 - Bedford 0700
CEMI 2018 - Mul'brg Prison 657
Circuit 0395 Harrogate Regs
Circuit 0690 Dwina Rebuild
Circuit 2209 Columbia S #6 CU
Circuit 286 Echo Vally Slate Ridge
Circuit 4603 Thackers Branch Relo
Circuit 4704 Strawberry Patch Relo
Circuit Dwina 0691 Dry Fork Relo
Circuit Hardening Circuit 0302
Danville East 2113 CIFI 2017
Deer Branch Circuit 0320 Relo
Denham St Circuit 531 Upgrade
Etown 2 2411 CIFI 2017
Fairfield 2503 KU CIFI 2017
Greenville URD Replacement
Hartford URD
Hopewell Circuit 287 to 285
Irvine/Dark Hollow Tie
KU CEMI RAP
KU SCADA 2018-2021
LAWRENCEBURG 2515 KU CIFI 2017
Lexington CEMI 2017
Lon Manchester Circuit 253 TO 254
London Circuit 200 Main St Recon
Maysville Tap Line 2017
Meldrum 0390 Circuit Hardening 2017
Middlesboro 1 Circuit 0366 Alt

- Middlesboro 1 Circuit 0366 Main
- Middlesboro 2 Circuit 355 Amble
- Middlesboro 2 Circuit 355 to 364
- Middlesboro Circuit 0360 Reloc
- Munfordville Circuit Hardening
- Paris 0806 CEMI 2017
- Pineville 0303 Circuit Hardening 2017
- Pride Distribution Work
- Recon Circuit 2136 Gwen Island
- Reconductor Circuit 2312
- REL KU CIFI RAP
- REL System Hardening KU RAP
- SCM ENHANCED SUB WILDLIFE
- Shawnee Gas 4402 Circuit Hardening 2017
- Shelbyville CEMI 2017
- SIO Fuse Savings KU
- SIO-SCADA EXPANSION V2
- SIO-SCADA VOLTAGE CONTROL KU
- SIO-SUB WILDLIFE PROTECT
- SIO-TTRANSFORMER UPGRADES
- Underground Williamsburg Trailer Park
- Volt Var Optimization DMS KU
- Whitley City 0576 13.2-12.4kV
- Williamsburg S Circuit 0227 Upg

N1DT

- N1DT KU Spare Transformers
- N1DT Middlesboro 1 4KV
- N1DT Middlesboro 2 4kV 780_1
- N1DT Middlesboro 2 Area Sub
- N1DT Middlesboro Area Sub
- N1DT STONEWALL 2 SUB
- N1DT STR Stonewall 2 Dist
- N1DT WEST HICKMAN EXPANSION
- N1DT Wilson Down 2 Upg Dist
- N1DT WILSON DOWNING 2

Other

- Aisin Circuit 4618 to Fariston Ind
- American Ave Circuit 0008
- Beattyville Hwy 52
- Buchanan Sub Property
- Circuit 2215 LEB South Recon
- Circuit 2215 Lebanon S City Conn

Circuit 2321 Alterna Feed Rich Ctr
Clinch Valley SCADA
Corbin US SteElectric Substation
Customer Requested - 011560
Customer Requested - 012160
Customer Requested - 012360
Customer Requested - 012460
Customer Requested - 012560
Customer Requested - 013150
Customer Requested - 013660
Customer Requested - 014160
Customer Requested - 014260
Customer Requested - 017660
Delaplain 1 Circuit 0401 dist
Distribution Capacitors KU 2018
Distribution Capacitors KU 2019
DSP American Ave Circuit 0008
DSP Beech Creek 4kV to 12kV
DSP BEECH CREEK SUB UPGRADE
DSP Beechmont 4kV to 12kV
DSP BEECHMONT SUB UPGRADE
DSP Bromley Distribution
DSP Bromley Upgrade
DSP Fairfield Distribution
DSP GEORGETOWN NORTH SUB PRO
DSP Georgetown Sub Land
DSP Hoover 2 Distribution
DSP Hoover 2 Sub
DSP Hoover 2 Sub Land
DSP Horse Cave Distribution
DSP Horse Cave Sub
DSP Horse Cave Sub Land
DSP HUME ROAD SUB PHASE2
DSP Kenton to Wedonia Ckt
DSP LaGrange Area Sub Land
DSP LaGrange East Distribution
DSP Lipps Circuit 0932 Distrib
DSP Lonesome Pine Sub
DSP Madisonville E Municipal
DSP Midway Sub Land
DSP MT VERNON SUBSTATION PROJ
DSP Nicholasville Sub Land

DSP Paris Circuit 805
DSP PAYNES MILL SUB PROJ
DSP Pepper Pike 138_12kV Dist
DSP Pepper Pike Sub Land
DSP RICHMOND NORTH SUB PROJ
DSP Sandy Ridge Circuit 0674
DSP Shelby City 12kV Dist
DSP SHELBY CITY 12KV UPGRADE
DSP SHELBYVILLE NORHT DIST
DSP SIMPSONVILLE 1 SUBSTATION
DSP SOMERSET NORTH SUB
DSP Viley 2 Dist
DSP Wedonia Circuit 965 Recon
DSP White Sulphur 138-12kV
DSP WHITE SULPHUR SUB
DSP Wise Sub Property
Electric Public Works - 011560
Electric Public Works - 012160
Electric Public Works - 012360
Electric Public Works - 012460
Electric Public Works - 012560
Electric Public Works - 013150
Electric Public Works - 013660
Electric Public Works - 014160
Electric Public Works - 014260
Electric Public Works - 017660
Etown 5 Sub Land Purchase
Georgetown 12kV 2 Dist
Highway 421
Hume Rd Sub phase 2 dist
KU Distribution Capacitors
KU Enhanced Wildlife
KU FIBERTECH REIMBURSABLE
KU Ky Wired Reimbursable
KYTC Reimb Elizabethtown
KYTC Reimb London
Lakeshore Sub Distribution Ckt
LAND PURCHASE VINE STREET
Lex Underground Vine to Race
Lonesome Pine Circuit Work
Mt. Vernon Substation Dist
Paynes Mill Rd Sub/Dist/fds

Peoples Rural Phone Reimb
Pepper Pike 38-12KV Sub
Rec Cir 154 Stan to Hust
Reconductor Irvine Broadway
Richmond N. Sub
SCM2018 DAN WILDLIFE PROTECT
SCM2018 EARL WILDLIFE PROTECT
SCM2018 KU LIGHTNING PROTECT
SCM2018 LEX WILDLIFE PROTECT
SCM2018 PINE WILDLIFE PROTECT
SCM2019 DAN WILDLIFE PROTECT
SCM2019 EARL WILDLIFE PROTECT
SCM2019 KU LIGHTNING PROTECT
SCM2019 LEX WILDLIFE PROT
SCM2019 PINE WILDLIFE PROTECT
SCM2020 DAN WILDLIFE PROTECT
SCM2020 EARL WILDLIFE PROTECT
SCM2020 KU LIGHTNING PROTECT
SCM2020 LEX WILDLIFE PROTECT
SCM2020 PINE WILDLIFE PROTECT
Simpsonville 1 Dist
Somerset Pole Yard Land Purch
System Enhancement - 011560
System Enhancement - 012160
System Enhancement - 012360
System Enhancement - 012460
System Enhancement - 012560
System Enhancement - 013150
System Enhancement - 013660
System Enhancement - 014160
System Enhancement - 014260
System Enhancement - 017660
Upgrade Scholls Substation
VERSAILLES BYPASS-0507 CIFI
VILEY 2 SUB XFMR
Vine St 4kV Distribution
Vine St 4KV Sub
W. Hickman Sub Distribution Circuit
West Hickman Land Purchase

DIST OPER-MAINTAIN THE NETWORK

2017 URD Replace LEXOC
2018 Earl Transformer Line Clear

2018 XM Underbuild DANOC
2018 XM Underbuild EAROC
2018 XM Underbuild LEXOC
2018 XM Underbuild LONOC
2018 XM Underbuild MAYOC
2018 XM Underbuild NOROC
2018 XM Underbuild PINOC
2018 XM Underbuild RICOC
2018 XM Underbuild SHEOC
Ashbyburg Pump Rebuild
Calhoun Distribution Work for XM
Calloway Sub Regulators
Capital CAP/REG/RECL - 011560
Capital CAP/REG/RECl - 012160
Capital CAP/REG/RECL - 012360
Capital CAP/REG/RECL - 012460
Capital CAP/REG/RECL - 012560
Capital CAP/REG/RECL - 013150
Capital CAP/REG/RECL - 013660
Capital CAP/REG/RECL - 014160
Capital CAP/REG/RECL - 014260
Capital CAP/REG/RECL - 017660
Capital Replace Defective Overhead - 011560
Capital Replace Defective Overhead - 012160
Capital Replace Defective Overhead - 012360
Capital Replace Defective Overhead - 012460
Capital Replace Defective Overhead - 012560
Capital Replace Defective Overhead - 013150
Capital Replace Defective Overhead - 013660
Capital Replace Defective Overhead - 014160
Capital Replace Defective Overhead - 014260
Capital Replace Defective Overhead - 017660
Capital Replace Defective Underground - 011560
Capital Replace Defective Underground - 012160
Capital Replace Defective Underground - 012360
Capital Replace Defective Underground - 012460
Capital Replace Defective Underground - 012560
Capital Replace Defective Underground - 013150
Capital Replace Defective Underground - 013660
Capital Replace Defective Underground - 014260
Capital Replace Defective Underground - 017660
Circuit 2522 Transformer UNDERBLD

Cumberland Gap Underground Bore
Danville PITP 2016
Danville PITP 2018
Danville Pole Inspection 2017
Earlington 4KV Substation
Earlington PITP 2018
Earlington Pole Inspect 2017
Elizabethtown PITP 2018
Elizabethtown Pole Ins 2017
Finchville Control House Distr
INSTALL MONITORS ON XFRMRS
KU Direct Burial Replacement
KU FIBERTECH NON-REIMB
KU Ky Wired Non-reimb
KU POLE INSPECTION
KU Portable Transformer
LEX UNDERGROUND SUPPORT
Lexington PITP 2018
Lexington Pole Inspect 2017
London PITP 2018
London Pole Inspection 2017
Maysville PITP 2018
Maysville Transformer Line Clear
MINOR FARM ENTRANCE ROAD
Norton PITP 2018
Norton Pole Inspection 2017
Pineville PITP 2018
Pineville Pole Inspection 2017
Pocket Sub 34KV Upgrade
Pole Repair/Replace - 011560
Pole Repair/Replace - 012160
Pole Repair/Replace - 012360
Pole Repair/Replace - 012460
Pole Repair/Replace - 012560
Pole Repair/Replace - 013150
Pole Repair/Replace - 013660
Pole Repair/Replace - 014160
Pole Repair/Replace - 014260
Pole Repair/Replace - 017660
Repair Street Lights - 011560
Repair Street Lights - 012160
Repair Street Lights - 012360

Repair Street Lights - 012460
Repair Street Lights - 012560
Repair Street Lights - 013150
Repair Street Lights - 013660
Repair Street Lights - 014160
Repair Street Lights - 014260
Repair Street Lights - 017660
Ric Remove Roundhill
Richmond PITP 2018
Richmond Pole Inspection 2017
SCM 2019 KU WOOD POLE SUB UPG
SCM 2020 KU WOOD POLE SUB UPG
SCM2017 DAN FAILED BRKR/RECL
SCM2017 DAN MISC CAPITAL PROJ
SCM2017 DAN REPL LEGACY BRKR
SCM2017 DAN WILDLIFE PROTECT
SCM2017 EARL MISC CAPITAL SUB
SCM2017 EARL SUB BLDG & GRNDS
SCM2017 EARL WILDLIFE PROTECT
SCM2017 KU LEGACY RELAY REPL
SCM2017 KU LTC OIL FILT ADDS
SCM2017 KU OIL CONTAINMENT UPG
SCM2017 KU RPL TRANSFORMER FANS
SCM2017 LEX LEGACY RTU REPL
SCM2017 LEX MISC CAPITAL SUB
SCM2017 LEX MISC NESC COMPL
SCM2017 LEX REPL BREAKERS
SCM2017 LEX REPL BUSHINGS
SCM2017 LEX REPL LEGACY BRKR
SCM2017 LEX REPL REGULATORS
SCM2017 PINE MISC CAPITAL SUB
SCM2017 PINE REPL LEGACY BRKR
SCM2017 PINE RPL 22KV&34KV BKR
SCM2018 DAN FAILED BRKR/RECL
SCM2018 DAN MISC CAPITAL PROJ
SCM2018 DAN MISC NESC COMPL
SCM2018 DAN REPL LEGACY BRKR
SCM2018 DAN REPL SUB BATTERY
SCM2018 DAN SUB BLD & GRNDS
SCM2018 EARL FAILED BRKR/RECL
SCM2018 EARL MISC CAPITAL SUB
SCM2018 EARL MISC NESC COMPL

SCM2018 EARL REPL SUB BATTERY
SCM2018 EARL SUB BLDG & GRNDS
SCM2018 KU LEGACY RELAY REPL
SCM2018 KU LTC OIL FILT ADDS
SCM2018 KU OIL CONTAINMENT UPG
SCM2018 KU REPL LTC/REG CNTRL
SCM2018 KU REPL TRANSFORMER FANS
SCM2018 KU SCRAP EQUIPMENT
SCM2018 LEX LEGACY RTU REPL
SCM2018 LEX MISC CAPITAL SUB
SCM2018 LEX MISC NESC COMPL
SCM2018 LEX REPL BREAKERS
SCM2018 LEX REPL BUSHINGS
SCM2018 LEX REPL LEGACY BRKR
SCM2018 LEX REPL REGULATORS
SCM2018 LEX REPL SUB BATTERY
SCM2018 LEX SUB BLDNG & GND
SCM2018 PINE FAILED BRKR/RECL
SCM2018 PINE MISC CAPITAL SUB
SCM2018 PINE MISC NESC COMPL
SCM2018 PINE REPL LEGACY BRKR
SCM2018 PINE REPL SUB BATTERY
SCM2018 PINE SUB BLDNG & GND
SCM2019 DAN FAILED BRKR/RECL
SCM2019 DAN MISC CAPITAL PROJ
SCM2019 DAN MISC NESC COMPL
SCM2019 DAN REPL LEGACY BRKR
SCM2019 DAN REPL SUB BATTERY
SCM2019 DAN SUB BLD & GRNDS
SCM2019 EARL FAILED BRKR/RECL
SCM2019 EARL MISC CAPITAL SUB
SCM2019 EARL MISC NESC COMPL
SCM2019 EARL REPL SUB BATTERY
SCM2019 EARL SUB BLDG & GRND
SCM2019 KU 34KV SUB MISC
SCM2019 KU LEGACY ARRST REPL
SCM2019 KU LEGACY RELAY REPL
SCM2019 KU LTC OIL FILT ADDS
SCM2019 KU OIL CONTAINMENT UPG
SCM2019 KU REPL LTC/REG CNTRL
SCM2019 LEX LEGACY RTU REPL
SCM2019 LEX MISC CAPITAL SUB

SCM2019 LEX MISC NESC COMPL
SCM2019 LEX REPL BREAKERS
SCM2019 LEX REPL BUSHINGS
SCM2019 LEX REPL LEGACY BRKR
SCM2019 LEX REPL REGULATORS
SCM2019 LEX REPL SUB BATTERY
SCM2019 LEX SUB BLDG & GND
SCM2019 PINE FAILED BRKR/RECL
SCM2019 PINE MISC CAPITAL SUB
SCM2019 PINE MISC NESC COMPL
SCM2019 PINE REPL LEGACY BRKR
SCM2019 PINE REPL SUB BATTERY
SCM2019 PINE SUB BLDNG & GND
SCM2020 DAN FAILED BRKR/RECL
SCM2020 DAN MISC CAPITAL PROJ
SCM2020 DAN MISC NESC COMPL
SCM2020 DAN REPL LEGACY BRKR
SCM2020 DAN REPL SUB BATTERY
SCM2020 DAN SUB BLDG & GRNDS
SCM2020 EARL FAILED BRKR/RECL
SCM2020 EARL MISC CAPITAL SUB
SCM2020 EARL MISC NESC COMPL
SCM2020 EARL REPL SUB BATTERY
SCM2020 EARL SUB BLDG & GRNDS
SCM2020 KU 34KV SUB MISC
SCM2020 KU LEGACY ARRST REPL
SCM2020 KU LEGACY RELAY REPL
SCM2020 KU LTC OIL FILT ADDS
SCM2020 KU OIL CONTAINMENT UPG
SCM2020 KU REPL LTC/REG CNTRL
SCM2020 LEX LEGACY RTU REPL
SCM2020 LEX MISC CAPITAL SUB
SCM2020 LEX MISC NESC COMPL
SCM2020 LEX REPL BREAKERS
SCM2020 LEX REPL BUSHINGS
SCM2020 LEX REPL LEGACY BRKR
SCM2020 LEX REPL REGULATORS
SCM2020 LEX REPL SUB BATTERY
SCM2020 LEX SUB BLDNG & GND
SCM2020 PINE FAILED BRKR/RECL
SCM2020 PINE MISC CAPITAL SUB
SCM2020 PINE MISC NESC COMPL

SCM2020 PINE REPL LEGACY BRKR
SCM2020 PINE REPL SUB BATTERY
SCM2020 PINE SUB BLDNG & GND
SHE Transfer UB E.Circuit 2522
Shelbyville Transformer Transfers
Shelbyville Transformer Transfers2
SIO RElectric KU Underground FCI Install
SIO-RELAY REPLACEMENT KU
SIO-SUB OIL BREAKERS KU
Somerset Distribution Underbuild 2018
St Charles Sub Reg/Pier Rep
Tom's Creek North Repl
Transfer for Lex Plant Pisgah
TRANSFORMER Containment Eastland
Transformer Line Clearance KU
Transformer UNDERBUILT PARKWAY
URD Cable KU 2019
URD Cable Repl/Rejuv Lex
WEST HIGH FENCE REPLACE
Westvaco Sub Partial Retire

DIST OPER-MISCELLANEOUS

1 TRANSFORMER TO LGE
2 TRANSFORMER FROM LGE
2017 VALLEY SUB RETIREMENT
Dan Remove Roundhill Line
DANOC Wire Trailer 2019
Danville Capital Tools 2018
Danville Capital Tools 2019
Danville Capital Tools 2020
Earlington Capital Tools 2018
Earlington Capital Tools 2019
Earlington Capital Tools 2020
Elizabethtown Capital Tools 2018
Elizabethtown Capital Tools 2019
Elizabethtown Capital Tools 2020
Elizabethtown Operations Center Pole Trailer 2019
Etown Capital Tools 2017-2019
KU HW/SW 2018
KU HW/SW ASSET MGMT 2017
KU HW/SW Asset Mgmt 2019
KU Pole Attach Mapping Asset
Lex Mini Excavator 2018

Lexington Capital Tools 2018
Lexington Capital Tools 2019
Lexington Capital Tools 2020
London Capital Tools 2018
London Capital Tools 2019
London Capital Tools 2020
London Pilot Line Winder
LONOC ATV Trailer 2019
LONOC Utility Trailer 2019
MAYOC Bobcat Track Loader
Maysville Capital Tools 2019
Maysville Capital Tools 2020
Maysville Trailers 2017
MOVE 1 TRANSFORMER FROM LGE
MOVE 3 TRANSFORMER FROM LGE TO KU
MOVE TRANSFORMER TO KU
Norton ARGO ATV 2019
Norton Capital Tools 2018
Norton Capital Tools 2019
Norton Capital Tools 2020
Norton Side Beside ATV 2019
ONE TRANSFORMER TO KU FROM LGE
Pineville Capital Tools 2018
Pineville Capital Tools 2019
Pineville Capital Tools 2020
PINOC Kubota Backhoe 2019
PINOC Kubota Backhoe 2020
RECEIVE ONE TRANSFORMER FROM LGE
Remove Texas to Perryville Line
Richmond Capital Tools 2017-2019
Richmond Capital Tools 2018
Richmond Capital Tools 2019
Richmond Capital Tools 2020
Richmond Kubota Backhoe
SCM2018 DAN TOOLS & EQUIPMENT
SCM2018 EARL TOOLS & EQUIPMENT
SCM2018 LEX TOOLS & EQUIPMENT
SCM2018 PINE TOOLS & EQUIPMENT
SCM2019 DAN TOOLS & EQUIPMENT
SCM2019 EARL TOOLS & EQUIPMENT
SCM2019 LEX TOOLS & EQUIP
SCM2019 PINE TOOLS & EQUIPMENT

SCM2019 TOOLS & EQUIP 013560
SCM2020 DAN TOOLS & EQUIPMENT
SCM2020 EARL TOOLS & EQUIPMENT
SCM2020 LEX TOOLS & EQUIPMENT
SCM2020 PINE TOOLS & EQUIPMENT
SCM2020 TOOLS & EQUIP 013560
Shelbyville Capital Tools 2018
Shelbyville Capital Tools 2019
Shelbyville Capital Tools 2020
Toyota Tsusho Pole Sale
TRANSFER 1 TRANSFORMER FROM KU TO LGE
TRANSFER 1 TRANSFORMER TO LGE
TRANSFORMER TO LGE

DIST OPER-REPAIR THE NETWORK

2018 KU TRANSFORMER REWIND
2019 KU TRANSFORMER REWIND
2020 KU TRANSFORMER REWIND
34.5:13.09 kV 5MVA Txfmr
Capital KU Major Storms
Capital Minor Storms - 011560
Capital Minor Storms - 012160
Capital Minor Storms - 012360
Capital Minor Storms - 012460
Capital Minor Storms - 012560
Capital Minor Storms - 013150
Capital Minor Storms - 013660
Capital Minor Storms - 014160
Capital Minor Storms - 014260
Capital Minor Storms - 017660
Capital Third Party - 011560
Capital Third Party - 012160
Capital Third Party - 012360
Capital Third Party - 012460
Capital Third Party - 012560
Capital Third Party - 013150
Capital Third Party - 013660
Capital Third Party - 014160
Capital Third Party - 014260
Capital Third Party - 017660
Capital Trouble Order Underground - 014160
Capital Trouble Orders Overhead - 011560
Capital Trouble Orders Overhead - 012160

Capital Trouble Orders Overhead - 012360
Capital Trouble Orders Overhead - 012460
Capital Trouble Orders Overhead - 012560
Capital Trouble Orders Overhead - 013150
Capital Trouble Orders Overhead - 013660
Capital Trouble Orders Overhead - 014160
Capital Trouble Orders Overhead - 014260
Capital Trouble Orders Overhead - 017660
Capital Trouble Orders Underground - 011560
Capital Trouble Orders Underground - 012160
Capital Trouble Orders Underground - 012360
Capital Trouble Orders Underground - 012460
Capital Trouble Orders Underground - 012560
Capital Trouble Orders Underground - 013150
Capital Trouble Orders Underground - 013660
Capital Trouble Orders Underground - 014260
Capital Trouble Orders Underground - 017660
CO464 TR REWIND
EW SUB TR 1 LTC
GOODYEAR SUB REMOVAL
KT0025 TR REWIND
KU MAJOR STORM CAPITAL-031218
KU MAJOR STORM-040318
KU MAJOR STORM-053118
KU MAJOR STORM-062618
KU MAJOR STORM-070518
LAWRENCEBURG SUB TR2
MARKLAND DAM XFRM
Millersburg Sub 5 MVA non-LTC
REPLACE TRANSFORMER AT GHENT 0451
Rewind M042 Txfmr
Spare 10 MVA LTC Transformer
UK West LTC TR2
VERSAILLES WEST XFRM
WICKLIFFE CITY TRANSFORMER

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 21

Responding Witness: Lonnie E. Bellar

Q-21. Refer to KU's Response to the Attorney General's Initial Request, Item 52. Confirm that the "Companies' two existing, separate locations" will be closed after the new facility is in service. If this cannot be confirmed, explain why not.

A-21. The Companies' existing Business Office in Elizabethtown will be closed and sold once the operations there are relocated to the new location. The Companies' existing office at the separate site in Elizabethtown will be closed and demolished. The property will continue to be used by the Companies.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 22

Responding Witness: Robert M. Conroy / Counsel

Q-22. Generally, describe KU's process to determine whether to request a Certificate of Public Convenience and Necessity.

A-22. LG&E and KU, through the Companies' State Regulation and Rates department and in consultation with counsel, determines whether a particular project may need a certificate of public convenience and necessity, or whether the project is an ordinary extension of its existing systems in the usual course of business based on Kentucky law and regulations, Commission orders and Commission Staff opinions.

The Commission has stated that KRS 278.020(1) and 807 KAR 5:001, Section 15(3), when viewed together, "clearly identify those facilities for which a Certificate of Public Convenience and Necessity is not required."[4] The Commission has distilled its regulation into a review of three factors, holding that a Certificate is not necessary "for facilities that do not result in the wasteful duplication of utility plant, do not compete with the facilities of existing public utilities, and do not involve a sufficient capital outlay to materially affect the existing financial condition of the utility involved or to require an increase in utility rates."[5]

As to the first factor, when determining whether the proposed project will duplicate any existing facilities, the Companies assess whether the proposed facilities are intended to serve unserved or underserved areas, meet additional demands due to customer growth, or whether portions of the project replace, repair or refurbish existing facilities. If so, they are considered not to be duplicative. Similarly, the Companies consider whether the planned facilities are necessary to comply with statutory or regulatory requirements, and, if so, they are not considered duplicative. As to the second factor, the Companies examine whether the proposed facilities will compete with the facilities of other utilities

---

4 *The Application of Northern Kentucky Water District (A) For Authority to Issue Parity Revenue Bonds in the Approximate Amount of $16,545,000; and (B) A Certificate of Convenience and Necessity for the Construction of Water Main Facilities*, Case No. 2000-481 (Ky. PSC Aug. 30, 2001) at 4 (referring to §15(3) prior to revisions in 807 KAR 5:001 resulted in renumbering).

5 *Id.*

given the constraints of the territorial boundary law, KRS 278.016 to 278.018. As to the third factor, the Companies consider whether a proposed project will materially affect their respective existing financial conditions by comparing the proposed project's cost with the relevant Company's current net utility plant. This approach follows that used by Kentucky Courts and the Commission. In Case No. 2014-00171, for example, the Commission acknowledged the use of this approach, stating:

> In assessing whether a proposed project is a system extension in the ordinary course of business, Kentucky courts have traditionally looked to the size and scope of a project in the context of the monetary cost involved. The Commission has similarly adopted this method and likewise looks to the scale of a proposed project in relation to the relative size of the utility and its present facilities.[6]

[6] *Application of Northern Kentucky Water District for Approval of Dixie Highway Water Main Improvements, Issuance of a Certificate of Convenience and Necessity and Approval of Financing*, Case No. 2014-00171 (Ky. PSC Aug. 6, 2014).

The Companies further review Commission precedent to ascertain the relative magnitude of the capital outlay that may trigger the request for a Certificate. A significant variance exists in the level that the Commission has historically used and there appears to be a flexible standard adapted to the particular circumstances of the case before the Commission.[7] In recent cases, however, the Commission has found projects representing between one percent to five percent of the utility's net utility plant to be ordinary extensions in the usual course of business.[8]

Based upon a review of the decisions of the Commission to date and given the size of the Companies' net utility plant, the Company believes that a standard of five percent of its current net utility plant should be utilized when evaluating the need for a Certificate for an investor owned utility.[9] If a project's expected cost represents five percent or less of the Company's current net utility plant, it should be considered as having no material effect on the Company's financial condition and therefore no Certificate should be required.

---

7 The Commission has recently found the construction of a project representing 92 and 55 percent of a utility's net utility plant to be within the ordinary course of business, but granted a Certificate to a project representing less than 0.8 percent of a utility's net utility plant. *See Application of Navitas KY NG, LLC For Approval of Transportation Agreement With FSR Services, LLC To Construct Pipeline Extension In Albany, Clinton County, Kentucky*, Case No. 2016-00065 (Ky. PSC Apr. 15, 2016); *Valley Gas, Inc. Request For Approval of a Special Contract With Mago Construction Company and A Deviation From the Gas Cost Adjustment Clause*, Case No. 2014-00368 (Ky. PSC Oct. 28, 2014). *See also Application of Northern Kentucky Water District for Approval of the Fort Thomas Treatment Plant Basin Improvements, Issuance of a Certificate of Convenience and Necessity and Approval of Financing*, Case No. 2015-00108 (Ky. PSC May 21, 2015).

8 *Application of Northern Kentucky Water District for Approval of Dixie Highway Water Main Improvements, Issuance of a Certificate of Convenience and Necessity and Approval of Financing*, Case No. 2014-00171 (Ky. PSC Aug. 6, 2014) (one percent of net utility plant); *Tariff Filing of Warren County Water District To Establish the Rockfield School Sewer Capital Recovery Fee*, Case No. 2012-00269 (Ky. PSC Nov. 19, 2012) (less than 2.1 percent of net utility plant); *Application of Madison County Utility District for an Order Issuing a Certificate of Public Convenience and Necessity and for Authority to Borrow Funds and to Refinance Certain Indebtedness of the District*, Case No. 2007-00424 (Ky. PSC Mar. 20, 2008) (five percent of net utility plant); *Application of Big Rivers Electric Corporation for Approval of an Interconnection Agreement with Kentucky Utilities Company*, Case No. 2007-00058 (Ky. PSC Apr. 16, 2007) (one percent of net utility plant); *Application of Southern Madison Water District to Issue Securities in the Approximate Amount of $860,000 for the Purpose of Refunding an Outstanding Revenue Bond of the District and Finance Certain System Improvements Pursuant to the Provisions of KRS 278.300 and 807 KAR 5:001*, Case No. 99-310 (Ky. PSC Sept. 1, 1999) (3.2 percent of net utility plant); *The Application of Kenton County Water District No. 1 for Authority to Perform Maintenance at Its Taylor Mill Treatment Plant by Replacing Filter Valves at a Total Cost of Approximately $700,000*, Case No. 92-028 (Ky. PSC Feb. 18, 1992) (less than 1.5 percent of net utility plant).

9 The Commission has expressly required utilities to apply for a Certificate for specific types of projects, such as major smart grid investments and the development of landfill gas to energy projects, regardless of the amount of the capital outlay

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 23

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q-23. Refer to KU's Response to the Attorney General's Initial Request for Information, Item 73.b.

a. Explain why KU forecasts $1.26 million in Customer Education advertising given that the program was removed from KU's DSM offerings for its lack of cost-effectiveness.

b. Provide Customer Education advertisement expenditures for the past five years.

A-23.

a. The Company proposes to include the cited funding for energy-efficiency education because it provides a material benefit to customers. The Commission's advertising regulation states at 807 KAR 5:016 Section 3, "Advertising expenditures by gas or electric utilities which produce a 'material benefit' include, but are not limited to the following: (a) Advertising limited exclusively to demonstration of means for ratepayers to reduce their bills or conserve energy …." The cited costs are for customer education efforts designed and intended to provide that material benefit. The Companies have long provided this benefit to customers with Commission approval.

With regard to the Customer Education and Public Information ("CEPI") Program, the Commission approved the program in Case Nos. 2007-00319 and 2014-00003. The program, which ended December 31, 2018, provided education and increased public awareness and understanding of the need for more efficient use of energy. The Companies included CEPI in their DSM portfolio to help drive DSM program participation, although no energy savings were attributed to CEPI. Previously, on a portfolio basis (including CEPI costs but no energy savings), the DSM portfolio had a positive cost-benefit ratio. As the Companies noted in their most recent DSM-EE proceeding, because the Companies proposed to scale back their DSM-EE programs to reflect changed conditions, it was prudent to discontinue the CEPI in DSM-EE, which was largely used to highlight and advertise the

Companies' DSM-EE programs.[10] But the Companies noted also that, although they proposed to let the program expire, they were committed to continuing education efforts regarding the benefits of reduced energy consumption.[11] The proposed customer education advertising cost cited in this response is consistent with that position.

Also, the elimination of the CEPI Program as a separate program from the Company's DSM-EE portfolio has not resulted in eliminating energy-efficiency education from the Companies' Commission-approved DSM-EE programming. For example, the WeCare program approved by the Commission in the Company's most recent DSM-EE proceeding contains an explicit energy education component, which the Commission cited in its order approving the program in October 2018: "WeCare provides energy audits, energy education, and the installation of weatherization and energy conservation measures for those customers meeting certain income requirements."[12] The Companies believe this education provides a material benefit and that the Commission correctly approved it.

In addition, the Companies' customers have demonstrated significant interest in energy-efficiency and conservation information created by the Companies. For example, for the 12 months ending and including November 2018, seven of the Companies' top ten most-watched videos (all with views in the tens of thousands) are energy-efficiency related. Similarly, four of the top 25 LG&E-KU corporate website pages in terms of non-employee visits (again, all with views in the tens of thousands) are energy-efficiency related. That includes a page on energy-efficiency tips not related to any DSM-EE program that received over 42,000 views. Therefore, customers have shown a strong and clear interest in receiving the kind of energy-efficiency information and education the Companies propose to provide using the cited funds.

b.

Customer Education & Public Information	2017	2016	2015	2014	2013
Amounts in ($000)	2,356	2,257	2,262	2,400	2,023

[10] *See, e.g.*, Case No. 2017-00441, Direct Testimony of Gregory S. Lawson at 15 (Dec. 6, 2017).
[11] *Id.*
[12] Case No. 2017-00441, Order at 5 (Oct. 5, 2018).

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 24

Responding Witness: Daniel K. Arbough

Q-24. Refer to KU's Response to the Attorney General's Initial Request, Item 79.

a. Identify each of the five separate matters forecasted between 2017 Regulatory to 2018 Regulatory. Include the amount forecasted for each matter.

b. Identify each of the six separate matters forecasted between 2018 Regulatory to 2019 Regulatory. Include the amount forecasted for each matter.

A-24.

a. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

b. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 25

Responding Witness: John K. Wolfe

Q-25. Refer to KU's Response to the Attorney General's Initial Request, Item 180.

a. Explain what "centralized grid operation" entails.

b. State whether a cost-benefit analysis was performed. If so, provide a copy of the analysis.

c. Explain, and quantify, the expected benefits to ratepayers of centralized grid operations.

d. Explain whether KU/LG&E will be operating separate "centralized grid operations." If so, explain whether that will result in increased cost or duplication of services.

A-25.

a. The approved Distribution Automation (DA) program is an enabler for centralized grid operations. See Mr. Bellar's direct testimony at pages 48-49, which discussed the Distribution Reliability and Resiliency Improvement Plan attached as Exhibit LEB-5. More specifically, section 3.0 Centralized Grid Operations Strategy on pages 13-14 of Exhibit LEB-5, describes the details of "centralized grid operation".

b. Mr. Thompson's direct testimony in Case No. 2016-00370 at pages 38-43 discussed the cost benefits and included Exhibit PWT-7 that provided the Capital Evaluation Model for Distribution Automation.

Mr. Bellar's direct testimony at pages 52-53 describes the construction of the consolidated Distribution Control Center (DCC). See attached Investment Proposals (IP) for the construction of the DCC.

c. See the response to part b.

d. LG&E and KU plan to monitor, control, and remotely operate its distribution grid centrally from its Simpsonville DCC, utilizing outage management and advanced distribution management software systems.

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Distribution Control Center Enhancement Project

Total Expenditures: $10,703K (includes $721K contingency)

Project Number(s): 153560LKS, 153561 and 153562

Business Unit/Line of Business: Electric Distribution Operations / Facilities

Prepared/Presented By: Jamie Archer and Steve Woodworth

Executive Summary

The Distribution Control Center (DCC) is a 24/7 operation that functions as the system operator for the LG&E and KU electric distribution system and includes monitoring, controlling, and operating the system. LG&E and KU operate their centers from two locations, Louisville - Broadway Office Complex (BOC) and Lexington - Kentucky Utilities General Office (KUGO).

The DCC is in need of significant facility enhancements for the following five reasons:

1. Upgrade aging facilities and ergonomics to accommodate 12 hour shifts and employee health issues.
2. Expand space for additional headcount due to retirement offsets, migration of distribution SCADA work from the Transmission Control Center (TCC), and support of Distribution Automation.
3. Improve scheduling and training opportunities to account for operator retirements which will greatly affect the workgroup. Operators can take up to five years to gain operational and situational knowledge to be a seasoned operator.
4. Adopt best practices for control centers to have redundant electrical and mechanical systems to ensure operations without downtime.
5. Improve technology and communications infrastructure in support of the Smart Grid, Advanced Meter Systems, and VoltVar optimization.

Electric Distribution Operations (EDO) partnered with Facilities and an engineering firm, Tech Site, to develop alternatives that addressed the five reasons above. Three options were evaluated: 1) consolidate both DCCs into one facility, 2) renovate existing facility locations, and 3) do nothing with minimal capital investment.

EDO seeks authorization from the Investment Committee to invest $10,703k towards consolidation of both DCCs into one facility located next to the TCC in Simpsonville. The requested authority level includes 10% contingency for contractor labor and materials. This

investment option has the lowest NPVRR of viable alternatives, and satisfies EDO's five primary reasons for action. EDO's proposal includes retaining the Lexington DCC as a hot backup site, and turning over the LG&E DCC office space (approximately 6,000 sq ft) to Facilities for reassignment to other departments needing BOC office space. This project is included in the 2017 Business Plan for $10,000K, but will require additional funding of $703K in total which will be addressed through normal RAC processes.

Background

General

The Distribution Control Center (DCC) is a 24/7 operation that functions as the system operator for the LG&E and KU electric distribution systems. The DCC monitors, controls, and operates the system as well as responds to emergency and outage calls. LG&E and KU operate their centers from two locations, Louisville and Lexington. The Louisville location serves the LG&E territory and is located in the Broadway Office Complex on the first floor. The Lexington location serves the KU territory and is located in the Kentucky Utilities General Office (KUGO) on the fourth floor. Each of these facilities is a backup to the other when emergencies arise or when localized storms increase volumes beyond capacity of that control center.

Currently, the DCC consists of one manager, two Group Leaders, one Lead Engineer, three Team Leaders, and 25 Distribution System Operators for a total of 32 FTEs. Distribution System Operators are non-exempt at both facilities.

Justification for Improvements

There are five main drivers for making improvements to the DCC facilities. Below is a brief description of those drivers and how they impact both control centers.

1. Both Louisville and Lexington DCCs have not been renovated in over 10 years. Due to the 24/7 nature of the work and the high occupancy of the DCC's during restoration events, the control rooms have outdated audio visual technology. New ergonomic workstations (sit/stand) are needed due to the long 12 hour shift work and employee health issues such as back ailments, previous field injuries, and the general aging of the workforce.
2. The DCC organization will outgrow their existing facilities due to assuming LG&E SCADA responsibilities from the Transmission Control Center (TCC) and monitoring / operating the new Distribution Management System (DMS) in support of Distribution Automation. This additional workload will require nine incremental operators and one engineer, and could require other personnel to be located in the DCC to support these systems. Seven incremental personnel for retirement offsets are also included in the Workforce Plan and will require work space as they overlap with potential retirees at least one year in advance.
3. The DCC workforce will be greatly affected by retirements in the near future. Currently there are 15 operators out of 25 with more than 10 years of control center experience; that number drops to 12 in 2019 and 8 in 2021. By 2021, the Louisville DCC workforce, as staffed today, will completely turn over with only a single system operator remaining with more than 10 years' experience. It is very rare to hire an operator who has DCC

experience so any new operators must be trained internally and gain experience on the job. The normal training period for an operator to be competent in switching and restoration operations is 18 to 24 months, and several more years of experience is required to gain operational and situational knowledge to be a seasoned operator.

4. Industry best practices for data and control centers utilize redundant electrical and mechanical systems to ensure operations without downtime due to failures or maintenance. The Uptime Institute, an independent data center advisory organization, has developed performance and reliability standard Tier classifications for critical infrastructure facilities. LKE is striving to operate at a minimum Tier II level which is defined as a concurrently maintainable system and requires no shutdowns for equipment replacement and maintenance. Currently, LKE DCC is not at this level, while TCC in Simpsonville and the PPL distribution and transmission control facility are Tier III.
5. Improved technology and communications infrastructure are needed to support technology advances that are being implemented at the company. The DCC will monitor and operate "Smart Grid" technologies that are currently planned over the next seven years, and will become the central hub for large amounts of data from these systems. The DMS system will be interfaced with the DSCADA and automated field devices and be monitored and operated in the DCC. The Advanced Metering Services (AMS) project is planned to have meter data and pinging capabilities interfaced with the DMS. Future technology could also include interfacing the DMS with VoltVAR Optimization (VVO) and/or Conservation Voltage Reduction (CVR) systems.

3rd Party Evaluation

Tech Site was contracted by Facility Services to evaluate the renovation plans and budgets of the two existing DCC facilities as well as develop a conceptual design and budget for the construction of a new facility at the existing TCC/DC Simpsonville site. LG&E provided Tech Site with previously developed design layouts for both the BOC and KUGO facilities to use as their basis for the renovation options. In addition to the architectural and ergonomic features illustrated on the design layouts, Tech Site reviewed and designed appropriate power and cooling infrastructure to meet Tier II reliability standards for the two facilities.

For the new facility, Tech Site gathered LG&E's occupancy and operational needs along with the security and reliability requirements for the DCC facility. This information was then used to develop a facility and site layout plan that was reviewed and revised over several iterations. Tech Site also provided a mechanical system that met Tier II reliability standards and multiple options for utility and backup power systems that met Tier II and III reliability standards which offered improved facility uptime. Several of the electrical system options utilized the existing system capacity and redundancy of the existing TCC/DC facility. LG&E security and communications groups also reviewed the plans and provided costs for their facilities to serve the building.

Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)

1. Recommendation: Consolidation in New Facility NPVRR: *$14,170K*

EDO recommends to construct a new facility which will consolidate and replace the existing DCC facilities in Louisville and Lexington, for a total projected capital cost of $10,703K. The Lexington DCC facility will remain and be used as a hot backup site. The new facility satisfies all of the five primary drivers and will provide adequate workspace for the expanding work group, improved ergonomic facilities to support the 24/7 operations, and a dedicated training area. The mechanical infrastructure will be designed to Tier II specifications and electrical infrastructure will be to Tier III specifications which will provide very high reliability and resiliency. The new "Smart Grid" technologies will be supported by redundant communications infrastructure. An option to harden the building to withstand a F3 tornado and enclose the exterior mechanical equipment similar to the existing TCC facility was also provided at a projected capital cost of $805K which is not included in the recommendation costs.

The consolidation of the workforce in one facility allows for more standardized processes across the LG&E and KU distribution systems. Operational efficiency will improve with the ability to balance work load across a combined workforce while at the same time cross training operators on the unique challenges of a rural and urban system. Increasing efficiency is especially important as the DCC takes on additional responsibilities including new "Smart Grid" technologies. Training and change management will dominate the DCC as these new technologies are implemented along with unprecedented workforce turnover. Effective training will be <u>critical</u> to quickly integrating new operators into the workforce to compensate for the significant experience leaving the Company over the next 7 years. This consolidation will also allow greater scheduling flexibility and lessen the need for multiple senior operators on the same shift. This is very important as the workforce is increasing and the experience and knowledge is decreasing due to retirements. Costs are also included for mileage and moving expenses similar to the program TCC offered for current employees being relocated to the consolidated facility.

The construction of the new facility on a greenfield site will have minor impact on existing company operations. Both Louisville and Lexington DCCs will continue to operate in their current facilities, and no other employees will need to be relocated during construction. Following the relocation to the new facility, the BOC DCC space will be available for re-use by other groups. The new facility will also have a large conference room that will be shared with the TCC. This will allow the current TCC conference room to be converted to office space which is needed as the current building is at full capacity. The reuse of these spaces and avoidance of leasing office space is included as savings.

2. <u>Next Best Alternative(s): Renovate Existing Locations</u> NPVRR: *$18,520K*
The Next Best Alternative is to renovate both current DCC facilities in Louisville and Lexington which meets three of the five primary drivers. The total projected capital cost is $8,810K. The Louisville project will renovate and expand the current DCC space in the BOC. The Lexington project will renovate the 9th floor and move the DCC from its current location on the 4th floor. The renovation at both facilities includes significant upgrades to the electrical and mechanical systems to increase building system resiliency and meet the Uptime Institute

Tier II reliability standard. The two separate facilities do not provide the operational and efficiency benefits of consolidating the workforce as opportunities will be limited to balance the workload, standardize processes, and train new and current operators. The two facilities will also eliminate scheduling flexibility and require more experienced operators to provide leadership due to staffing at two separate locations. Costs are included for one additional training position to allow for a trainer at each DCC location. Also, additional overtime training costs are included as the shift coverage requirements at the two locations will not allow for the regular scheduling of training.

The coordination of the renovations will be very difficult and complex due to renovating currently in-use buildings. Louisville DCC employees and several other workgroups will be impacted as the BOC DCC and Security office will have to be relocated during construction along with the 9th floor KUGO occupants. Ground level space is very tight at KUGO which is needed to house equipment such as generators and fuel tanks. This equipment likely would impact the already limited parking. The existing dock or another area would be needed at the BOC to house similar equipment which could also impact parking.

3. Do Nothing: Removal of Tier II NPVRR: *$14,390K*
This alternative is not a viable option as it will not support the current and future operational needs of LKE. Therefore, the Do Nothing option is to renovate and expand the two existing locations, but not include improvements to the mechanical, electrical and communications infrastructure. This alternative meets only two of the five primary drivers. The total projected capital cost is $5,723K. Renovations are needed to modernize the control centers and provide ergonomic workstations for the operators. With the expansion of the workgroup, additional space is needed to provide workspace for the 10 new employees and 16 retirement offsets over the next 10 years. Improvements to the power, mechanical, and communications infrastructure are needed to meet Tier II best practice standards and support the "Smart Grid" technologies that will be operated from the DCC. The two separate facilities do not provide the operational and efficiency benefits of consolidating the workforce as opportunities will be limited to balance the workload, standardize processes, and train new and current operators. The two facilities will also eliminate scheduling flexibility and require more experienced operators to provide leadership due to staffing at two separate locations. Costs are included for one additional training position to allow for a trainer at each DCC location. Also, additional overtime training costs are included as the shift coverage requirements at the two locations will not allow for the regular scheduling of training.

Project Description

EDO's proposed project will consolidate DCC operations into one new facility in Simpsonville at the northeast corner of the property adjacent to the TCC/DC. The new DCC will be a stand-alone, single story building that will not be physically connected to the TCC/DC building. EDO's new building will be operational by July 2019.

- **Project Scope and Timeline**
  The project scope includes the following:

- Site development to prepare for new construction
- Design and construction of a 25,000 square foot Tier II facility
    - Large control room with four (4) pods of ergonomic workstations
    - Office space for management and support personnel
    - Dedicated training room
    - Large conference room/Storm Restoration War room
    - CIP PSP construction and access standards in most areas of the building
    - Kitchen, break areas, restroom and locker facilities
    - Electrical service to be provided through existing TCC/DC switchgear which provides redundant utility and generator supply
    - Multimode (N+1) UPS system
    - Independent mechanical system with N+1 cooling capacity and separate cooling for the PSP spaces
    - Network, security, and fire suppression systems
    - New parking lot for the DCC
    - New walkway to TCC/DC and North parking lot.

- Project Timeline:

November 29, 2016	Investment Committee Meeting
December 1, 2016+	Obtain final signatures
May 2017	Design and Construction Documents Complete
December 2017	Bidding and Contracts Complete
January 2018	Construction Begins
June 2019	Construction Complete
July 2019	Building Operational

- **Project Cost**

  The projected cost of this project is $10,703k which includes $721k of contingency or approximately 7% of the total project. The contingency was calculated based on 10% of the contractor labor and material cost only. Furniture, security, telecom costs are fixed. This project is included in the 2017 Business Plan, but will require additional funding of $703K which will be addressed through the normal Business Plan RAC processes. The CEM was adjusted for cost savings of $887K for the reuse of the BOC DCC office space and the conversion of the TCC conference room to usable office space.

Economic Analysis and Risks

- **Bid Summary**

  The bid process will begin after the final design is completed.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,409	4,118	4,176	-	10,703
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,409	4,118	4,176	-	10,703
4. Capital Investment 2017 BP	5,000	5,000	-	-	10,000
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	5,000	5,000	-	-	10,000
7. Capital Investment variance to BP (4-1)	2,591	882	(4,176)	-	(703)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	2,591	882	(4,176)	-	(703)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The total project costs are higher than the 2017 BP amounts and the timing is different as well. The lower than budgeted spending in 2017 will be given up to the Corporate RAC and the 2018 and 2019 differences will be addressed in the 2018 BP process.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 250
Contract Labor:	$ 5,645
Materials:	$ 3,764
Property Tax Capitalization:	$ 129

Burdens:	$ 194
Contingency:	$ 721
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 10,703

Financial Analysis - Project Summary ($000)	2017	2018	2019	2020	2021	Life of Project
Project Net Income	67.00	133.00	472.00	533.00	512.00	11,497.00
Project ROE	5.20%	4.20%	6.70%	9.20%	10.00%	9.70%

- **Assumptions**

Economic useful life is 50 years.

- **Risks**
  - The completion date is contingent on the weather.
  - Obtaining permits and easements.
  - Existing DCC personnel may leave group or retire early due to relocation and driving distance.

Conclusions and Recommendation

EDO recommends that the Investment Committee approve the Distribution Control Center Enhancement Project for $10,703k. The consolidated distribution control center satisfies all of EDO's five primary drivers for action and will provide adequate workspace for the expanding DCC work group, improve ergonomic facilities to support the 24/7 operations, and create infrastructure needed to handle the emerging "Smart Grid" technologies.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: 12/20/2017

Project Name: Distribution Control Center Enhancement Project

Total Approved Expenditures: $10,703k (Approved on 11/29/2016)

Total Revised Expenditures: $13,334k, with an additional $2,631k requested

Project Number(s): 153560LKS, 153561 and 153562

Business Unit/Line of Business: Electric Distribution Operations / Facilities

Prepared/Presented By: Zac Conley/Cheryl Bruner

Reason for Revision

This project was originally approved by the Investment Committee in November 2016 for $10,703k. An additional $2,631k is necessary to complete the project. Several factors have contributed to the increase in construction costs for the proposed Distribution Control Center (DCC). Originally, the new DCC was planned to be a stand-alone, single-story building designed with Tier II Mechanical and Tier III Electrical systems that would provide high reliability and resiliency. Following the review of the original proposal, Senior Management requested the project include hardening the facility to withstand an F3 tornado (150 mph winds) and enclosing the mechanical equipment. Accordingly, redesigned specifications were developed for a hardened facility with an F3 tornado rating, matching the existing rating of the adjacent Transmission Control & Data Center (TC&DC) on the Simpsonville site. The proposed DCC will now include 10" thick concrete walls and a 6,000 sq. ft. mechanical penthouse, which is also hardened, to protect the enclosed mechanical equipment. Additionally, by hardening the facility a mechanical redesign was required, which was adaptive to the addition of a mechanical penthouse. The basic rooftop HVAC units originally proposed were redesigned and the building climate will now be supported by a chilled water system and associated chilled water units. Accordingly, as a result of hardening the structure, there will be cost increases not only to the construction of the building structure, but also to the mechanical systems and electrical scope of work.

Further adding to the increased cost, the geo-technical report from January 2017 revealed shallow bedrock throughout the planned location of the DCC. Because the site also contains the critical TC&DC, blasting the rock is not an option. Accordingly, the DCC building location had to be shifted south on the site. By moving the building location and elevating the finished floor four feet, rock cut and removal would be minimized. It is anticipated, however, approximately 1,000 cubic yards of rock will still be required to be removed, and it must be performed through mechanical means as opposed to blasting. All tasks affected by the results of the geo-technical report increased the cost of constructing the building. These additional costs include: concrete and steel, stairs and railings and all other associated construction methods required to build a facility directly on bedrock. Also as result of shifting the building location, additional site work is now necessary. Construction phasing is now required to maintain uninterrupted access to the occupied and fully operational TC&DC. This additionally required, phased, civil work will include a temporary access roadway which will be built around the building site which, at the conclusion of construction, will become a permanent roadway and also provide additional parking for the facility.

Several additional internal and external factors related to security, IT infrastructure and permitting also contributed to the increase in the overall cost of the project. Among these are additional security procedures during construction. CIP-14 requirements provide that not only must the existing facility (the TC&DC) be secured, but the entrance and egress into the fenced property must also be secured and monitored. To comply with this requirement, a temporary security trailer with a full-time security guard coverage will be staffed throughout the duration of the project. The additional security personnel will be responsible for monitoring and securing the front entry into the property, the signing-in and logging of all contractors and deliveries, and providing all DCC construction contractors access into the TC&DC grounds.

Also not identified in the original Investment Proposal is the replacement of the core data switches that currently serve the TC&DC network. LKE IT Infrastructure identified these core data switches as equipment approaching end of life and IT endorsed their replacement to increase the redundancy of the new facility.

In addition to material and labor costs, the A&G burden rate originally applied to the project is scheduled to be increased effective January 1, 2018. This rate increase will result in additional cost to the project.

Lastly, it was identified through the design development process that the local permitting authority, Triple S (i.e., Simpsonville/Shelbyville/Shelby County) will require Special Inspections of the structure periodically throughout the duration of construction by a licensed, third party engineering firm. The fee for those Special Inspections will be borne by the company as well.

Incremental Cost Overview	**30% Est.**	**Bid Pricing**	**Incremental**
Construction (+10% Contingency)	7,369	9,053	(1,684)
LG&E-KU (Owner Costs)	2,275	2,922	(647)
Engineering & Design	736	736	-
Burdens and Tax	323	623	(300)
Totals Incremental	10,703	13,334	(2,631)

Incremental Cost Attribution	**Total**	**Percent**
Construction	1,684	64%

LGE-KU (Owner Costs)	647	25%
Engineering & Design	0	0%
Burdens and Tax	300	11%
Total Incremental Cost	2,631	100%

- **Project Scope and Timeline**
  The project scope includes the following:
  - Site development to prepare for new construction
  - Design and construction of a 31,000 square foot Tier III facility which includes a 6,000 square foot mechanical penthouse
    - Large control room with four (4) pods of ergonomic workstations
    - Office space for management and support personnel
    - Dedicated Training Room
    - Large conference room/Storm Restoration War Room
    - PSP construction and access to CIP standards in required areas of the building
    - Kitchen, break areas, restroom and locker facilities
    - Electrical service to be provided through existing TC&DC switchgear which provides redundant utility and generator supply
    - Multimode (N+1) UPS system
    - Independent mechanical system with N+1 cooling capacity and separate cooling for the PSP spaces
    - Network, security, and fire suppression systems
    - New parking lot for the DCC
    - New walkway to TC&DC and North parking lot

  - Project Timeline:
    - November 29, 2016 — Investment Committee Meeting
    - December 1, 2016 — Obtain final signatures
    - October 12, 2017 — Design and Construction Documents Complete
    - December 2017 — Bidding and Contracts Complete
    - December 20, 2017 — Investment Committee Meeting
    - December 21, 2017 — Obtain final signatures on project revision
    - February 2018 — Construction Begins
    - May 2019 — Construction Complete
    - June 2019 — Building operational

Financial Summary

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.5%	6.32%	
Capital Breakdown:			
Labor:	$ 250	$ 279	
Contract Labor:	$ 5,645	$ 9,234	Increases in scope (see detail above) resulted in higher construction costs.

Materials:	$ 3,764	$ 2,315	Bids were lower than original estimates.
Miscellaneous:	$ 0	$ 60	
Burdens/Local Engineering:	$ 194	$ 466	Increase in total project cost, as well as higher burden rates effective 1/1/2018.
Contingency:	$ 721	$ 823	
Property Tax Capitalization:	$ 129	$ 157	
Net Capital Expenditure:	$ 10,703	$ 13,334	See above
NPVRR:	$ 14,170	$16,344	

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Capital Investment Proposed	118	1,726	7,183	4,307		13,334
2. Cost of Removal Proposed						-
3. Total Capital and Removal Proposed (1+2)	118	1,726	7,183	4,307	-	13,334
4. Capital Investment 2018 BP	118	1,949	4,118	4,177		10,362
5. Cost of Removal 2018 BP						-
6. Total Capital and Removal 2018 BP (4+5)	118	1,949	4,118	4,177	-	10,362
7. Capital Investment variance to BP (4-1)	-	223	(3,065)	(130)	-	(2,972)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	223	(3,065)	(130)	-	(2,972)

Financial Detail by Year - O&M ($000s)	**2016**	**2017**	**2018**	**2019**	**Post 2019**	**Total**
1. Project O&M Proposed			25	363	708	1,096
2. Project O&M 2018 BP			-	304	412	716
3. Total Project O&M Variance to BP (2-1)	-	-	(25)	(59)	(296)	(380)

Capital funding of $10,362k was included in the proposed 2018 BP. The incremental amount requested in 2018 will be requested through the Corporate RAC process. The incremental amount in 2019 will be requested in the 2019 BP. Facility Services will seek to cover operating expenses within the existing budget.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Distribution Control Center Enhancement project for a revised amount of $13,334k. The consolidated DCC satisfies all of EDO's five primary drivers:

1. Upgrade aging facilities and ergonomics to accommodate 12 hour shifts and employee health issues.
2. Expand space for additional headcount due to retirement offsets, migration of distribution SCADA work from the Transmission Control Center (TCC), and support of Distribution Automation.
3. Improve scheduling and training opportunities to account for operator retirements which will greatly affect the workgroup. Operators can take up to five years to gain operational and situational knowledge to be a seasoned operator.
4. Adopt best practices for control centers to have redundant electrical and mechanical systems to ensure operations without downtime.
5. Improve technology and communications infrastructure in support of the Smart Grid, Advanced Meter Systems, and VoltVar optimization.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		President and Chief Operating Officer	

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 26

Responding Witness: Robert M. Conroy / John K. Wolfe

Q-26. Refer to KU's Response to Charter Communication Operating, LLC's First Requests for Information, Item 13.b. State whether it is KU's intention to pass through the pro-rata costs of the ongoing Attachment Audit to its Attachment Customers if the Commission approves KU's proposed mechanism.

A-26. The Company intends to pass through the pro-rata costs of the Company's current audit to its Attachment Customers if the Commission approves the Company's proposed mechanism. The Company intends to pass through costs incurred after the effective date of any Commission approval.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 27

Responding Witness: Elizabeth J. McFarland

Q-27. Refer to KU's Response to the Lexington-Fayette Urban County Government's First Request for Information, Item 58.

a. Explain why a paperless customer cannot apply for the Late Payment Credit online.

b. Explain how KU will advertise the Late Payment Credit option.

A-27.

a. Customers will be able to request the Late Payment Credit online through the Contact Us form on the website.

b. The Company is not planning on advertising the Late Payment Credit option.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 28

Responding Witness: David S. Sinclair

Q-28. Refer to KU's Response to Kentucky Industrial Utility Customers, lnc.'s First Request for Information, Item 14. Explain why purchases up to 558 MW per hour from other utilities were included in the Loss of Load Probability analysis.

A-28. The LOLP analysis recognizes that a potential loss of load scenario would require the Companies to attempt to purchase power from other utilities. The Companies included the purchases as a resource that can be called upon to avoid a loss of load. See also the response to AG 2-6.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 29

Responding Witness: Daniel K. Arbough

Q-29. Refer to the Application, Schedule J-1.

a. Provide KU's capitalization allocated to generation, transmission, distribution, and general.

b. Explain the drivers for KU's projected increase in capitalization.

A-29.

a. See the response to Question No. 19.

b. See pages 5 and 6 of Mr. Blake's Testimony for the drivers of the projected increase in capitalization.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 30

Responding Witness: Daniel K. Arbough

Q-30. Refer to the Direct Testimony of Daniel K. Arbough, page 22, lines 3-7. Provide KU's policy for hedging again risk exposure for interest rate changes.

A-30. The regulatory assets discussed in the testimony are associated with the issuance of first mortgage bonds in 2015. Attachment 1 is the risk management program in place at the time the interest rate swaps that resulted in the regulatory asset were done. The regulatory liabilities mentioned in the testimony are connected with the 2013 first mortgage bond issuance. Attachments 2 and 3 are the risk management programs in place at the time the interest rate swaps that resulted in the regulatory liability were done. The swaps associated with the 2013 issuance became effective during 2012 and 2013 and the policy was updated during that period. See attached. The information is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 31

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-31. Refer to the Direct Testimony of Lonnie E. Bellar, Exhibit LEB-2.

a. Explain why KU/LG&E did not contact PJM or MISO representatives for review and validation of key assumptions and modeling methodology.

b. Refer page 12 of 40 wherein the study states, "The Companies used their production cost software tool, PROSYM, to forecast the potential trade benefits of joining an RTO . . . ." Explain why PROSYM is the preferred analytical model for undertaking the Regional Transmission Operator (RTO) market analysis set forth in Exhibit LEB-2.

c. Refer page 6 of 40 wherein the study states, "To determine which components of RTO membership might have a material impact, the team: Reviewed relevant material, including . .. EKPC cost-benefit analysis . . . . "

(1) Explain how PROSYM compares to GE MAPS Model used in the EKPC RTO Membership Assessment.

(2) Explain why KU/LG&E chose not to model entering PJM as a Fixed Resource Requirement (FRR) Alternative.

d. Refer to page 14-40, wherein the study states, "The trade benefits estimates are highly uncertain as they depend on the level of market electricity prices, which directly depend on many uncertain variables including fuel costs, weather, and RTO-wide load and generation performance. They may also be indirectly influenced by many external factors, including state and federal policy."

(1) Confirm that KU /LG&E do not have the modeling capabilities to evaluate uncertain variables such as fuel costs, weather, RTO-wide load and generation performance and other external factors such as state and federal policies.

(2) Explain the ability of PROSYM to evaluate the uncertainty of fuel costs, weather, load, and generation performance.

e. Refer to page 4-40, wherein the study states, "As in the previous analysis, a cross-functional team was organized to identify the major costs, benefits, opportunities, and uncertainties compared to the status quo operations of the Companies." Explain the cross function team's capabilities to conduct sensitivity analysis in order to evaluate uncertainty in the KU/LG&E modeling outcomes.

f. Refer to Appendix E-Non-Quantifiable Considerations, starting on page 34 of 40 generally.

(1) Explain whether KU/LG&E considered customer demand response and energy efficiency benefits of RTO participation.

(2) Explain whether participation in an RTO allow KU/LG&E to obtain more demand response and energy efficiency pathways for customers.

g. Refer to page 7 of 40 wherein the study lists a key assumption, "The purchase or sale of ancillary services has net zero cost because the Companies are both buyers and sellers of these products and any charges are offset by credits."

(1) Explain why these benefits and costs were not quantified.

(2) Explain whether KU/LG&E's Energy Storage Research and Demonstration Site at its E.W. Brown Generating Station currently provides ancillary services.

(3) Explain whether KU/LG&E quantified potential cost and benefits of the Energy Storage Research and Demonstration Site at its E.W. Brown Generating Station in terms of participating in ancillary services markets.

A-31.

a. The Companies considered contacting MISO and PJM, but ultimately determined it was unnecessary for several reasons. The Companies have adequate experience and knowledge of MISO and PJM markets to conduct a thorough and unbiased analysis of RTO membership. RTO rules are transparent via published tariffs and business practice documents. The Companies regularly transact with PJM and MISO and interface with staff of RTO members. The Companies discussed RTO membership experiences with the utilities' sister company PPL Electric Utilities and Kentucky RTO member companies Big Rivers Electric, East Kentucky Power, and Duke

Energy. In addition, PJM has presented its value proposition to the Companies' leadership in the past. Because the Companies have adequate internal expertise, there were no aspects of the modelling methodology or assumptions for which the Companies needed to obtain external validation as the Companies are confident in the methodology and assumptions used. Finally, the Companies wanted to protect the confidentiality of the analysis and underlying data and retain control over the process to ensure that it was unbiased, reasonable, and defensible. It was determined that outreach to external entities with an incentive to promote RTO membership (such as the RTOs themselves) was not consistent with approaching the analysis in a way that would ensure an unbiased view focused on benefits to customers.

b. The Companies have extensive knowledge and experience with PROSYM and use it regularly to perform various analyses including developing business plans, integrated resource plans, and market transaction forecasts, which are similar to the analysis required to determine trade benefits in the RTO Membership Analysis. Prior to making the decision to utilize PROSYM for the RTO Membership Analysis, its capabilities were evaluated. After evaluating the PROSYM setup modifications that were necessary to simulate RTO participation, it was determined that PROSYM would be an effective tool to estimate the potential trade benefits of joining an RTO. As noted in the response to Question No. 18, the Companies used AURORA software to model electricity prices in the RTO markets. The resulting electricity prices were used as an input to PROSYM to develop a detailed simulation of the Companies' operations in an RTO.

c.

(1) The Companies use the AURORA software tool to model electricity prices in PJM and MISO, which are used as an input to PROSYM when modeling the Companies' participation in an RTO. The Companies do not use GE MAPS and are therefore not very familiar with this particular software. However, based on the information contained in EKPC's testimony and exhibits presented in their Case No. 2012-00169 and dated May 3, 2012,[13] it appears that GE MAPS is similar to AURORA and PROSYM in several ways. The models include inputs for forecasted demand and energy levels and shapes, generating unit characteristics, transmission grid topology and constraints, fuel costs, and environmental costs. These models perform a granular simulation of the system's commitment and dispatch and produce various outputs, including system operation data, market transaction data, and (in both AURORA and GE MAPS) electricity prices. EKPC noted that "GE MAPS is time-consuming to set-up, run, and post-process" and therefore modeled three

[13] See EKPC's application at https://psc.ky.gov/PSCSCF/2012%20cases/2012-00169/20120503_EKPC_Application_Volume%201.pdf.

years and interpolated the results in the intervening years. In contrast, the Companies were able to model each year very effectively in both AURORA and PROSYM for a more complete and detailed view of the ten-year period that was analyzed.

(2) The Companies chose not to model a FRR so that the potential revenues that could be realized from participating in the PJM's capacity market could be included as a potentially large benefit of joining PJM. The supply resource qualifications and performance requirements for use in FRR Capacity Plans are similar to Reliability Planning Model resources; however, capacity resources included in a Load Serving Entity's FRR Capacity Plan do not receive any RPM Resource Clearing Prices for capacity.[14] Modeling a FRR plan would eliminate between $1 million and $36 million of annual benefit in the Mid and High cases, and between $2 million and $4 million of annual cost in the Low case as shown on page 28 of Exhibit LEB-2.

d.

(1) The statement being referenced was intended to explain why a range of uncertain variables were analyzed and how future results could be potentially different than shown. The statement was not intended to state that the Companies do not have the modeling capabilities to evaluate uncertain variables. For each of the major cost and benefit components evaluated in the 2018 RTO Membership Analysis, the Companies modeled variables using a reasonable range of possible outcomes. When combined, the resulting net costs or benefits reflected a wide range of possible futures, which was reasonable given the many uncertainties the Companies considered and aided in evaluating and understanding risks and uncertainties. The primary driver of variation in the trade benefits component is electricity price, which is primarily a function of fuel cost, for which the Companies modeled a range of uncertainty. The Companies routinely evaluate uncertainty in key variables as has been demonstrated in numerous prior filings with the Kentucky Public Service Commission, including the RTO analysis.

(2) PROSYM is able to model a detailed hourly dispatch of the Companies' system for one static case at a time. The Companies model uncertainty with PROSYM by running multiple cases to evaluate a reasonable range of inputs for combinations of the key variables, such as the electricity prices evaluated in the RTO analysis. Various electricity price forecasts reflect variable fuel costs, weather, and load. Generation performance is evaluated by random generator outages in PROSYM with each case.

[14] See *PJM Manual 18: PJM Capacity Market*, https://pjm.com/-/media/documents/manuals/m18.ashx?la=en

e. The cross functional team included team members with skills and experience in resource planning who are very familiar with conducting sensitivity type analysis in their normal course of work, such as preparing integrated resource plans, generation investment CPCNs, and other such future looking analyses that contain various levels of uncertainty.

f.

(1) For both PJM and MISO, Curtailable Service Rider (CSR) load and Demand Conservation Program (DCP) load reductions were not included in estimates of the benefits of RTO membership, as noted on page 16 of Exhibit LEB-2.

Load Management Demand Resources (DR) and Energy Efficiency Resources (EE)[15] that meet PJM's Capacity Performance requirements are eligible to offer as Capacity Performance resources and receive capacity payments in the RPM.[16] While PJM does not deal directly with end-users, these resource types can bid into the market through their designee, which may be the Load Serving Entity, Electric Distribution Company, or Curtailment Service Provider. An unforced capacity value is calculated for these resource types based upon their nominated capacity performance value. These resources are subject to verification of their performance during Capacity Performance Hours.

PJM's recognized DR programs include Legacy Direct Load Control, Firm Service Level (FSL) and Guaranteed Load Drop (GLD). While the Companies currently employ a Direct Load Control program with retail air conditioning units, PJM's effective period for this type of load management program expired on May 31, 2016. PJM's FSL and GLD programs are similar in concept to the load management programs achieved by the Companies' CSR rates; however, while the Companies' tariffs limit the number and duration of interruptions to these customers, PJM's performance requirements for these types of programs specify an unlimited number of interruptions for unlimited duration of time. Given these stricter program constraints, the Companies did not include any

[15] Capacity Performance EE must provide a permanent, continuous reduction in load during the EE performance hours that is not reflected in the peak load forecast prepared for the Delivery Year. It also must have an expected average load reduction during defined winter hours. An EE Resource may be used as a Capacity Resource in the PJM Capacity Market. Planned energy efficiency projects will be allowed to offer into Reliability Pricing Model Auctions or to be committed in a Fixed Resource Requirement Alternative Capacity Plan for up to four consecutive Delivery Years. Examples of EE Resources are efficient lighting, appliance, or air conditioning installations; building insulation or process improvements; and permanent load shifts that are not dispatched based on price or other factors.

[16] Likewise, DR and EE may be part of a Fixed Resource Requirement portfolio.

changes to existing customer demand response programs in the RTO membership analysis.

MISO offers several options for DR and load modifying resource (LMR) registration and markets participation.[17,18] However, MISO's Market Monitor has expressed concern over the increase in cleared DR/LMR in the 2018/2019 Planning Resource Auction due to these resources not being available under critical conditions.[19] Additionally, MISO initiated a Resource Availability and Need process to address issues with increasing reliance on, but underperformance of, DR/LMR.[20] Given these concerns, the Companies did not include any changes to existing customer demand response programs in the RTO membership analysis.

Finally, given the limited applicability of these types of programs to the broader customer base and their small impact on overall revenue requirements, it was unlikely that a detailed analysis of the issue would have had a material impact on the overall financial analysis.

(2) The Companies have reservations regarding the viability of the Companies existing demand response and energy efficiency programs under RTO membership due to the challenges noted in the response to part (1). However, the RTO markets continue to evolve and may become more conducive to demand response and energy efficiency in the future. PJM's strategy, presented in *Demand Response Strategy*,[21] notes that PJM is working with state commissions and other stakeholders to see demand response fully integrated into the retail market as a long-term goal. Similarly, the results of MISO's Resource Availability and Need process, noted in part (1), may alter pathways for demand response and energy efficiency in the MISO footprint.

g.

(1) The benefits and costs of purchasing and selling ancillary services (such as regulation and operating reserve) were not quantified because the Companies would be both suppliers and purchasers of the services. In an RTO construct, the Companies' generation fleet would sell these services into the respective ancillary services market and the Companies' load

---

[17] See MISO Demand Resource Primer, https://cdn.misoenergy.org/Demand%20Response%20Primer118479.pdf
[18] These options are defined under Module A of MISO's Open Access Transmission Tariff.
[19] https://www.potomaceconomics.com/wp-content/uploads/2018/06/IMM-Quarterly-Report_Spring-2018_Final.pdf
[20] https://cdn.misoenergy.org/20181101%20RSC%20Item%2005%20RAN%20Presentation%20-%20MR025288763.pdf
[21] See *Demand Response Strategy*, PJM Interconnection, June 28, 2017, https://www.pjm.com/~/media/library/reports-notices/demand-response/20170628-pjm-demand-response-strategy.ashx

would purchase the services from the market, resulting in an immaterial cost or benefit since total revenue paid to the generation fleet and total expense paid by load is expected to offset each other.

(2) The 1 MW energy storage site does not currently provide ancillary services as it is a research and demonstration project and is not available or configured for commercial operations.

(3) The Companies did not quantify the potential benefits and costs of the 1 MW energy storage site for the reasons provided in the preceding responses.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 32

Responding Witness: Lonnie E. Bellar

Q-32. Since submittal of the 2018 RTO Membership Analysis by KU/LG&E, several renewable energy projects have entered the KU/LG&E Generation Interconnection Que. Explain how RTO membership may affect KU/LG&E's obligation under the Public Utility Regulatory Policies Act.

A-32. RTO membership, by itself, does not impact the Companies' PURPA obligations. If the Companies were to join an RTO, they may apply to FERC for termination of mandatory purchase obligations. FERC granted a similar request from EKPC in 2017 and the Commission subsequently approved corresponding changes to EKPC's retail tariffs.

Since the Companies' current obligations under PURPA require the purchase price paid to Qualifying Facilities to be at the avoided cost of capacity and energy, the PURPA obligation does not impose a cost to its retail customers today. The RTO Analysis appropriately assumed there is not a material impact from the Companies' PURPA obligations in either the status quo or the RTO membership cases.

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 33

Responding Witness: Lonnie E. Bellar

Q-33. Since submittal of the 2018 RTO Membership Analysis by KU/LG&E, PJM, in October, submitted two capacity repricing proposals to the Federal Energy Regulatory Commission.[22] Explain how these proposals may affect the potential outcomes of the 2018 RTO Membership Analysis.

A-33. The Companies have reviewed PJM's filing and will continue to follow the Federal Energy Regulatory Commission's proceeding. Given the range of capacity prices assumed in the 2018 RTO Membership Analysis, the Companies do not expect the outcome of PJM's referenced proposal to have a material impact on the results. However, PJM is continually updating its procedures and its markets continue to evolve as market rules change, the impacts of which the Companies will continue to monitor.

PJM's proposal filed with the Federal Energy Regulatory Commission (FERC) on October 2, 2018, was in response to FERC's directive to submit a proposal 'that recognizes states' authority to shape the makeup of their generation fleet, while transparently and carefully ensuring that the costs associated with state actions are borne by the states taking those actions. Just as important, the proposal must guarantee that price outcomes for generation sellers, including those not benefiting from state support, remain fair and competitive.' As the Companies noted in the "2018 RTO Membership Analysis," while PJM's Reliability Planning Model has relatively more market maturity, it continues to evolve and change as market rules change. This evolution of market rules is demonstrated by the iterative process in which PJM has been engaged with FERC to address what FERC has described as a threat to the integrity of PJM's wholesale electricity markets. Future market prices are subject to volatility and remain changeable as PJM market rules evolve. The outcomes of the "2018 RTO Membership Analysis" are presented as a range of outcomes, rather than a single outcome, in part to reflect the volatility and changeability of the markets due to such changes in market rules.

---

[22] https://www.pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Third Request for Information
Dated December 13, 2018

Case No. 2018-00294

Question No. 34

Responding Witness: Elizabeth J. McFarland / John K. Wolfe

Q-34 Explain the boundary between distribution automation and advanced metering infrastructure. Include in the explanation any change that resulted from the Commission's decision in Case No. 2018-00005.[23]

A-34. The boundary between Distribution Automation (DA) and Advanced Metering Infrastructure (AMI) is generally at the meter. Distribution Automation includes a Distribution Management System (DMS) and any connected intelligent and SCADA capable devices (reclosers, relays, capacitors, switches, etc.) on the electric distribution grid. DA technology enables remote monitoring, control, and operation of distribution circuits where intelligent devices are installed. AMI enables more granular monitoring and control. Data from AMI can be interfaced with DMS to enable real time awareness of service outages or abnormal operating conditions at the customer level. AMI also enables identification of nested outages during major outage events, and enhances line technician safety through identification of backfeed from behind customer meters.

The Companies had proposed plans to integrate AMI data into its DMS and Outage Management System (OMS) in order to improve outage response and identification in Case No. 2018-00005. At this time the systems are independent given the Commission's decision in Case No. 2018-00005; however, if the Companies sought AMI full deployment in the future, it is likely that the cost to integrate AMI with distribution systems would again be included because it provides incremental benefit to DA in the form of enabling identification of meter specific outages, restoration, and circuit voltage profile for use in voltage regulation and nested outage identification. The additional data enhances DA's capabilities.

---

[23] Case No. 2018-00005, Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems, (Ky. PSC Aug. 30, 2018).