LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 126

Responding Witness: Christopher M. Garrett

Q-126. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the most recent actual 12-months available:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross kWh produced during the period; and,

h. net (less station use) kWh produced during the period.

Provide in executable electronic (Excel) format.

A-126. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 127

Responding Witness: Daniel K. Arbough

Q-127. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the fully forecasted test year:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross kWh produced during the period; and,

h. net (less station use) kWh produced during the period.

Provide in executable electronic (Excel) format.

A-127.

a-c. See the response to Question No. 126, parts (a) through (c).

d. LG&E does not maintain gross investment information in the forecasted test period at generating unit level.

e. LG&E does not maintain depreciation reserve information in the forecasted test period at a generating unit level.

f. LG&E does not maintain book depreciation expense in the forecasted test period at a generating unit level.

g-h. See attachment being provided in Excel format. The generation values reflect the total production of each unit with the exception of Trimble County Units 1 and 2 where the Companies' 75 percent ownership share of these units is presented.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 128

Responding Witness: David S. Sinclair

Q-128. Provide the combined KU and LG&E generating order of dispatch by unit and the basis for this order of dispatch.

A-128. The Companies' dispatch order as of January 2021 is provided in the table below. It is ranked in ascending order by average generating cost at maximum load, inclusive of variable fuel, emission allowances, and operating and maintenance costs. The dispatch order will vary depending on the price of natural gas and coal and other variables.

Dispatch Order (Lowest Cost to Highest Cost)	Unit	Dispatch Order (Lowest Cost to Highest Cost)	Unit
1	BROWN SOLAR	18	TRIMBLE 7
2	HYDRO (OHIO FALLS AND DIX DAM)	19	TRIMBLE 8
3	CANE RUN 7	20	TRIMBLE 9
4	TRIMBLE 2	21	TRIMBLE 10
5	TRIMBLE 1	22	BROWN 6
6	MILL CREEK 1	23	BROWN 7
7	MILL CREEK 4	24	PADDYS RUN 13
8	MILL CREEK 2	25	BROWN 9
9	MILL CREEK 3	26	BROWN 10
10	GHENT 1	27	BROWN 5
11	GHENT 2	28	BROWN 8
12	GHENT 3	29	BROWN 11
13	GHENT 4	30	HAEFLING
14	OVEC	31	PADDYS RUN 11
15	BROWN 3	32	PADDYS RUN 12
16	TRIMBLE 5	33	ZORN 1
17	TRIMBLE 6		

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 129

Responding Witness: Christopher M. Garrett

Q-129. For each KU and LG&E generating unit, provide average monthly and annual fuel costs per kWh during the most recent 12-months available. Provide in executable electronic (Excel) format.

A-129. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 130

Responding Witness: David S. Sinclair

Q-130. For each KU and LG&E generating unit, provide forecasted average monthly and annual fuel costs per kWh for the fully forecasted test year. Provide in executable electronic (Excel) format.

A-130. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 131

Responding Witness: David S. Sinclair

Q-131. For each KU KY Jurisdictional sales for resale customer whose sales and revenue are included in the forecasted test year, provide the following:

a. name of customer;

b. type(s) of service (e.g., firm requirements, short-term opportunity, etc.);

c. maximum contract demand;

d. demand charge(s) per KW;

e. energy charge(s) per KWh;

f. fixed charge(s) per day or per month;

g. other rate charge(s) per unit;

h. forecasted test year hourly loads as available;

i. forecasted test year monthly actual demands;

j. forecasted test year monthly billed demands;

k. forecasted test year kWh; and,

l. forecasted test year revenues.

Provide in executable electronic (Excel) format.

A-131. This question is not applicable to LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 132

Responding Witness: David S. Sinclair

Q-132. For each LG&E KY Jurisdictional sales for resale customer whose sales and revenue are included in the forecasted test year, provide the following:

a. name of customer;

b. type(s) of service (e.g., firm requirements, short-term opportunity, etc.);

c. maximum contract demand;

d. demand charge(s) per KW;

e. energy charge(s) per kWh;

f. fixed charge(s) per day or per month;

g. other rate charge(s) per unit;

h. forecasted test year hourly loads as available;

i. forecasted test year monthly actual demands;

j. forecasted test year monthly billed demands;

k. forecasted test year kWh; and,

l. forecasted test year revenues.

Provide in executable electronic (Excel) format.

A-132. LG&E has no sales for resale customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 133

Responding Witness: William Steven Seelye

Q-133. With regard to Mr. Seelye's KU class cost of service study Excel model, Mr. Seelye shows total KU system sales for resale revenue of $8,863,601. This amount is equal to $9,557,872.60 minus $694,271.50. In this regard, please provide a detailed explanation along with all calculations showing the development of $9,557,872.60 and $694,271.50.

A-133. The Company's forecasted Sales for Resale during the forecast period is $12,065,009 as shown on Page 7 of Schedule C 2.1. This amount is then reduced by $2,507,137 to account for adjustments shown on Page 7 of Schedule D-2 to remove the Off-System Sales Mechanism revenues, which results in revenue of $9,557,873. This amount is further adjusted to remove ECR Off-System Sales revenues of $684,271.50 as shown on Page 1 of Schedule D-2.1, which results in total Sales for Resale revenues of $8,863,601.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 134

Responding Witness: William Steven Seelye

Q-134. With regard to Mr. Seelye's LG&E electric class cost of service study Excel model, Mr. Seelye shows total LG&E system sales for resale revenue of $34,405,720. This amount is equal to $42,910,931 minus $6,102,286 minus $2,402,925. In this regard, please provide a detailed explanation along with all calculations showing the development of $42,910,931, $6,102,286 and $2,402,925.

A-134. The Company's forecasted Sales for Resale during the forecast period is $42,910,932 as shown on Page 7 of Schedule C 2.1. This amount is then reduced by $6,102,286 to account for adjustments shown on Page 7 of Schedule D-2 to remove the Off-System Sales Mechanism revenues, which results in revenue of $36,808,645. This amount is further adjusted to remove ECR Off-System Sales revenues of $2,402,945 as shown on Page 1 of Schedule D-2.1, which results in total Sales for Resale revenues of $34,405,720.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 135

Responding Witness: William Steven Seelye

Q-135. Explain why electric sales for resale customers are not allocated any costs in Mr. Seelye's cost of service studies but rather, revenues are credited back to jurisdictional customers. In this regard, also explain how the loads associated with sales for resale are considered and reflected in Mr. Seelye's LOLP method.

A-135. Sales for Resale revenues are collected from sales to non-firm wholesale customers that are not in the Companies' retail service territory. These sales are made by the Companies when marginal revenues exceed the marginal cost of generating energy to sell and that energy is not needed by retail customers.

The cost-of-service study utilizes a revenue credit approach for revenues received by the Companies from non-firm wholesale customers, which are then credited back to retail customers who pay for the generation facilities that allow the sales to be made.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 136

Responding Witness: Robert M. Conroy

Q-136. For each electric (KU and LG&E) negotiated or special contract rate customer, please provide:

a. KU or LG&E customer;

b. name of customer;

c. copy of contract;

d. type of service (firm, interruptible, etc.);

e. reasons, support, and all analyses showing the need for a negotiated or special contract rate;

f. cost support and analyses for negotiated or special contract rate;

g. forecasted test period revenues at current and proposed rates;

h. forecasted test period billing determinants;

i. voltage level at which customer is served (e.g., transmission, sub-transmission, primary, etc.);

j. jurisdictional annual coincident peak demand for each of the last three years;

k. jurisdictional annual non-coincident peak demand for each of the last three years; and,

l. identification of the class in which each customer is included in Mr. Seelye's electric class cost of service study.

A-136. All special contracts are submitted to and approved by the KPSC. Information for subparts e and f are not readily available. The Company did not perform the analyses for subparts g, h, j, k, and l for each special contract. Other subpart information can be found in the current effective special contracts found on the KPSC website:

KU:
https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Contracts/Current/

LG&E Electric:
https://psc.ky.gov/tariffs/electric/louisville%20gas%20and%20electric%20company/contracts/Current/

LG&E Gas:
https://psc.ky.gov/tariffs/Natural%20Gas/Local%20Distribution%20Companies/Louisville%20Gas%20&%20Electric/Contracts/Current/

For the LG&E Electric special contract with the Louisville Water Company, the forecasted test period billing determinants (subpart h) can be found in the LG&E Filing Requirements Attachment to Tab 66 Schedule M-2.3-E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 137

Responding Witness: Daniel K. Arbough

Q-137. With regard to the curtailable load credits reflected in the fully forecasted test year and Mr. Seelye's class cost of service studies, provide the level (megawatts) of curtailable load embedded in the revenue credit separately by each rate schedule and by CSR-1 and CSR- 2 separately for KU and LG&E.

A-137. See attached for the LG&E information.

Louisville Gas and Electric Company
Case No. 2020-00350
Curtailable Service Rider

	Curtailable Demand, kVA
CSR-1 Primary Voltage Service	
Time-of-Day Primary (TODP)	38,819
CSR-2 Transmission Voltage Service	
Retail Transmission Service (RTS)	394,219

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 138

Responding Witness: David S. Sinclair

Q-138. Provide a detailed itemization of each requested curtailment during the last five years. In this response, provide the date, duration, requested load curtailment by individual customer and by CSR-1 and CSR-2, along with the amount of load actually curtailed separately for KU and LG&E.

A-138. LG&E did not request physical curtailments of any customer participating in either of the CSR-1 or CSR-2 service riders during the last five years. See attached for the LG&E requested curtailments under the buy-through option of the tariffs. The CSR-1 and CSR-2 service riders do not require monitoring of actual load reduction during buy-through events, so any load reduction is at the discretion of the customer.

Customer	Start Date/Time	End Date/Time	Hours	Type	kWh billed during Buy Through Period
1	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	382,452
2	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	32,866
3	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	111,283
1	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	330,634
2	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	37,411
3	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	119,290
1	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	356,755
2	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	51,058
3	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	126,749
1	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	399,559
2	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	56,539
3	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	125,510
1	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	304,719
2	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	255,192
3	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	116,755
1	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	296,214
2	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	254,674
3	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	107,280
1	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	387,984
2	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	29,299
3	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	142,502
1	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	27,701
3	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	92,821
1	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	138,536
1	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	195,968
3	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	83,965

Notes: LGE Customer #2's CSR 2 rider ended 3/6/2020.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 139

Responding Witness: Robert M. Conroy

Q-139. Please explain in detail how KU and LG&E treat curtailment buy-through revenues in setting base rates and/or modifying its Fuel Adjustment Clause.

A-139. The Companies did not include any curtailment buy-through revenues in the forecasted test year for determining base rates in this proceeding. Regardless, curtailment buy-through revenues are recorded to fuel revenues and therefore would not affect the determination of base rates.

For Fuel Adjustment Clause purposes, buy-through revenues are credited to monthly fuel costs for determining the FAC factor. LG&E and KU decrease the total fuel costs represented by F(m) by the excess of the curtailment buy-through revenues over the revenues received from the CSR customer's standard rate schedule billings. The latter recovers the CSR customer's portion of the actual fuel and purchase power costs incurred by the Company from the CSR customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 140

Responding Witness: William Steven Seelye

Q-140. Please identify and explain detail how KU and LG&E treat test-year curtailment buy-through revenue in the electric cost-of-service studies filed in this case.

A-140. There are no buy-through revenues included in the forecast period and therefore are not included in the cost-of-service studies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 141

Responding Witness: William Steven Seelye

Q-141. Provide the most recent KU and LG&E (individually) loss factors for energy and demand separated by voltage level; i.e., transmission, sub-transmission, primary, secondary.

A-141. See table below for LG&E loss factors.

Company	Voltage Level of Service	Energy Loss Factor	Demand Loss Factor
LG&E	Transmission	1.01033	1.01549
LG&E	Primary Substation	1.01619	1.02152
LG&E	Primary	1.02998	1.04295
LG&E	Secondary	1.05325	1.06325

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 142

Responding Witness: Christopher M. Garrett

Q-142. Provide the current number of KU retail jurisdictional customers (accounts) by rate schedule for each zip code within the Company's service area. Note: lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format.

A-142. This request is not applicable to LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 143

Responding Witness: Christopher M. Garrett

Q-143. Provide the current number of LG&E retail jurisdictional customers (accounts) by rate schedule for each zip code within the Company's service area. Note: lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format.

A-143. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 144

Responding Witness: William Steven Seelye

Q-144. With regard to the Company's KU CCOSS, explain why Rate PS-Secondary, Rate TOD-Secondary, and Outdoor Sports Lighting (OSL) are not allocated any secondary lines (overhead or underground) costs.

A-144. PS-Secondary, TOD-Secondary, and OSL customers require loads too large to be served off of secondary line conductors and typically take service directly from the secondary transformation equipment that is connected to the backbone primary distribution system. Those customers that do have secondary conductor in place are required to self-fund the facilities needed past the transformer and are also responsible for any O&M associated with this equipment.

Since these customers typically do not have secondary conductor installed to serve them, the CCOSS should not allocate secondary line costs, both demand and customer, to PS-Secondary, TOD-Secondary, and OSL customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 145

Responding Witness: William Steven Seelye

Q-145. With regard to the Company's LG&E CCOSS, explain why Rate PS-Secondary is allocated secondary demand-classified costs for distribution primary and secondary lines but no customer-classified costs.

A-145. PS-Secondary customers require loads too large to be served off of secondary line conductors and typically take service directly from the secondary transformation equipment that is connected to the backbone primary distribution system. Those customers that do have secondary conductor in place are required to self-fund the facilities needed past the transformer and are also responsible for any O&M associated with this equipment.

Since these customers typically do not have secondary conductor installed to serve them, the CCOSS should not allocate secondary line costs, both demand and customer, to PS-Secondary customers. Therefore, PS-Secondary customers should not be allocated demand-related secondary line costs in the Company's CCOSS.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 146

Responding Witness: William Steven Seelye

Q-146. With regard to the Company's LG&E CCOSS, explain why Rate TOD-Secondary is not allocated any secondary distribution lines costs (demand or customer).

A-146. TOD-Secondary customers typically require loads too large to be served off of secondary line conductors and thus typically take service directly from the secondary transformation equipment. Since these customers typically do not have secondary conductor installed to serve them, the CCOSS should not allocate secondary line costs, both demand and customer, to TOD-Secondary customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 147

Responding Witness: William Steven Seelye

Q-147. With respect to KU Rate Schedule TE (Traffic Energy), please provide a separation of the current number of traffic signals that are metered and unmetered.

A-147. As of December 2020, the number of metered LG&E TE devices was 1,105, and the number of unmetered LG&E TE devices was 10.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 148

Responding Witness: William Steven Seelye

Q-148. With respect to KU Rate Schedule LE (Lighting Energy), please provide a separation of the current number of lights or connections that are metered and unmetered. In this regard, if multiple lighting fixtures are included in a single account, provide the number of accounts that are metered and unmetered.

A-148. As of December 2020, the number of metered LG&E LE devices was 193, and the number of unmetered LG&E LE devices was 14.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 149

Responding Witness: William Steven Seelye

Q-149. With respect to KU Rate Schedule TE (Traffic Energy), please provide the current number of separate accounts; i.e., number of bills rendered monthly.

A-149. There were 1,115 LG&E TE bills rendered in the month of December 2020.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 150

Responding Witness: William Steven Seelye

Q-150. With respect to KU Rate Schedule LE (Lighting Energy), please provide the current number of separate accounts; i.e., number of bills rendered monthly.

A-150. There were 207 LG&E LE bills rendered in the month of December 2020.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 151

Responding Witness: William Steven Seelye

Q-151. With regard to KU and LG&E electric, please provide an executable electronic (Excel) copy of the Companies' revenue proof at current and proposed rates.

A-151. See the following attachments to PSC 1-56:
"2020_Att_KU_PSC_1-56_ElecScheduleM_Forcasted.zip" and
"2020_Att_LGE_PSC_1-56_ElecScheduleM_Forecasted.xlsx".

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 152

Responding Witness: Lonnie E. Bellar

Q-152. Please provide a copy of all presentations made to the Kentucky PSC and/or the Kentucky OAG regarding KU/LG&E's potential subscription to the Southeast Energy Exchange Market ("SEEM").

A-152. See the response to PSC 2-33.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 153

Responding Witness: Lonnie E. Bellar

Q-153. Please provide a copy of all filings made with the FERC regarding KU/LG&E's participation in SEEM.

A-153. See the response to PSC 2-33.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 154

Responding Witness: David S. Sinclair

Q-154. Please explain how KU/LG&E's potential participation in a SEEM will or may impact:

a. the dispatch of the Companies' generating assets;

b. levels of purchased power;

c. levels of sales for resale; and,

d. system loss of load probabilities.

A-154.

a-c. See the response to PSC 2-33. As a voluntary intra-hour supplement to the existing hourly market, SEEM could potentially increase opportunities for off-system sales and economy power purchases. The dispatch of the Companies' generating assets would follow such sales or purchases in a similar manner to their response to activity in the existing hourly market.

d. The Companies do not anticipate that SEEM will affect system reliability, and SEEM has not been included in any modeling associated with system loss of load probabilities. If the Companies encountered a serious reliability event that resulted in a declaration of an advanced Energy Emergency Alert (EEA), steps to avoid load shedding would include immediate energy purchases from neighboring utilities regardless of cost. The Companies would not wait to see if bids and offers aligned within the SEEM system in an attempt to meet load under emergency circumstances. Even considering system disturbances that do not approach EEA levels, the Companies must restore the balance of generation and load to its pre-contingency state within the 15-minute window required by NERC Reliability Standard BAL-002-3. The transaction timing currently contemplated for SEEM would not support the 15-minute requirement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 155

Responding Witness: Christopher M. Garrett

Q-155. For the most recent 36-month period, please provide monthly number of customers and CCF or therm sales by jurisdictional rate schedule for LG&E gas.

A-155. See attachment being provided in Excel format. Some customers have multiple contracts and are reflected in multiple rate codes. The duplications are removed in the Duplicate Customers lines.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 156

Responding Witness: William Steven Seelye

Q-156. With regard to LG&E gas and Mr. Seelye's Exhibit WSS-35, please provide:

a. all source documents and workpapers supporting degree days of 3,585 and 3,677; and,

b. an explanation of why Residential and Commercial degree days are 3,585 while the other class degree days are 3,677.

Provide all workpapers in executable electronic (Excel) format.

A-156.

a. See attachment being provided in Excel format.

b. See response to PSC 2-49 part a.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 157

Responding Witness: William Steven Seelye

Q-157. With regard to LG&E gas and Mr. Seelye's Exhibits WSS-35 and WSS-38, please explain why the development of the mains allocator is based on a design day temperature of -14ºF (79 degree days) while the storage allocator is based on 4ºF (61 degree days).

A-157. See the response to PSC 2-149.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 158

Responding Witness: Robert M. Conroy

Q-158. For each LG&E gas negotiated or special contract rate customer, please provide:

a. name of customer;

b. copy of contract;

c. type of service (firm, interruptible, etc.);

d. reasons, support, and all analyses showing the need for a negotiated or special contract rate;

e. cost support and analyses for negotiated or special contract rate;

f. forecasted test period revenues at current and proposed rates;

g. forecasted test period billing determinants;

h. jurisdictional annual coincident peak demand for each of the last three years;

i. jurisdictional annual non-coincident peak demand for each of the last three years; and,

j. identification of the class in which each customer is included in Mr. Seelye's gas class cost of service study.

A-158. See the response Question No. 136.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 159

Responding Witness: Lonnie E. Bellar

Q-159. For each of the last three years, please provide daily natural gas injections and withdrawals from storage. If daily amounts are not available, provide monthly natural gas injections and withdrawals. Provide in executable electronic (Excel) format.

A-159. 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.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 160

Responding Witness: William Steven Seelye

Q-160. With regard to LG&E gas, please provide an executable electronic (Excel) copy of the Company's revenue proof at current and proposed rates.

A-160. See the following attachment to PSC 1-56:
"2020_Att_LGE_PSC_1-56_GasScheduleM_Forecasted.xlsx".

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 161

Responding Witness: David S. Sinclair

Q-161. Please provide the excel version of Mr. Sinclair's Exhibits DSS-1 and DSS-2, including all supporting schedules, also in excel.

A-161. See the response and attachments to PSC 1-56.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 162

Responding Witness: David S. Sinclair

Q-162. Please provide, by month, the actual gWh sales and mW/mVa billing demands by rate schedule for the portion of the "base period" that is projected in Mr. Sinclair's Exhibits DSS-1 and DSS-2. This would be the monthly sales data for the period September 2020 through December 2020. Please provide the requested information in excel format with formulas intact.

A-162 See attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 163

Responding Witness: David S. Sinclair

Q-163. With regard to Mr. Sinclair's testimony on page 9, please provide the names of the 30 major account customers surveyed and indicate which utility they take service on.

A-163. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

CONFIDENTIAL INFORMATION REDACTED **Sinclair**

Individually Forecasted Major Accounts - Electric
[redacted]

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 164

Responding Witness: Daniel K. Arbough

Q-164. Please provide all supporting workpapers in excel format with formulas, including all excel models used to develop the Companies' base period and test year revenue forecasts by rate schedule.

A-164. See the responses and attachments to PSC 1-56 and 1-57.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 165

Responding Witness: David S. Sinclair

Q-165. Please provide, in excel spreadsheet format, the electric sales forecast, by month, by rate class, by Company that supports the 2021 Business Plan Electric Load Forecast (KAR 5:001 Sec. 16(7)(c)C).

A-165. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 166

Responding Witness: David S. Sinclair

Q-166. For each Company, please identify any large customer loads expected in the Future Test Year on rates RTS, TOD-PRI, TOD-SEC and FLS) that the Company is currently aware of but were not included in the test year projected mWh and revenues. For each such customer, provide the customer's name, the rate class on which the customer is expected to take service, the mWh expected by month during the test year the base revenues expected by month during the test year.

A-166. The Companies are not aware of any new large customer loads that were not included in the forecasted test year.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 167

Responding Witness: Robert M. Conroy / Eileen L. Saunders

Q-167. With respect to the Companies' response to the previous question, please indicate whether the Companies have provided any incentives and/or discounts (e,g., discounted contracts) associated with such customer. If there were such incentives and/or discounts provided, please provide the specific incentives/discount provisions associated with such customer.

A-167. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 168

Responding Witness: David S. Sinclair

Q-168. Please state whether KU has included the kWh sales and kVa billing demand, and revenues associated with the announced expansion project of Phoenix Paper Wickliffe in Ballard County in future test year billing determinants and revenues. If these billing determinants and revenues have been included in the future test year, please provide for each month the kWh sales, kVa billing demand and revenue, by rate element (e.g. kWh) and adjustment clause associated with this expansion. Also, please identify the rate schedule for service to this customer.

A-168. Question is not applicable to LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 169

Responding Witness: David S. Sinclair

Q-169. To the extent that the sales forecast shown in Schedule M-2.2 is different for any rate class from the 2021 Business Plan Electric Forecast GWh, please provide a reconciliation and an explanation for any differences.

A-169. The sales forecast in Schedule M-2.2-E is not different from the 2021 Business Plan Electric Forecast.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 170

Responding Witness: David S. Sinclair

Q-170. Please provide an analysis of the actual base period kWh energy sales through December 2020 on a weather normalized basis for each rate class.

A-170. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 171

Responding Witness: David S. Sinclair

Q-171. With regard to 807 KAR 5:001 Sec. 16(7)(c)B (Electric Sales & Demand Forecast Process), please provide an explanation of how the individual customer information from customer surveys or is incorporated into the forecast, including whether such information is combined with econometric forecast results for the rate class.

A-171. See Mr. Sinclair's testimony beginning at page 8, line 14. For the 30 or so major accounts that are forecasted individually, information from customer surveys regarding expansions, shutdowns, energy efficiency gains, equipment changes, etc. is incorporated directly into the rate forecasts. For some rates, this information is incorporated as an adjustment to the econometric forecast for the rate class in total. For other rates, the major account forecasts are simply added to a forecast for customers on the rate who are not forecasted individually. See 807 KAR 5:001 Sec. 16(7)(c)B (Electric Sales & Demand Forecast Process) 4.2.9 - 4.2.13 for more information.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 172

Responding Witness: Robert M. Conroy / David S. Sinclair

Q-172. Please provide a description of the methodology used to develop the avoided cost rates reflected in Rider SQF. Also provide, in excel format with formulas, the support for the most recent update of avoided costs paid under Rider SQF.

A-172. See attached. Regarding Attachment 2 (Avoided Cost support in Excel format), the information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. Attachments 3, 4, and 5 are the PSC-approved stamped tariff, supporting calculations, and cover letter, respectively, for the biennial SQF tariff filing filed on May 27, 2020.

Avoided Cost Calculation Methodology

The estimates of avoided cost rates are based on forecasts of hourly marginal costs. The derivation of hourly marginal costs is performed using PROSYM software, which is based on many detailed inputs maintained by LG&E and KU (collectively "the Companies"). To provide an understanding of the marginal cost calculation and demonstrate the reasonableness of the PROSYM results, the Companies manually calculated the primary components of marginal cost based on the most significant inputs, which are incremental heat rates, fuel prices, variable operating and maintenance costs, and in limited instances, purchased power costs. Also provided are schedules of these input assumptions.

A detailed explanation of the process of developing the generation forecast in PROSYM is located in Section 16(7)(c) – Item G, at Tab 16 of the Filing Requirements.

Attachment 2 provides the calculations of the proposed 2020 avoided cost rates and hourly marginal costs as well as schedules of the primary assumptions used in PROSYM for developing the proposed rates. It comprises the following eleven tabs.

Tabs 1 and 2 show the calculation of avoided cost rates and hourly marginal costs.

1. **Summary Avoided Cost Calculation.** This tab demonstrates how the hourly marginal costs derived in PROSYM were summarized among the designated peak categories and for each of the years 2020 through 2025 and for the two-year period beginning July 1, 2020. The rates filed in the Companies' original filing are calculated in the cells highlighted in green.

2. **Hourly Marginal Costs**.
   Columns A through G, shown in blue text, show the PROSYM output for modeled hourly marginal costs, indicating for each hour:
   a. **Column E –** the hourly marginal cost in cents/kWh
   b. **Column F –** the unit (or a market electricity purchase[1]) that resulted in each hour's marginal cost
   c. **Column G –** the operating level of the marginal unit in megawatts (MW)[2]

   To demonstrate how the marginal cost is calculated, in Columns K through P, the cost of the marginal unit/purchase specified by PROSYM (shown in Column F) is derived for each as a function of the following inputs:

   a. **Column K –** the incremental heat rate[3] of each unit at the operating level specified by PROSYM (shown in Column G)

[1] For the six years evaluated, market electricity purchases resulted in the system marginal cost in eleven hours.
[2] Columns H, I, and J are used for categorizing time periods.
[3] The incremental heat rate indicates the amount of fuel required to generate the next single incremental MW for a unit. It is typically much lower than the "average" heat rate, which is more often shown for generating units and which indicates the fuel required to generate all of the MWs for a unit, not just the incremental MW.

   b. **Column L –** the monthly delivered fuel price for each marginal unit
   c. **Column M –** the incremental fuel cost, which is the product of incremental heat rate and delivered fuel price
   d. **Column N –** variable operating and maintenance ("VOM") costs for coal-fired units,[4] which reflect consumable materials including limestone, ammonia, activated carbon, etc.
   e. **Column O –** gross purchase cost of market electricity for hours when purchases were indicated by PROSYM to result in the marginal cost
   f. **Column P –** the total calculated hourly marginal cost, which is a sum of the fuel cost, VOM cost, and/or the purchase cost[5]

Tabs 3 through 11 show most relevant input data to the PROSYM model.

3. **Winter Incremental Heat Rates –** applies to the months December, January, and February.
   a. Rows 3 through 5 show the coefficients of the heat rate curves developed for each unit based on historical observations.
   b. Rows 10 through 709 show the incremental heat rate for every operating level (MW) up to the maximum operating level for each thermal generating unit.
4. **Spring/Fall Incremental Heat Rates –** applies to the months March, April, May, September, October, and November. The data is structured similarly to Tab 3.
5. **Summer Incremental Heat Rates –** applies to the months June, July, and August. The data is structured similarly to Tab 3.
6. **Fuel Prices.** This tab shows the forecasted monthly delivered coal and gas prices for each of the thermal generating units.
7. **Variable O&M.** This tab shows the forecasted annual VOM costs for coal-fired units.
8. **Load.** This tab shows the forecasted monthly energy and peak demand load data.
9. **Market Electricity Price.** This tab shows the average monthly price for market electricity, exclusive of transmission and other costs applicable to market transactions.[6]
10. **Capacity Ratings.** This tab shows the minimum and maximum seasonal net capacity ratings for each of the thermal generating units.
11. **Outage Rates.** This tab shows the forecasted annual average Equivalent Unplanned Outage Rate ("EUOR") for each of the thermal units.[7]

[4] Gas-fired units do not have VOM costs that are included in marginal costs.
[5] These values are comparable to the PROSYM output values shown in Column E. However, unlike the marginal costs shown in Column E, for simplicity, Column P excludes emissions allowances costs, which are complex to manually calculate and which typically result in a cost less than 0.08 cents/kWh.
[6] Market electricity prices are forecasted to vary hourly within each month.
[7] EUOR includes forced and maintenance outages and derates but excludes planned outages.

The entire attachment is Confidential and provided separately under seal.

Louisville Gas and Electric Company

Standard Rate Rider SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

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

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

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

RATE A: TIME-DIFFERENTIATED RATE

1. For summer billing months of June, July, August and September (on-peak hours)	$0.02282 per kWh	R
2. For winter billing months of December, January and February (on-peak hours)	$0.02236 per kWh	R
3. During all other hours (off-peak hours)	$0.02145 per kWh	R

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

On-peak hours for winter billing months of December through February are defined as weekdays (exclusive of holidays) from 6:01 A.M. to 9:00 P.M., Eastern Standard Time (under 2 above).

Off-peak hours are defined as all hours other than those listed as on-peak (under 3 above).

Company reserves the right to change the hours designated as on-peak from time to time as conditions indicate to be appropriate.

RATE B: NON-TIME-DIFFERENTIATED RATE

For all kWh purchased by Company	$0.02173 per kWh	R

DATE OF ISSUE: May 28, 2020

DATE EFFECTIVE: With Bills Rendered On and After June 30, 2020

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

KENTUCKY
PUBLIC SERVICE COMMISSION
Kent A. Chandler
Executive Director

EFFECTIVE
6/30/2020
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Attachment 1

2020 Avoided Energy Cost Filing
(cents/kWh)

Time Period	MW	Summer Peak Period	Winter Peak Period	Off Peak Period	Average Day
7/2020-6/2022	1	2.282	2.236	2.145	2.173
2020	1	2.237	2.169	2.098	2.124
2021	1	2.311	2.224	2.148	2.178
2022	1	2.368	2.287	2.183	2.218
2023	1	2.348	2.298	2.214	2.240
2024	1	2.373	2.343	2.245	2.272
2025	1	2.426	2.371	2.278	2.308

Attachment 2

2020 Avoided Energy Cost Filing

Planned Capacity Additions and Retirements

Year	Unit Added	Unit Retired	Summer Rating (MW)	Unit Type	Capacity Cost ($/kW)	Fuel Cost (cent/kWh)
2020						
2021		Zorn 1	14	CT		
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						

a PPL company

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Michael E. Hornung
Manager Pricing/Tariffs
T 502-627-4671
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mike.hornung @lge-ku.com

VIA ELECTRONIC TARIFF FILING SYSTEM

Mr. Kent A. Chandler
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

May 28, 2020

RE: ***Revised Louisville Gas and Electric Company Purchase Rates for Small Capacity Cogeneration and Small Power Production Qualifying Facilities***

Dear Mr. Chandler:

Louisville Gas and Electric Company ("LG&E") files herewith revised sheets of its Tariff P.S.C. Electric No. 12 Original Sheet No. 55, effective with bills rendered on and after June 30, 2020.

This filing is being made to revise the rates for both Time-Differentiated Rates and Non-Time-Differentiated rates. As supporting documentation for these revisions and to comply with 807 KAR 5:054, Section 5(2)(a), (b), and (c), the attached information is also being filed:

(1) Attachment 1 showing the estimated avoided energy cost on a cents per kilowatt-hour basis during daily, seasonal on-peak and off-peak periods, for the applicable period between July 2020 and June 2022 as well as by year for 2020 through 2025;

(2) Attachment 2 showing there is currently one unit retirement and no capacity additions included in the 10-year plan.

LG&E has updated its methodology for estimating the avoided energy cost included in this filing. The updated methodology (1) produces an avoided energy cost for one megawatt instead of 100 megawatts, (2) assumes the Small Capacity Cogeneration and Small Power Production Qualifying Facilities will have no impact on unit commitment, and (3) focuses on the two-year period to which the revised rates will be applied instead of the current year. This updated methodology provides a more accurate estimation of avoided energy costs by better reflecting the collective capacity of LG&E's Small Capacity Cogeneration and Small Power Production Qualifying Facilities, better estimating the operational impact of these facilities to LG&E's system, and more appropriately considering the applicable time period of the revised rates.

Please let me know if you have any questions regarding this filing.

Sincerely,

Michael E. Hornung

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 173

Responding Witness: William Steven Seelye

Q-173. Please provide each of the class cost of service models presented in Seelye Exhibits WSS-21 and 22 (LOLP, 12 CP, 6 CP) in excel format with formulas. Also provide all supporting workpapers, including excel spreadsheets with formulas. At a minimum, include the following supporting information:

a. the excel models used to develop the projected test year hourly system and rate class loads.

b. an excel spreadsheet containing the LOLP hourly results and the development of the LOLP rate class demand allocation factors, the 12 CP rate class demand allocation factors and the 6 CP rate class demand allocation factors.

c. the loss study used to support the energy and demand loss factors used in the class cost of service study.

A-173.

a. See attachment being provided in Excel format.

b. See attachment being provided in Excel format.

c. See attached.

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

LG&E AND KU SERVICES COMPANY

LG&E Power System
2010 Analysis of System Losses

August 2012

Prepared by:

Management Applications Consulting, Inc.
1103 Rocky Drive – Suite 201
Reading, PA 19609
Phone: (610) 670-9199 / Fax: (610) 670-9190

MANAGEMENT APPLICATIONS CONSULTING, INC.

1103 Rocky Drive • Suite 201 • Reading, PA 19609-1157 • 610/670-9199 • fax 610/670-9190 •www.manapp.com

August 16, 2012

Mr. Robert M. Conroy
Director of Rates
LG&E and KU Services Company
220 West Main Street
Louisville, KY 40202

RE: 2010 LOSS ANALYSIS – LG&E

Dear Mr. Conroy:

Transmitted herewith are the results of the 2010 Analysis of System Losses for LG&E and KU Services Company's Louisville Gas & Electric (LG&E) power system. Our analysis develops cumulative expansion factors (loss factors) for both demand (peak/kW) and energy (average/kWh) losses by discrete voltage levels applicable to metered sales data. Our analysis considers only technical losses in arriving at our final recommendations. Please note that the proposed loss factors include a common or system-wide transmission factor for both LG&E and KU studies.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detailed load research and sales data by voltage level, coupled with a summary of power flow data and power system model, forms the foundation for determining reasonable and representative power losses on the LG&E system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

Enclosure
PMN/rjp

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

This report presents LG&E 2010 Analysis of System Losses for the power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system for LG&E. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered kW and kWh sales data for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study were similar to prior studies and emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's peak hour power flow data and transformer plant investments in the model. In addition, measured and estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered poles.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated and actual Company load data provided the starting point for performing a “bottom-up” approach for calculating the remaining distribution losses. Basically, this “bottom-up” approach develops line loadings by first determining loads and losses at each level beginning at a customer’s meter service entrance and then going through secondary lines, line transformers, primary lines, and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on page 4.

Appendix A of this report presents the Transmission loss analysis which was calculated separately and the results incorporated into the final loss factors as shown on Table 1 on the next page.

Table 1 (columns (a) and (b)) also provides the final results from Appendix B for the 2010 calendar year. Exhibits 8 and 9 of Appendix B present a more detailed analysis of the final calculated summary results of losses by segments and delivery voltage of the power system. The following Table 1 cumulative loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system’s input level.

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

TABLE 1
Loss Factors at Sales (Meter) Level, Calendar Year 2010

Voltage Level of Service	Total LG&E	Delivery System (Excludes Transmission)	Recalculated Total LG&E With Appendix A Transmission Losses	
	(a)	(b)	(c)	(d) = 1/(c)
Demand (kW)				
Transmission[1]	1.01549	1.00000	1.02805	0.97272
Primary Substation	1.02152	1.00594	1.03415	0.96698
Primary	1.04295	1.02704	1.05585	0.94710
Secondary	1.06325	1.04703	1.07640	0.92902
Energy (kWh)				
Transmission[1]	1.01033	1.00000	1.02271	0.97779
Primary Substation	1.01619	1.00581	1.02865	0.97215
Primary	1.02998	1.01946	1.04261	0.95913
Secondary	1.05325	1.04160	1.06525	0.93875

Losses – Net System Input[2]	4.37% MWh
	5.56% MW
Losses – Net System Output[3]	4.57% MWh
	5.89% MW

Notes: *Column (a)* *Results derived from Appendix A for Transmission and Appendix B for all remaining factors.*

Column (b) *Column (a) loss factors excluding all Transmission-related losses.*

Column (c) *Column (b) delivery-only loss factors with incorporating the composite LGEE system-wide Transmission loss factors from Appendix A, Schedule 1, lines 5 and 10.*

Column (d) *All loss factors presented in columns (a), (b), and (c) are expansion factors applicable to metered sales as a multiplier. Column (d) is simply the inverse of column (c) and results in a loss factor that is used to divide metered sales to derive sales requirement at input.*

The loss factors presented in the Delivery Only column of Table 1 are the Total LG&E loss factors divided by the transmission loss factor from column (a) in order to remove these losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.04703 includes the recovery of all remaining non-transmission losses from the distribution substation, primary lines, line transformers, secondary conductors and services.

[1] Reflects results for 500 kV, 345 kV, 161 kV, 138 kV and 69 kV from Appendix A.
[2] Net system input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendix A, Exhibit 1, for their calculations.
[3] Net system output uses losses divided by output or sales data as a reference.

The net system input shown in Table 1 represents the MWh losses of 4.37% for the total LG&E load using calculated losses divided by the associated input energy to the system. The 5.56% represents the MW losses also using system input as a reference. The net system output reference shown in Table 1 represents MWh losses of 4.57% and MW losses of 5.89%. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the data and results shown on Exhibits 1, 7 and 9 of the study.

Due to the very nature of losses being primarily a function of equipment loadings, the loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or –) in loads throughout the power system. It is therefore important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery based on prospective fixed loss factors for each service voltage.

The derivation of the cumulative loss factors (Appendix B) shown in Table 1 (columns (a) and (b)) have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 2).

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

Figure 1

MANAGEMENT APPLICATIONS CONSULTING, INC.
ELECTRIC LOSS MODEL OVERVIEW

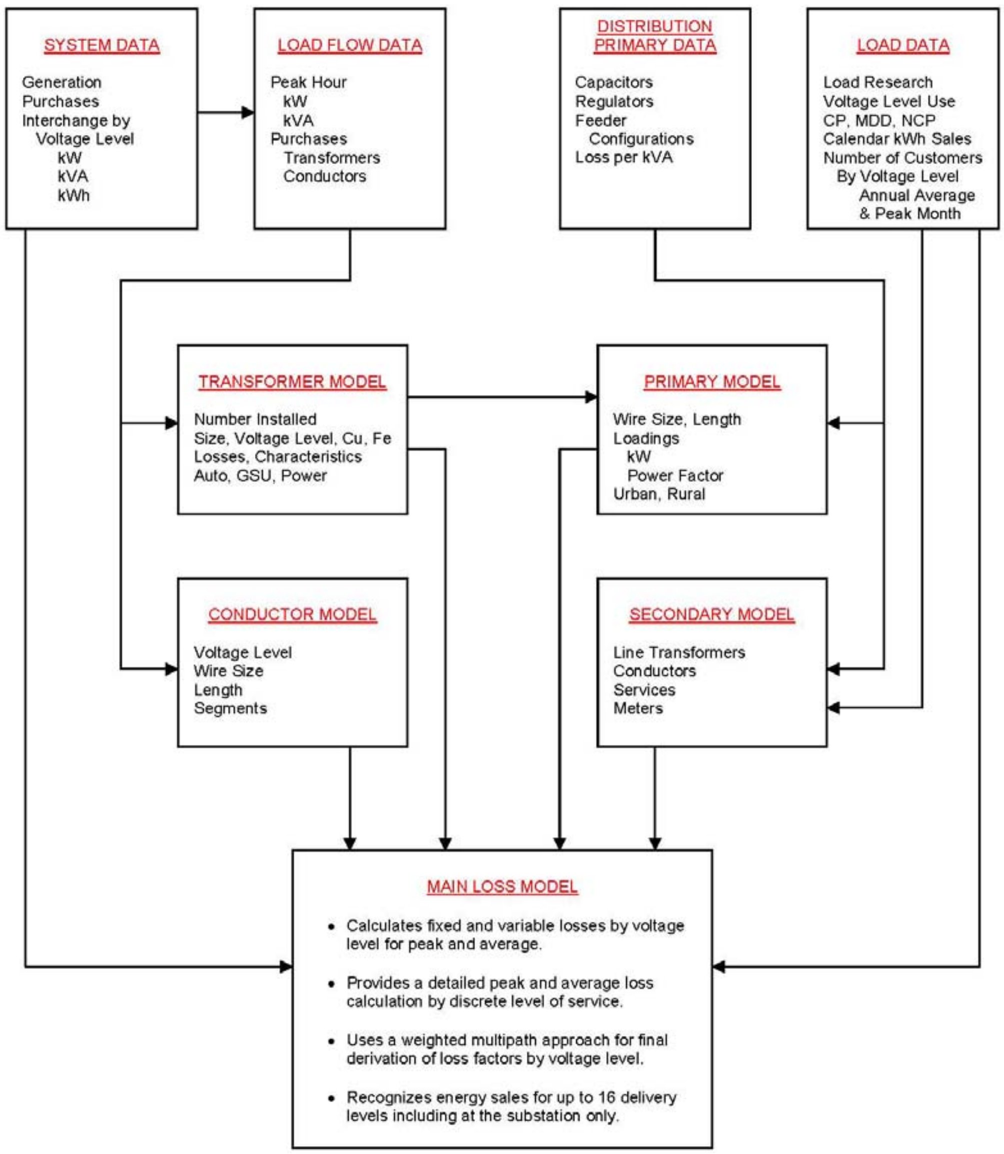
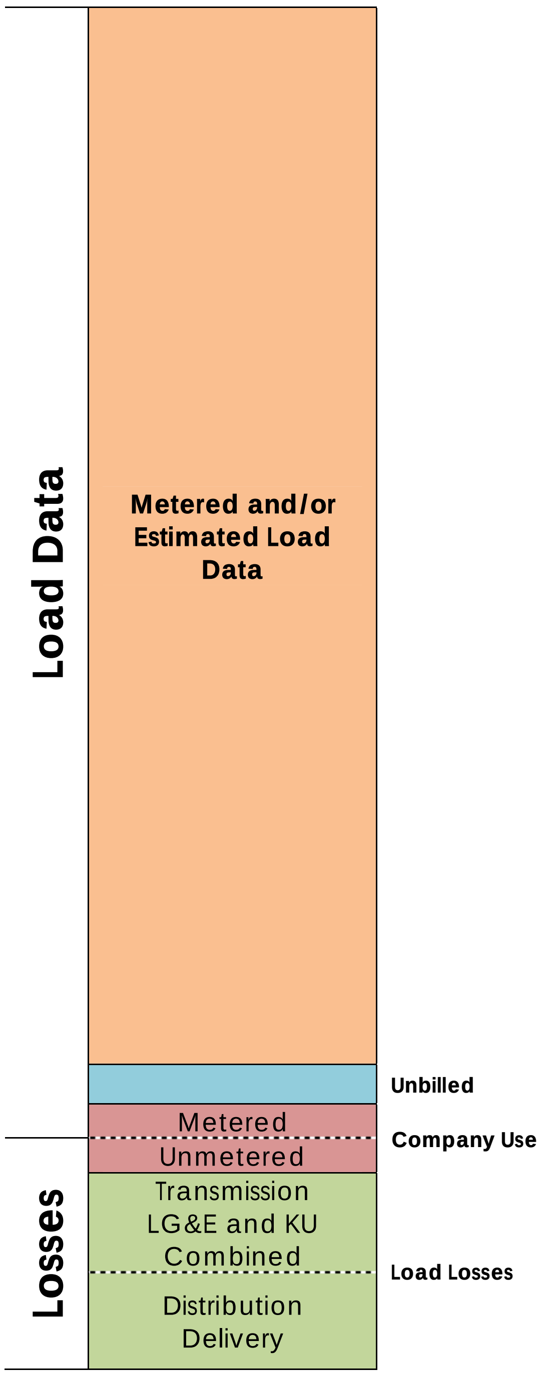


Figure 2
LG&E and KU Services Company – LG&E Jurisdiction Energy and Loss Components



2.0 INTRODUCTION

This report of the 2010 Analysis of System Losses for the LG&E power system provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total kWh requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[4] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC provided assistance as necessary to construct databases, transfer files, perform calculations, and check the reasonableness of results. A review of the preliminary results provided for additions to the database and modifications to certain initial assumptions based on available data. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information concerning peak demand and annual energy requirements by voltage level,
2. High voltage power system power flow data and associated loss calculations,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage for peak demand (kW) and annual energy (kWh) requirements at the point of delivery (meter).

[4]Copyright by Management Applications Consulting, Inc.

2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of these losses is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are proportional to the square of the current (I^2R). These losses can be as high as 75% of all technical losses. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required by a power system to energize various electrical equipment regardless of their loading levels. The major portion of no-load losses consists of core or magnetizing energy related to installed transformers throughout the power system.

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level as appropriate because we assume that improving technology and utility practices have minimized these amounts.

2.3 Description of Model

The loss model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.

- Transformer sheet which contains data input and loss calculations for each distribution substation. Separate iron and copper losses are calculated for each transformer by identified type.

Appendix A presents a separate hourly loss study result which derived the loss factors for the combined LGEE system-wide Transmission only (69 kV through 500 kV) of the LG&E and KU power system. These Transmission results are then incorporated on Table 1 of the Executive summary to derive the final LG&E 2010 loss factors by voltage level of energy delivery.

Appendix B presents a detailed loss study result which derives the loss factors for the Company's system-wide power system. Appendix B, Exhibits 8 and 9, presents the final detailed summary results of the demand and energy losses for each major portion of the total LG&E power system.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)

    - MWH generation and MWH sales.
    - Coincident peak estimates and net power supply input from all sources and voltage levels.
    - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
    - System default values, such as power factor, loading factors, and load factors by voltage level.

2. High Voltage System (Appendix A)

- Conductor information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company's power flow data with the losses calculated and incorporated into the final loss calculations.

- Transformer information was developed in a database to model transformation at each voltage level. Substation power, step-up, and auto transformers were individually identified along with any operating data related to loads and losses.

- Power flow data and calculations for each hour (8760) formed the basis for the peak and annual load losses in the high voltage (500 kV through 69 kV) loss calculations.

3. Distribution System (Appendix B)

- Distribution Substations – Data was developed for modeling each substation as to its size and loading. The Company provided loss characteristics for each transformer. Loss calculations were performed from this data to determine no load losses separately for each transformer. The annual load losses were calculated using an average load level for each transformer which replaced the prior Hoebel formula method.

- Primary lines – Line loading and loss characteristics for several representative primary circuits were obtained from the Company. These loss results developed kW loss per MW of load and a composite average percentage was calculated to derive the primary loss estimate.

- Line transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and to calculate load and no load losses.

- Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.

- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.

- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.

- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.

- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated (Appendix B, Exhibits 6 and 7).

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk and Transmission Lines (500 kV – 69 kV)

The transmission line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow data and configuration for the entire integrated Power System (Appendix A). Specific information as to length of line, type of conductor, voltage level, and hourly loading were utilized as data input in the power flow analyses.

Actual MW and MVA line loadings were based on LG&E’s hourly loading conditions. Calculations of line losses were performed and summarized by fixed and variable components for both Transmission and GSU facilities for reporting purposes as shown in Appendix A of this report.

3.2.2 Bulk and Transmission Transformers

The transmission transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and copper losses within each of these transformer types in order to obtain reasonable peak (kW) and average annual energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of copper losses due to hourly equipment loadings.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor of 0.10%. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed the lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, and grounding transformers.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

<u>Distribution Substations</u>

The Distribution Substation loss derivation required several steps to recognize the loss characteristics relating to iron or fixed losses versus the copper or load varying (I^2R) losses. The fixed component was based on Company loss characteristics from manufacturer's test results. The annual variable loss calculations considered a different approach by using an average hourly loading level and used this to the peak hour losses as a ratio $(\text{average/peak})^2$ times 8760 hours with an average adjustment factor and peak hour losses.

<u>Primary Lines</u>

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Primary line loss estimates were prepared by the Company for use in this loss study. These estimates considered loads per substation, voltage levels, loadings, total circuit miles, wire size, and single- to three-phase investment estimates. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate copper and iron losses for distribution line transformers, based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

A calculation of secondary line circuit losses was performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of these investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit is provided in Appendices A and B:

<u>Exhibit 1 – Summary of Company Data</u>

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

<u>Exhibit 2 – Summary of Conductor Information</u>

A summary of MW and MWH load and no load losses for Distribution conductors by voltage levels is presented. The sum of all calculated losses by high voltage is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

<u>Exhibit 3 – Summary of Transformer Information</u>

This exhibit summarizes Distribution transformer losses by various types and voltage levels throughout the system. Load losses reflect the copper portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using an average load loss factor for copper and the annual load losses times the test year hours.

<u>Exhibit 4 – Summary of Losses Diagram (2 Pages)</u>

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distribution system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

<u>Exhibit 5 – Summary of Sales and Calculated Losses</u>

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 – Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 – Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to the kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the LG&E power system.

Exhibit 9 – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on reported metered sales.

Appendix A

Results of LGEE (LG&E and KU) Transmission System 2010 Loss Analysis

Louisville Gas and Electric Company (LGE)
Kentucky Utilities Company (KU)
2011 Transmission Loss Analysis

Louisville Gas and Electric Company (LGE)
Kentucky Utilities Company (KU)
2011 Transmission Loss Analysis

Schedule 5, Page 9	Summary of seasonal peak hour MW and average MWH loss results for KU by season and voltage level.

Appendices:

Page 10	A - Peak Demand
Page 11	B - Monthly Energy
Page 12	C - Energy Summary
Page 13	D - Demand Summary
	Appendices include summaries of hourly calculation of losses for each identified type at transmission voltage levels by season identified by fixed and variable with GSU losses identified separately.

Workpapers:

Page 14	1 - LGE
Page 15	2 - KU
	Workpapers 1 and 2 present detailed summary results of eight separate power flows for each control area (LGE and KU) for a total of sixteen unique simulations and loss results.
	3 - Corona Loss Calculations
Page 16	Page presents the Corona loss estimate and calculations by voltage level and control area (LGE and KU) for the peak in MW and the annual MWH for 2010.
Page 17	Page presents the pole miles by company and voltage level.

LGEE (LGE & KU) 2011 TRANSMISSION LOSS ANALYSIS (1)

		LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
I	**TRANSMISSION LOSSES WITH GSU**					
	A. DEMAND	**Peak (MW) Summer (June - September)**				
1	LGE	57.9	27.8%	4,060	4,002	1.01448
2	KU	150.3	72.2%	4,865	4,715	1.03187
3	Total Demand Losses Combined (3)	208.2	100.0%	7,905	7,697	1.02705
4	Unmetered Station Use Adjustment					0.00100
5	Demand Loss Factor					1.02805
	B. ENERGY	**Annual MWH**				
6	LGE	199,404	21.5%	21,626,727	21,427,323	1.00931
7	KU	727,568	78.5%	27,462,725	26,735,158	1.02721
8	Total Energy Losses Combined (3)	926,971	100.0%	43,634,621	42,707,650	1.02171
9	Unmetered Station Use Adjustment					0.00100
10	Energy Loss Factor					1.02271

	II TRANSMISSION GSU LOSSES	**LOSSES (MW)**			**LOSSES (MWH)**		
		FIXED	**VARIABLE**	**TOTAL**	**FIXED**	**VARIABLE**	**TOTAL**
	A. GSU LOSSES (2)						
11	LGE	2.90	8.50	11.40	15,715	38,826	54,541
12	KU	2.40	5.40	7.80	14,820	25,784	40,604
13	Total GSU Losses	5.30	13.90	19.20	30,535	64,610	95,145

		LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
III	**TRANSMISSION ONLY LOSSES**					
	A. DEMAND LOSSES (Loss II-A)	**Peak (MW) Summer (June - September)**				
14	LGE	46.5	24.6%	4,049	4,002	1.01163
15	KU	142.5	75.4%	4,857	4,715	1.03021
16	Total Demand Combined (2)	189.0	100.0%	7,886	7,697	1.02456
17	Unmetered Station Use Adjustment					0.00100
18	Demand Loss Factor					1.02556
	B. ENERGY LOSSES (Loss II-A)	**Annual MWH**				
19	LGE	144,863	17.4%	21,572,186	21,427,323	1.00676
20	KU	686,964	82.6%	27,422,121	26,735,158	1.02570
21	Total Energy Combined (2)	831,826	100.0%	43,539,476	42,707,650	1.01948
22	Unmetered Station Use Adjustment					0.00100
23	Energy Loss Factor					1.02048

Notes:
(1) Study Period from February 2011 through January 2012.
(2) GSU losses from Schedule 3.
(3) See Schedule 1A, Schedule 1B, and Schedule 2.

LGE 2011 TRANSMISSION LOSS ANALYSIS

		LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
I	**TRANSMISSION LOSSES WITH GSU**				
	A. DEMAND	**Peak (MW) Summer (June - September)**			
1	LGE	57.9	4,060	4,002	1.01448
2	Unmetered Station Use Adjustment				0.00100
3	Demand Loss Factor				1.01548
	B. ENERGY	**Annual MWH**			
4	LGE	199,404	21,626,727	21,427,323	1.00931
5	Unmetered Station Use Adjustment				0.00100
6	Energy Loss Factor				1.01031

		LOSSES (MW)			LOSSES (MWH)		
II	**TRANSMISSION GSU LOSSES**	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
	A. GSU LOSSES (1)						
7	LGE	2.90	8.50	11.40	15,715	38,826	54,541

		LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
III	**TRANSMISSION ONLY LOSSES**				
	A. DEMAND LOSSES	**Peak (MW) Summer (June - September)**			
8	LGE (Line 1 - Line 7)	46.5	4,049	4,002	1.01163
9	Unmetered Station Use Adjustment				0.00100
10	Demand Loss Factor				1.01263
	B. ENERGY LOSSES	**Annual MWH**			
11	LGE (Line 4 - Line 7)	144,863	21,572,186	21,427,323	1.00676
12	Unmetered Station Use Adjustment				0.00100
13	Energy Loss Factor				1.00776

Notes:
1. GSU losses from Schedule 3.
2. See Schedule 2

KU 2011 TRANSMISSION LOSS ANALYSIS

			LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
I	TRANSMISSION LOSSES WITH GSU					
	A.	DEMAND	Peak (MW) Summer (June - September)			
1		KU	150.3	4,865	4,715	1.03187
2		Unmetered Station Use Adjustment				0.00100
3		Demand Loss Factor				1.03287
	B.	ENERGY	Annual MWH			
4		KU	727,568	27,462,725	26,735,158	1.02721
5		Unmetered Station Use Adjustment				0.00100
6		Energy Loss Factor				1.02821

			LOSSES (MW)			LOSSES (MWH)		
II	TRANSMISSION GSU LOSSES		FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
	A.	GSU LOSSES (1)						
7		KU	2.40	5.40	7.80	14,820	25,784	40,604

			LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
III	TRANSMISSION ONLY LOSSES					
	A.	DEMAND LOSSES	Peak (MW) Summer (June - September)			
8		KU (Line 1 - Line 7)	142.5	4,857	4,715	1.03021
9		Unmetered Station Use Adjustment				0.00100
10		Demand Loss Factor				1.03121
	B.	ENERGY LOSSES	Annual MWH			
11		KU (Line 4 - Line 7)	686,964	27,422,121	26,735,158	1.02570
12		Unmetered Station Use Adjustment				0.00100
13		Energy Loss Factor				1.02670

Notes:
1. GSU losses from Schedule 3.
2. See Schedule 2

LGEE (LGE & KU) POWER FLOW RESULTS - SUMMARY OF LOSSES

TRANSMISSION LOSSES WITH GSU	PEAK (SUMMER) Total (MW)	PEAK (SUMMER) % of Total System Losses	PEAK (OTHER) Total (MW)	PEAK (OTHER) % of Total System Losses	ANNUAL Total Annual (MWH)	ANNUAL % of Total System Losses
LGE						
1 Transmission Use (Peak MW, Annual MWH)	4,002		3,300		21,427,323	
2 Input (Line 1 + Line 5)	4,060		3,328		21,626,727	
Transmission						
3 Fixed	5.9	2.9%	5.2	2.3%	43,657	4.7%
4 Variable	52.0	25.0%	22.5	10.0%	155,747	16.8%
5 Total Transmission - LGE	57.9	27.8%	27.7	12.3%	199,404	21.5%
6 Losses % of Input (Line 5/Line 2)	1.43%		0.83%		0.92%	
7 Losses % of Output (Line 5/Line 1)	1.45%		0.84%		0.93%	
KU						
8 Transmission Use (Peak MW, Annual MWH)	4,715		4,961		26,735,158	
9 Input (Line 8 + Line 12)	4,865		5,159		27,462,725	
Transmission						
10 Fixed	8.2	3.9%	8.1	3.6%	67,476	7.3%
11 Variable	142.0	68.2%	190.0	84.1%	660,091	71.2%
12 Total Transmission - KU	150.3	72.2%	198.1	87.7%	727,568	78.5%
13 Losses % of Input (Line 12/Line 9)	3.09%		3.84%		2.65%	
14 Losses % of Output (Line 2/Line 8)	3.19%		3.99%		2.72%	
TOTAL LGE & KU						
15 LGEE Load (Peak MW, Annual MWH) Input	8,925		8,487		49,089,452	
16 LGE Energy Delivery to KU	-1,020		-1,228		-5,454,831	
17 Total Load (Peak MW, Annual MWH)	7,905		7,259		43,634,621	
Transmission						
18 Fixed	14.2	6.8%	13.4	5.9%	111,133	12.0%
19 Variable	194.0	93.2%	212.5	94.1%	815,838	88.0%
20 Total System	208.2	100.0%	225.9	100.0%	926,971	100.0%
21 Losses % of Input (Line 20/Line 15)	2.33%		2.66%		1.89%	
22 Losses % of Output (Line 20/(Line 15/Line 20))	2.39%		2.73%		1.92%	

COMBINED LGEE DELIVERED ENERGY & LOSSES

	SUMMER		WINTER		ANNUAL	
23 LGEE Load (All data in MWH) Output	17,146,907		31,015,574		48,162,481	
24 LGE Energy Delivery to KU	-1,689,262		-3,765,569		-5,454,831	
25 Total Load (Annual MWH) Output	15,457,645		27,250,005		42,707,650	
Transmission Losses						
26 Fixed	37,940	11.1%	73,193	12.5%	111,133	12.0%
27 Variable	303,970	88.9%	511,869	87.5%	815,838	88.0%
28 Total Transmission Losses	341,909	100.0%	585,062	100.0%	926,971	100.0%
29 Losses % of Output (Line 28/Line 23)	1.99%		1.89%		1.92%	

LGEE (LGE & KU) POWER FLOW RESULTS - TOTAL TRANSMISSION

CONDUCTOR AND TRANSFORMER LOSSES (MW)

	TIME	MW TRANSMISSION USE	Transmission Fixed	Transmission Variable	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer	Load Adjustment for Combined Only
	OTHER - LGE							
1	PEAK - MW	3,300	3.15	16.50	2.10	6.00	27.75	1228.00
2	LOSS % TO LOAD		0.095%	0.500%	0.064%	0.182%	0.841%	
3	LOSS % TO TOTAL LOSSES		11.349%	59.461%	7.568%	21.622%	100.000%	
4								
5	OTHER MWH	13,679,183	18,668	63,034	10,054	24,023	115,779	3,765,569
6	LOSS % TO LOAD		0.136%	0.461%	0.073%	0.176%	0.846%	
7	LOSS % TO TOTAL LOSSES		16.124%	54.443%	8.684%	20.749%	100.000%	
	SUMMER - LGE							
8	PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95	1020.00
9	LOSS % TO LOAD		0.076%	1.087%	0.072%	0.212%	1.448%	
10	LOSS % TO TOTAL LOSSES		5.262%	75.066%	5.004%	14.668%	100.000%	
11								
12	SUMMER MWH	7,748,140	9,274	53,887	5,661	14,803	83,625	1,689,262
13	LOSS % TO LOAD		0.120%	0.695%	0.073%	0.191%	1.079%	
14	LOSS % TO TOTAL LOSSES		11.090%	64.439%	6.770%	17.702%	100.000%	
	TOTAL ANNUAL - LGE							
15	SUMMER PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95	1020.00
16	ANNUAL MWH	21,427,323	27,942	116,921	15,715	38,826	199,404	5,454,831
17	LOSS % TO TOTAL ANNUAL OUTPUT		0.130%	0.546%	0.073%	0.181%	0.931%	
	LOSS FACTORS - LGE							
18	Demand						1.01448	
19	Energy						1.00931	
	OTHER - KU							
20	PEAK - MW	4,961	5.81	183.94	2.30	6.10	198.15	
21	LOSS % TO LOAD		0.117%	3.708%	0.046%	0.123%	3.994%	
22	LOSS % TO TOTAL		2.930%	92.831%	1.161%	3.079%	100.000%	
23								
24	OTHER MWH	17,336,391	35,105	408,661	9,366	16,151	469,283	
25	LOSS % TO LOAD		0.202%	2.357%	0.054%	0.093%	2.707%	
26	LOSS % TO TOTAL LOSSES		7.481%	87.082%	1.996%	3.442%	100.000%	
	SUMMER - KU							
27	PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25	
28	LOSS % TO LOAD		0.123%	2.898%	0.051%	0.115%	3.187%	
29	LOSS % TO TOTAL		3.864%	90.945%	1.597%	3.594%	100.000%	
30								
31	SUMMER MWH	9,398,766	17,551	225,647	5,454	9,633	258,285	
32	LOSS % TO LOAD		0.187%	2.401%	0.058%	0.102%	2.748%	
	TOTAL ANNUAL - KU							
33	PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25	
34	ANNUAL MWH	26,735,158	52,656	634,307	14,820	25,784	727,568	
35	LOSS % TO TOTAL ANNUAL OUTPUT		0.197%	2.373%	0.055%	0.096%	2.721%	
	LOSS FACTORS - KU							
36	Demand						1.03187	
37	Energy						1.02721	
	TOTAL ANNUAL - LGEE OUTPUT & LOSSES							
38	PEAK SUMMER - MW	8,717	8.86	180.15	5.30	13.90	208.20	1020.00
39	SUMMER MWH	17,146,907	26,825	279,534	11,115	24,436	341,909	1,689,262
40	PEAK OTHER MW	8,262	8.96	200.44	4.40	12.10	225.90	1228.00
41	OTHER MWH	31,015,574	53,773	471,695	19,420	40,174	585,062	3,765,569
42	ANNUAL MWH	48,162,481	80,598	751,228	30,535	64,610	926,971	5,454,831

LGE POWER FLOW RESULTS

CONDUCTOR AND TRANSFORMER LOSSES (MW)

	TIME	MW-LGE TRANSMISSION USE	Transmission Fixed (4)	Transmission Variable	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer
	OTHER - LGE						
1	PEAK - MW	3,300	3.15	16.50	2.10	6.00	27.75
2	LOSS % TO LOAD		0.095%	0.500%	0.064%	0.182%	0.841%
3	LOSS % TO TOTAL LOSSES		11.349%	59.461%	7.568%	21.622%	100.000%
4							
5	OTHER MWH	13,679,183	18,668	63,034	10,054	24,023	115,779
6	LOSS % TO LOAD		0.136%	0.461%	0.073%	0.176%	0.846%
7	LOSS % TO TOTAL LOSSES		16.124%	54.443%	8.684%	20.749%	100.000%
	SUMMER - LGE						
8	PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95
9	LOSS % TO LOAD		0.076%	1.087%	0.072%	0.212%	1.448%
10	LOSS % TO TOTAL LOSSES		5.262%	75.066%	5.004%	14.668%	100.000%
11							
12	SUMMER MWH	7,748,140	9,274	53,887	5,661	14,803	83,625
13	LOSS % TO LOAD		0.120%	0.695%	0.073%	0.191%	1.079%
14	LOSS % TO TOTAL LOSSES		11.090%	64.439%	6.770%	17.702%	100.000%
	TOTAL ANNUAL - LGE						
15	SUMMER PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95
16	LOSS % TO SUMMER PEAK MW		0.076%	1.087%	0.072%	0.212%	1.448%
17	ANNUAL MWH	21,427,323	27,942	116,921	15,715	38,826	199,404
18	LOSS % TO ANNUAL MWH		0.130%	0.546%	0.073%	0.181%	0.931%
	LOSS FACTORS - LGE						
19	Demand						1.01448
20	Energy						1.00931

NOTES:
(1) Summer Period includes June, July, August, and September.
(2) Other Period includes all non Summer Period months.
(3) Transmission Use = Load + Exports + Passthroughs
(4) Transmission Fixed includes Corona Losses

KU POWER FLOW RESULTS

CONDUCTOR AND TRANSFORMER LOSSES (MW)

	TIME	MW-KU TRANSMISSION USE	Transmission Fixed (4)	Transmission Variable (5)	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer
	OTHER - KU						
1	PEAK - MW	4,961	5.81	183.94	2.30	6.10	198.15
2	LOSS % TO LOAD		0.117%	3.708%	0.046%	0.123%	3.994%
3	LOSS % TO TOTAL LOSSES		2.930%	92.831%	1.161%	3.079%	100.000%
4							
5	OTHER MWH	17,336,391	35,105	408,661	9,366	16,151	469,283
6	LOSS % TO LOAD		0.202%	2.357%	0.054%	0.093%	2.707%
7	LOSS % TO TOTAL LOSSES		7.481%	87.082%	1.996%	3.442%	100.000%
	SUMMER - KU						
8	PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25
9	LOSS % TO LOAD		0.123%	2.898%	0.051%	0.115%	3.187%
10	LOSS % TO TOTAL LOSSES		3.864%	90.945%	1.597%	3.594%	100.000%
11							
12	SUMMER MWH	9,398,766	17,551	225,647	5,454	9,633	258,285
13	LOSS % TO LOAD		0.187%	2.401%	0.058%	0.102%	2.748%
14	LOSS % TO TOTAL LOSSES		6.795%	87.364%	2.112%	3.730%	100.000%
	TOTAL ANNUAL - KU						
15	SUMMER PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25
16	LOSS % TO SUMMER PEAK MW		0.123%	2.898%	0.051%	0.115%	3.187%
17	ANNUAL MWH	26,735,158	52,656	634,307	14,820	25,784	727,568
18	LOSS % TO ANNUAL MWH		0.197%	2.373%	0.055%	0.096%	2.721%
	LOSS FACTORS - KU						
19	Demand						1.03187
20	Energy						1.02721

NOTES:
(1) Summer Period includes June, July, August, and September.
(2) Other Period includes all non Summer Period months.
(3) Transmission Use = Load + Exports + Passthroughs
(4) Transmission Fixed includes Corona Losses
(5) Transmission Variable includes Losses at 0.5% from Appendix A (MW) and Appendix B (MWH)

	Kentucky Utilities	OTHER	SUMMER	OTHER	SUMMER
		2/11/11 8:00	7/11/11 16:00		
		February-11	July-11		
	Loads:				
1	KU Load (including losses)	4,292	4,102		
2	EKPC on KU	446	355		
3	TVA on KU	59	58		
4	OMU Load (3%)	-	12		
5	BREC on KU	6	6		
6	KMPA Load (3%)	108	129		
7	Total Load	4,911	4,662	4,911.00	4,662.00
	Export (Delivered):				
8	KU Off-System Sales	-	-		
9	AMEM - Pass Through	-	-		
10	CARGILL - Pass Through	-	-		
11	OMU Exports	249	204		
12	KMPA Exports	-	-		
13	Constellation - Pass Through	-	-		
14	TEA - Pass Through	-	-		
15	TVA (OATT) - Pass Through	-	-		
16	Total Exports	249	204	249.00	204.00
17	BTM (0.5%) - OMU Network Load	112	182		
18	BTM (0.5%) - KMPA Gen	-	49		
19	Total BTM	112	231		
				5,160.00	4,866.00
20	Losses at 0.5%	0.560	1.155		
21	Losses from Schedule 5, Lines 1 and 8			-198.71	-151.41
22	Peak MW Load			4,961.29	4,714.59
	Louisville Gas and Electric				
	Loads:				
23	LGE Load (including losses)	1,725	2,654		
23	EKPC on LGE	61	77		
24	Hoosier on LGE	5	6		
25	Total Load	1,791	2,737	1,791.00	2,737.00
	Export (Delivered):				
26	IMEA	146	146		
27	IMPA	155	157		
28	LGE Off-System Sales	8	-		
29	OVEC to SIGE	-	-		
30	Total Exports	309	303	309.00	303.00
31	LGE to KU	1,228	1,020	1,228.00	1,020.00
				3,328.00	4,060.00
32	Losses from Schedule 4, Lines 1 and 8			-27.75	-57.95
33	Peak MW Load			3,300.25	4,002.05

Notes:
(1) Information above was gathered through the Peak Load spreadsheet which is used for FERC Form 1 data collection. Additionally, information was gathered from the individual billings each month, which also flows into FERC Form 1.
(2) OSS information was gathered through multiple spreadsheets from Revenue Accounting and Transmission groups.

Kentucky Utilities

Prepared by: FR/DH

	February-11	March-11	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	January-12	Total	Other	Summer
Loads:															
1 KU Load (including losses)	1,882,033	1,838,010	1,567,127	1,688,187	1,906,541	2,167,087	2,097,914	1,653,158	1,650,548	1,687,623	1,918,215	2,083,767	22,140,210		
2 EKPC on KU	192,766	183,756	155,967	163,451	164,293	182,579	182,121	147,273	142,289	161,421	192,322	213,632	2,081,870		
3 TVA on KU	30,019	26,656	20,497	22,985	27,885	34,587	29,211	21,634	19,664	26,719	36,278	34,830	330,965		
4 OMU Load (3%)	-	-	-	555	-	1,043	1,328	165	6,757	-	-	-	9,848		
5 BREC on KU	3,047	2,972	2,440	2,382	2,575	2,943	3,367	3,272	3,715	2,495	3,797	4,364	37,370		
6 KMPA Load (3%)	53,933	54,624	50,868	58,455	71,032	79,177	77,514	57,137	49,740	51,011	56,115	56,274	715,880		
7 Total Load	2,161,798	2,106,018	1,796,898	1,936,015	2,172,326	2,467,416	2,391,455	1,882,639	1,872,713	1,929,269	2,206,727	2,392,867	25,316,143	16,402,307	8,913,836
Export (Delivered):															
8 KU Off-System Sales	10,003	1,971	14	13,001	23,568	12,175	4,828	384	29,307	2,890	542	265	98,948		
9 AMEM - Pass Through	-	-	2,400	-	-	-	-	-	12,000	2,400	11,338	51,500	79,638		
10 CARGILL - Pass Through	31,261	100	-	23,399	2,400	-	-	20,527	13,749	70	-	-	91,506		
11 OMU Exports	165,206	183,023	175,905	50,051	156,463	143,444	137,842	155,042	106,507	137,874	176,030	158,940	1,746,327		
12 KMPA Exports	-	-	-	-	-	-	-	-	59	-	-	-	59		
13 Constellation - Pass Through	-	-	-	11,734	4,740	24,485	34,163	25,048	34,099	-	-	-	134,269		
14 TEA - Pass Through	-	-	-	-	-	-	-	-	59	66	-	-	125		
15 TVA (OATT) - Pass Through	-	-	308	-	-	-	-	-	-	-	-	-	308		
16 Total Exports	206,470	185,094	178,627	98,185	187,171	180,104	176,833	201,001	195,780	143,300	187,910	210,705	2,151,180	1,406,071	745,109
17 BTM (0.5%) - OMU Network Load	64,375	67,851	62,989	71,662	86,097	103,156	96,293	73,876	61,587	65,420	69,832	70,719	893,857		
18 BTM (0.5%) - KMPA Gen	-	-	-	1,054	4,315	9,837	4,422	858	1,839	-	1,479	1,872	25,677		
19 Total BTM	64,375	67,851	62,989	72,716	90,412	112,993	100,715	74,734	63,426	65,420	71,311	72,591	919,534		
20 Losses at 0.5%	322	339	315	364	452	565	504	374	317	327	357	363	4,598		
21 Total MWH Input														17,808,378	9,658,945
22 Losses from Schedule 5, Lines 5 and 12														-471,986	-260,179
23 Total MWH Output														17,336,391	9,398,766

Louisville Gas and Electric

	February-11	March-11	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	January-12	Total		
Loads:															
23 LGE Load (including losses)	903,869	935,217	852,840	998,568	1,189,433	1,431,090	1,316,506	968,118	877,979	870,461	958,046	988,020	12,290,147		
24 EKPC on LGE	25,617	24,530	20,953	24,482	30,141	37,883	33,856	23,583	21,869	22,649	27,706	29,346	322,615		
25 Hoosier on LGE	3,006	3,093	2,628	3,247	3,465	3,908	3,767	3,220	3,081	2,998	3,210	3,263	38,886		
26 Total Load	932,492	962,840	876,421	1,026,297	1,223,039	1,472,881	1,354,129	994,921	902,929	896,108	988,962	1,020,629	12,651,648	7,606,677	5,044,971
Export (Delivered):															
27 IMEA	87,925	74,691	45,921	89,073	102,288	100,626	86,582	74,691	75,238	61,640	90,715	99,872	989,262		
28 IMPA	93,431	79,319	48,912	94,516	107,515	106,729	90,741	77,329	79,575	65,340	97,587	105,971	1,046,965		
29 LGE Off-System Sales	155,240	139,458	45,904	124,917	96,244	96,890	49,158	108,739	205,726	207,341	158,716	95,688	1,484,021		
30 OVEC to SIGE	-	-	-	-	-	-	-	-	-	-	-	-	-		
31 Total Exports	336,596	293,468	140,737	308,506	306,047	304,245	226,481	260,759	360,539	334,321	347,018	301,531	3,520,248	2,422,716	1,097,532
32 LGE to KU	484,518	444,877	370,225	397,072	364,002	440,065	446,201	438,994	458,456	438,203	561,790	610,428	5,454,831	3,765,569	1,689,262
33 Total MWH Input														13,794,962	7,831,765
34 Losses from Schedule 4, Lines 5 and 12														-115,779	-83,625
35 Total MWH Output														13,679,183	7,748,140

Information above was gathered through the Peak Load spreadsheet which is used for FERC Form 1 data collection. Additionally, information was gathered from the individual billings each month, which also flows into FERC Form 1
OSS information was gathered through multiple spreadsheets from Revenue Accounting and Transmission groups.

LGEE Loss Summary

	LGE Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
1	O	01	1,944	8,405	1,405	3,124
2	O	02	1,753	7,950	1,165	3,114
3	O	03	1,970	8,159	1,205	3,317
4	O	04	1,923	6,323	1,217	2,547
5	O	05	1,978	9,932	1,207	3,076
6	S	06	1,877	13,384	1,289	3,615
7	S	07	1,933	16,655	1,542	4,380
8	S	08	1,940	15,067	1,454	3,936
9	S	09	1,915	8,781	1,376	2,872
10	O	10	1,999	7,087	1,180	2,917
11	O	11	1,937	6,926	1,273	2,856
12	O	12	1,960	8,252	1,402	3,072
13		Total	23,129	116,921	15,715	38,826
14		Summer Corona	1,609			
15	S	Total LGE Summer	9,274	53,887	5,661	14,803
16		Other Corona	3,204			
17	O	Total LGE Other	18,668	63,034	10,054	24,023

	KU Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
18	O	01	3,246	66,020	1,272	2,314
19	O	02	2,937	65,153	1,209	2,146
20	O	03	3,279	51,357	1,244	2,220
21	O	04	3,200	40,542	1,058	1,929
22	O	05	3,312	41,568	1,190	2,000
23	S	06	3,155	59,549	1,405	2,449
24	S	07	3,247	64,025	1,459	2,832
25	S	08	3,260	61,754	1,436	2,666
26	S	09	3,187	42,213	1,154	1,686
27	O	10	3,306	42,719	1,079	1,752
28	O	11	3,189	49,382	1,089	1,865
29	O	12	3,271	54,623	1,225	1,925
30		Total	38,589	638,905	14,820	25,784
31		Summer Corona	4,702			
32	S	Total KU Summer	17,551	227,541	5,454	9,633
33		Other Corona	9,365			
34	O	Total KU Other	35,105	411,364	9,366	16,151

	LGEE Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
35	O	01	5,190	74,425	2,677	5,438
36	O	02	4,690	73,103	2,374	5,260
37	O	03	5,249	59,516	2,449	5,537
38	O	04	5,123	46,865	2,275	4,476
39	O	05	5,290	51,500	2,397	5,076
40	S	06	5,032	72,933	2,694	6,064
41	S	07	5,180	80,680	3,001	7,212
42	S	08	5,200	76,821	2,890	6,602
43	S	09	5,102	50,994	2,530	4,558
44	O	10	5,305	49,806	2,259	4,669
45	O	11	5,126	56,308	2,362	4,721
46	O	12	5,231	62,875	2,627	4,997
47		Total	61,718	755,826	30,535	64,610
48		Summer Corona	6,311			
49	S	Total LGEE Summer	26,825	281,428	11,115	24,436
50		Other Corona	12,569			
51	O	Total LGEE Other	53,773	474,398	19,420	40,174

Notes:
(1) Includes Corona Losses from Workpaper 3

Summer Peak Hour 2011-07-11-1600

		Transmission Losses		Generation Losses	
		Fixed (1)	Variable	Fixed	Variable
1	KU	5.8	137.8	2.4	5.4
2	LG&E	3.0	43.5	2.9	8.5
3	Combined	8.9	181.3	5.3	13.9

Winter Peak Hour 2011-02-11-0800

		Transmission Losses		Generation Losses	
		Fixed (1)	Variable	Fixed	Variable
4	KU	5.8	184.5	2.3	6.1
5	LG&E	3.1	16.5	2.1	6.0
6	Combined	9.0	201.0	4.4	12.1

		Corona Losses (MW)
		Fixed (1)
7	KU	1.606
8	LG&E	0.549
9	Combined	2.155

Notes:
(1) Includes Corona Losses from Workpaper 3

Hour	LG&E Load	KU on LG&E	EKPC on LG&E	HE on LG&E	LG&E T Loss-f	LG&E T Loss-v	LG&E G Loss-f	LG&E G Loss-v	Net Export	BLG Export	Month
2011-02-01-0100	1217.7	6.3	35.6	4.3	2.6	11.5	1.7	4.6	1394.6	0	02
2011-02-01-0200	1179.1	6	34.4	4.4	2.6	11	1.7	4.4	1373.9	0	02
2011-02-01-0300	1147.9	5.8	33.6	4	2.6	10.8	1.7	4.3	1354.7	0	02
2011-02-01-0400	1138.1	5.6	33	4	2.6	11.6	1.7	4.3	1374.9	0	02
2011-02-01-0500	1149.1	5.7	33.8	3.9	2.6	12	1.7	4.5	1398.1	0	02
2011-02-01-0600	1201.1	6	37.3	4	2.6	12.5	1.7	4.6	1379.2	0	02
2011-02-01-0700	1347.6	6.8	41.9	4.1	2.6	15.3	1.7	5.6	1454.3	0	02
2011-02-01-0800	1429.8	7.2	43.4	4.3	2.6	15.6	1.7	5.6	1354.1	0	02
2011-02-01-0900	1431	7.1	41.9	4.7	2.6	15.6	1.7	5.5	1329.5	0	02
2011-02-01-1000	1424.8	7	41	4.6	2.6	15.4	1.7	5	1236.6	0	02
2011-02-01-1100	1440.5	7	40.8	4.6	2.6	14	1.7	4.6	1122.7	0	02
2011-02-01-1200	1442.4	6.9	40.3	4.5	2.6	14.3	1.7	4.7	1132	0	02
2011-02-01-1300	1438.7	6.8	40.3	4.5	2.6	14.5	1.7	4.8	1159.1	0	02
2011-02-01-1400	1394.7	6.7	39.4	4.4	2.6	13.6	1.7	4.6	1138.9	0	02
2011-02-01-1500	1371.6	6.6	39	4.6	2.6	13.2	1.7	4.3	1098	0	02
2011-02-01-1600	1388.5	6.7	39.7	4.6	2.6	13.2	1.7	4.2	1038.9	0	02
2011-02-01-1700	1408.8	6.8	41.6	4.3	2.6	13.5	1.7	4.3	1064.8	0	02
2011-02-01-1800	1448.7	7	44.2	4.3	2.6	14.7	1.7	4.6	1129.1	0	02
2011-02-01-1900	1483.7	7.2	45.7	4.4	2.6	15.1	1.7	4.8	1162.1	0	02
2011-02-01-2000	1450.8	7.1	45.2	4.7	2.6	15	1.7	4.6	1149.2	0	02
2011-02-01-2100	1414.2	7	44	4.7	2.6	14.5	1.7	4.6	1163.9	0	02
2011-02-01-2200	1337.9	6.6	41.1	4.6	2.6	12.8	1.7	4.5	1190.9	0	02
2011-02-01-2300	1255.5	6.1	37.2	4.2	2.6	11.5	1.7	4.1	1168.2	0	02
2011-02-02-0000	1140.4	5.7	32.8	4	2.6	9	1.7	3.4	1062.1	0	02
2011-02-02-0100	1076.3	5.4	30.7	4.3	2.6	8.1	1.7	3.2	1029.2	0	02
2011-02-02-0200	1046.7	5.3	30.5	4.2	2.6	7.9	2.1	3.3	1168.7	0	02
2011-02-02-0300	1071.2	5.4	32.4	4.1	2.6	8.1	2.1	3.5	1273.5	0	02
2011-02-02-0400	1101.7	5.7	35.5	4.2	2.6	8.3	2	3.6	1282.3	0	02
2011-02-02-0500	1162.1	6.1	38.3	4.3	2.6	9.4	2.1	4.2	1451.1	0	02
2011-02-02-0600	1230.2	7	42.9	4.5	2.6	10.5	2.1	4.6	1495.4	0	02
2011-02-02-0700	1387.9	8.1	49.3	4.7	2.6	13.1	2.1	5.6	1531.5	0	02
2011-02-02-0800	1502.7	9	51.8	4.6	2.6	15.4	2.1	6.5	1611.9	0	02
2011-02-02-0900	1511.5	9	50.4	4.6	2.6	15.2	2.1	6.3	1585.1	0	02
2011-02-02-1000	1514.9	9.3	49.8	4.8	2.6	15.1	2.1	6.2	1560.6	0	02
2011-02-02-1100	1544.2	9.1	49.4	4.9	2.6	15.6	2.1	6.4	1580	0	02
2011-02-02-1200	1552	9.1	49	4.7	2.6	15.7	2.1	6.4	1549	0	02
2011-02-02-1300	1558.5	9	48.6	4.5	2.6	15.9	2.1	6.8	1617.1	0	02
2011-02-02-1400	1559.7	8.9	48.3	4.5	2.6	16	2.1	6.7	1606.8	0	02
2011-02-02-1500	1554.9	8.8	47.3	4.5	2.6	15.8	2.1	6.6	1601.7	0	02
2011-02-02-1600	1538.9	8.7	47.9	4.6	2.6	15.6	2.1	6.5	1595	0	02
2011-02-02-1700	1537.9	8.6	50.4	5	2.6	15.6	2.1	6.9	1654.1	0	02
2011-02-02-1800	1556.3	9	52.5	5	2.6	15.6	2.1	6.7	1595.9	0	02
2011-02-02-1900	1616.8	9.4	56.5	5	2.6	16.6	2.1	6.5	1492.9	0	02
2011-02-02-2000	1618.7	9.4	57.6	5	2.6	16.6	2.1	6.5	1486	0	02

Hour	KU Load	KU on LG&E	KU on EKPC	EKPC on KU	BREC on KU	TVA on KU	OMU on KU	KMPA on KU	KU T Loss-f	KU T Loss-v	KU G Loss-f	KU G Loss-v	Net Export	OMU Export	PADP Gen	Month
2011-02-01-0100	2345.7	6.3	59.6	280.6	5	37.6	82	68.6	4.4	85.8	1.9	2.1	-1050.5	146.1	0	02
2011-02-01-0200	2259.9	6	57.9	265.6	4.9	35.2	83.5	65	4.4	82.9	1.9	1.9	-924.7	200.2	0	02
2011-02-01-0300	2191.3	5.8	56.9	257.6	4.7	33.7	82.5	63.8	4.4	82.7	1.9	1.8	-891.2	209	0	02
2011-02-01-0400	2131.8	5.6	56.5	257.6	4.7	32.5	83.8	63.4	4.4	88.1	1.9	1.9	-713	261.3	0	02
2011-02-01-0500	2137.1	5.7	56.5	259.3	4.5	32.5	85.3	64.1	4.4	88	1.9	2.1	-658.3	285.5	0	02
2011-02-01-0600	2244.3	6	58.2	274.8	5.3	33.8	86.3	66.1	4.4	92.3	1.9	2.3	-679.2	282.5	0	02
2011-02-01-0700	2500.3	6.8	62.4	286.8	5.5	37.6	91.7	72.1	4.3	103.6	1.9	3.5	-549.8	277.5	0	02
2011-02-01-0800	2682.1	7.2	67.2	271.4	5.6	43	102.2	82.5	4.3	100	1.9	3.5	-768.4	277	0	02
2011-02-01-0900	2691.9	7.1	68.7	287	5.7	40.3	110.7	88.1	4.3	100.7	1.9	3.5	-802.1	259.3	0	02
2011-02-01-1000	2698.6	7	69	273.9	6.1	38.8	111.1	91.6	4.3	100.1	1.9	3.5	-811.1	222.6	0	02
2011-02-01-1100	2693.2	7	68.6	279.1	5.4	38.7	111.1	92.6	4.4	92.6	1.9	3.1	-1025.6	139.2	0	02
2011-02-01-1200	2651	6.9	67.8	248.7	5.9	38.1	111	93.1	4.4	90.2	1.9	3	-973.1	146.9	0	02
2011-02-01-1300	2613.9	6.8	67	275.6	6	37.6	110	93.3	4.4	90.3	1.8	3.2	-891.5	181	0	02
2011-02-01-1400	2572.4	6.7	66.8	272.8	5.7	37.1	108.8	92.7	4.4	85.9	1.8	2.9	-969.7	143.2	0	02
2011-02-01-1500	2589.4	6.6	67.4	265.5	5.9	36.7	111.3	91.2	4.4	86.2	1.8	3.1	-898.7	166	0	02
2011-02-01-1600	2575.3	6.7	66.9	274.1	6.1	36.9	111.4	89.8	4.4	88.3	1.8	3.3	-812.7	181	0	02
2011-02-01-1700	2602.6	6.8	67.8	275.4	6.3	38.4	108.4	87.5	4.4	91.7	1.8	3.4	-803	190.5	0	02
2011-02-01-1800	2624.9	7	68.9	238.4	5.8	41.1	109.3	86.5	4.4	94.1	1.8	3.5	-723.5	205.5	0	02
2011-02-01-1900	2663.8	7.2	69.2	302.1	5.5	43.6	111.1	87.6	4.4	92.3	1.8	3.7	-789.1	204.2	0	02
2011-02-01-2000	2622.6	7.1	68.4	289	5.7	44.3	112.1	87.7	4.4	93.4	1.8	3.6	-713.7	256.7	0	02
2011-02-01-2100	2563.1	7	66.5	273.6	6	43.4	110.2	89.2	4.4	90.2	1.8	3.4	-687.2	282	0	02
2011-02-01-2200	2507.5	6.6	64.8	209.9	6.6	42.3	103.5	89.6	4.4	82.9	1.8	3	-751.7	205	0	02
2011-02-01-2300	2368.7	6.1	61.7	207	6	40.3	99.1	87.9	4.4	79.3	1.8	2.5	-830.1	182.7	0	02
2011-02-02-0000	2254.8	5.7	59.2	259.1	6.1	39.4	100.7	85.1	4.4	67.9	1.8	1.7	-1208.7	5.4	0	02
2011-02-02-0100	2176.4	5.4	57.5	224.2	5	38.8	96.9	81.1	4.4	58.5	1.8	1.6	-1101	62.2	0	02
2011-02-02-0200	2133.6	5.3	56.1	215.2	5.4	41	96.4	79.9	4.4	65.9	1.8	1.8	-950.7	105.5	0	02
2011-02-02-0300	2110	5.4	57.9	216.3	5.3	44.4	98.6	79.9	4.4	68.5	1.8	1.7	-899.7	151.2	0	02
2011-02-02-0400	2176.8	5.7	60.6	227	5.2	47	96.1	79.4	4.4	69.7	1.8	1.8	-955	156	0	02
2011-02-02-0500	2336.8	6.1	63.4	169.1	5	48.8	95.2	80.5	4.4	77.7	1.8	1.9	-1049.8	155.8	0	02
2011-02-02-0600	2567.8	7	68.1	194.7	5.6	52.8	96.9	83.3	4.4	88.2	1.8	2.4	-1133.3	155	0	02
2011-02-02-0700	2924.8	8.1	74.6	226.9	5.4	58.2	102.9	89.2	4.3	112.3	1.9	3.4	-1207.1	154.8	0	02
2011-02-02-0800	3226	9	81.8	238.4	5.4	64.2	113.3	99.3	4.3	124.3	1.9	4.5	-1232.2	149.9	0	02
2011-02-02-0900	3300.9	9	84.2	232.4	6	62.8	119.2	103.1	4.3	126.6	1.9	4.6	-1250.3	142.5	0	02
2011-02-02-1000	3382	9.3	84.9	235.4	6.4	63	121.8	105.2	4.3	133.4	1.9	4.8	-1295.4	137.9	0	02
2011-02-02-1100	3356	9.1	85.9	238.8	6.8	63.9	123.4	106.3	4.3	134.6	1.9	4.8	-1275.6	137.7	0	02
2011-02-02-1200	3363.5	9.1	86.2	239.7	6.6	62.9	123.4	106.9	4.3	136.2	2	4.8	-1235.3	138.5	0	02
2011-02-02-1300	3378.4	9	85.4	236.6	6.5	62.3	123.5	106.1	4.3	141.1	2	4.7	-1315.8	137.3	0	02
2011-02-02-1400	3340.1	8.9	85.3	232.6	7.3	60.8	125.9	104.4	4.3	142.4	2	4.7	-1293.7	137.4	0	02
2011-02-02-1500	3329	8.8	84.5	230.2	6.9	60.1	127.1	103.6	4.3	141.5	2	4.6	-1289.9	137.4	0	02
2011-02-02-1600	3260.3	8.7	83.9	232.4	7.1	60.1	125.4	102.5	4.3	139.7	2	4.5	-1250.9	138.6	0	02
2011-02-02-1700	3267.5	8.6	84.2	273.5	7.4	61.6	110.9	100.9	4.3	142.4	1.9	4.4	-1376.6	138.8	0	02
2011-02-02-1800	3385	9	85	325.2	7.4	64.4	112.4	102.1	4.3	138.9	1.9	4.6	-1384.8	180.4	0	02
2011-02-02-1900	3495.9	9.4	86.9	325.3	6.7	68.5	119	106.7	4.3	143.5	1.9	4.9	-1408.1	233.8	0	02
2011-02-02-2000	3498	9.4	87.8	340	6.3	69.5	122.9	108.5	4.3	146.4	1.9	4.9	-1405.7	260.1	0	02

LGE & KU - CORONA LOSS ESTIMATE

		VOLTAGE (kV)	MILES	CORONA PEAK LOSS FACTOR (MW Mile)	CORONA LOSSES (MW)	CORONA WINTER HOURS & LOSSES (MWH)	CORONA SUMMER HOURS & LOSSES (MWH)	CORONA TOTAL LOSSES (MWH)
A.	Fair Weather Corona Losses							
	LGE					5,832	2,928	
1		345	172	0.0032	0.549	3,204	1,609	4,813
2		161	116	0.0000	0.000	0	0	0
3		138	334	0.0000	0.000	0	0	0
4		69	289	0.0000	0.000	0	0	0
5	Subtotal		911		0.549	3,204	1,609	4,813
	KU					5,832	2,928	
6		500	57	0.0060	0.341	1,990	999	2,989
7		345	395	0.0032	1.265	7,375	3,703	11,078
8		161	518	0.0000	0.000	0	0	0
9		138	888	0.0000	0.000	0	0	0
10		69	2,218	0.0000	0.000	0	0	0
11	Subtotal		4,076		1.606	9,365	4,702	14,067
12	TOTAL		4,987		2.155	12,569	6,311	18,880
B.	Unmetered Station Use							
13	Estimated Unmetered Substation Use at				0.0010			

NOTE:
(1) Lines 5 and 11 loss results included in Schedules 3, 4, and 5.

LGE & KU

	Voltage by Company	Number of Miles LGE	KU	Total
1	**LGE**			
2	Overhead			
3	345	171.7		
4	161	116.4		
5	138	329.6		
6	69	286.3		
7	Total Overhead	904.0		904.0
8				
9	Underground			
10	138	4.0		
11	69	2.9		
12	Total Underground	6.9		6.9
13				
14	**Total LGE**	910.9		910.9
15				
16	**KU**			
17	500		56.9	
18	345		395.2	
19	161		518.2	
20	138		887.6	
21	69		2,218.4	
22				
23	**Total KU**		4,076.3	4,076.3
24				
25				
26	**Total Pole Miles**	910.9	4,076.3	4,987.2

Appendix B

Results of LG&E 2010 Loss Analysis

LG 2010 LOSS ANALYSIS

LG&E

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	2,852	MW
ANNUAL SYSTEM INPUT	12,966,029	MWH
ANNUAL SALES	12,399,868	MWH
SYSTEM LOSSES @ INPUT	566,161	or 4.37%
SYSTEM LOAD FACTOR	51.9%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	500,345,138 69	43.5	1.53%	27.43%	132,516	1.02%	23.41%
PRIM SUBS	33,12,1	16.2	0.57%	10.21%	70,977	0.55%	12.54%
PRIMARY	33,12,1	55.2	1.94%	34.83%	160,720	1.24%	28.39%
SECONDARY	120/240,to,477	43.7	1.53%	27.54%	201,948	1.56%	35.67%
TOTAL		158.6	5.56%	100.00%	566,161	4.37%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND (Peak) d	1/d	ENERGY (Annual) e	1/e
TOT TRANS	500,345,138 69	1.01549	0.98475	1.01033	0.98978
PRIM SUBS	33,12,1	1.02152	0.97894	1.01619	0.98407
PRIMARY	33,12,1	1.04295	0.95882	1.02998	0.97089
SECONDARY	120/240,to,477	1.06325	0.94052	1.05235	0.95025

SUMMARY OF CONDUCTOR INFORMATION

DESCRIPTION		CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	500 KV OR GREATER								
TIE LINES		0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT		0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	138 KV TO 500.00 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	345 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	138 KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT		0.0		0.000	0.000	0.000	0	0	0
--- SUBTRANS ------	35 KV TO 138 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	KV	0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	KV	0.0	0.00%	0.000	0.001	0.001	0	6	6
SUBTOT		0.0		0.000	0.001	0.001	0	6	6
PRIMARY LINES		6,278		50.143	2.685	52.828	129,898	23,520	153,418
SECONDARY LINES		3,543		4.845	0.000	4.845	8,557	0	8,557
SERVICES		5,656		9.764	0.824	10.587	26,554	7,214	33,768
TOTAL		15,477		64.752	3.509	68.261	165,009	30,739	195,748

SUMMARY OF TRANSFORMER INFORMATION

DESCRIPTION		KV VOLTAGE	CAPACITY MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		500	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0
BULK - TRANS1		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	345	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	345	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	345	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	138	33	115.5	4	28.9	60.99%	70	0.209	0.205	0.415	503	1,501	2,004
TRANS2 -	138	12	1,464.0	50	29.3	80.26%	1,175	3.771	2.805	6.576	9,059	19,624	28,683
TRANS2 -	138	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	12	1,817.3	81	22.4	89.16%	1,620	5.000	3.745	8.745	12,012	25,976	37,988
SUBTRAN1-	69	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			172.7	38	4.5	86.05%	149	0.870	0.307	1.177	2,090	2,687	4,777
LINE TRANSFRMR			5,499.8	86,403	63.7	45.60%	2,508	12.631	14.398	27.028	26,952	126,123	153,074
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			9,069	86,576				22.481	21.460	43.941	50,615	175,911	226,527

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 2852 MW

BULK TIE LINES	
LOAD	0.00% MW
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

BULK LINES	
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

BULK STEP UP	
LOADING	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVG SIZE	0 MVA
NUMBER	0

BULK-BULK	
LOADING	0.00%
NO LOAD	0 MW
LOAD	0 MW
AVG SIZE	0 MVA
NUMBER	0

TRANS TIE LINES	
LOAD	0.00% MW
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

BULK-TRANS1 STEP DOWN	
LOADING	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVG SIZE	0 MVA
NUMBER	0

TRAN1-TRAN2 STEP DOWN	
LOADING	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVG SIZE	0 MVA
NUMBER	0

BULK-TRANS2 STEP DOWN	
LOADING	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVG SIZE	0 MVA
NUMBER	0

TRANS 1&2 STEP UPS	
LDNG TR1SU	0.00%
NOLOAD1&2	0.000 MW
LOAD 1&2	0.000 MW
AVSIZ TR1SU	0.0 MVA
NUMBER	0

TRANS1	345.0 KV
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

TRANS2	138.0 KV
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

TRANS CUST	
SUBS	0.000 MW
	0.000 MVA
LINES	MW
	MVA

SUBTRANS TIE LINES	
LOAD	0.00% MW
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

TRANS1&2-SUBTRANS1	
LDNG TR2-ST	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVSIZ TR2	0 MVA
NUMBER	0

SUBTR1&2-SUBTRANS2&3	
LOADING	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVG SIZE	0 MVA
NUMBER	0

TRANS1&2- SUBTRANS2	
LDNG TR2-ST	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVSIZ TR2-ST	0.00 MVA
NUMBER	0

TRANS1&2-SUBTRANS3	
LDNG TR2-ST2	0.00%
NO LOAD	0.00
LOAD	0.00
AVSIZ TR2-ST2	0.00
NUMBER	0

SUBTRANS1,2,&3 STEP UPS	
LDNG ST1SU	0.00%
NO LOAD	0.000 MW
LOAD	0.000 MW
AVSIZ ST2	0.0 MVA
NUMBER	0

SUBTRANS1	69 KV
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

SUBTRANS2	66 KV
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.000 MW

SUBTRANS2	35 KV
LOADING	0.00%
LOAD LOSS	0.000 MW
NOLD LOSS	0.001 MW

SUBTRANS CUST	
SUBS - MW	0.000
MVA	0.000
LINES- MW	
MVA	

TO DISTRIBUTION SYSTEM
TOTAL 2865.6 MVA 2808.3 MW

TRANS1	0.0 MVA
	0.00%
345 KV	

TRANS2	1,245.4 MVA
	43.46%
138 KV	

SUBTRANS1	1,620.2 MVA
	56.54%
69 KV	

SUBTRANS2	0.0 MVA
	0.00%
66 KV	

SUBTRANS3	0.0 MVA
	0.00%
35 KV	

FROM HIGH VOLTAGE SYSTEM

TOTAL 2,866 MVA 2,808 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
0.0 MVA	1,245.4 MVA	1,620.2 MVA	0.0 MVA	0.0 MVA
0.00%	43.46%	56.54%	0.00%	0.00%
345 KV	138 KV	69 KV	66 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	0	0	0	70	1,175	0	0	1,620	0	0	0	0	0	0	0
% SYS TOT	0.00%	0.00%	0.00%	2.46%	41.00%	0.00%	0.00%	56.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.000	0.000	0.000	0.205	2.805	0.000	0.000	3.745	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.000	0.000	0.000	0.209	3.771	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	0.0	0.0	0.0	28.9	29.3	0.0	0.0	22.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	0	0	0	4	50	0	0	81	0	0	0	0	0	0	0
DIVERSITY RATIO	0.000	0.000	0.000	1.000	1.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES

LOADING	2685.191	MW
@ SYS PF	2739.991	MVA
LOAD LOSS	50.143	MW
NOLD LOSS	2.685	MW
TOT LOSS	52.828	MW

PRIM/PRIM TRANSF

LOADING	148.562	MW
NOLD LOSS	0.307	MW
LOAD LOSS	0.870	MW
AVG SIZE	4.54	
NUMBER	38	

PRIM CUST LOADS

NO LINES	0.000	MW
CUST SUB	0.000	MVA
NO LINES	38.300	MW
CO. SUB	39.082	MVA
PRIM WITH	345.000	MW
LINES	375.000	MVA

LINE TRANSFORMERS

LOADING	2286.187	MW	MVA	2534.666
NOLD LOSS	14.398	MW		
LOAD LOSS	12.631	MW		
AVG SIZE	63.7	KVA		
NUMBER	86403			

SECONDARY LINES

LOAD	894.040	MW
LOAD LOSS	4.845	MW
NOLD LOSS	0.000	MW
TOT LOSS	4.845	MW

NO SECONDARY LINES

LOAD 1365.118 MW

SERVICES

LOAD	2254.313	MW
LOAD LOSS	9.764	MW
NOLD LOSS	0.824	MW
TOT LOSS	10.587	MW

CUSTOMER SECONDARY LOAD

2243.726 MW

0

LG 2010 LOSS ANALYSIS

EXHIBIT 5

SUMMARY of SALES and CALCULATED LOSSES

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS GSU	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	4.43	39.07	43.50	0.000000	0.000000	0	29,013	103,503	132,516	0.0000000	0.0000000
TOTAL TRAN	2,852.0	4.43	39.07	43.50	1.015489	1.015489	12,966,029	29013	103503	132,516	1.0103258	1.0103258
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000		0	6	0	6	0.0000000	
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000		0	6	0	6	0.0000000	
22 TOT TRANS LOSS FAC	**2,852.0**	**4.43**	**39.07**	**43.50**	**1.015489**	**1.015489**	**12,966,029**	**29,013**	**103,503**	**132,516**	**1.010326**	**1.0103258**
DISTRIBUTION SUBST												
TRANS1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TRANS2	1,151.5	3.01	3.98	6.99	1.006108	0.000000	5,338,276	21,126	9,562	30,687	1.0057818	0.0000000
SUBTR1	1,587.8	3.74	5.00	8.74	1.005538	0.000000	6,944,729	25,976	12,012	37,988	1.0055001	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	2,739.2	6.76	8.98	15.74	1.005778	1.021356	12,283,005	47,102	21,574	68,675	1.0056225	1.0160063
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	2,684.9	2.68	51.01	53.70	1.020408	1.042200	11,989,742	23,520	131,988	155,508	1.0131405	1.0293572
LINE TRANSF	2,286.2	14.40	12.63	27.03	1.011964	1.054669	9,493,517	126,123	26,952	153,074	1.0163883	1.0462266
SECONDARY	2,259.2	0.00	4.84	4.84	1.002149	1.056935	9,340,443	0	8,557	8,557	1.0009169	1.0471860
SERVICES	2,254.3	0.82	9.76	10.59	1.004719	1.061923	9,331,886	7,214	26,554	33,768	1.0036317	1.0509890
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		29.09	126.30	155.39				232,971	319,127	552,098		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	66.4	1.0	67.4	1.01549	0.98475
PRIM SUBS	38.3	0.8	39.1	1.02136	0.97909
PRIM LINES	345.0	14.6	359.6	1.04220	0.95951
SECONDARY	2,243.7	138.9	2,382.7	1.06192	0.94169
TOTALS	2,693.4	155.3	2,848.8		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	536,042	5,535	541,577	1.01033	0.98978
PRIM SUBS	224,991	3,601	228,592	1.01601	0.98425
PRIM LINES	2,340,717	68,717	2,409,434	1.02936	0.97148
SECONDARY	9,298,118	474,102	9,772,220	1.05099	0.95148
TOTALS	12,399,868	551,955	12,951,823		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	67.43	541,577
PRIM SUBS	39.12	228,592
PRIM LINES	359.56	2,409,434
SECONDARY	2,382.66	9,772,220
SUBTOTAL	2,848.77	12,951,823
ACTUAL ENERGY	2,852.00	12,966,029
MISSMATCH	(3.23)	(14,206)
% MISSMATCH	-0.11%	-0.11%

LG 2010 LOSS ANALYSIS

DEVELOPMENT of LOSS FACTORS
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	66.4	0.0	1.0	67.4	1.01549	0.98475
PRIM SUBS	38.3	0.0	0.8	39.1	1.02152	0.97894
PRIM LINES	345.0	0.0	14.8	359.8	1.04295	0.95882
SECONDARY	2,243.7	0.0	141.9	2,385.6	1.06325	0.94052
			158.6			
TOTALS	2,693.4	0.0	158.6	2,852.0		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	536,042	0	5,535	541,577	1.01033	0.98978
PRIM SUBS	224,991	0	3,643	228,634	1.01619	0.98407
PRIM LINES	2,340,717	0	70,184	2,410,901	1.02998	0.97089
SECONDARY	9,298,118	0	486,797	9,784,915	1.05235	0.95025
			566,159			
TOTALS	12,399,868	0	566,161	12,966,027		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	67.43	541,577
PRIM SUBS	39.12	228,634
PRIM LINES	359.82	2,410,901
SECONDARY	2,385.63	9,784,915
	2,852.00	12,966,027
ACTUAL ENERGY	2,852.00	12,966,029
MISSMATCH	0.00	(2)
% MISSMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted
Service Drop Losses	10.59	10.58	33,768	33,756
Secondary Losses	4.84	4.84	8,557	8,554
Line Transformer Losses	27.03	27.02	153,074	153,022
Primary Line Losses	53.70	53.67	155,508	155,455
Distribution Substation Losses	15.74	15.73	68,675	68,652
Transmission System Losses	43.50	43.50	132,516	132,516
Total	155.39	155.34	552,098	551,955

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	-0.31	-1,143
Secondary Losses	-0.14	-290
Line Transformer Losses	-0.78	-5,183
Primary Line Losses	-1.55	-5,265
Distribution Substation Losses	-0.45	-2,325
Transmission System Losses	0.00	0
Total	-3.23	-14,206

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	10.89	6.9%	34,899	6.2%
Secondary Losses	4.98	3.1%	8,844	1.6%
Line Transformer Losses	27.80	17.5%	158,205	27.9%
Primary Line Losses	55.22	34.8%	160,720	28.4%
Distribution Substation Losses	16.18	10.2%	70,977	12.5%
Transmission System Losses	43.50	27.4%	132,516	23.4%
Total	158.57	100.0%	566,161	100.0%

Loss Factors by Segment	**MW**	**MWH**	
Retail Sales from Service Drops	2,243.726	9,298,118	
Adjusted Service Drop Losses	10.888	34,899	
Input to Service Drops	2,254.614	9,333,017	
Service Drop Loss Factor	**1.00485**	**1.00375**	
Output from Secondary	2,254.614	9,333,017	
Adjusted Secondary Losses	4.983	8,844	
Input to Secondary	2,259.597	9,341,861	
Secondary Conductor Loss Factor	**1.00221**	**1.00095**	
Output from Line Transformers	2,259.597	9,341,861	
Adjusted Line Transformer Losses	27.796	158,205	
Input to Line Transformers	2,287.393	9,500,066	
Line Transformer Loss Factor	**1.01230**	**1.01694**	
Retail Sales from Primary	345.000	2,340,717	
Req. Whls Sales from Primary	0.000	0	
Input to Line Transformers	2,287.393	9,500,066	
Output from Primary Lines	2,632.393	11,840,783	
Adjusted Primary Line Losses	55.224	160,720	
Input to Primary Lines	2,687.617	12,001,503	
Primary Line Loss Factor	**1.02098**	**1.01357**	
Output Pl from Distribution Substations	2,687.617	12,001,503	
Req. Whls Sales from Substations	0.000	0	
Retail Sales from Substations	38.300	224,991	
TotalOutput from Distribution Substations	2,725.917	12,226,494	
Adjusted Distribution Substation Losses	16.183	70,977	
Input to Distribution Substations	2,742.100	12,297,471	
Distribution Substation Loss Factor	**1.00594**	**1.00581**	
Retail Sales at from SubTransmission	66.400	536,042	
Req. Whls Sales from SubTransmission	0.000	0	
Non-Req. Whls Sales from SubTransmission	0.000	0	
Losses	0.000	0	4457
Input to Distribution Substations	2,742.100	12,297,471	
Output from SubTransmission	2,808.500	12,833,513	2,852.000
SubTransmission System Losses	43.500	132,516	43.500
Input to Transmission	2,852.000	12,966,029	43.500
TotTransmission System Loss Factor	**1.01549**	**1.01033**	43.500

DEMAND MW **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

PAGE 1 of 2

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		2,243.7		2,243.7				
3	LOSSES			10.9	10.9				
4	INPUT				2,254.6				
5	**EXPANSION FACTOR**	**1.00485**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			5.0	5.0				
9	INPUT				2,259.6				
10	**EXPANSION FACTOR**	**1.00221**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			27.8	27.8				
14	INPUT				2,287.4				
15	**EXPANSION FACTOR**	**1.01230**							
16	**PRIMARY**								
17	SECONDARY				2,287.4				
18	SALES		345.0			345.0			
19	LOSSES			55.2	48.0	7.2			
20	INPUT				2,335.4	352.2			
21	**EXPANSION FACTOR**	**1.02098**							
22	**SUBSTATION**								
23	PRIMARY				2,335.4	352.2			
24	SALES		38.3				38.3		
25	LOSSES			16.2	13.9	2.1	0.2		
26	INPUT				2,349.2	354.3	38.5		
27	**EXPANSION FACTOR**	**1.00594**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				2,349.2	354.3	38.5		
37	SALES		66.4						66.4
38	LOSSES			43.5	36.4	5.5	0.6		1.0
39	INPUT				2,385.6	359.8	39.1		67.4
40	**EXPANSION FACTOR**	**1.01549**							
41	**TOTALS** LOSSES			158.6	141.9	14.8	0.8		1.0
42	% OF TOTAL			100%	89.49%	9.34%	0.52%		0.65%
43	SALES		2,693.4		2,243.7	345.0	38.3		66.4
44	% OF TOTAL		100.00%		83.30%	12.81%	1.42%		2.47%
45	INPUT		2,852.0		2,385.6	359.8	39.1		67.4
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.06325**	**1.04295**	**1.02152**		**1.01549**

ENERGY MWH — **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** — **EXHIBIT 9**
PAGE 2 of 2

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		9,298,118		9,298,118				
3	LOSSES			34,899	34,899				
4	INPUT				9,333,017				
5	**EXPANSION FACTOR**	**1.00375**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			8,844	8,844				
9	INPUT				9,341,861				
10	**EXPANSION FACTOR**	**1.00095**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			158,205	158,205				
14	INPUT				9,500,066				
15	**EXPANSION FACTOR**	**1.01694**							
16	**PRIMARY**								
17	SECONDARY				9,500,066				
18	SALES		2,340,717.000			2,340,717			
19	LOSSES			160,720	128,948	31,772			
20	INPUT				9,629,014	2,372,489			
21	**EXPANSION FACTOR**	**1.01357**							
22	**SUBSTATION**								
23	PRIMARY				9,629,014	2,372,489			
24	SALES		224,991				224,991		
25	LOSSES			70,977	55,898	13,773	1,306		
26	INPUT				9,684,912	2,386,261	226,297		
27	**EXPANSION FACTOR**	**1.00581**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				9,684,912	2,386,261	226,297		
37	SALES		536,042						536,042
38	LOSSES			132,516	100,004	24,640	2,337		5,535
39	INPUT				9,784,917	2,410,901	228,634		541,577
40	**EXPANSION FACTOR**	**1.01033**							
41	**TOTALS** LOSSES			566,161	486,799	70,184	3,643		5,535
42	% OF TOTAL			100%	85.98%	12.40%	0.64%		0.98%
43	SALES		12,399,868		9,298,118	2,340,717	224,991		536,042
44	% OF TOTAL		100.00%		74.99%	18.88%	1.81%		4.32%
45	INPUT		12,966,029		9,784,917	2,410,901	228,634		541,577
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.05235**	**1.02998**	**1.01619**		**1.01033**

Appendix C

Discussion of Hoebel Coefficient

COMMENTS ON THE HOEBEL COEFFICIENT

The Hoebel coefficient represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) $F_{LS} \;.\; A_{LS} \;)\; P_{LS}$

where: F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) $F_{LD} \;.\; A_{LD} \;)\; P_{LD}$

where: F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ F_{LS}\ .\ H*F_{LD}^2 + (1-H)*F_{LD}$$

where: F_{LS} = Loss Factor
F_{LD} = Load Factor
H = Hoebel Coeff

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ F_{LS}\ .\ 0.90*F_{LD}^2 + 0.10*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ A_{LS}\ .\ P_{LS}\ *\ [H*F_{LD}^2 + (1-H)*F_{LD}]$$

where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 174

Responding Witness: William Steven Seelye

Q-174. Please provide each excel model, with formulas, used to produce each of Mr. Seelye's exhibits.

A-174. See the responses and attachments to PSC 1-56 and 1-57.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 175

Responding Witness: William Steven Seelye

Q-175. Please provide, in excel format, for each rate class, by Company, monthly coincident peak demand at the generation level (i.e., including losses), for the test year. These rate classes should correspond to the rate classes used in Mr. Seelye's class cost of service studies.

A-175. This data is included in attachment to Question No. 1-173(a). Coincident peak demand is with the LGE and KU combined system.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 176

Responding Witness: David S. Sinclair / William Steven Seelye

Q-176. To the extent not provided in response to the previous question, please provide the following information for each rate class/rate schedule included as a separate class in the class cost of service study for the test year 12 months ending June 2022:

a. monthly system peak load (LGE and KU separately stated and combined).

b. the load of each rate class at the time of the monthly LGE/KU system peak, showing the following:
   i. load at meter
   ii. losses
   iii. load at generation

c. Monthly mWh energy at the generation voltage level for the rate class/rate schedule.

d. Energy and demand loss factors for each voltage level, by rate class/rate schedule, at which customers on the rate class/rate schedule take service.

e. Monthly mWh energy sales at the meter, separately stated for each voltage at which customers in each rate class/rate schedule take service, by rate class/rate schedule (for example, the metered mWh for Rate PS secondary and Rate PS primary by month).

A-176.

a. See the attachment being provided in Excel format.

b. This data is included in attachment to Question No. 1-173(a). Coincident peak demand is with the LGE and KU combined system. Only load at generation was prepared for the class cost of service study.

c. See the Excel attachment 4, worksheet PivotLE, to the response to Question No. 181 part b.

d. See the Excel attachment 4, worksheet Map, to the response to Question No. 181 part b.

e. Only load at generation was prepared for the class cost of service study.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 177

Responding Witness: William Steven Seelye

Q-177. With regard to Exhibit WSS-21 (LOLP), pages 1 and 2, please provide all supporting workpapers, in excel format with all formulas intact, used to develop this exhibit. This would include, but not be limited to:

a. hourly system load

b. hourly rate class load at:
   i. meter
   ii. generation voltage
   iii. loss factor used to convert metered load into load at generation

c. hourly LOLP for the combined KU-LGE system

A-177.

a. See the response to Question No. 122 part a.

b. See the Excel attachments to the response to Question No. 181 part b.

c. See the response to Question No. 122 part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 178

Responding Witness: William Steven Seelye

Q-178. Please provide the output of the analysis used to develop hourly LOLP. Provide in excel format, with formulas intact.

A-178. See the response to Question No. 122 part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 179

Responding Witness: Christopher M. Garrett

Q-179. Provide, for the years 2020, 2019, 2018, and 2017) the following actual information:

a. monthly system peak load (LGE and KU separately stated and combined system.

b. date and hour of the LGE + KU monthly peaks

c. date and hour of the separate LGE and KU monthly peaks

A-179. See attached.

2020 LGE Monthly Peak	Megawatts	Day of Month	Hour
January	1,675	22	800
February	1,703	14	1000
March	1,439	6	2000
April	1,582	8	1700
May	1,870	26	1400
June	2,243	10	1500
July	2,505	21	1600
August	2,349	25	1600
September	2,208	9	1600
October	1,586	12	1500
November	1,540	30	1900
December	1,598	17	1900
Total	22,298		

2019 LGE Monthly Peak	Megawatts	Day of Month	Hour
January	1,934	30	2000
February	1,656	1	1100
March	1,750	5	800
April	1,694	30	1700
May	2,206	28	1700
June	2,340	28	1600
July	2,555	19	1600
August	2,609	19	1700
September	2,460	11	1600
October	2,424	2	1600
November	1,675	12	1900
December	1,718	18	2000
Total	25,021		

2018 LGE Monthly Peak	Megawatts	Day of Month	Hour
January	1,909	2	900
February	1,695	2	1000
March	1,570	21	1200
April	1,499	16	2000
May	2,315	15	1600
June	2,548	18	1600
July	2,618	5	1500
August	2,500	28	1600
September	2,486	20	1600
October	2,210	5	1500
November	1,748	27	1900
December	1,694	11	800
Total	24,792		

2017 LGE Monthly Peak	Megawatts	Day of Month	Hour
January	1,791	6	1900
February	1,609	9	2000
March	1,627	16	800
April	1,802	20	1600
May	2,118	18	1600
June	2,431	14	1600
July	2,608	21	1600
August	2,460	17	1400
September	2,305	21	1600
October	1,880	4	1600
November	1,538	20	900
December	1,731	27	1900
Total	23,900		

2020 KU Monthly Peak	Megawatts	Day of Month	Hour
January	3,638	22	800
February	3,457	14	900
March	2,758	6	2000
April	2,484	15	700
May	2,659	26	1400
June	3,206	10	1500
July	3,567	21	1500
August	3,341	13	1400
September	3,180	9	1500
October	2,468	22	1600
November	2,854	18	800
December	3,314	2	900
Total	36,926		

2019 KU Monthly Peak	Megawatts	Day of Month	Hour
January	4,352	31	900
February	3,436	1	900
March	3,994	5	800
April	3,113	1	700
May	3,200	24	1400
June	3,250	28	1600
July	3,532	10	1500
August	3,671	19	1600
September	3,596	10	1600
October	3,505	2	1600
November	3,693	13	800
December	3,639	19	800
Total	42,981		

2018 KU Monthly Peak	Megawatts	Day of Month	Hour
January	4,790	2	900
February	3,846	2	900
March	3,535	22	700
April	3,143	17	700
May	3,563	14	1700
June	3,933	18	1500
July	3,872	5	1500
August	3,892	28	1500
September	3,909	4	1600
October	3,454	5	1500
November	3,659	28	900
December	3,814	11	800
Total	45,410		

2017 KU Monthly Peak	Megawatts	Day of Month	Hour
January	4,004	8	900
February	3,630	10	800
March	3,815	16	700
April	2,906	20	1600
May	3,345	18	1500
June	3,710	13	1400
July	3,914	21	1700
August	3,783	17	1500
September	3,518	27	1600
October	3,002	9	1600
November	3,318	20	800
December	3,961	28	900
Total	42,906		

2020 Combined Monthly Peak	Megawatts	Day of Month	Hour
January	5,317	22	700
February	5,161	14	800
March	4,200	6	1900
April	3,709	15	600
May	4,534	26	1300
June	5,455	10	1400
July	6,069	21	1600
August	5,664	25	1400
September	5,386	9	1500
October	4,022	22	1500
November	4,393	30	1800
December	4,873	2	800
Total	58,783		

2019 Combined Monthly Peak	Megawatts	Day of Month	Hour
January	6,234	31	800
February	5,083	1	800
March	5,744	5	700
April	4,552	1	600
May	5,390	24	1500
June	5,590	28	1500
July	6,086	19	1500
August	6,278	19	1500
September	6,056	11	1500
October	5,929	2	1500
November	5,351	13	700
December	5,321	19	700
Total	67,614		

2018 Combined Monthly Peak	Megawatts	Day of Month	Hour
January	6,699	2	800
February	5,534	2	800
March	5,104	22	600
April	4,603	5	600
May	5,860	14	1600
June	6,458	18	1500
July	6,490	5	1400
August	6,390	28	1400
September	6,384	4	1500
October	5,664	5	1400
November	5,363	27	1900
December	5,508	11	700
Total	70,057		

2017 Combined Monthly Peak	Megawatts	Day of Month	Hour
January	5,679	6	1100
February	5,229	10	700
March	5,434	16	600
April	4,708	20	1500
May	5,446	18	1400
June	6,078	13	1300
July	6,503	21	1600
August	6,233	17	1300
September	5,763	21	1500
October	4,807	4	1500
November	4,853	20	700
December	5,612	28	800
Total	66,345		

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 180

Responding Witness: Christopher M. Garrett

Q-180. Please provide in excel spreadsheet format, by month, by Company, by rate class, the following information for each of the past 3 years:

a. actual kWh sales

b. weather normalized kWh sales using the same weather normalization methodology that is used by the Companies and PPL in the Quarterly Earnings Call Presentations

c. the number of customers

A-180. See attachment being provided in Excel format for the LG&E information.

For part a, the net unbilled accrual line for each year is not performed on a rate class basis.

For part c, some customers have multiple contracts and are reflected in multiple rate codes. The duplications are removed in the Duplicate Customers line.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 181

Responding Witness: David S. Sinclair

Q-181. Please provide the following information regarding the development of rate class hourly loads for the projected test year ending June 30, 2022:

a. A narrative fully explaining the methodology used by the Companies to develop hourly loads by rate class, including each adjustment made to reconcile these rate class hourly loads to the Companies' load and energy forecast for the test year.

b. All workpapers showing the development of test year hourly loads by rate class.

A-181.

a. See Case Nos. 2020-00349 and 2020-00350 Attachment to Filing Requirement 807 KAR 5:001 Sec. 16(7)(c) E.

b. See the attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 182

Responding Witness: William Steven Seelye

Q-182. With regard to the LOLP analysis used in the class cost of service study, please provide the following:

a. an explanation of how tie line capacity to other utilities was treated in the analysis.

b. an explanation of whether there were any adjustments to hourly loads in the development of the LOLP analysis.

c. a detailed description of the methodology used to calculate the hourly LOLP results.

A-182.

a. No purchases from other utilities were included in the analysis.

b. There were no adjustments to the 2021 Business Plan's hourly loads in the development of the LOLP analysis.

c. See the response to Question No. 121.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 183

Responding Witness: William Steven Seelye

Q-183. Please provide any information available to Mr. Seelye, the Prime Group or LG&E/KU regarding the following:

a. Any regulatory jurisdiction that has adopted the LOLP cost of service method used by Mr. Seelye in this case.

b. For each such jurisdiction, please provide a copy of a Commission Order addressing this issue.

c. Identification of any electric utility that supported the LOLP method in testimony before a state regulatory commission. Please identify the name of the utility, the case number and a copy of the testimony.

d. Identification of any electric utility in KY that has presented testimony before the KPSC in support of the LOLP cost of service method. For each such utility, please provide the name of the utility, the case number and a copy of the testimony.

A-183.

a. See the response to PSC 2-157.

b. See the response to PSC 2-157.

c. See the response to PSC 2-157.

d. See the response to PSC 2-157.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 184

Responding Witness: William Steven Seelye

Q-184. Please provide any testimony, papers or presentations prepared by Mr. Seelye or any other employee of the Prime Group in the past ten years which addresses the LOLP cost of service methodology. This would include all testimony (other than prior LGE/KU proceedings), papers or presentations supporting the LOLP method and testimony opposing the LOLP method.

A-184. The only documents prepared by Mr. Seelye in the last ten years that addresses the LOLP cost of service methodology are his direct and rebuttal testimony in prior LG&E and KU proceedings.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 185

Responding Witness: David S. Sinclair

Q-185. With regard to the Rate FLS, please identify, by month for the last 3 years, each curtailment pursuant to the following provision of the FLS tariff:

a. "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA:
   i. Company reserves the right to interrupt up to 95% of Customer's load to facilitate Company compliance with system contingencies and with industry performance criteria. Customer will permit Company to install electronic equipment and associated real-time metering to permit Company interruption of Customer's load. Such equipment will immediately notify Customer five (5) minutes before an electronically initiated interruption that will begin immediately thereafter and last no longer than ten (10) minutes nor shall the interruptions exceed twenty (20) per month. Such interruptions will not be accumulated nor credited against annual hours, if any, under either Rider CSR-1 or CSR-2. Company's right to interrupt under this provision is restricted to responses to unplanned outage or de-rates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked. LKE System, as used herein, shall consist of KU and LG&E. At Customer's request, Company shall provide documentation of the need for interruption under this provision within sixty (60) days of the end of the applicable billing period."
   ii. For each such curtailment, provide the following information:

b. The length of the interruption, and the date and hour of the interruption.

c. The MW amount of load interrupted.

d. The specific reason (e.g., unplanned outage or de-rate of LG&E and KU owned generation or when Automatic Reserve Sharing is invoked) for the curtailment.

e. The specific actions taken by LKE during the 10-minute interruption to respond to the unplanned outage or de-rate, once the 10-minute maximum interruption period is completed (for example, start-up a quick start unit, rely on spinning reserve capacity, etc.).

A-185.

a.-e. See attachment for details of events during the period January 1, 2018, through January 11, 2021, where curtailment occurred under the KU FLS tariff. LG&E does not have customers on the FLS rate.

Date	Est. Time (EST)	Event	Response: Spinning Reserves	Response: Fast Start CT	Response: Automatic Reserve Sharing	FLS load before curtailment (MW)
1/31/2018	22:04	Unplanned outage	Yes	No	No	112
2/7/2018	18:04	Unplanned derate	Yes	No	No	0
2/19/2018	10:24	Unplanned outage	Yes	No	No	12
2/24/2018	16:55	Unplanned outage	Yes	No	No	123
2/24/2018	11:54	Unplanned outage	Yes	Yes	No	120
2/25/2018	6:55	Unplanned outage	Yes	Yes	No	69
3/7/2018	3:06	Unplanned outage	Yes	Yes	No	0
3/12/2018	1:46	Unplanned outage	Yes	Yes	No	61
3/28/2018	14:42	Unplanned outage	Yes	Yes	No	0
3/28/2018	13:41	Unplanned outage	Yes	Yes	No	164
4/12/2018	17:17	Unplanned outage	Yes	No	No	146
4/29/2018	7:20	Unplanned outage	Yes	Yes	No	58
5/1/2018	18:32	Unplanned outage	Yes	No	No	130
5/13/2018	12:19	Unplanned outage	Yes	Yes	No	124
5/14/2018	19:08	Unplanned outage	Yes	Yes	No	6
5/15/2018	00:12	Unplanned outage	Yes	No	No	71
5/20/2018	13:35	Unplanned outage	Yes	No	No	94
5/23/2018	16:58	Unplanned outage	Yes	Yes	No	40
5/29/2018	20:10	Unplanned outage	Yes	No	No	0
6/7/2018	15:11	Unplanned outage	Yes	Yes	No	0
6/13/2018	12:38	Unplanned derate	Yes	No	No	195
6/14/2018	00:50	Unplanned outage	Yes	No	No	147
6/17/2018	23:21	Unplanned outage	Yes	No	No	84
6/18/2018	13:01	Unplanned outage	Yes	Yes	No	139
6/29/2018	14:19	Unplanned outage	Yes	Yes	No	14
8/21/2018	12:15	Unplanned outage	Yes	No	No	62
8/25/2018	21:26	Unplanned derate	Yes	No	No	106
9/8/2018	22:11	Unplanned outage	Yes	No	No	58
9/18/2018	12:10	Unplanned outage	Yes	Yes	No	55
9/30/2018	23:52	Unplanned outage	Yes	No	No	0
10/02/2018	19:11	Unplanned outage	Yes	No	No	118
10/03/2018	12:16	Unplanned outage	Yes	No	Yes	52
10/03/2018	11:35	Unplanned outage	Yes	No	No	62
10/05/2018	11:21	Unplanned outage	Yes	Yes	Yes	84
10/07/2018	17:31	Unplanned outage	Yes	No	No	148
11/01/2018	0:46	Unplanned outage	Yes	No	Yes	77
11/01/2018	23:23	Unplanned outage	Yes	Yes	No	0
2/2/2019	22:49	Unplanned outage	Yes	No	No	77
2/13/2019	4:48	Unplanned outage	Yes	Yes	No	150

Date	Est. Time (EST)	Event	Response: Spinning Reserves	Response: Fast Start CT	Response: Automatic Reserve Sharing	FLS load before curtailment (MW)
2/19/2019	13:34	Unplanned outage	Yes	Yes	No	85
4/2/2019	9:17	Unplanned outage	Yes	Yes	No	154
4/20/2019	17:44	Unplanned outage	Yes	Yes	No	171
4/20/2019	11:39	Unplanned outage	Yes	Yes	No	59
4/22/2019	1:23	Unplanned outage	Yes	No	No	158
4/26/2019	1:59	Unplanned outage	Yes	Yes	No	0
5/16/2019	17:05	Unplanned outage	Yes	No	No	139
5/16/2019	6:54	Unplanned outage	Yes	No	No	128
5/16/2019	1:30	Unplanned outage	Yes	No	No	125
6/26/2019	4:03	Unplanned outage	Yes	No	No	13
7/1/2019	6:02	Unplanned outage	Yes	No	No	137
7/13/2019	3:47	Unplanned outage	Yes	No	No	149
8/10/2019	14:18	Unplanned outage	Yes	No	Yes	148
9/3/2019	12:34	Unplanned outage	Yes	Yes	No	147
9/12/2019	8:45	Unplanned outage	Yes	No	No	82
9/19/2019	17:09	Unplanned outage	Yes	Yes	No	69
10/10/2019	15:45	Unplanned outage	Yes	No	No	149
10/16/2019	23:01	Unplanned outage	Yes	No	No	142
10/24/2019	15:51	Unplanned derate	Yes	No	No	142
11/12/2019	6:21	Unplanned outage	Yes	Yes	No	62
11/15/2019	22:04	Unplanned outage	Yes	Yes	No	82
11/17/2019	21:29	Unplanned outage	Yes	No	No	154
11/19/2019	15:44	Unplanned outage	Yes	No	No	0
12/16/2019	21:04	Unplanned outage	Yes	No	No	80
12/18/2019	12:37	Unplanned outage	Yes	Yes	No	57
12/22/2019	17:12	Unplanned outage	Yes	Yes	No	69
1/20/2020	6:00	Unplanned outage	Yes	Yes	No	169
3/2/2020	10:31	Unplanned outage	Yes	No	No	144
3/4/2020	9:37	Unplanned outage	Yes	Yes	No	150
3/16/2020	8:54	Unplanned derate	Yes	No	No	138
4/5/2020	18:05	Unplanned outage	Yes	No	No	87
4/16/2020	14:25	Unplanned outage	Yes	No	No	168
5/1/2020	16:37	Unplanned outage	Yes	No	No	124
5/1/2020	20:10	Unplanned outage	Yes	No	No	186
5/2/2020	15:52	Unplanned outage	Yes	No	No	102
5/4/2020	22:35	Unplanned outage	Yes	No	No	165
5/7/2020	9:52	Unplanned outage	Yes	Yes	No	10
7/6/2020	14:53	Unplanned outage	Yes	Yes	No	86
7/11/2020	12:29	Unplanned outage	Yes	Yes	No	146

Date	Est. Time (EST)	Event	Response: Spinning Reserves	Response: Fast Start CT	Response: Automatic Reserve Sharing	FLS load before curtailment (MW)
7/16/2020	8:46	Unplanned outage	Yes	Yes	No	130
9/1/2020	9:20	Unplanned outage	Yes	No	No	143
9/1/2020	14:51	Unplanned outage	Yes	No	No	178
9/17/2020	0:12	Unplanned outage	Yes	No	No	60
10/11/2020	5:39	Unplanned outage	Yes	No	No	83
10/16/2020	8:08	Unplanned outage	Yes	No	No	179
10/30/2020	20:06	Unplanned outage	Yes	No	No	58
10/31/2020	6:23	Unplanned outage	Yes	No	No	55
11/1/2020	21:19	Unplanned outage	Yes	Yes	No	0
11/4/2020	6:41	Unplanned outage	Yes	Yes	No	155
11/5/2020	22:29	Unplanned outage	Yes	Yes	Yes	70
11/17/2020	8:06	Unplanned outage	Yes	Yes	No	68
11/20/2020	12:43	Unplanned outage	Yes	No	No	13
11/24/2020	15:25	Unplanned outage	Yes	No	No	181

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 186

Responding Witness: David S. Sinclair

Q-186. With regard to the FLS "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA," please provide the following:

a. a detailed explanation of Automatic Reserve Sharing, including LKE's obligations under that provision.

b. identification of each instance during the past 3 years in which Automatic Reserve Sharing was invoked, including the name of the party invoking this provision.

c. LKE's obligations under the Automatic Reserve Sharing provision

d. identification of each instance during the past 3 years in which LKE relied on Automatic Reserve Sharing, and a description of the reason(s) for LKE's need for Automatic Reserve Sharing.

A-186.

a. LG&E/KU and TVA constitute an Automatic Reserve Sharing ("ARS") group that collectively maintains, allocates, and supplies operating reserves required for each member's use in recovering from contingencies within the required 15-minute period. See attachment for more details on the reserve sharing group's 2021 operating protocols. The TCRSG Deliverability Certificate is located on the Companies' Transmission OATI OASIS website (under Miscellaneous): http://www.oatioasis.com/LGEE/index.html. The current LG&E/KU contingency reserve allocation is equal to the TRM deliverability value contained in this document.

b. The table below details events during the period January 1, 2018, through January 11, 2021, where LG&E/KU received ARS assistance. TVA did not call on ARS during this period.

LG&E KU ARS Events 1/1/2018 - 1/11/2021

Date	Party initiating ARS	Event Start Time (EST)	Event End Time (EST)	ARS assistance (MW)	Event
10/3/2018	LG&E KU	12:12	13:00	149	Unplanned outage
10/5/2018	LG&E KU	11:25	12:00	224	Unplanned outage
11/1/2018	LG&E KU	0:45	1:30	337	Unplanned outage
1/9/2019	LG&E KU	6:12	7:00	439	Unplanned outage
8/10/2019	LG&E KU	14:18	15:00	418	Unplanned outage
11/5/2020	LG&E KU	22:28	23:00	396	Unplanned outage

c. See the response to part a.

d. See the response to part b.

TEE Contingency Reserve Sharing Group (TCRSG)

Operating Protocols

Revision History

Version	Description of Revision/Change	Revised by:	Effective Date
1	Initial		November 10, 2009
2	Annual review • Updated Attachment A to show (1) 2009 peak load data, (2) MSSC based on gross MW instead of net MW, and (3) associated Contingency Reserves Requirements including additional Contingency Reserves (difference between gross and net MW) that were entered in ARS System as "Extra CRs" until completion of deliverability study	C. Freibert	January 29, 2010
3	Updated Attachment A to adjust Contingency Reserves Requirements after completion of deliverability study that included MSSC based on gross MW and Trimble County 2 operations	C. Freibert	May 11, 2010
4	Annual review • Added revision history • Revised language to provide that a Party experiencing a DCS event not be required to enter that event in the ARS System if the Party chooses to self-recover without using any of the group's Contingency Reserves including its own (Section 2.1.2) • Revised language stating that each Party's peak load data and MSSC shall be submitted to the Administrator by October 15 each year for the previous 12-month period ending October 1 (Sections 1.4 and 3.3) • Updated Attachment A to show 2010 peak load data and associated Contingency Reserves Requirements • Added language stating that the Operating Protocols will be reviewed on an annual basis (Section 8.0)	M. Dalloul	January 31, 2011

5	Annual review • Revised language to clarify that a DCS event would be reported by the Administrator on behalf of the TCRSG only when the Party experiencing the event requests Contingency Reserves Activation from one or more other members of the TCRSG; if the Party experiencing the event does not request Contingency Reserves Activation from one or more other members of the TCRSG, that Party will report its DCS compliance as an individual BA (Section 1.10) • Deleted language determined to no longer be needed regarding consequences for multiple Contingency Reserves Activation requests due to Other Extreme Conditions (Sections 2.2.3 and 2.3.2 and Attachment B) • Corrected section reference numbers (Sections 5 and 6) • Updated Attachment A to show 2011 peak load data and associated Contingency Reserves Requirements	C. Freibert C. Freibert C. Freibert M. Dalloul	January 31st, 2012
6	Annual review • Updated Attachment A to reflect 2012 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC	S. Homberg	January 31st, 2013
7	• Update Attachment A to reflect EKPC withdrawal for the TEE-RSG, reallocation of Contingency Reserve Requirements among members	S. Homberg	June 1st, 2013
8	Annual review • Updated Attachment A to reflect 2013 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC	S. Homberg	January 31st, 2014
9	Interim changes (Section 2.6.1.2, 2.6.1.3, add 2.7.2.1) • Require Tag for events > 60 minutes • Tagging Extension above TRM • Extending an event at a reduced amount • Administrator modify an event MWs ATF • Corrected numbering in Section 5.2	S. Homberg	October 1st, 2014
10	Annual review • Updated Attachment A to reflect 2014 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC	S. Homberg	January 31st, 2015

11	Annual review • Updated Attachment A to reflect 2015 peak load data, and reallocation of Contingence Reserve Requirements, reviewed MSSC • Revised language to introduction that clarifies that the Operating Protocols establish processes and procedures and if there is a conflict the "Agreement" is the legally binding document. • Changes to (Section 2.2.3, 2.5.2, 2.6.1.2, 2.9) • Allowing the use of OEC more than once a day if the contingent BA is in an EEA1 or higher and if a contingent BA cannot restore their Contingency Reserve requirement an EEA2 or higher must be declared. • If a tag is required refer to Section 2.9 • Section 2.9 establishes the tagging requirements for events > 60mins.	S. Homberg	January 31st, 2016
12	Annual review • Updated Attachment A to reflect 2016 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC • Revised language stating that each Party's peak load data and MSSC shall be submitted to the Administrator by September 15 each year for the previous 12-month period ending September 1 (Sections 1.4 and 3.3)	S. Homberg	January 31st, 2017
13	Annual review • Updated Attachment A to reflect 2017 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC. • Various term changes associated with BAL-002-2 • Removed reporting requirements references • Removed references to penalty reserves (Sections 1.15, 2.3.2, 2.4.2 and 3.5) • Removed extensions of lesser amount (2.6.1.3) • Added section to reflect BAL-002-2 compliance exemptions (4.2.1, 4.2.2) • Removed subsequent event language found in 4.5, 4.6, 4.7 and 4.8 • Changed Attachment A to reflect BAL-002-2 and added a second Attachment A	C. Lawson	January 1st, 2018

14	Annual Review • Updated Attachment A to reflect 2018 peak load data and reallocations of Contingency Reserve Requirements, reviewed MSSC. • Added language to 4.2.2 to reflect BAL-002-3 changes • Removed second Attachment A	C. Lawson	January 31st, 2019
15	Annual Review • Grammatical clean-up (Reserves to Reserve) throughout • Section 2.3.1 – Removed reference to spinning reserve adjustment • Added Attachment C	C. Lawson	January 31st, 2020
16	Annual Review • Updated Attachment A • Updated Attachment C	C. Lawson	January 31st, 2021

These Operating Protocols establish processes and procedures pursuant to which the Parties to the TEE Contingency Reserve Sharing Group Agreement ("Agreement") will make Contingency Energy available to other Parties when conditions on one or more of the systems require that such assistance be made available.

Capitalized terms used in these Operating Protocols and not otherwise defined herein shall have the respective definitions provided in the Agreement or in the NERC Glossary. In the event of a conflict between the Operating Protocols and the Agreement, the Agreement shall control. The "Agreement" shall be the legally binding document.

The Parties and the Administrator shall adhere to, and the Administrator shall apply, as applicable, the following procedures and criteria for implementing a Contingency Reserve Activation under these Protocols, unless and until such Operating Protocols are modified in writing by action of the Operating Committee.

1. OBLIGATIONS

1.1 The TCRSG shall comply with the applicable Reliability Standards, including DCS requirements, as a single Reserve Sharing Group.

1.2 Each Party within the TCRSG Region shall comply with the DCS requirements under the Reliability Standards for its Balancing Authority Area by returning its ACE to the lesser of zero or its pre-disturbance level within the default Contingency Event Recovery Period.

1.3 The Contingency Reserve Obligation for the TCRSG shall equal the Most Severe Single Contingency of the TCRSG. The Contingency Reserve Obligation shall be allocated among the TCRSG Parties as shown in Attachment A. The Most Severe Single Contingency and the Contingency Reserve Obligation shall be reviewed at least annually and updated accordingly.

1.4 The Contingency Reserve Obligation shall be allocated among the Parties on a load ratio share basis using the coincident peak load levels of all LSEs in each Party's Balancing Authority Area for the 12-month period ending on September 1 of each calendar year as described in Attachment A. The Most Severe Single Contingency for the TCRSG shall be allocated by pro-rating each Party's coincident peak load MW amount for the 12-month period ending on September 1 each calendar year against the sum of the coincident peak load levels for each Party for the same 12-month period. Attachment A shall be updated by the Administrator by January 31 of each calendar year to reflect any changes in the allocation of the Contingency Reserve Obligation and when circumstances warrant or when instructed to do so by the Operating Committee.

1.5 Contingency Reserve shall be made available by each Party as necessary to satisfy the applicable Reliability Standards in an amount equal to each Party's Contingency Reserve Requirement established in Attachment A.

1.6 At any time, any Party may offer Contingency Reserve in addition to its Contingency Reserve Requirement ("Extra Contingency Reserve"), which shall be accessible only by the offering Party until the TCRSG Parties have fully deployed all available Contingency Reserve in accordance with their respective Contingency Reserve Requirements. After the Contingency Reserve Requirements of all the Parties are fully deployed, any unfulfilled and subsequent requests for Contingency Reserve Activation shall be allocated a pro-rated amount of Extra Contingency Reserve, if any.

1.7 In order to ensure full deployment of the Contingency Reserve allocation within the Contingency Event Recovery Period, each Party shall take into consideration: (a) the maximum time delay for Contingency Reserve Activation requests stated in Section 2.1.3 (up to three minutes), (b) the processing time between the Contingency Reserve Activation request and the Party receiving the request, and (c) any additional time required for the receiving Party to deploy its Contingency Reserve.

1.8 The minimum Operating Reserve-Spinning requirement shall be established by the Operating Committee and shall be the amount required by the applicable Reliability Standard or 0% of each Party's Contingency Reserve Requirement, whichever is greater.

1.9 A Party may use Qualified Interruptible Load in meeting its Contingency Reserve Requirement, provided that each Qualified Interruptible Load resource meets the applicable NERC and SERC criteria and applicable tariff requirements of the Party. Qualified Interruptible Load resources that are designated by a Party as Contingency Reserve resources shall be load that is capable of being removed from the system within the Contingency Event Recovery Period and remaining removed for the duration of the Contingency Reserve Activation Period or until replaced by equivalent resources following the Contingency event. The TCRSG will not limit the amount of interruptible load a Party may use as Contingency Reserve.

1.10 The Reportable Balancing Contingency Event level shall be determined in accordance with applicable Reliability Standards and included in Attachment A. The Operating Committee must approve any changes to the Reportable Balancing Contingency Event level.

1.10.1 The Administrator, on behalf of and on the direction of the TCRSG, shall document and if applicable report in accordance with the applicable NERC DCS Reliability Standards as a Reserve Sharing Group if any Party(ies) within the TCRSG Region experiences a Reportable Balancing Contingency Event as outlined in the applicable NERC DCS Reliability Standards and such Party(ies) requests Contingency Reserve Activation from one or more other members of the TCRSG.

1.10.2 If a Party(ies) experiences a Reportable Balancing Contingency Event and does not request a Contingency Reserve Activation from one or more other members of the TCRSG, such Party shall document and, if applicable, report its DCS compliance under the applicable NERC DCS Reliability Standards as a single Party.

1.11 The Parties shall provide all data necessary to determine compliance with the applicable Reliability Standards to the Administrator as set forth in the TCRSG Administration Agreement. The Administrator shall compile the data and maintain the necessary reports for the time period covering the Contingency Event Recovery Period and the Contingency Reserve Restoration Period including any extensions of the Contingency Reserve Restoration Period caused by additional Balancing Contingency Events**.**

1.12 The Administrator shall implement and maintain a backup process for failure of the primary ARS System. In the event of a failure of the ARS System, the Administrator shall manually communicate the requirement for each Party to deploy its Contingency Reserve and the amount requested.

1.13 The Parties shall not count more than once the same portion of resource capacity (e.g., reserves from jointly owned generation) as Contingency Reserve.

1.14 A Party's ability to deliver Contingency Energy is subject to deliverability constraints as identified in the deliverability report.

2. CONTINGENCY RESERVE ACTIVATION REQUIREMENTS

2.1 <u>TCRSG Disturbances</u>

2.1.1 In accordance with the applicable NERC DCS Reliability Standard, each Party shall meet, and be measured against, the requirements of each Reportable Balancing Contingency Event.

When a Party experiences a Balancing Contingency Event and utilizes any of its Contingency Reserve set aside for the TCRSG, such Party shall enter the Balancing Contingency Event in the ARS System for a Contingency Reserve Activation for the amount needed, which may be less than the loss.

2.1.2 If the Contingent System fails to request assistance within 3 minutes of the start of the Balancing Contingency Event, and the TCRSG is non-compliant with respect to a Balancing Contingency Event, the Contingent System will bear any penalties imposed and (or) required mitigations for the non-compliant response to the Balancing Contingency Event. .

2.1.3 The maximum amount of Contingency Reserve that can be requested through the ARS System for multiple Contingency Reserve Activations is the sum of each Party's available Contingency Reserve (consisting of such Party's Contingency Reserve Requirement and Extra Contingency Reserve, if any) as reflected in the ARS System. If such total available Contingency Reserve for all Parties drops below the Most Severe Single Contingency, the ARS System shall alarm the Parties and the Administrator 15 minutes after a Contingency Reserve Activation has occurred of the need for the Parties to voluntarily make available Extra Contingency Reserve to cover the Most Severe Single Contingency. If the ARS System does not alarm the Parties of the shortage of Contingency Reserve, the Administrator will notify the Parties as necessary through other means.

2.2 Conditions Precedent to Contingency Reserve Activation

2.2.1 Loss of Generation. A Party may request a Contingency Reserve Activation if such Party experiences a Loss of Generation (i.e., the loss of a specific generating unit(s) not exceeding the capability of such generating unit(s)). After the initial Contingency Reserve Activation request based on Loss of Generation, any subsequent Contingency Reserve Activation requests, other than an extension due to the original Contingency, will be submitted as Other Extreme Conditions (or OEC).

2.2.1.1 Loss of Schedule. A Party may request a Contingency Reserve Activation if a Party experiences a Loss of Schedule. The Administrator shall handle the request in the same manner as the Loss of Generation in Section 2.2.1. After the initial use of Loss of Schedule, any subsequent Contingency Reserve Activation requests other than an extension due to the original Contingency will be submitted as OEC.

2.2.2 Other Extreme Conditions. The ARS System may be activated when such Contingency Reserve Activation is needed by a Party for OEC such as to prevent the curtailment of firm load, or to restore its ACE within acceptable limits as required to maintain compliance with applicable Reliability Standards. The use of OEC more than once in the same day by the Contingent System Party is only allowed after the TCRSG has re-established its Contingency Reserve Obligation (Extra Reserve maybe used). Or if an EEA1 or higher is declared by the Contingent System Party. If the Contingent System Party cannot restore its Contingency Reserve Requirement, it must request an Emergency Energy Alert Level 3 ("EEA3").

2.3 Contingency Reserve Allocation

2.3.1 The "BA Adjustment" field in the ARS System allows Parties to adjust the amount of available Contingency Reserve. Acceptable use of this field include: reduction in a Party's Contingency Reserve Requirement due to an EEA3, as defined in Section 2.2.3;

2.3.2 A Party may voluntarily offer Extra Contingency Reserve, which shall be considered part of such Party's Contingency Reserve and available to all Parties, subject to the following conditions:

2.3.2.1 Extra Contingency Reserve shall be deployed and subject to the terms and conditions of the Agreement and the Operating Protocols.

2.3.2.2 Extra Contingency Reserve may be offered in response to a request from the Administrator for additional Contingency Reserve.

2.3.2.3 A Party may offer Extra Contingency Reserve into the ARS System to allow the TCRSG to cover the Most Severe Single Contingency after Contingency Reserve have been deployed for a Disturbance.

2.3.2.4 Extra Contingency Reserve may be used in response to a Party's own request for a Contingency Reserve Activation.

2.3.2.5 Extra Contingency Reserve shall be available for another Party's request for Contingency Reserve Activation when the Contingency Reserve Requirements of all Parties in the TCRSG are fully deployed.

2.3.2.6 A Party providing Extra Contingency Reserve will not be assessed performance penalties if such Extra Contingency Reserve are not deliverable

2.3.2.7 A Party shall consider deliverability when offering Extra Contingency Reserve to the TCRSG, except in instances when the TCRSG is deficient due to an ongoing Contingency Reserve Activation.

2.4 Contingency Reserve Deployment

The Administrator shall ensure that the ARS System shall deploy the Contingency Reserve as follows:

2.4.1.1 The Contingency Reserve (including any offered Extra

Contingency Reserve) of the Contingent System are utilized first toward meeting the amount of Contingency Energy required by the Contingent System. Next, the Contingency Reserve of the TCRSG Parties will be utilized on a pro rata basis. If necessary to meet the Contingency Reserve Activation Request, any Extra Contingency Reserve will be deployed on a pro rata basis.

2.4.2 Each Party shall acknowledge a Contingency Reserve Activation on the ARS System and respond with its allocation of its Contingency Reserve Requirements and Extra Reserve as determined by the ARS System.

2.4.3 Contingency Reserve allocated and deployed under a Contingency Reserve Activation cannot be recalled or reallocated until expiration of such Contingency Reserve Activation.

2.5 Contingency Reserve Activation

2.5.1 A Contingent System Party shall request a Contingency Reserve Activation by identifying the Contingency type (Loss of Generation, Loss of Schedule or OEC) and the MW amount of the reserve request, and entering the information in the ARS System. The ARS System shall calculate the share of the total megawatts of Contingency Reserve to be provided by each Party and will notify the Contingent System and each Delivery System of their respective requirements.

2.5.2 Unless a request is submitted in the ARS System, or as a result of a Contingent System Party's declaration of an EEA2 or EEA3, such Party has adjusted its Contingency Reserve Requirement, the Contingent System Party shall retain its Contingency Reserve Requirement obligation to the other Parties. Upon receipt of a Contingency Reserve Activation request, schedules for Contingency Energy shall immediately be implemented utilizing an instantaneous or zero (0) Ramp. The minimum schedule shall be 30 minutes and the schedule shall end on the nearest half or top of the hour immediately following the conclusion of the 30 minute minimum requirement. A Tag may be required, refer to Section 2.9 Tagging Requirements.

2.5.2.1 Contingency Energy shall be supplied to any Party making a Contingency Reserve Activation using the ARS System.

2.5.2.2 Each Party shall be responsible for providing Contingency Energy under the Operating Protocols up to the maximum amount specified herein.

2.5.2.3 The Administrator shall ensure the implementation of Contingency Reserve is in accordance with the Operating Protocols.

2.5.3 The Administrator will configure the ARS System and any back-up system so that it achieves the following:

2.5.3.1 If a Contingency Reserve Activation is requested when a prior Contingency Reserve Activation is still in effect, the ARS System shall calculate additional allocations to attempt to accommodate the later Contingency Reserve Activation without modifying any previously determined allocations for the prior Contingency Reserve Activation.

2.5.3.2 Such additional allocations shall include the amount of remaining Contingency Reserve Requirement, including Extra Contingency Reserve that were not deployed in connection with the prior Contingency Reserve Activation(s).

2.5.3.3 The ARS System shall compare the total Contingency Reserve Activations then in effect to the total Contingency Reserve Obligation to ensure that the total requests for Contingency Energy do not exceed the Contingency Reserve Obligation, plus any Extra Contingency Reserve.

2.5.3.4 If a Delivery System experiences a sudden unscheduled loss of a resource while it is providing Contingency Energy to a Contingent System, it shall continue to provide such Contingency Energy in accordance with the Operating Protocols.

2.6 Contingency Reserve Extensions

The Contingent System Party may request only one extension of the Contingency Reserve Activation no later than 10 minutes prior to the termination of such Contingency Reserve Activation, at an end time to be selected by the Party, provided that:

2.6.1.1 Such extension shall end on a quarter hour and shall not extend the total Contingency Reserve Activation to greater than 105 minutes to ensure that Contingency Reserve are replenished within the 90-minute Contingency Reserve Restoration Period after the 15-minute Contingency Event Recovery Period.

2.6.1.2 An extension which modifies an event to a duration greater than 60 minutes shall be tagged within 60 minutes of the loss of resource. A Tag may be required, refer to Section 2.9 Tagging Requirements.

2.6.1.3 With regard to any extension of a Contingency Reserve Activation, the requesting Party may extend the event at the current MW value. The requesting Party shall not request an increase or cancelation of an existing Contingency Reserve Activation. If the Contingent System Party needs additional assistance during the extension, such Contingent System Party may make a second Contingency Reserve Activation request for the additional amount of Contingency Reserve.

2.6.2 The extension of a Contingency Reserve Activation event does not constitute a new Contingency Reserve Activation event.

2.7 Contingency Reserve Activation Cancellations

2.7.1 A Party shall not cancel an initial request or an extension of a Contingency Reserve Activation, except that the Contingent System may request that the Administrator cancel a Contingency Reserve Activation if no other Party is participating in such Contingency Reserve Activation and the Contingent System has restored its Contingency Reserve.

2.7.2 The Administrator may cancel a Contingency Reserve Activation for ARS System problems or at the direction of the TVA Reliability Coordinator.

2.7.2.1 The Administrator with the prior approval of the OC may make modifications to event data (after the fact) to reflect actual values, when a Reliability Adjustment has modified energy delivered.

2.7.3 Any findings associated with non-compliance of applicable NERC Reliability Standards due to the cancellation of a Contingency Reserve Activation at the direction of the TVA Reliability Coordinator shall be reviewed and considered for submittal to NERC for exclusion in the calculation of Reportable Balancing Contingency Event compliance requirements.

2.8 Contingency Reserve Termination

2.8.1 The ramp rate used for terminating a Contingency Reserve Activation shall be: 10 minutes ramp out across the ending quarter, half or top of the clock hour.

2.9 Tagging Requirements

2.9.1 A tag shall be submitted with in 60 minute of the Loss of Resource time, for an event requesting reserves which is greater than 60 minutes from the Loss of Resource time. (INT-10-2.1 R1) Tag Start and Stop time should match CRSG event start and stop time. If the CRSG event does not exceed 60 minutes from Loss of Resource, No Tag is required.

2.9.2 An event extended greater than 60 minutes from the Loss of Resource time, a Tag shall be submitted for the Start and Stop time of the Extension only.

2.9.2.1 TRM: An extension which creates an event greater than 60 minutes from the loss of resource and is greater than the TRM value, the contingent BA shall request Point-to-Point transmission service for the amount above TRM. A separate tag with a Tag Type of "Emergency" shall be submitted for the amount above TRM.

2.9.3 Loss of Resource (LOR) time shall be the breaker open time of the first unit or element lost triggering the event.

2.9.4 Tag Type shall be Emergency and the MISC Info field of the GCA line should have a Token = SUBTYPE and Value = TEE-RSG. A standard 10 minute Ramp should be used for start and stop of Tags.

2.9.5 Schedule: The schedule created for the event will continue to be the mechanism for energy deliver until the Implemented Tags starts. When a manually created schedule and Tag created schedule overlap one should be adjusted to prevent double counting of Interchange Schedules.

3. REQUIRED DATA

To perform the studies required to determine the Contingency Reserve Obligations, the Contingency Reserve Requirements, and compliance with the obligations imposed by the Operating Protocols, each Party shall submit data requested by the Administrator to the Administrator in conformance with the following minimum requirements:

3.1 All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Operating Committee.

3.2 Data shall be submitted in an electronic format, or as otherwise specified by the Operating Committee and/or Administrator.

3.3 On or before September 15 of each calendar year, each Party's BA coincident peak load level of all LSEs in the BA for the preceding 12-month period ending on September 1 and the Most Severe Single Contingency for that same 12-month period shall be submitted to the Administrator. Such data shall be updated at any time for any known material changes. Based on each Party BA's Most Severe Single Contingency, the TCRSG's Most Severe Single Contingency will be reviewed and updated as necessary, but no less frequently than annually. Each Party's BA will use its established operating process to determine its MSSC.

3.4 The Parties acknowledge that additional information required to determine the Contingency Reserve Requirement shall be provided by the Parties to the Administrator in accordance with the provisions of the Agreement.

4. COMPLIANCE DATA SUBMITTAL

4.1 The Administrator shall collect the data and perform the calculations necessary for each Reportable Balancing Contingency Event to determine TCRSG and individual Party compliance under this Agreement.

4.2 No later than the following business day after each Contingency Reserve Activation, the Contingent System shall provide the Administrator with the actual time of the Balancing Contingency Event ("T_0") in hour, minute, and second detail in Central Prevailing Time ("CPT"), indication of whether or not it is a Reportable Balancing Contingency Event, and the MW amount

4.2.1 If the Balancing Contingency Event is determined to be a Reportable Balancing Contingency Event, the Contingent System will provide the TCRSG Administrator with the information required to complete the NERC CR Form 1.

4.2.2 If the TCRSG is exempt from returning Reporting ACE to the recovery value within the Contingency Event Recovery Period for a Reportable Balancing Contingency Event due to an exception in the applicable NERC DCS Reliability Standard, the Parties shall provide as applicable and the TCRSG Administrator shall compile and retain evidence that demonstrates applicability of such an exception.

1. A BA or the TCRSG may not be subject to compliance if it is experiencing a Reliability Coordinator declared EEA and has removed some or all of its Contingency Reserve from the TCRSG to mitigate and operating emergency and has depleted its CR to a level below its MSSC and has communicated with its RC to notify them of the conditions described above preventing the Responsible Entity from complying with applicable NERC DCS Reliability Standards and provided the RC with an ACE recovery plan including target

recovery time.

2. A Party and or the TCRSG may not be subject to compliance if the group experiences multiple contingencies where the combined MW loss exceeds the groups Most Severe Single Contingency or if the TCRSG experiences multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and the Contingency Reserve Restoration Period whose combined magnitude exceeds the TCRSG's Most Severe Single Contingency

4.3 In a format agreed to by the Operating Committee, each Party shall provide its ACE, Frequency Error, and other four-second data for the period starting 15 minutes prior to the Contingency Reserve Activation request time, and ending 45 minutes after the Contingency Reserve Activation request time, or per the reporting criteria of the applicable NERC DCS Reliability Standard. The data provided shall be from the same source data as used by the Party for determining compliance to the Reliability Standards.

4.4 The Party shall provide the Administrator with the information required in Section 4.2.1, Section 4.2.2, and Section 4.3 within 7 calendar days after the request for data from the Administrator for each Reportable Balancing Contingency Event.

4.4.1 All data provided to and generated by the Administrator may be subject to review under a NERC compliance audit.

4.4.2 The Party is responsible for the accuracy of all data provided to the Administrator and shall bear all responsibility for any associated non-compliance of the TCRSG directly attributed to the quality or accuracy of the data provided.

5 CALCULATION OF TCRSG COMPLIANCE TO THE DCS

5.1 The Administrator shall collect the data and perform the calculations necessary to determine the TCRSG compliance with the applicable Reliability Standards associated with DCS.

6 NERC AND SERC PENALTY ALLOCATION

This section will outline the process for allocating NERC and SERC penalties for non-compliance with the Reliability Standards as they relate to the TCRSG and/or any Party's activities under the Agreement, the Administration Agreement or these Operational Protocols.
DCS Requirements

6.1 According to applicable Reliability Standards, if the TCRSG does not meet the NERC DCS requirements financial or settlement penalties may be imposed, to the extent applicable. Any such settlements shall be allocated to those Parties that did not satisfy the NERC DCS requirements for each Reportable Balancing Contingency Event . The Administrator shall calculate the allocation using a methodology pre-approved by the Operating Committee.

6.1.1 For any Reportable Balancing Contingency Event in which the TCRSG is not DCS compliant, the Administrator shall coordinate with the Operating Committee any self-reporting.).

6.1.2 In the event that the TCRSG receives a financial penalty associated with non-compliance of a Reportable Balancing Contingency Event, the Administrator shall allocate the financial penalty pro-rated to each Party's performance associated with the non-compliance event.

6.1.3 In the event the TCRSG mitigates through settlement for non-compliance of a Reportable Balancing Contingency Event the Operating Committee shall have approval of such settlement.

6.2 Any penalty not associated with Reportable Balancing Contingency Event that are incurred by TCRSG or any Party, which penalty is related to such Party's or the TCRSG's activities under the Agreement, the penalty will be allocated pursuant to the terms of the Agreement.

7 CONTINGENCY RESERVE DELIVERABILITY REQUIREMENTS

7.1 Transmission Reliability Margin ("TRM") Determination

7.1.1 Provision of TRM is the responsibility of the applicable Transmission Service Provider within the TCRSG Region. The Operating Committee and/or Administrator shall work with the applicable Transmission Service Providers to determine the proper amount of TRM to be used for Contingency Reserve Activations. Annual updates of deliverability studies will be performed by the applicable Transmission Service Provider as directed by the Operating Committee.

7.1.2 Each Party shall ensure the deliverability of its Contingency Reserve Requirement.

7.1.3 Each Party shall provide written certification ("Certification of Deliverability") stating that its Contingency Reserve Requirement is deliverable, generally describing the methodology utilized in its deliverability study and specifying the amount of TRM that has been set aside for the purpose of receiving and/or delivering Contingency Reserve.

7.2 Maintaining Contingency Reserve Deliverability

The deliverability of Contingency Reserve is maintained through the withholding of TRM from firm transmission service usage. However, no transmission owner will be required to upgrade its transmission system solely to provide TRM for TCRSG purposes. Such conditions will be identified during the deliverability study process under Section 7.1 and communicated to the Parties in a timely manner.

7.2.1 In the real-time operations, the amount of TRM that is set aside for the purposes of deliverability of Contingency Reserve (as stated in the

Certification of Deliverability) may be maintained through initiating redispatch and/or other operating actions.

8 ANNUAL REVIEW OF TCRSG OPERATING PROTOCOLS

The Operating Committee will perform a review of the TCRSG Operating Protocols on an annual basis. This review will occur no sooner than October 1 and no later than March 31.

Attachment A

TCRSG Most Severe Single Contingency (MSSC)	1347 MW	
Reportable Balancing Contingency Event (equal to or greater than)	900 MW	
TCRSG Party	2020 Peak Load	CONTINGENCY RESERVE
LGEE	6,650	252 (1)
TVA	28,931	1095 (1)
Total	35,581	1347 (1)

(1) CRRs are calculated using each Party's 2020 peak load (peak load level during the 12-month period from September 1, 2019 to September 1, 2020).
- These CRRs were provided to the Transmission Planners to use in performing the Deliverability Study for 2021.
- They are effective on January 31st, 2021

Attachment B

Billing Process

Final Bill Determination

The cost of Contingency Energy provided under the TCRSG Agreement will be the greater of $100/MWH or 110% of the verifiable cost as determined by the following TCRSG Costing Guidelines. Transmission costs (equal to the Transmission Provider's posted non-firm hourly point-to-point rate) incurred by the supplying Party will be added to the energy cost. This may include cost of redispatch for deliverability.

Billing and settlement between the Parties will follow the existing interchange settlement process, procedures and requirements.

TCRSG Costing Guidelines

This section provides guidelines for costing of energy supplied during a Contingency Reserve Activation event under the TCRSG. These guidelines represent generally accepted practices among TCRSG participants.

General Guidelines

The cost of Contingency Energy provided during Contingency Reserve Activation events shall be the verifiable cost of the resource(s) used to provide such service. This cost can either be from the units that actually responded to the event or based on an economic stacking of resources that assigns the highest cost units to the sale. Under either approach, actual unit cost is applied. Under an economic stacking approach, units online during the event (including units providing Non-Spinning Reserve) are stacked from highest to lowest cost and decremented down from the unit hourly output until the MW response has been covered.

In general, megawatts at or below minimum load from units that were online prior to the event are not assigned to the sale because this energy represents sunk commitment costs for pre-existing sales or native load. Actual cost for such units can include incremental fuel and O&M costs, environmental costs or other costs that otherwise would not have been incurred absent the Contingency Reserve Activation event.

For offline units started in response to the event, all MW produced including those below minimum load are assigned to the sale. Actual cost for these units can include average fuel and O&M costs, environmental costs, or other costs that otherwise would not have been incurred absent the Contingency Reserve Activation. Startup costs may be assigned to the sale for those units that were started to supply Non-Spinning Reserve or started in response to a subsequent Contingency Reserve Activation during the recovery period.

Costs for all units assigned to the sale should be aggregated to determine an average cost for all response MWs. This cost becomes the basis for comparison to the 110% of verifiable costs.

Non-Spinning Reserve Generation Considerations

For units started that have a minimum runtime longer than the reserve call duration, costs incurred beyond the end of the call should not be assigned to the sale. These costs are generally borne by the supplier.

If minimum load for a unit started for a Contingency Reserve Activation is greater than the Non-Spinning Reserve request from that participant, all costs for that unit can still be assigned to the sale. Excess energy from these units will reduce the MW response from units carrying Spinning Reserve.

Demand Response Considerations

In general, pricing of reserve supplied from demand response resources should be based on the highest cost generation determined from the economic stacking process defined above. To the extent contracts for interruptible load used to supply Non-Spinning Reserve define payments for curtailment, those costs should only be used if they are less than or equal to the highest cost units in the stack for the Party that otherwise would have supplied the reserves. Avoided costs for Non-Spinning Reserve units not started due to reserves supplied from demand response should not be used.

Forward and Economic Purchase Considerations

Pricing of Contingency Reserve sales should not include costs associated with forward purchases of energy.

Under circumstances where a Party is able to purchase economic energy during the replenishment period of the reserve activation which reduces the response from the Party's resources, the cost of those units or units that remain in the Party's economic stack can be assigned to the sale for the remainder of the activation.

Attachment C

Notice: The Parties' designated contacts (which for the TCRSG Parties, may be such Parties' Representatives and Alternates under the Reserve Sharing Agreement) are as follows:

For TVA as Administrator:

Representative	**Alternate**
G. Wayne Talley	William George
Manager, Transmission & Interchange Services	Sr Specialist, Transmission & Interchange
Phone: (423)751-6172	Phone: (423)697-4124
gwtalley@tva.gov	wmgeorg2@tva.gov

For TVA:

Representative	**Alternate**
Phillip Wiginton	Cameron Lawson
Sr Prog Mgr, NERC TOCE	Manager, Balancing Authority
Phone: (423)751-4182	Phone: (423)751-4250
prwiginton@tva.gov	cclawson@tva.gov

For LGEE:

Representative	**Alternate**
Charlie Martin	Linn Oelker
Manager, Generation Dispatch and Trading	Manager, Market Compliance
Phone: (502)627-4242	Phone: (502)627-3245
Charlie.Martin@lge-ku.com	Linn.Oelker@lge-ku.com

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 187

Responding Witness: David S. Sinclair

Q-187. With regard to the FLS "SYSTEM CONTINGENCIES AND INDUSTRY SYSTEM PERFORMANCE CRITERIA," provision, please explain how the Companies would respond to unplanned outage or derates of LG&E and KU Energy LLC System (LKE System) owned or purchased generation or when Automatic Reserve Sharing is invoked if this curtailment provision was not in the FLS tariff.

A-187. LG&E/KU currently responds to generation contingencies, such as unplanned outages or derates, in the first 15 minutes by 1) deploying spinning reserves, 2) if needed, calling on the FLS curtailment provision to remove the uncertainty of fluctuating load during an ensuing 10 minute period, 3) if needed, deploying quick start combustion turbines, and 4) if needed, invoking ARS.

Without the FLS curtailment provision, LG&E/KU would perform the same steps, excluding step 2. The fluctuation of FLS load could potentially increase the amount of time required to restore the balance of generation and load to its pre-contingency state within the 15-minute window required by NERC Reliability Standard BAL-002-3.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 188

Responding Witness: William Steven Seelye

Q-188. Please provide copies of a unit cost of service analysis (e.g., Rate RTS unit energy costs per kWh, unit demand costs per kVa, customer cost per customer) based on each of the 3 class cost of service studies presented by the Companies in this case (LOLP, 12 CP, 6 CP).

A-188. See attachments being provided in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 189

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-189. Please provide, for each rate class serving coal mine or coal extraction customers, an excel schedule (with formulas) identical to Schedule M-2.3 comprised of billing determinants for only coal mine or coal extraction customers. For example, provide a version of Schedule M-2.3 for Rate PTOD, as shown on M-2.3, page 11 of 26, containing only billing determinants and revenues for customers in the coal mine or coal extraction industry.

A-189. The Companies do not have a reliable means of identifying their coal mine or coal extraction customers. Therefore, the Companies cannot provide the requested information.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 190

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-190. For Rate Schedules TODP and RTS please provide the following information.

a. The MWh energy usage for the 20 largest customers for both the base and future test year periods.

b. Please confirm that the North American Industry Classification System for each of the 20 largest customers is Sections 21, 22, 31,32 or 33. If that is not true as to any individual customer, then please so identify.

c. The test year MWh energy on each rate schedule, separately stated by rate schedule, for customers:
   iii. Classified under NAICS Section 21, 22, 31, 32 or 33.
   iv. All other customers taking service on the rate schedule.

A-190.

a. See attachment being provided in Excel format.

b. The Companies do not have reliable NAICS data for their customers. Therefore, the Companies cannot provide the requested information.

c. The Companies do not have reliable NAICS data for their customers. Therefore, the Companies cannot provide the requested information.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 191

Responding Witness: William Steven Seelye

Q-191. For Rate Schedules TODP and RTS, please provide the following information regarding the design of proposed rates:

a. A narrative explaining the methodology used to develop the proposed kWh energy charge of each rate. Also provide an explanation for the 21% increase in the proposed energy charge of each rate.

b. A complete set of workpapers, including excel spreadsheets with formulas, showing the development of the energy charge, with specific references and citations to TABs, cell references in the class cost of service study.

A-191.

a. The proposed TODP and RTS energy charges include all costs classified as Energy-related in the Cost-of-Service study which includes Fuel, Variable Operations and Maintenance expenses such as scrubber reactant, and any other expenses that vary with the cost of energy.

In the 2018 rate case, the Cost-of-Service study showed an Energy charge of \$0.031934/kWh for TODP and \$0.031523/kWh for RTS. The Company proposed an Energy charge of \$0.03193/kWh for TODP and \$0.03152/kWh for RTS in the Application for the 2018 rate case.

The Energy charges that are currently charged by the Company were the result of the settlement agreement by all parties in the Company's 2018 Rate Case and are not reflective of actual Energy cost from that case. Therefore, the 21% increase in the Energy charges are due to the Company proposing to update the Energy charges to reflect the actual cost of energy as calculated in the Cost-of-Service study in this case similar to what the Company proposed in the 2018 Rate Case.

b. The proposed energy charges were calculated directly from the Cost-of-Service studies and the costs included can be seen on the unit cost sheets included in the response Question No. 188.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00350

Question No. 192

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-192. Please provide the MWh energy associated with customers engaged in the extraction or processing of coal, by rate schedule, for the following periods:

a. The most recent 5-year historic period (e.g., 2016 through 2020) by year.

b. The Base period in this case.

c. The project test year in this case.

A-192. See the response to Question No. 189.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021

Case No. 2020-00350

Question No. 193

Responding Witness: Kent W. Blake

Q-193. Refer to Witness Blake Testimony, page 10 at 4, which states, "The Companies also propose to record a regulatory liability until its first base rate proceedings following implementation to the extent their actual meter reading and field service expenses are less than the forecast test period level embedded into base rates during these current proceedings." The OAG understands the stated intention is to secure for customers the meter reading and field service expense reduction benefits anticipated during the deployment period.

a. Please describe any commitments the Companies are willing to make regarding the level of expense reductions reflected as rate reductions after the deployment period, for example, through test-year adjustments in the rate case used to recover AMI investment costs. If the Companies are not willing to make such commitments, please explain why not.

b. Please describe any commitments the Companies are willing to make to measuring actual expense reductions, and the Companies' recommendations on a measurement approach. If the Companies are not willing to make such a commitment, please explain why not.

c. Describe any commitments the Companies make, or are willing to make to sharing the risk of shortfalls of actual expense reductions from projected expense reductions. If the Companies are not willing to make such a commitment, please explain why not.

A-193.

a. As discussed in Mr. Blake's testimony, the Companies propose to account for expense reductions by recording a regulatory liability for the period after implementation and until their next base rate proceedings to the extent the actual meter reading and field service expenses are less than the amount of those expenses embedded in base rates during these cases. Exhibit KWB-2 shows that, based on the Companies' projections, this regulatory liability can be amortized over the first 5 years after implementation in a manner that eliminates any combined net incremental revenue requirement. Any further adjustments will be resolved using actual costs and projected savings in the Companies' next base rate cases.

b. The Companies are proposing no cost recovery until the entire AMI project is put in service. The Companies' proposed ratemaking treatment also includes recording as a regulatory liability any reduction in annual recorded meter reading and field service expenses below that embedded in base rates during this proceeding.

c. The Companies have presented their best current estimates of costs and benefits associated with the AMI project and have put forward a case that shows the benefits exceed the costs even with a significant amount of unquantified benefits. The Companies are not proposing any form of cost recovery until a future base rate case proceeding when all costs will actually be known. Based on all information available to the Companies at this time, the Companies have put forward its proposal for full deployment of AMI as a prudent investment with significant immediate and future benefits to customers. The Companies hope that the OAG will join the Companies in supporting this project for the benefit of our customers.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00350

Question No. 194

Responding Witness: Christopher M. Garrett

Q-194. Refer to Witness Blake Testimony, page 24, line 16, which describes how six robotic process automation projects resulted in a reduction of one full time headcount and three interns.

a. Describe each of the six robotic process automation (RPA) projects. Include in these descriptions how the associated work processes were performed prior to RPA implementation, and how the RPA project automates them.

b. Provide the amount the Companies capitalized for each of the six RPA projects.

c. Provide the period (in years or months) over which each of the six RPA projects will be depreciated.

d. Provide the salary and benefits associated with the one full time headcount in 2019.

e. Provide the salary and benefits associated with the three interns in 2019.

A-194.

a. **AR Upload Process**-this RPA automated the process to upload transactions from the Oracle Accounts Receivable module to the general ledger. Prior to implementing the RPA, this was a manual process performed twice monthly by accounting analysts. Accounting analysts logged into Oracle and performed numerous reviews and checks to ensure complete information before transferring to the General Ledger. The RPA now performs these reviews and checks and, once complete, uploads to the General Ledger.

Automate Cash Receipts for AR Process-this RPA applies miscellaneous accounts receivable receipts in Oracle. Before implementing the RPA, the accounting analyst entered the receipts manually in Oracle from information contained in Excel files. The RPA now accesses the Excel files and creates batches in Oracle to upload receipts.

Oracle eBusiness Suite (OEBS) Access Removal-Once a request to remove access to OEBS is approved, this RPA removes access in the OEBS system. Prior to implementing the RPA, an accounting system analyst manually removed the user in OEBS.

Data to Identify Preliminary Retirements-This RPA reviews data to identify projects that qualify for preliminary retirement, based on certain established criteria. Before implementing the RPA, the accounting analyst obtained the list of preliminary retirements by running a query from PowerPlan, exporting it to Excel and performing manual work in Excel such as filtering, formatting, applying formulas, comparing to prior periods, and more. The RPA now runs those reports and performs the Excel functions to provide the analyst with the list of preliminary retirements for consideration.

Transmission Journal Entry-This RPA automated several journal entries related to transmission accounting. Previously this task was completed by an accounting analyst who manually copied source data from an Excel file into Excel journal entry files where pivot tables would be refreshed monthly. The RPA process now prepares the journal entry file by automating the tasks the accounting analyst performed.

Zero Balance Account Reconciliations-This RPA reconciles balance sheet accounts that have a zero balance by confirming the balance is $0 in Oracle and signing off on the journal entry preparation checklist. Previously, accounting analysts or interns manually ran reports from Oracle and prepared a reconciliation showing confirmation of the $0 balance.

b.

Process Name	**LGE Share**
AR Upload Process	$ 14,796
Automate Cash receipts for AR process	$ 15,085
Oracle eBusiness Suite Access Removal	$ 16,313
Data to Identify Preliminary Retirements	$ 8,467
Transmission Journal Entry	$ 12,400
Zero Balance Account Reconciliations	$ 12,069

c. The RPA assets at LG&E are included in the depreciation group LGE-330300 – Misc. Intangible Plant which has an amortization life of approximately five years.

d. For LG&E the salary and benefits associated with one full time headcount in 2019 was approximately $44,895.

e. For LG&E the salary associated with three interns in 2019 was approximately $29,241, there are no benefits associated with interns.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 195

Responding Witness: Lonnie E. Bellar

Q-195. Refer to Witness Blake testimony, Exhibit KWB-2, page 1. For each of the items under the "Status Quo Case", provide the actual amounts incorporated into the revenue requirement calculations for the test year used in this rate case:

a. Cost of Capital – Existing Meters;

b. Depreciation – Existing Meters;

c. Revenue Requirement – New Meters;

d. Revenue Requirement – Voltage Meters;

e. Revenue Requirement – Handhelds and MAM;

f. Revenue Requirement – Other;

g. Meter Reading;

h. Field Services; and

i. Property Taxes – Existing Meters

A-195.

a. The amount of Cost of Capital - Existing Meters incorporated for the test year in this rate case is $945,230 for LG&E.

b. The amount of Depreciation – Existing Meters incorporated for the test year in this rate case is $970,022 for LG&E.

c. The amount of New Meters incorporated into the revenue requirement calculations for the test year is $3,357,494 for LG&E. The differential between the exhibit and the amount noted in the test year is capital that would need to be purchased if AMI were not approved.

d. The amount of Revenue Requirement – Voltage Sensors incorporated for the test year in this rate case is $0 for LG&E. Voltage sensors in the Status Quo case would only be required if the proposed AMI project is not approved.

e. Included with the revenue requirement – Handhelds and MAM there is $16,875 of Handhelds included within the revenue requirement of the current case. MAM is not included within the current case. The differential between the exhibit and the amount noted above is capital that would need to be purchased if AMI were not approved.

f. Revenue Requirement – Other represents capital burdens allocated to the AMI project. This line item incorporates $287,706 for the test year in this rate case for the AMI project.

g. The amount of Meter Reading incorporated for the test year in this rate case is $6,887,169 for LG&E.

h. The amount of Field Services incorporated for the test year in this rate case is $6,042,051 for LG&E.

i. The amount of Property Taxes – Existing Meters incorporated for the test year in this rate case is $262,810 for LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021**

Case No. 2020-00350

Question No. 196

Responding Witness: Kent W. Blake

Q-196. Refer to Witness Blake testimony, Exhibit KWB-2, page 2 (15-yr Meter Life). Provide detailed calculations by year for the following items under the "AMI Case":

a. Regulatory Asset Amortization (please include details for each of the three components – deferred operating expenses, net book value of electric meters replaced, and the differences between AFUDC as proposed vs. FERC methodology); and

b. Regulatory Liability Amortization (please include details for each of the four components – meter reading, field services, ADIT for retired & replaced meters, and ADIT for AMI Placed in Service for Income Tax Purposes).

A-196.

a. The calculations are contained within the Excel attachment to the response to PSC 1-56 named "2020_Att_KU_LGE_PSC_1-56_Exhibit_KWB-2.xlsx" and are described on pages 16-17 of the Blake testimony. The regulatory asset amortization is being shown in total to convey the point that, based on the Companies' projections, we can amortize them in this manner without ever incurring an increase in the Companies' combined revenue requirement. For purposes of Exhibit KWB-2, it is fair to assume that, since all regulatory assets are associated with the implementation of AMI meters, each is being amortized at the same pace. That is to say that the annual amortization could be applied to each of the three components of the regulatory asset on a pro-rata basis based on their relative values shown in Exhibit KWB-1.

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 197

Responding Witness: Kent W. Blake

Q-197. Refer to Witness Blake testimony, Exhibit KWB-2, page 3 (20-year Meter Life). Provide detailed calculations by year for the following items under the "AMI Case":

a. Regulatory Asset Amortization (please include details for each of the three components – deferred operating expenses, net book value of electric meters replaced, and the differences between AFUDC as proposed vs. FERC methodology); and

b. Regulatory Liability Amortization (please include details for each of the four components – meter reading, field services, ADIT for retired & replaced meters, and ADIT for AMI Placed in Service for Income Tax Purposes).

A-197.

a. See the response to Question No. 196.

b. See the response to Question No. 196.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 198

Responding Witness: Eileen L. Saunders

Q-198. Explain whether there is any difference in the projected life spans of the residential electric meters, as compared with that for the proposed commercial and industrial meters.

A-198. All of the proposed AMI meters have the same projected life span.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 199

Responding Witness: Lonnie E. Bellar

Q-199. Provide the projected life spans of: (i) the AMI communications module LG&E proposes to attach to gas meters located within the LG&E electric service territory; and (ii) the encoder receiver transmitter to be attached to gas meters in LG&E's gas-only service area, which will enable the use of AMR technology.

a. If the batteries designed to be used for the equipment in both subparts (i) and (ii) above carry a different life span, provide that projected life span.

A-199. See Application Exhibit 6. Both the AMI communications module and the encoder receiver transmitter have expected lives of 20 years.

a. The batteries in the AMI communications module and the encoder receiver transmitter both carry expected lives of at least 20 years.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00350

Question No. 200

Responding Witness: Lonnie E. Bellar

Q-200. Refer to Witness Blake Testimony, pages 23-30, which describes the Companies' efforts to reduce costs, as well as pages 30-31, which describes the Companies' business and financial planning processes designed to improve efficiency and productivity. Refer also to Witness Blake Testimony, page 18: 18-23, which describes the communications network the Companies propose to install for its smart meter (AMI) deployment. The OAG is aware that the present value of building and operating such communications networks, including capital and O&M, likely amounts to tens of millions of dollars. Provide any financial analyses the Companies completed comparing the cost to install and operate their own meter mesh communications network to the cost to secure meter data communications services from public wireless data network providers such as AT&T and Verizon Wireless. If the Companies completed no such analysis, please explain why not.

A-200. The Companies are using a combination of private and commercial networks to support AMI. The backhaul from the collectors will be accomplished through a combination of third-party cellular networks and the Companies' existing fiber network. For the portions of the network from the collector to the meter, beyond utilizing existing public cellular networks, the Companies are not aware of other existing third-party private networks available for supporting the communication needs of the AMI deployment. The proposed RF Mesh network buildout was ultimately selected because it provides self-identifying and self-healing communication routes. Exclusively utilizing public cellular networks is not desirable due to ongoing monthly fees and the possibility that commercial cellular technology could change sufficiently to render the meters' communications equipment obsolete prior to the end of the meters' useful life. The Companies have already experienced this risk in the AMS Opt-In offering when 2,000 cellular meters utilizing the Verizon 3G network had to be replaced prematurely after less than 5 years of life because the providers elected to shut down that network. The RF Mesh network accounts for $18.9 million (or 5%) of the total AMI project cost ($352 million) and $0.4 to $1.1 million of annual ongoing costs starting in 2026.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 201

Responding Witness: Lonnie E. Bellar

Q-201. Refer to Witness Blake Testimony, Exhibit KWB-1, page 1, line entitled "Capital Expenditures". Refer also to Mr. Blake's Testimony, pages 18-19, which describes various capital items required to provide AMI functionality. Provide the details of the "Capital Expenditures" line item be year for each of the five years indicated in this schedule. Be sure to included, at a minimum, the cost details for the items described in Mr. Blake's Testimony, including, but not limited to:

a. RF mesh network design, hardware, installation, and testing;

b. Meters (excluding the remote service switch);

c. Meter remote service switches;

d. Any other optional Meter features and capabilities (such as Zigbee or other home area/energy management network communications chips);

e. Meter testing, handling, and Installation; and

f. Each of the seven meter software applications described on page 19 of Mr. Blake's Testimony.

A-201. See attached.

AMI Capital Expenditures		**Total Implementation Period**	**Implementation Period**				
Note	**Project**		**7/1/21 to 6/30/22**	**7/1/22 to 6/30/23**	**7/1/23 to 6/30/24**	**7/1/24 to 6/30/25**	**7/1/25 to 3/31/26**
a	AMI Network-Communications	18,867,323	2,465,821	5,389,734	5,905,516	5,051,908	54,344
b - d	AMI Meters	132,170,651	2,747,483	31,430,627	37,047,054	37,393,848	23,551,639
e	AMI Meter testing, handling, and installation	87,423,397	7,058,140	22,752,577	26,199,349	20,314,883	11,098,448
f(1)	Meter Deployment Systems (Excluding Command Center)	8,981,453	7,991,109	990,344	-	-	-
	AMI IT (Excluding IT Cybersecurity)	21,508,841	8,031,420	5,653,840	4,903,737	2,257,989	661,855
f(2)	IT Cybersecurity	1,550,000	1,550,000	-	-	-	-
f(3)	Command Center	4,423,513	4,423,513	-	-	-	-
f(4)	Meter-to-Cash	14,414,122	3,947,555	8,901,431	658,925	618,279	287,933
f(5)	Remote Service Switch	8,609,434	-	3,477,084	5,132,350	-	-
f(6)	Customer Engagement Tools	548,042	-	365,599	182,443	-	-
f(7)	Integration with Distribution	4,006,289	-	-	2,617,145	1,389,143	-
Total Capital Expenditures		**302,503,064**	**38,215,041**	**78,961,236**	**82,646,520**	**67,026,049**	**35,654,219**

Notes
a. Includes RF mesh network design, hardware, installation, and testing
b. Meters (excluding the remote service switch); Includes other optional meter features and capabilities
c. Meter remote service switches
d. Includes other optional meter features and capabilities
e. Includes meter testing, handling, and installation
f(1). Meter Deployment Systems
f(2). IT Cybersecurity
f(3). Command Center
f(4). Meter to Cash
f(5). Remote Service Switch
f(6). Customer Engagement Tools
f(7). Integration with Distribution

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 202

Responding Witness: Kent W. Blake

Q-202. Refer to Witness Blake Testimony, Exhibit KWB-1, page 1, line "Remaining Net Book Value – Retired & Replaced Meters". Refer also to Witness Bellar Testimony, Exhibit LEB-3, Table 2, which indicates that the Companies will replace (or augment) 756,000 meters. Provide details which indicate that the book value of meters and/or other equipment removed from service to complete the AMI deployment the Companies have proposed totals the $26.8 million listed on Exhibit KWB-1, page 1.

A-202. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 203

Responding Witness: Lonnie E. Bellar

Q-203. Refer to Witness Bellar Testimony, Exhibit LEB-3, Table 1 on page 4.

a. The referenced analysis appears to cover a 30-year period. Please explain why the Companies believe this is the most appropriate period for the referenced analysis.

b. Provide an active MS Excel worksheet or workbook, with all formulas intact and available for review, offering the details behind each of the options in Column (A) (PVRR, AMR becomes obsolete) and each of the options in Column (B) (PVRR, AMR Remains Viable) by year from 2021- 2050 (8 worksheets/workbooks in total), including:

i. Status Quo (A, B)
ii. Full AMI (A, B)
iii. AMI + AMR GO (A, B)
iv. Full AMR (A, B)

A-203.

a. At the end of a 30-year analysis period, cash flows begin to approach a steady-state across all alternatives. In addition, a 30-year analysis period provides sufficient time to evaluate costs and benefits over more than one meter replacement cycle.

b. See attachment being provided in Excel format. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. Details for the alternatives where AMR remains viable can be found in rows 56-179 of the Summary worksheet by changing the number of the metering alternative in cell B2. Details for the Full AMI alternative where AMR becomes obsolete are identical to those where AMI remains viable. Details for the other alternatives where AMR becomes obsolete can be found on the Risk_SQ, Risk_AMI+AMR_GO, and Risk_AMR worksheets.

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 204

Responding Witness: Lonnie E. Bellar

Q-204. Refer to Witness Bellar Testimony, Exhibit LEB-3, pages 17-19, which describe the Companies' concerns regarding potential AMR obsolescence risks.

a. Provide the exact report or other data source used to create Figure 8. (The OAG was unable to locate the data source after navigating to the link provided.)

b. Confirm that the data listed in Figure 8 consists only of electric meters. If this cannot be confirmed please explain.

c. The OAG is aware that hundreds of millions of natural gas and water meters in the U.S. are read monthly by utilities via AMR, including those utilities which do not offer electric service (and thereby have no tie-in to electric AMI technology). Discuss how this fact could mitigate AMR obsolescence risk.

d. Refer to the Companies' response to subpart (c) of this question. Identify and describe the technologies increasingly available to operators of natural gas and water utilities which might contribute to AMR obsolescence risks.

e. AMI technologies are also subject to obsolescence risks. Describe the steps the Companies took to address AMI obsolescence risk during AMI plan development, and identify any such evidence in materials the Companies provided in the two instant proceedings (Case Nos. 2020-00349 and 2020-00359).

f. Identify any evidence of the AMI obsolescence risk reduction actions provided in response to subpart (e) of this question among the materials the Companies provided in the two instant proceedings.

A-204.

a. See attached. The correct link is https://www.eia.gov/electricity/annual/html/epa_10_10.html (please note the use of "_" between "epa", "10", and "10" at the end of the URL).

b. Confirmed.

c. The Companies cannot confirm the referenced number of natural gas and water meters. As discussed in Exhibit LEB-3 on page 17, response to the Companies' March 2020 RFI indicate dwindling support of AMR, with only one vendor committing to future AMR research and investment.

d. The Companies are unaware of technologies available to water companies. The availability of AMI to gas companies increases the risk of AMR obsolescence.

e. See also the response to Question No. 221. The Companies agree there is obsolescence risk associated with any technology, including AMI. The risk for AMI technologies as a whole remains low over the 30-year analysis period as AMI has become the predominant metering technology in the United States. Unlike AMR, the Companies' March 2020 RFI indicated that multiple vendors are committed to supporting AMI investment and research. In addition, AMI accounted for over 70% of these vendors' annual sales over the last 5 years (see Exhibit LEB-3 at page 17 and Exhibit LEB-3, Confidential Appendix B).

   Specific risk areas of AMI obsolescence that the Companies have monitored in the industry include meter life, communications network approach, and vendor consolidation amongst supporting IT systems required with AMI. To address the risk of meters failing earlier than expected the Companies have evaluated a 15-year meter life in addition to the 20-year life supported by the vendor (see Exhibit LEB-3, Confidential Appendix F) as well as the Companies' own experience (see Exhibit LEB-3, pages 8 - 10).

   To mitigate the risks of communication network obsolescence the Companies have proposed installing and maintaining their own communication network rather than utilizing a public cellular network for individual meter communications (see Companies' response to Question No. 200 above) which can sunset networks and strand meters without communication. To the extent a similar risk is still present where the Companies plan to utilize public cellular for backhaul from some collectors, the Companies have modeled the on-going costs to upgrade backhaul hardware every six years (see Exhibit LEB-3, Appendix A, page A-12).

   To mitigate the risk of IT systems becoming obsolete or outdated, which in turn can increase operational risks and drive support costs higher, the Companies have modeled the on-going costs to upgrade systems and replace hardware associated with the systems every six years (see Exhibit LEB-3, Appendix A, page A-12).

f. See the response to part e.

Table 10.10. Advanced Metering Count by Technology Type,

2010 through 2019

Year	Residential	Commercial	Industrial	Transportation	Total
Automated Meter Reading (AMR)					
2010	43,913,225	4,611,877	159,315	626	48,685,043
2011	41,451,888	4,341,105	172,692	77	45,965,762
2012	43,455,437	4,691,018	185,862	125	48,330,822
2013	42,491,242	4,632,744	196,132	1,202	47,321,320
2014	41,830,781	4,781,167	216,459	1,252	46,829,659
2015	42,326,302	5,049,978	226,908	1,023	47,604,211
2016	41,508,261	5,074,877	223,584	971	46,807,693
2017	39,325,014	4,813,029	230,099	707	44,368,849
2018	36,365,339	4,591,398	213,108	712	41,170,557
2019	32,750,506	4,160,628	207,286	861	37,119,281
Advanced Metering Infrastructure (AMI)					
2010	18,369,908	1,904,983	59,567	67	20,334,525
2011	33,453,548	3,682,159	154,659	7	37,290,373
2012	38,524,639	4,461,350	179,159	35	43,165,183
2013	47,321,995	5,770,067	248,515	845	53,341,422
2014	51,710,725	6,563,614	270,683	916	58,545,938
2015	57,107,785	7,324,345	310,889	813	64,743,832
2016	62,360,132	8,119,223	342,766	1,345	70,823,466
2017	69,474,626	9,060,128	365,447	1,389	78,901,590
2018	76,498,388	9,932,993	411,287	1,489	86,844,157
2019	83,539,594	10,850,886	446,871	1,504	94,838,855
Standard (non-AMR/AMI) Meters					
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	32,059,522	5,104,322	244,114	132	37,408,090
2014	32,995,176	5,642,247	254,621	1,331	38,893,375
2015	32,430,105	5,744,831	290,354	432	38,465,722
2016	28,491,094	4,929,344	280,406	416	33,701,260
2017	24,351,523	4,261,918	225,949	445	28,839,835
2018	21,982,727	3,884,695	186,001	414	26,053,837
2019	20,778,995	3,734,399	175,344	478	24,689,216
Total Number of Meters					

Year	Residential	Commercial	Industrial	Transportation	Total
2010	--	--	--	--	--
2011	--	--	--	--	--
2012	--	--	--	--	--
2013	121,872,759	15,507,133	688,761	2,179	138,070,832
2014	126,536,682	16,987,028	741,763	3,499	144,268,972
2015	131,864,192	18,119,154	828,151	2,268	150,813,765
2016	132,359,487	18,123,444	846,756	2,732	151,332,419
2017	133,151,163	18,135,075	821,495	2,541	152,110,274
2018	134,846,454	18,409,086	810,396	2,615	154,068,551
2019	137,069,095	18,745,913	829,501	2,843	156,647,352

Prior to 2010, the count was the number of customers, not number of meters.
Starting in 2013 Standard (Non-AMR/AMI) meter data was collected on the EIA-861.
This data is not collected on the EIA-861S.
Source: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." Form EIA-861S, "Annual Electric Power Industry Report (Short Form)."

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 205

Responding Witness: Lonnie E. Bellar

Q-205. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 16, regarding the expansion of AMR in the Companies' "gas only" service area.

a. Identify alternatives to AMR expansion the Companies considered to reading gas meters in the "gas only" service area.

b. Provide any and all analyses the Companies completed to compare these alternatives to each other, and which resulted in the choice of AMR expansion for the gas only service area. If the Companies did not complete such analyses/comparisons, please explain why not.

A-205.

a. As described in Section 4 of Exhibit LEB-3, the Companies considered three metering alternatives in the gas-only service territory: manual meter reading (Status Quo), remote meter reading via AMI (Full AMI), and vehicular meter reading via AMR (AMI+AMR_GO and Full AMR).

b. The analysis of these alternatives is summarized in Section 5 of Exhibit LEB-3.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 206

Responding Witness: Lonnie E. Bellar / Eileen L. Saunders

Q-206. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 15, which states, "After Commission approval is received, any in-scope electric meters that fail prior to or outside the meter deployment project in a different part of the service territory will be replaced with AMI meters as they fail."

a. Provide a list of meters, and the counts of each, which have failed by year from 2015-2019. In this list of meters, include identifiers such as 1) manufacturer; 2) model; 3) type (electromechanical or electronic); 4) phase (single vs. polyphase).

b. The OAG is aware that the Companies have been considering an AMI transition since at least 2010, when the Companies' parent, PPL Corporation, began installing smart meters in Pennsylvania. Explain why the Companies have not been following the replacement process described in the quoted statement, above, on a routine basis to reduce the stranded costs associated with an anticipated AMI transition.

c. Provide any analyses the Companies completed historically – for example since 2010, when AMI meters became commonly available, or since 2012, when electric AMI meter installations first surpassed electric AMR meter installations in the U.S. -- which indicated that continuing to replace failed meters with "dumb" (non-AMI) meters would be less costly for customers overall than replacing failed meters with AMI meters in anticipation of a future AMI transition. If the Companies never completed any such analyses, please explain why not.

A-206.

a. See attached.

b. The Companies have not been following the described replacement process in the quoted statement for several reasons. First, as demonstrated in Exhibit LEB-3, Section 5.2, installing AMI meters in that manner over a prolonged and indefinite timeframe is not the least reasonable cost option for customers.

Second, in the April 13, 2016 Order (at p. 11) of Case 2012-00428[9], the Commission stated: "With regard to CPCNs, the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources." Thus, the Companies considered that it had limited authority to install an AMI meter. Third, AMI meter unit costs are comparatively high and would not have been a prudent investment historically if the Companies had simply installed them and not used their full suite of functionality to produce cost savings.

c. As described in LEB-3, the Companies considered a slower deployment and found it to be more costly due to the incurrence of up-front system costs and the delay of benefits. Additionally, the Companies completed several analyses. In 2016, the Companies filed for a CPCN to install AMI meters. In 2018, the Companies again filed for approval of a CPCN to install AMI meters. Without approval the Companies could not proceed as suggested.

Additionally, AMI meters are more costly than non-communicating meters. If these meters are replaced in a non-contiguous fashion, as would be expected by replacing failed meters, then they may not communicate and would thus need to be manually read. If they do communicate, and the contractor is asked not to read the AMI meter but walk past the meter, then the contract price is likely to not decrease and may increase. The other option is to overbuild the communication network. The result is increased cost and decreased benefits.

[9] https://psc.ky.gov/order_vault/orders_2016/201200428_04132016.pdf.

Year	Manufacturer	Model	Phase	Type	Count
2015	General Electric	I-210	Single-Phase	Electronic	3
2015	General Electric	I-210 (ERT)	Single-Phase	Electronic	19
2015	General Electric	I-50A	Single-Phase	Electromechanical	1
2015	General Electric	I-50S	Single-Phase	Electromechanical	49
2015	General Electric	I-55S	Single-Phase	Electromechanical	70
2015	General Electric	I-60S	Single-Phase	Electromechanical	218
2015	General Electric	I-70A	Single-Phase	Electromechanical	176
2015	General Electric	I-70A ENSCN AC	Single-Phase	Electromechanical	53
2015	General Electric	I-70S	Single-Phase	Electromechanical	650
2015	General Electric	I-70S ENSCN AC	Single-Phase	Electromechanical	66
2015	General Electric	I-70S (2W)	Single-Phase	Electromechanical	72
2015	General Electric	I-70SA	Single-Phase	Electromechanical	87
2015	General Electric	I-70SA ENSCN AC	Single-Phase	Electromechanical	5
2015	General Electric	IM-70S	Single-Phase	Electromechanical	29
2015	General Electric	kV2c (2S)	Single-Phase	Electronic	2
2015	General Electric	EV-2	Three-Phase	Electronic	2
2015	General Electric	EV-2 (SC)	Three-Phase	Electronic	58
2015	General Electric	EV-3 (TR)	Three-Phase	Electronic	5
2015	General Electric	EV-4	Three-Phase	Electronic	1
2015	General Electric	EV-4 (SC)	Three-Phase	Electronic	81
2015	General Electric	EV-5 (TR)	Three-Phase	Electronic	35
2015	General Electric	kV2c	Three-Phase	Electronic	50
2015	General Electric	V-612-S	Three-Phase	Electromechanical	8
2015	General Electric	V-62S	Three-Phase	Electromechanical	1
2015	General Electric	V-65S	Three-Phase	Electromechanical	2
2015	General Electric	VM-63A	Three-Phase	Electromechanical	1
2015	General Electric	VM-64A	Three-Phase	Electromechanical	4
2015	General Electric	VM-65A	Three-Phase	Electromechanical	64
2015	General Electric	VM-65S	Three-Phase	Electromechanical	1
2015	General Electric	VMW-65A	Three-Phase	Electromechanical	7
2015	Itron	C1S	Single-Phase	Electronic	70
2015	Itron	C1SD	Single-Phase	Electronic	12
2015	Itron	C1SL	Single-Phase	Electronic	17
2015	Itron	C1SR	Single-Phase	Electronic	20
2015	Itron	C1SR (ERT)	Single-Phase	Electronic	322
2015	Itron	C2SOS - OpenWay Cell	Single-Phase	Electronic	6
2015	Itron	J3S	Single-Phase	Electromechanical	1
2015	Itron	J4ES	Single-Phase	Electromechanical	4
2015	Itron	J4S	Single-Phase	Electromechanical	233
2015	Itron	J5A	Single-Phase	Electromechanical	2
2015	Itron	J5S	Single-Phase	Electromechanical	646
2015	Itron	J5S (R200)	Single-Phase	Electromechanical	420
2015	Itron	J5S (R300)	Single-Phase	Electromechanical	23
2015	Itron	J5SA (R300)	Single-Phase	Electromechanical	6

Year	Manufacturer	Model	Phase	Type	Count
2015	Itron	J5SD	Single-Phase	Electromechanical	1
2015	Itron	CN1S	Three-Phase	Electronic	5
2015	Itron	CP1SD	Three-Phase	Electronic	14
2015	Itron	P20AP	Three-Phase	Electromechanical	1
2015	Itron	P20AY	Three-Phase	Electromechanical	1
2015	Itron	P20DAP	Three-Phase	Electromechanical	2
2015	Itron	S12S	Three-Phase	Electromechanical	4
2015	Itron	S3DA	Three-Phase	Electromechanical	1
2015	Itron	S5DA	Three-Phase	Electromechanical	2
2015	Itron	S5S	Three-Phase	Electromechanical	1
2015	Itron	SL12S	Three-Phase	Electromechanical	348
2015	Itron	SM3ATR FULCRUM	Three-Phase	Electronic	3
2015	Itron	SM5ATR FULCRUM	Three-Phase	Electronic	31
2015	Itron	SS2S	Three-Phase	Electronic	9
2015	Itron	SS3S	Three-Phase	Electronic	6
2015	Itron	SS4S	Three-Phase	Electronic	22
2015	Itron	SS5AD	Three-Phase	Electronic	6
2015	Itron	SV2S	Three-Phase	Electronic	59
2015	Itron	SV2S EXT/MM	Three-Phase	Electronic	2
2015	Itron	SV2S (ERT)	Three-Phase	Electronic	1
2015	Itron	SV2S(X)	Three-Phase	Electronic	1
2015	Itron	SV2SD DEMAND	Three-Phase	Electronic	30
2015	Itron	SV2SD(X) DEMAND	Three-Phase	Electronic	285
2015	Itron	SV3A	Three-Phase	Electronic	1
2015	Itron	SV3AD DEMAND	Three-Phase	Electronic	1
2015	Itron	SV3AD(X) DEMAND	Three-Phase	Electronic	3
2015	Itron	SV3AR EXT	Three-Phase	Electronic	1
2015	Itron	SV3AR EXT/MM	Three-Phase	Electronic	1
2015	Itron	SV3AR(X) EXT	Three-Phase	Electronic	2
2015	Itron	SV3S	Three-Phase	Electronic	11
2015	Itron	SV3S (ERT)	Three-Phase	Electronic	2
2015	Itron	SV4S	Three-Phase	Electronic	404
2015	Itron	SV4S EXT/MM	Three-Phase	Electronic	7
2015	Itron	SV4S (ERT)	Three-Phase	Electronic	1
2015	Itron	SV4S(X)	Three-Phase	Electronic	1
2015	Itron	SV4SD DEMAND	Three-Phase	Electronic	29
2015	Itron	SV4SD(X) DEMAND	Three-Phase	Electronic	530
2015	Itron	SV5A	Three-Phase	Electronic	19
2015	Itron	SV5AD DEMAND	Three-Phase	Electronic	28
2015	Itron	SV5AD(X) DEMAND	Three-Phase	Electronic	35
2015	Itron	SV5AR EXT/MM	Three-Phase	Electronic	22
2015	Itron	SV5AR(X) EXT	Three-Phase	Electronic	2
2015	Landis + Gyr	ALF	Single-Phase	Electronic	23
2015	Landis + Gyr	ALF (Trilliant)	Single-Phase	Electronic	153

Year	Manufacturer	Model	Phase	Type	Count
2015	Landis + Gyr	ALF Trill CL320	Single-Phase	Electronic	1
2015	Landis + Gyr	AX-SD (Disc)	Single-Phase	Electronic	8
2015	Landis + Gyr	DXMS	Single-Phase	Electromechanical	10
2015	Landis + Gyr	Focus (ALF)	Single-Phase	Electronic	2
2015	Landis + Gyr	Focus AXR - Mesh	Single-Phase	Electronic	1
2015	Landis + Gyr	Focus RXR - Mesh	Single-Phase	Electronic	1
2015	Landis + Gyr	MQS	Single-Phase	Electromechanical	17
2015	Landis + Gyr	MS	Single-Phase	Electromechanical	126
2015	Landis + Gyr	MS (ENSCAN AC)	Single-Phase	Electromechanical	18
2015	Landis + Gyr	MSII	Single-Phase	Electromechanical	274
2015	Landis + Gyr	MX	Single-Phase	Electromechanical	130
2015	Landis + Gyr	AXS4 (DEMAND)	Three-Phase	Electronic	33
2015	Landis + Gyr	DDS2	Three-Phase	Electronic	1
2015	Landis + Gyr	DDS2-12S	Three-Phase	Electronic	2
2015	Sangamo	J5S	Single-Phase	Electromechanical	5
2015	Sangamo	P20AY	Three-Phase	Electromechanical	1
2015	Sangamo	P20DAP	Three-Phase	Electromechanical	1
2015	Sangamo	SL12S	Three-Phase	Electromechanical	1
2015	Westinghouse	AB1	Single-Phase	Electromechanical	154
2015	Westinghouse	D4S	Single-Phase	Electromechanical	241
2015	Westinghouse	D5S	Single-Phase	Electromechanical	29
2015	Westinghouse	D4S-5U	Three-Phase	Electromechanical	30
2015	Westinghouse	D5S-5U	Three-Phase	Electromechanical	1
2015	Westinghouse	D5S-8	Three-Phase	Electromechanical	3
2016	General Electric	I-210 (ERT)	Single-Phase	Electronic	27
2016	General Electric	I-50S	Single-Phase	Electromechanical	69
2016	General Electric	I-55S	Single-Phase	Electromechanical	73
2016	General Electric	I-60S	Single-Phase	Electromechanical	234
2016	General Electric	I-70A	Single-Phase	Electromechanical	33
2016	General Electric	I-70A ENSCN AC	Single-Phase	Electromechanical	54
2016	General Electric	I-70S	Single-Phase	Electromechanical	820
2016	General Electric	I-70S ENSCN AC	Single-Phase	Electromechanical	50
2016	General Electric	I-70S (2W)	Single-Phase	Electromechanical	65
2016	General Electric	I-70SA	Single-Phase	Electromechanical	105
2016	General Electric	I-70SA ENSCN AC	Single-Phase	Electromechanical	5
2016	General Electric	IM-70S	Single-Phase	Electromechanical	2
2016	General Electric	EV-2 (SC)	Three-Phase	Electronic	8
2016	General Electric	EV-3 (TR)	Three-Phase	Electronic	4
2016	General Electric	EV-4 (SC)	Three-Phase	Electronic	1
2016	General Electric	EV-5 (TR)	Three-Phase	Electronic	47
2016	General Electric	kV2c	Three-Phase	Electronic	55
2016	General Electric	V-612-S	Three-Phase	Electromechanical	12
2016	General Electric	V-62A	Three-Phase	Electromechanical	1
2016	General Electric	V-65A	Three-Phase	Electromechanical	1

Year	Manufacturer	Model	Phase	Type	Count
2016	General Electric	VM-64A	Three-Phase	Electromechanical	2
2016	General Electric	VM-65A	Three-Phase	Electromechanical	11
2016	General Electric	VMW-65A	Three-Phase	Electromechanical	1
2016	Itron	C1S	Single-Phase	Electronic	91
2016	Itron	C1SD	Single-Phase	Electronic	17
2016	Itron	C1SDR2	Single-Phase	Electronic	1
2016	Itron	C1SL	Single-Phase	Electronic	15
2016	Itron	C1SR	Single-Phase	Electronic	22
2016	Itron	C1SR (ERT)	Single-Phase	Electronic	159
2016	Itron	C2SOS	Single-Phase	Electronic	1
2016	Itron	C2SOS - OpenWay Cell	Single-Phase	Electronic	2
2016	Itron	J3S	Single-Phase	Electromechanical	2
2016	Itron	J4ES	Single-Phase	Electromechanical	4
2016	Itron	J4S	Single-Phase	Electromechanical	248
2016	Itron	J5A	Single-Phase	Electromechanical	2
2016	Itron	J5S	Single-Phase	Electromechanical	794
2016	Itron	J5S (R200)	Single-Phase	Electromechanical	357
2016	Itron	J5S (R300)	Single-Phase	Electromechanical	16
2016	Itron	J5SA (R300)	Single-Phase	Electromechanical	6
2016	Itron	J5SD	Single-Phase	Electromechanical	1
2016	Itron	SS1S	Single-Phase	Electronic	1
2016	Itron	CN1S	Three-Phase	Electronic	3
2016	Itron	CP1SD	Three-Phase	Electronic	16
2016	Itron	CP1SDR2	Three-Phase	Electronic	1
2016	Itron	P20DAY	Three-Phase	Electromechanical	2
2016	Itron	S12S	Three-Phase	Electromechanical	2
2016	Itron	SL12S	Three-Phase	Electromechanical	7
2016	Itron	SS2S	Three-Phase	Electronic	9
2016	Itron	SS3AD	Three-Phase	Electronic	1
2016	Itron	SS3S	Three-Phase	Electronic	8
2016	Itron	SS4S	Three-Phase	Electronic	31
2016	Itron	SS5AD	Three-Phase	Electronic	8
2016	Itron	SS5S	Three-Phase	Electronic	1
2016	Itron	SV2S	Three-Phase	Electronic	12
2016	Itron	SV2S (ERT)	Three-Phase	Electronic	4
2016	Itron	SV2SD DEMAND	Three-Phase	Electronic	8
2016	Itron	SV2SD(X) DEMAND	Three-Phase	Electronic	60
2016	Itron	SV3A	Three-Phase	Electronic	4
2016	Itron	SV3AD DEMAND	Three-Phase	Electronic	11
2016	Itron	SV3AD(X) DEMAND	Three-Phase	Electronic	3
2016	Itron	SV3S	Three-Phase	Electronic	13
2016	Itron	SV3S (ERT)	Three-Phase	Electronic	1
2016	Itron	SV4AR(X) EXT	Three-Phase	Electronic	1
2016	Itron	SV4S	Three-Phase	Electronic	51

Year	Manufacturer	Model	Phase	Type	Count
2016	Itron	SV4S (ERT)	Three-Phase	Electronic	2
2016	Itron	SV4SD DEMAND	Three-Phase	Electronic	2
2016	Itron	SV4SD(X) DEMAND	Three-Phase	Electronic	56
2016	Itron	SV5A	Three-Phase	Electronic	23
2016	Itron	SV5AD DEMAND	Three-Phase	Electronic	46
2016	Itron	SV5AD(X) DEMAND	Three-Phase	Electronic	24
2016	Itron	SV5AR EXT/MM	Three-Phase	Electronic	3
2016	Landis + Gyr	ALF	Single-Phase	Electronic	24
2016	Landis + Gyr	ALF (Trilliant)	Single-Phase	Electronic	126
2016	Landis + Gyr	AX-SD (Disc)	Single-Phase	Electronic	3
2016	Landis + Gyr	DDMS	Single-Phase	Electromechanical	1
2016	Landis + Gyr	DXMS	Single-Phase	Electromechanical	9
2016	Landis + Gyr	Focus AXR - Mesh	Single-Phase	Electronic	1
2016	Landis + Gyr	MQS	Single-Phase	Electromechanical	147
2016	Landis + Gyr	MS	Single-Phase	Electromechanical	170
2016	Landis + Gyr	MS (ENSCAN AC)	Single-Phase	Electromechanical	20
2016	Landis + Gyr	MSII	Single-Phase	Electromechanical	357
2016	Landis + Gyr	MX	Single-Phase	Electromechanical	143
2016	Landis + Gyr	ALF	Three-Phase	Electronic	2
2016	Landis + Gyr	ALF Trill Netw	Three-Phase	Electronic	3
2016	Landis + Gyr	AXS4	Three-Phase	Electronic	2
2016	Landis + Gyr	AXS4 (DEMAND)	Three-Phase	Electronic	9
2016	Sangamo	J4S	Single-Phase	Electromechanical	1
2016	Sangamo	J5S	Single-Phase	Electromechanical	2
2016	Sangamo	S1S	Single-Phase	Electronic	1
2016	Sangamo	S5S	Three-Phase	Electromechanical	1
2016	Westinghouse	AB1	Single-Phase	Electromechanical	4
2016	Westinghouse	D4S	Single-Phase	Electromechanical	252
2016	Westinghouse	D5S	Single-Phase	Electromechanical	3
2017	General Electric	I-210	Single-Phase	Electronic	5
2017	General Electric	I-210 (ERT)	Single-Phase	Electronic	25
2017	General Electric	I-50A	Single-Phase	Electromechanical	3
2017	General Electric	I-50S	Single-Phase	Electromechanical	63
2017	General Electric	I-55S	Single-Phase	Electromechanical	71
2017	General Electric	I-60S	Single-Phase	Electromechanical	312
2017	General Electric	I-70A	Single-Phase	Electromechanical	395
2017	General Electric	I-70A ENSCN AC	Single-Phase	Electromechanical	89
2017	General Electric	I-70S	Single-Phase	Electromechanical	988
2017	General Electric	I-70S ENSCN AC	Single-Phase	Electromechanical	59
2017	General Electric	I-70S (2W)	Single-Phase	Electromechanical	50
2017	General Electric	I-70SA	Single-Phase	Electromechanical	443
2017	General Electric	I-70SA ENSCN AC	Single-Phase	Electromechanical	6
2017	General Electric	IM-70S	Single-Phase	Electromechanical	34
2017	General Electric	kV2c (2S)	Single-Phase	Electronic	2

Year	Manufacturer	Model	Phase	Type	Count
2017	General Electric	EV-2 (SC)	Three-Phase	Electronic	4
2017	General Electric	EV-3 (TR)	Three-Phase	Electronic	1
2017	General Electric	EV-4 (SC)	Three-Phase	Electronic	1
2017	General Electric	EV-5 (TR)	Three-Phase	Electronic	11
2017	General Electric	kV2c	Three-Phase	Electronic	67
2017	General Electric	V-612-S	Three-Phase	Electromechanical	1
2017	General Electric	VM-65A	Three-Phase	Electromechanical	1
2017	Itron	C1S	Single-Phase	Electronic	82
2017	Itron	C1SD	Single-Phase	Electronic	25
2017	Itron	C1SL	Single-Phase	Electronic	10
2017	Itron	C1SR	Single-Phase	Electronic	27
2017	Itron	C1SR (ERT)	Single-Phase	Electronic	162
2017	Itron	C2SOS - OpenWay Cell	Single-Phase	Electronic	43
2017	Itron	J4ES	Single-Phase	Electromechanical	29
2017	Itron	J4S	Single-Phase	Electromechanical	284
2017	Itron	J5A	Single-Phase	Electromechanical	21
2017	Itron	J5S	Single-Phase	Electromechanical	759
2017	Itron	J5S (R200)	Single-Phase	Electromechanical	458
2017	Itron	J5S (R300)	Single-Phase	Electromechanical	11
2017	Itron	J5SA (R300)	Single-Phase	Electromechanical	12
2017	Itron	SS1S	Single-Phase	Electronic	2
2017	Itron	CN1S	Three-Phase	Electronic	6
2017	Itron	CP1SD	Three-Phase	Electronic	33
2017	Itron	S3A	Three-Phase	Electromechanical	1
2017	Itron	SL12S	Three-Phase	Electromechanical	14
2017	Itron	SS2S	Three-Phase	Electronic	7
2017	Itron	SS3S	Three-Phase	Electronic	5
2017	Itron	SS4S	Three-Phase	Electronic	22
2017	Itron	SS5AD	Three-Phase	Electronic	3
2017	Itron	SV2S	Three-Phase	Electronic	9
2017	Itron	SV2S(X)	Three-Phase	Electronic	1
2017	Itron	SV2SD DEMAND	Three-Phase	Electronic	5
2017	Itron	SV2SD(X) DEMAND	Three-Phase	Electronic	34
2017	Itron	SV3A	Three-Phase	Electronic	1
2017	Itron	SV3A(X)	Three-Phase	Electronic	1
2017	Itron	SV3AD DEMAND	Three-Phase	Electronic	4
2017	Itron	SV3AD(X) DEMAND	Three-Phase	Electronic	4
2017	Itron	SV3AR EXT/MM	Three-Phase	Electronic	2
2017	Itron	SV3S	Three-Phase	Electronic	16
2017	Itron	SV3S (ERT)	Three-Phase	Electronic	1
2017	Itron	SV4S	Three-Phase	Electronic	22
2017	Itron	SV4SD DEMAND	Three-Phase	Electronic	2
2017	Itron	SV4SD (DEMAND)	Three-Phase	Electronic	1
2017	Itron	SV4SD(X) DEMAND	Three-Phase	Electronic	16

Year	Manufacturer	Model	Phase	Type	Count
2017	Itron	SV5A	Three-Phase	Electronic	5
2017	Itron	SV5AD DEMAND	Three-Phase	Electronic	7
2017	Itron	SV5AD(X) DEMAND	Three-Phase	Electronic	8
2017	Itron	SV5AR EXT/MM	Three-Phase	Electronic	4
2017	Landis + Gyr	ALF	Single-Phase	Electronic	29
2017	Landis + Gyr	ALF (Trilliant)	Single-Phase	Electronic	50
2017	Landis + Gyr	AX-SD (Disc)	Single-Phase	Electronic	2
2017	Landis + Gyr	DXMS	Single-Phase	Electromechanical	2
2017	Landis + Gyr	DXMSE	Single-Phase	Electromechanical	1
2017	Landis + Gyr	MS	Single-Phase	Electromechanical	178
2017	Landis + Gyr	MS (ENSCAN AC)	Single-Phase	Electromechanical	22
2017	Landis + Gyr	MSII	Single-Phase	Electromechanical	314
2017	Landis + Gyr	MX	Single-Phase	Electromechanical	159
2017	Landis + Gyr	AXS4 (DEMAND)	Three-Phase	Electronic	9
2017	Sangamo	J5S	Single-Phase	Electromechanical	8
2017	Westinghouse	D4S	Single-Phase	Electromechanical	303
2017	Westinghouse	D5S-8	Three-Phase	Electromechanical	1
2018	General Electric	I-210	Single-Phase	Electronic	9
2018	General Electric	I-210 (ERT)	Single-Phase	Electronic	15
2018	General Electric	I-50A	Single-Phase	Electromechanical	4
2018	General Electric	I-50S	Single-Phase	Electromechanical	104
2018	General Electric	I-55S	Single-Phase	Electromechanical	108
2018	General Electric	I-60S	Single-Phase	Electromechanical	516
2018	General Electric	I-70A	Single-Phase	Electromechanical	136
2018	General Electric	I-70A ENSCN AC	Single-Phase	Electromechanical	51
2018	General Electric	I-70S	Single-Phase	Electromechanical	990
2018	General Electric	I-70S ENSCN AC	Single-Phase	Electromechanical	58
2018	General Electric	I-70S (2W)	Single-Phase	Electromechanical	37
2018	General Electric	I-70SA	Single-Phase	Electromechanical	138
2018	General Electric	I-70SA ENSCN AC	Single-Phase	Electromechanical	5
2018	General Electric	IM-70S	Single-Phase	Electromechanical	2
2018	General Electric	EV-2	Three-Phase	Electronic	3
2018	General Electric	EV-3	Three-Phase	Electronic	4
2018	General Electric	EV-4	Three-Phase	Electronic	1
2018	General Electric	EV-5	Three-Phase	Electronic	17
2018	General Electric	kV2c	Three-Phase	Electronic	89
2018	General Electric	V-612-S	Three-Phase	Electromechanical	1
2018	General Electric	VM-63A	Three-Phase	Electromechanical	3
2018	General Electric	VM-65A	Three-Phase	Electromechanical	1
2018	Itron	C1S	Single-Phase	Electronic	71
2018	Itron	C1SD	Single-Phase	Electronic	26
2018	Itron	C1SDR2	Single-Phase	Electronic	1
2018	Itron	C1SL	Single-Phase	Electronic	20
2018	Itron	C1SR	Single-Phase	Electronic	77

Year	Manufacturer	Model	Phase	Type	Count
2018	Itron	C1SR (ERT)	Single-Phase	Electronic	132
2018	Itron	C2SOS	Single-Phase	Electronic	197
2018	Itron	C2SOS - OpenWay Cell	Single-Phase	Electronic	53
2018	Itron	J4ES	Single-Phase	Electromechanical	9
2018	Itron	J4S	Single-Phase	Electromechanical	189
2018	Itron	J5A	Single-Phase	Electromechanical	10
2018	Itron	J5S	Single-Phase	Electromechanical	568
2018	Itron	J5S (R200)	Single-Phase	Electromechanical	652
2018	Itron	J5S (R300)	Single-Phase	Electromechanical	10
2018	Itron	J5SA (R300)	Single-Phase	Electromechanical	17
2018	Itron	J5SD	Single-Phase	Electromechanical	1
2018	Itron	SS1S	Single-Phase	Electronic	5
2018	Itron	CN1S	Three-Phase	Electronic	12
2018	Itron	CP1SD	Three-Phase	Electronic	39
2018	Itron	SM3AT	Three-Phase	Electronic	1
2018	Itron	SM5AT	Three-Phase	Electronic	1
2018	Itron	SS2S	Three-Phase	Electronic	14
2018	Itron	SS3S	Three-Phase	Electronic	18
2018	Itron	SS4S	Three-Phase	Electronic	42
2018	Itron	SS5AD	Three-Phase	Electronic	21
2018	Itron	SS5S	Three-Phase	Electronic	1
2018	Itron	SV2S	Three-Phase	Electronic	14
2018	Itron	SV2S(X)	Three-Phase	Electronic	35
2018	Itron	SV3A	Three-Phase	Electronic	6
2018	Itron	SV3A(X)	Three-Phase	Electronic	13
2018	Itron	SV3S	Three-Phase	Electronic	4
2018	Itron	SV4S	Three-Phase	Electronic	37
2018	Itron	SV4S(X)	Three-Phase	Electronic	62
2018	Itron	SV5A	Three-Phase	Electronic	31
2018	Itron	SV5A(X)	Three-Phase	Electronic	32
2018	Itron	SV5AR	Three-Phase	Electronic	1
2018	Landis + Gyr	ALF	Single-Phase	Electronic	31
2018	Landis + Gyr	ALF (Trilliant)	Single-Phase	Electronic	27
2018	Landis + Gyr	AX-SD	Single-Phase	Electronic	27
2018	Landis + Gyr	DXMS	Single-Phase	Electromechanical	6
2018	Landis + Gyr	Focus AXR - Mesh	Single-Phase	Electronic	4
2018	Landis + Gyr	MS	Single-Phase	Electromechanical	273
2018	Landis + Gyr	MS (ENSCAN AC)	Single-Phase	Electromechanical	27
2018	Landis + Gyr	MSII	Single-Phase	Electromechanical	488
2018	Landis + Gyr	MX	Single-Phase	Electromechanical	205
2018	Landis + Gyr	AXS4	Three-Phase	Electronic	3
2018	Sangamo	J4ES	Single-Phase	Electromechanical	11
2018	Sangamo	J4S	Single-Phase	Electromechanical	225
2018	Sangamo	J5A	Single-Phase	Electromechanical	1

Year	Manufacturer	Model	Phase	Type	Count
2018	Sangamo	J5S	Single-Phase	Electromechanical	1110
2018	Sangamo	P20AY	Three-Phase	Electromechanical	1
2018	Sangamo	S12S	Three-Phase	Electromechanical	1
2018	Sangamo	SL12S	Three-Phase	Electromechanical	6
2018	Westinghouse	D4S	Single-Phase	Electromechanical	274
2018	Westinghouse	D5S-5	Three-Phase	Electromechanical	1
2019	General Electric	EV-2	Three-Phase	Electronic	8
2019	General Electric	EV-3	Three-Phase	Electronic	14
2019	General Electric	EV-5	Three-Phase	Electronic	24
2019	General Electric	I-210	Single-Phase	Electronic	51
2019	General Electric	I-50S	Single-Phase	Electromechanical	63
2019	General Electric	I-55S	Single-Phase	Electromechanical	74
2019	General Electric	I-60S	Single-Phase	Electromechanical	380
2019	General Electric	I-70S	Single-Phase	Electromechanical	1894
2019	General Electric	I-70SA	Single-Phase	Electromechanical	57
2019	General Electric	IM-70S	Single-Phase	Electromechanical	4
2019	General Electric	kV2c	Single-Phase	Electronic	2
2019	General Electric	kV2c	Three-Phase	Electronic	87
2019	General Electric	V-612-S	Three-Phase	Electromechanical	1
2019	General Electric	V-65A	Three-Phase	Electromechanical	1
2019	General Electric	VM-63A	Three-Phase	Electromechanical	1
2019	General Electric	VM-65A	Three-Phase	Electromechanical	5
2019	Itron	C1S	Single-Phase	Electronic	138
2019	Itron	C1SD	Single-Phase	Electronic	20
2019	Itron	C1SDR2	Single-Phase	Electronic	3
2019	Itron	C1SL	Single-Phase	Electronic	23
2019	Itron	C1SL (C12.19)	Single-Phase	Electronic	1
2019	Itron	C1SR	Single-Phase	Electronic	322
2019	Itron	C2SOS	Single-Phase	Electronic	43
2019	Itron	CN1S	Three-Phase	Electronic	18
2019	Itron	CP1SD	Three-Phase	Electronic	32
2019	Itron	CP1SDR2	Three-Phase	Electronic	1
2019	Itron	J5S	Single-Phase	Electromechanical	1
2019	Itron	SP4AM	Three-Phase	Electronic	2
2019	Itron	SS1S	Single-Phase	Electronic	4
2019	Itron	SS2S	Three-Phase	Electronic	16
2019	Itron	SS3S	Three-Phase	Electronic	124
2019	Itron	SS4S	Three-Phase	Electronic	64
2019	Itron	SS5AD	Three-Phase	Electronic	8
2019	Itron	SV2S	Three-Phase	Electronic	12
2019	Itron	SV2S(X)	Three-Phase	Electronic	12
2019	Itron	SV3A	Three-Phase	Electronic	16
2019	Itron	SV3A(X)	Three-Phase	Electronic	6
2019	Itron	SV3AR	Three-Phase	Electronic	2

Year	Manufacturer	Model	Phase	Type	Count
2019	Itron	SV3AR(X)	Three-Phase	Electronic	1
2019	Itron	SV3S	Three-Phase	Electronic	7
2019	Itron	SV4S	Three-Phase	Electronic	36
2019	Itron	SV4S(X)	Three-Phase	Electronic	12
2019	Itron	SV5A	Three-Phase	Electronic	45
2019	Itron	SV5A(X)	Three-Phase	Electronic	15
2019	Itron	SV5AR	Three-Phase	Electronic	3
2019	Landis + Gyr	ALF	Single-Phase	Electronic	49
2019	Landis + Gyr	AXS4	Three-Phase	Electronic	7
2019	Landis + Gyr	AX-SD	Single-Phase	Electronic	4
2019	Landis + Gyr	DXMS	Single-Phase	Electromechanical	5
2019	Landis + Gyr	Focus AXR - Mesh	Single-Phase	Electronic	27
2019	Landis + Gyr	Focus AXRe-SD Mesh	Three-Phase	Electronic	27
2019	Landis + Gyr	Focus RXR - Mesh	Single-Phase	Electronic	3
2019	Landis + Gyr	Focus RXR - Mesh	Three-Phase	Electronic	2
2019	Landis + Gyr	MS	Single-Phase	Electromechanical	272
2019	Landis + Gyr	MSII	Single-Phase	Electromechanical	626
2019	Landis + Gyr	MX	Single-Phase	Electromechanical	201
2019	Sangamo	J4ES	Single-Phase	Electromechanical	9
2019	Sangamo	J4S	Single-Phase	Electromechanical	371
2019	Sangamo	J5S	Single-Phase	Electromechanical	1378
2019	Sangamo	S12S	Three-Phase	Electromechanical	5
2019	Sangamo	S3A	Three-Phase	Electromechanical	1
2019	Sangamo	SL12S	Three-Phase	Electromechanical	14
2019	Westinghouse	D4S	Single-Phase	Electromechanical	403
2019	Westinghouse	D5S	Single-Phase	Electromechanical	3

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 207

Responding Witness: John K. Wolfe

Q-207. Refer to Witness Bellar Testimony, Exhibit LEB-3, page 15, which explains that AMI data will enable the Companies to anticipate transformer failures.

a. Explain how AMI capabilities will be used to anticipate transformer failures.

b. Provide any analyses the Companies have completed which indicates that the incremental cost to residential customers of prospective replacement of distribution transformers before they fail (present value of revenue requirement) is less than the economic benefits to residential customers of the associated reliability improvements.

A-207.

a. See Witness Wolfe Testimony, page 26 line 11 through page 27 line 9 as well as Exhibit JKW-2, pages 30, 34, and 35. AMI provides voltage data. When voltage increases by approximately 7% behind a transformer for a certain period this increase indicates an impending transformer failure.

b. The Companies plan to use AMI voltage data to target replacement of distribution line transformers indicating malfunction or impending failure. Planned replacements should occur relatively close to when targeted transformers would have failed. The Companies estimate that planned versus reactive replacement of distribution transformers will save on average 1.5 hours of outage time on approximately 320 avoided customer outages annually.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 208

Responding Witness: Eileen L. Saunders

Q-208. Refer to Witness Bellar Testimony, at 56: 9-10, which indicates that customers want AMI meters. In support of this statement, Mr. Bellar notes that 20,000 customers have opted-in to the Companies' existing voluntary AMI offer, with 5,200 customers on a waiting list. Provide any customer research the Companies have conducted which indicates the current level of interest in AMI capabilities among the Companies' customers overall.

A-208. The Companies have surveyed customers participating in the AMS opt-in program on AMI capabilities. The Companies have not conducted customer research regarding interest level specific to having an AMI meter. In May 2017, the Companies surveyed members of the LG&E and KU Proprietary Customer Panel, which is designed to be representative of the Companies' customers overall, to gauge awareness of the AMS Opt-In Program, as well as understand what benefits of the program should be highlighted. That survey found that 92% of respondents were not participating in the AMS Opt In program, of which 71% were at least somewhat likely to participate. Importantly, the survey also found that 79% of the respondents that were not participating cited a lack of awareness the program existed as the reason why.

When the AMS Opt-In Program participation limit increased from 10,000 to 20,000 customers, the Companies enhanced educational materials and tutorials (see Exhibit ELS-2 for samples) and set out to inform customers that the capabilities were available to them as a tool at no additional cost. Customers responded enthusiastically and both Companies were fully subscribed within only eight months of the program expansion with no evidence that the high level of interest was waning. A waitlist was started that continues today despite the Companies ceasing all outbound communications on the program in June 2019.

This customer response indicates a significant interest in AMI capabilities. Additionally, the value proposition for customers proposed in the current case is much the same as it was in 2019 -- additional tools and information for customers at no additional cost. The proposed case for AMI has the added benefit that it does not require customers to actively participate in any way in order to enjoy net savings from the operational benefits.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 209

Responding Witness: Kent W. Blake

Q-209. Refer to Witness Bellar Testimony, Exhibit LEB-3, pages 15-16, which allude to several types of potential AMI benefits which are difficult to quantify, including reduced usage on inactive meters, bad-debt write offs, and theft, which will increase the Companies' billed sales volumes and/or revenues to the extent they can be accomplished. However, the OAG notes that none of these benefits will result in rate reductions for customers until they are 1) implemented to their maximum benefit potential; and 2) included in a rate case test year, test year adjustment, bad debt accrual rate reduction, or sales volume forecast.

a. Describe any commitments the Companies are willing to make to maximizing the revenue improvement potential of smart meters.

b. Describe any commitments the Companies are willing to make to measuring the actual revenue improvements delivered from smart meters.

c. Describe any commitments the Companies are willing to make to ensure all revenue improvements from smart meters are represented in the test year, test year adjustments, sales volume forecasts, or bad debt accrual rates of the rate case in which the Companies seek to secure AMI cost recovery.

A-209. a-b. The Companies are not sure they understand the OAG's reference to "revenue improvement potential" in the request for information. In terms of potential benefits not quantified in the Companies' cost-benefit analysis, theft and other non-technical losses were mentioned by Mr. Bellar. To the extent such detected theft losses limit unauthorized consumption, the fuel benefit will automatically flow through to customers the Companies' fuel adjustment clause.

c. The Companies will follow the Commission's regulations when filing their next base rate cases.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 210

Responding Witness: Lonnie E. Bellar

Q-210. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix A, Tables 26 and 27 on pages A-19 and A-20.

a. For the AMI +AMR_GO scenario, provide the calculations, assumptions, estimates, and other details associated with the ePortal Fuel Savings projection for each year from 2021-2050. Any worksheets provided in response should be active with no protected cells, all calculations available for review, no pasted values, and all input data cited as to sources. Please include all assumptions, such as customers counts/sales volume forecasts by year, and low and high marginal cost of energy forecasts by year, from 2021-2050, with your response.

b. For the AMI+AMR_GO scenario, provide the calculations, assumptions, estimates, and other details associated with the CVR Fuel Savings projection for each year from 2021-2050. Any worksheets provided in response should be active with no protected cells, all calculations available for review, no pasted values, and all input data cited as to sources. Please include all assumptions not included in response to (a), (confirming any data not also provided in response to (b) are the same), such as number of circuits, percentage of circuits, sales volume forecasts by circuit, etc. with your response.

A-210.

a. See attachment to the response to Question No. 203(b). ePortal savings are a function of the pace of meter deployment, total energy requirements for customers who will be receiving AMI meters, the assumed energy reduction percentage, and the marginal system fuel price derived from the Companies' production cost forecasting model. Inputs for the pace of meter deployment can be found on the Profiles_Dep tab in rows 172-174, total energy requirements can be found on the Profiles_Ind tab in rows 34-36, the assumed energy reduction percentage as described in Exhibit LEB-3 Section 6.6 can be found on the Summary tab in cells E33:G33, marginal system fuel costs can be found on the Profiles_Ind tab in rows 37-39, and the product of these inputs can be found on the Model tab in rows 139-141.

b. See attachment to the response to Question No. 203(b). CVR fuel savings are a function of the rate at which CVR is implemented across the distribution system, the total CVR energy savings potential, and the marginal system fuel price derived from the Companies' production cost forecasting model. The rate at which CVR is implemented can be found on the Profiles_Dep tab in rows 200-202, the total CVR energy savings potential as described in Exhibit LEB-3 Section 6.6 can be found on the Summary tab in cells E32:G32, and the product of these inputs can be found on the Model tab in rows 142-144.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 211

Responding Witness: Eileen L. Saunders

Q-211. Refer to Witness Saunders Testimony, Appendix A, regarding e-Portal capabilities. Provide any commitments the Companies are willing to make regarding the measurement and reporting each year of the count of the:

a. unique number of customers who have accessed their own usage dashboard in the e-Portal at least once each year (slides A-2 and A-3);

b. unique number of customers who have accessed their own usage dashboard in the e-Portal more than once in the last year, by access frequency (2 times, 3 times, 4 times, etc.);

c. customers enrolled in the Threshold Notifications feature (slide A-6) of the e-Portal each year;

d. customers with a current Property Profile completed in the e-Portal each year;

e. customers who are making consumption data available to third parties on an ongoing (no end date) basis (slide A-12) through the e-Portal each year;

f. customers receiving service under the RTOD-E rate; and

g. customers receiving service under the RTOD-D rate.

A-211. a. – g. The Companies are willing to commit to reporting all of these items annually to the extent the Commission believes such reporting would be useful and requires the same.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 212

Responding Witness: Eileen L. Saunders

Q-212. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix E, the e-Portal energy reduction analysis completed by Tetra Tech.

a. Explain in detail how the results of the analysis were used to project annual energy savings from the e-Portal. For example, were the (discounted) energy savings percentages simply multiplied by forecast energy billings by residential and small commercial customers to project energy use reductions?

b. Describe any commitments the Companies are willing to make regarding the measurement of actual energy use reductions from the e-Portal, and describe the Companies' recommended measurement approach. If the Companies are not willing to make any such commitment, please explain why not.

A-212.

a. As stated in Section 6.6 of Exhibit LEB-3, Tetra Tech determined that AMS Opt-In customers had 1.4% to 1.7% lower energy consumption, and the Companies' analysis assumed a range of 0.0% to 0.7% lower energy consumption for the remaining AMI meter population. The energy savings were calculated as the product of assumed energy reduction percentages, total forecasted energy requirements of customers who would be receiving an AMI meter, and the pace of AMI meter deployment.

b. Measuring energy savings as a result of the e-Portal savings would require creating treatment and contrast groups to compare their differences. This would require the Companies to prohibit the use of the MyMeter portal for some customers. These customers would be denied the benefits of using AMI data. The Companies do not recommend denying some customers their benefit of AMI data to determine e-Portal savings.

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Question No. 213

Responding Witness: Lonnie E. Bellar / John K. Wolfe

Q-213. Refer to Witness Bellar Testimony, Exhibit LEB-3, Appendix D, the CVR Potential Study. Page 8 of the Study identifies three voltage control thresholds: 116, 117, and 118 volts, resulting in annual energy reductions of 2.61, 1.99, and 1.40 percent respectively. Refer also to the Companies' response to the OAG-KIUC DR 1-206 (b), above.

a. Confirm that CVR can be implemented with a relatively few smart meters or line sensors per circuit, and does not require full system-wide AMI deployment. If this cannot be confirmed, please explain.

b. The OAG understands that CVR can be implemented without a full systemwide smart meter deployment. If so, for purposes of an "apples to apples" comparison, it would be important to add CVR-related fuel cost savings to the AMR scenarios. Explain why the Companies did not estimate CVR fuel savings using only a relatively few smart meters or line sensors in the AMR scenarios.

c. Explain in detail how the results of the CVR potential study were used to project annual energy savings from CVR. For example, does the CVR potential study multiply the energy savings percentages by the forecast energy billed on the 404 "candidate" circuits to project annual energy reductions from CVR?

d. The OAG is aware of two approaches to implementing CVR. One is static, in which field equipment settings (load tap changers, voltage regulators, cap banks, etc.) are modified periodically to reduce average circuit voltage. The other is dynamic, in which field assets are upgraded or replaced to accept remote wireless control, and in which settings are optimized continuously based on instructions from software populated with data from field sensors in near real time. Which approach did the Companies assume when selecting the three voltage control thresholds?

e. Identify where in the Companies' response to OAG-KIUC DR 1-199 (b), above, the incremental O&M and/or capital costs of the CVR approach identified in subpart (d) of this question can be found. If these costs are not included in analyses which include CVR benefits, please explain why not.

f. Provide any studies or analyses the Companies completed comparing the energy savings potential and benefit-cost analyses of the "static" approach described in subpart (d) of this question to the "dynamic" approach described in subpart (d) of this question. If no such studies or analyses have been completed, please explain why not.

g. Describe any commitments the Companies are willing to make regarding the measurement and reporting of actual energy use (or voltage) reductions from CVR, and describe the Companies' recommended measurement approach. If the Companies are not willing to make any such commitment, please explain why not.

A-213.

a. The Companies do not believe that CVR can be reliably and efficiently deployed with a relatively few smart meters or line devices per circuit, particularly as the distribution grid becomes more complex with increased adoption of distributed energy resources and electric vehicles by customers. When using only a few meters or line sensors there is no indication between these devices whether voltage at the point of delivery (the meter) is within operating tolerance limits (note length of service line varies by customer and approximately 50% of the voltage drop can occur between the service transformer and the meter) prescribed by the American National Standards Institute (ANSI), thereby creating risk of improper operation and damage to customers' end use devices. Consequently, the Companies believe full AMI is required to have affirmative indication of voltage at customers' meters and thus, ensure customers' equipment operates as intended.

b. See the response to part a.

c. As detailed in Exhibit LEB-3 Appendix D, the CVR energy savings rate associated with each scenario is applied to calendar year 2019 energy for CVR candidate circuits to estimate CVR savings potential. The annual CVR energy savings is computed as the product of the CVR savings potential and the pace of CVR deployment. For further discussion, see the response to Question No. 210(b).

d. The Companies plan to implement a dynamic approach to CVR as described by the AG.

e. There was no part b in Question No. 199. There are no incremental costs associated with CVR implementation.

f. The Companies did not formally perform such a study to compare the static vs dynamic approaches to CVR. As distributed generation and customer use of the distribution system evolves, the Companies anticipate the need for additional sensing devices to monitor and control the distribution system. With the on-going implementation of the Advanced Distribution Management System and Company strategy to move towards Centralized Grid Operations on the Distribution System, the Companies sought to implement a dynamic approach to CVR.

g. The Companies are willing to report on voltage and operation of the CVR system to the extent the Commission believes it is necessary.

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Question No. 214

Responding Witness: Eileen L. Saunders

Q-214. Refer to Witness Bellar's testimony, at 62: 14, regarding access to near-real time usage data. The OAG is aware that some AMI meters are equipped with wireless communications capabilities which allow customers to "tap into" meter data in near real time via their existing home area wireless networks. The OAG understands this capability is typically enabled via a device (typically called a "bridge") between the meter and a customer's home area wireless network which the customer must purchase or secure from a third party (or which could conceivably be supplied by a utility as part of a demand-side management program or an unregulated home energy management services offering).

a. Does the Companies' selected AMI vendor offer this home area network wireless communications capability as an option?

b. Do the Companies plan to install meters with this capability? If so, please discuss the extent to which this capability will be deployed, as well as the Companies' plans, if any, to utilize the capability.

c. Describe any commitments the Companies are willing to make to ensure that such a capability will not be used to secure any advantage for the Companies or unregulated affiliates over third parties competing in unregulated home energy management services markets, or over third parties offering "bridge" devices.

A-214.

a. Yes.

b. Yes, the Companies plan to install AMI meters between 2022 and the first quarter of 2026, which will all be equipped with the Zigbee wireless communication protocol. The Companies note that the existing AMI meters deployed also have this capability. The Zigbee wireless communication will be available for customers who purchase their own "bridge" or compatible device. The Companies have investigated using devices that provide real-time information. The cost of a "bridge" can be almost the same cost of an AMI meter thus doubling the overall cost. The Companies have considered offering devices to customers for a fee and/or evaluating the value in a DSM program.

c. The Companies will inform customers upon request if third party devices will communicate with their meter, remotely supporting the customer in setting up their device with their meter as needed, and listing third-party “bridge” options through the Companies’ online Marketplace program (www.lge-ku.com/marketplace). The online Marketplace enables customers to easily compare appliances and electronics and directly links customers to retailers if they wish to buy.

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Question No. 215

Responding Witness: Robert M. Conroy

Q-215. Refer to Witness Bellar's testimony, at 58:17, which indicates the Companies' commitment to offer a prepay program. The OAG understands that prepayment programs offer cost reductions to utilities, including reductions in working capital requirements/associated interest expense (normally needed to fund accounts receivable), and reductions in bad debt provision rates. Describe any commitments the Companies are willing to make that such cost reductions will be incorporated into the prepaid rates the Companies will offer.

A-215. The Companies believe the foundation of ratemaking is cost of service. Therefore, the Companies will take into account all relevant costs when proposing prepayment programs.

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Question No. 216

Responding Witness: Robert M. Conroy

Q-216. Refer to Witness Bellar's testimony, at 58:17, which indicates the Companies' commitment to offer time-of-day rates. Describe any commitments the Companies are willing to make regarding the types or results of time-of-day rates offered, including:

a. A commitment to offer a time-of-day rate with a critical peak price feature;

b. A commitment to offer a universal (all customer) peak-time rebate program;

c. A commitment as to the minimum percentage of residential customers who elect to receive service on a time-of-day rate;

d. A commitment as to the reductions in system peak demand (in MW) secured through time-of-day rates with critical peak price or peak time rebate features;

e. Any other commitments related to time-of-day rates the Companies believe will increase the value of AMI to customers.

A-216. a-e. The Companies have not yet evaluated or studied the time-of-day approaches set forth in this request, therefore they cannot offer any of the requested commitments. The Companies' commitment concerning time-of-day rates, which is clarified in Mr. Conroy's testimony at page 10, lines 16-17, states, "[T]he Companies commit to expand the availability of time-of-day rates after full AMI deployment." The Companies are not committing to a particular rate design in these proceedings; rather, they are committing to expand the availability of time-of-day rates and to consider additional cost-of-service-driven time-of-day offerings after acquiring customer data from the AMI deployment.

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Question No. 217

Responding Witness: Eileen L. Saunders

Q-217. Refer to Witness Bellar's testimony, Exhibit LEB-3, page 12, which states ". . . off-cycle meter reads, move-out and move-in orders, and disconnect and reconnect orders are completed with an in-person visit to the customer's premise." The OAG understands that the Companies will be installing meters with remote disconnect capabilities if the AMI CPCN is approved.

a. Confirm that, to the extent AMI meters with remote disconnect capabilities are installed, remote disconnections for non-payment will still involve an in-person visit to the customer's premise, and that compliance with this and all other consumer protections in current PSC regulations associated with disconnection for non-payment will continue. If this cannot be confirmed, please explain any and all departures from such regulations the Companies are requesting.

b. Refer to the Companies' response to subpart (a) of this question, as well as to the PVRR Table on page 56 of Mr. Bellar's testimony. Confirm that the figures in the Table assume that in-person visits and all other consumer protections associated with disconnections for non-payment will continue if the AMI CPCN is approved. If this cannot be confirmed, provide modifications to the figures in the Table which would reflect continued compliance with these consumer protections.

A-217.

a. The Companies confirm that they will comply with all PSC regulations in a disconnect situation. In the majority of cases, an in-person visit to the customer's premise for disconnects or reconnects will not be required.

b. The PVRR figures on page 56 assume no in-person visits to disconnect or reconnect service in the majority of cases. The analysis assumes that all consumer protections associated with disconnections for non-payment continue.

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Question No. 218

Responding Witness: Eileen L. Saunders

Q-218. Refer to Witness Saunders' testimony on the AMI Customer Engagement and Communication Plan, Exhibit ELS-2, generally, and to Witness Bellar's testimony related to the AMI CPCN, pages 53-63, generally. The OAG notes no discussion on how the Companies intend to use the increased information on customers' energy usage smart meters make available.

a. Provide the Companies' current customer data usage policy. Highlight those sections of the policy which detail how, and for what purposes, the Companies are permitted to use customer data, including energy usage data, today.

b. Provide all modifications to the current customer data usage policy the Companies will make if the AMI CPCN is approved.

A-218.

a. The Companies' current customer data usage policy can be found at the Companies' website, https://lge-ku.com/privacy. The privacy policy states:

We will make every effort to protect and preserve customer account information and will not share specific information about your account with third parties, without written authorization or unless we are required to do so by a court order, subpoena or other compulsory process, or by operation of law.

Customer account information may be used by the Companies in the following representative ways:

- To verify the existence of a customer's energy service;
- To communicate with a customer and handle customer requests;
- To compile information about how our Web site is reached and used;
- To compile research that does not identify the customer as an individual, group or entity other than age group and gender;
- To contact our customers about other products or services offered by our alliance partners; and
- To collect debts owed by a customer.

b. There are no planned modifications to the usage policy above if the AMI CPCN is approved.

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Question No. 219

Responding Witness: Robert M. Conroy

Q-219. Refer to Witness Bellar's testimony related to the AMI CPCN, pages 53-63, generally.

a. Confirm that the AMI meters the Companies propose to install will enable demand rates for residential customers. If this cannot be confirmed, please explain.

b. Describe any commitments the Companies are willing to make regarding demand rates for residential customers. For example, are the Companies willing to commit that residential demand rates will not be offered on anything other than a voluntary (i.e., not default) basis?

A-219.

a. Confirmed.

b. As described in my testimony on page 10, "The Companies are committing that, if the Commission approves the proposed AMI deployment, they will offer innovative rate designs to ensure customers receive benefits from AMI beyond the operations savings that will be reflected in their bills following future rate cases." The Companies commit to consider customer and interested parties' perspectives as these rates are developed. The Companies are not willing to make commitments regarding demand rates for residential customers, but they do not presently plan to require demand rates for residential customers. The Company currently has a demand rate option for residential customers.

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Question No. 220

Responding Witness: Eileen L. Saunders

Q-220. Refer to Witness Saunders' testimony, Appendix (MyMeter Screenshots), slide A-12, regarding customer authorization of third-party access to customer usage data. Confirm that the Companies commit to full compliance with Green Button's Connect My Data standard. If this cannot be confirmed, please explain.

A-220. Note that the third-party access to customer usage data shown on slide A-12 is not Green Button's Connect My Data. The Company plans to implement Green Button Connect My Data and will comply with Green Button's Connect My Data Standard for that service upon implementation.

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Question No. 221

Responding Witness: Lonnie E. Bellar

Q-221. Reference the Blake testimony at 10: 18-23 through 11: 1-5. Explain whether it would be cost effective to delay the AMI project by the amount of time necessary for the Companies' existing meters to be fully depreciated, and how doing so would affect the NPV values.

A-221. No. The Companies' existing meter population primarily consists of electromechanical meters, which are obsolete and no longer manufactured, and non-communicating electronic meters, which are readily commercially available. In the Status Quo, when an electromechanical or non-communicating electronic meter fails, it is replaced by a non-communicating electronic meter. Over time, the net book asset value of these electromechanical and non-communicating meters will not appreciably decrease unless the Companies employ an approach where as these meters fail they are replaced with AMI meters.

The Replace-As-Meters-Fail timelines outlined in Section 5.2 of Exhibit LEB-3 evaluates two such scenarios, utilizing this approach that results in a delay of full AMI deployment from the base assumption of 2026 by five and ten years, until 2031 and 2036 respectively. This scenario was developed to address potential concerns regarding wasteful duplication. However, the Companies' analysis in Section 5.2 shows that replacing meters as they fail with AMI meters is progressively not as cost effective as the proposed AMI project implementation timeline. Additionally, delaying AMI implementation delays other benefits not quantified in the PVRR analysis, such as improved customer experience, improved safety, improved reliability, the reduction of non-technical losses and the ability to offer additional customer programs or services.

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Question No. 222

Responding Witness: Lonnie E. Bellar

Q-222. Reference the Blake testimony at 11: 21-22, in which he states that the proposed AMI capital project is a single project that includes interdependent systems. Explain whether it could be possible for the Companies to share any back-office computer hardware and software that their affiliate, PPL Electric Co. has deployed for its AMI project.

A-222. While it may be possible it is unlikely to be cost-effective because the Companies and PPL have different regulatory requirements, different back-office systems, and PPL does not provide natural gas to customers.

PPL does not have SAP as their customer care system. Additionally, PPL does not provide natural gas service which was required in our meter asset management system, along with specific programming to meet KPSC requirements. PPL's meter data management system is specifically configured to communicate with their customer care system.

The complexity of sharing back-office systems would require additional labor to configure and manage the network infrastructure. Meeting state specific requirements would require separate applications and database services. All of this would lead to increased cost.

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Question No. 223

Responding Witness: Kent W. Blake

Q-223. Reference the Blake testimony at 13: 20-21, in which he states, with regard to the proposed AMI project, that several state public utility commissions have approved other utilities' requests to accrue AFUDC using the utility's WACC. Explain what benefit would accrue to ratepayers in the event the Kentucky Commission should approve this request.

A-223. In the event the Commission approves the Companies' proposed ratemaking that includes accruing AFUDC using their WACC, customers will benefit from the installation of the AMI system. Based on the Companies' projections, that will be accomplished with no increase in the Companies' combined revenue requirement.

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Question No. 224

Responding Witness: Kent W. Blake

Q-224. Reference the Blake testimony at 16: 8-22 through 17: 1-12. Confirm that under the Companies' analysis, by the fifth year following complete deployment, net benefits of the proposed AMI project will have exceeded net costs, such that ratepayers will not be paying any costs for the project.

A-224. The Companies are proposing no cost recovery or bill impact associated with the AMI project in this proceeding or during its implementation. As demonstrated in Exhibit KWB-2 and explained on pages 15-17 of Mr. Blake's testimony, the benefits of the AMI project will outweigh the costs of the project over time. The Companies have carefully and thoughtfully used available ratemaking and accounting principles to develop the proposal in this case that best matches costs incurred with benefits received. The Companies' projections show that this ratemaking treatment can be accomplished in a way that provides the Companies' full recovery of project costs with no increase in the Companies' combined annual revenue requirement and thus no net bill impact.

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Question No. 225

Responding Witness: Kent W. Blake

Q-225. Reference the Bellar testimony generally. Provide the undepreciated costs for existing meters at the current time. Provide also the projected undepreciated costs at the time of the proposed AMI project's completion.

A-225. The Companies' net book value of electric meters to be retired and replaced as part of the AMI project as of August 31, 2020 was $40.9 million. The net book value of these same meters when the implementation of AMI is complete is projected to be $26.8 million as shown in Exhibit KWB-2 and detailed in response to Question No. 202.

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Question No. 226

Responding Witness: Lonnie E. Bellar / Eileen L. Saunders

Q-226. Reference the Bellar testimony generally. Provide a discussion of whether the proposed system-wide AMI rollout would increase the risk of cybersecurity threats, and describe the actions the Companies propose to mitigate any such threat increase.

A-226. The Companies take cybersecurity threats seriously and the AMI rollout is no exception. Expanding the connectivity and interconnected capabilities of the Companies' operational technologies does present additional risks that must be taken into account. The Companies have already taken steps within the existing population of AMI meters by performing penetration testing on the metering components and by implementing advanced security capabilities on the Landis+Gyr system that individually encrypts the data from each meter to Command Center, ensuring that a compromised meter is unable to be utilized to communicate with additional meters. As part of the proposed system-wide AMI rollout the Companies have included a robust cyber security assessment intended to identify vulnerabilities and mitigation strategies.

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Question No. 227

Responding Witness: John K. Wolfe

Q-227. Reference the Wolfe testimony at 21:16-18. Explain whether the benefits to distribution management resulting from AMI deployment discussed therein can be tracked and quantified. If so, please describe that process.

A-227. No. AMI provides additional sensors that will be input into the Distribution Management System (DMS) and will improve the accuracy of the Power Flow DMS module. This will allow other DMS modules to operate with refined accuracy including Feeder Load Management (FLM) and Fault Location Isolation and Service Restoration (FLISR).

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Question No. 228

Responding Witness: John K. Wolfe

Q-228. Reference the Wolfe testimony at 27:5-7, wherein he states: "AMI meters can enhance fault locating and isolation, and service restoration capabilities once the final phase of the advanced distribution management system [ADMS] is deployed." Clarify whether it is the final phase of ADMS, or AMI to which he is referring.

A-228. Mr. Wolfe's testimony is referring to the final phase of ADMS.

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Question No. 229

Responding Witness: John K. Wolfe

Q-229. Reference the Wolfe testimony, Exhibit JKW-1, p. 27. Explain whether there is any duplication between Volt/VAR Optimization program, discussed on this page, and the Conservation Voltage Reduction program, as part of the proposed AMI project.

A-229. There is no duplication between the Companies planned Volt/VAR Optimization (VVO) and Conservation Voltage Reduction programs. Conversely, CVR will be enabled by operations, communications, and information technology deployed for the overall VVO program.

The Companies intend to deploy VVO in the coming years, through adding necessary voltage control devices to the distribution system, and deployment of necessary communications and information technologies in supplement of its existing Network Management System (NMS). Associated investments are independent of the Companies planned AMI deployment and are deemed essential to assuring continued delivery of safe, reliable, and high-quality electric service for customers as the grid experiences increased adoption of distributed energy resources and electric vehicles. By itself, the planned VVO program and associated technologies will provide the Companies the ability to manage system voltages near the midpoint of acceptable operating voltage ranges prescribed by American National Standards Institute (ANSI) to assure voltage at the point of delivery enables customer equipment and appliances to operate correctly.

The Companies planned CVR program involves a more aggressive voltage management strategy which focuses on operating distribution system voltages below the midpoint of the acceptable ANSI voltage range, using technology deployed for VVO, with the goal of achieving energy savings.

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Question No. 230

Responding Witness: John K. Wolfe

Q-230. Reference numerical paragraph 20 in the LG&E application, and its identical counterpart in the KU application numerical paragraph 18, wherein it is stated, inter alia: "The proposed savings derive from . . . fuel savings resulting from the ability to leverage AMI to reduce customers' energy usage by incrementally lowering distribution voltages."

a. Explain how much more expense the Companies will incur for additional distribution grid upgrades in order to achieve the stated savings in either or both of the Conservation Voltage Reduction and Volt/VAR Optimization programs.

b. Explain whether the sums identified in subpart a. to this question were factored into the AMI cost-benefit analysis. If not, explain why not.

A-230.

a. No additional expense is needed to achieve the stated savings. Volt/VAR Optimization ("VVO") is necessary to maintain reliability on the distribution system regardless of whether the Companies deploy AMI. Should the application for AMI deployment be denied, the Companies will incur an incremental $14 million in capital costs for VVO voltage sensors and the stated energy savings will not be achieved.

b. The incremental costs and energy savings identified in subpart a. were factored into the AMI cost-benefit analysis.

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Question No. 231

Responding Witness: John K. Wolfe

Q-231. Reference the Wolfe testimony, Exhibit JKW-2, p. 5. Under the heading "Why this matters," describe how the Companies propose to "tune" the AMI system with other distribution operations data resources.

a. Regarding all such "tuning," describe in complete detail how much is necessary to provide full functionality to the proposed AMI system, and how much is tuning is related to other distribution system enhancements not related to AMI functionality.

b. With regard to your response to subpart a. of this question, provide: (i) all applicable cost estimates; and (ii) any benefit-cost analyses for such "tuning" the Companies may have conducted.

c. Explain whether the sums identified in subpart b. to this question were factored into the AMI cost-benefit analysis. If not, explain why not.

A-231.

a. Tuning the AMI system to work efficiently with other distribution systems ensures information is presented accurately and in a timely manner for operators to make decisions about the distribution grid. This tuning consists of identifying specific AMI data needed by the distribution systems, e.g. Network Management System (NMS) and Geographic Information System (GIS), and then developing the necessary interfaces between AMI and these distribution systems.

b. $4.0 million has been allocated for integration between AMI and various Distribution systems. These costs enable the Companies to achieve the distribution O&M savings and CVR savings detailed respectively in Sections 6.5 and 6.6 of Exhibit LEB-3.

c. Yes, these integration costs were included in the AMI cost-benefit analysis.

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Question No. 232

Responding Witness: Eileen L. Saunders

Q-232. Reference Application Exhibit 5, p. 3 (identical in both dockets) regarding commercial and industrial metering, the statement under the "Highlights" column that states "Unsurpassed 10KV surge protection for safety." Explain if the surge protection referenced here refers to the entire structure, or only to the meter itself. Provide the same information with regard to the residential meters the Companies propose to deploy.

A-232. The surge protection referenced refers only to the meter itself. The residential meters the Companies propose to deploy have the same surge protection.

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Question No. 233

Responding Witness: Lonnie E. Bellar

Q-233. Explain whether the Companies will be installing AMI in the ODP service territory. If so, could that deployment lead to synergies and/or cost savings for LG&E-KU ratepayers? Explain.

A-233. Yes. The impact of installing AMI in the ODP service territory and any associated synergies are already reflected in the Companies' analysis. As noted in the application there are no costs included in the revenue requirement for the test year.

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Question No. 234

Responding Witness: Paul W. Thompson

Q-234. Reference the Thompson testimony, p. 19: 6-21. Explain how the Companies' and PPL Corporation's voluntary goal of reducing CO2 70% by 2040, and 80% by 2050 will impact the Companies' decision-making related to identifying, procuring and supplying the least cost resource for meeting their customers' energy needs.

A-234. It will have no impact. See the response to PSC 2-20.

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Question No. 235

Responding Witness: Kent W. Blake

Q-235. Reference the Blake testimony at 3: 1-3, wherein he states the Companies sought ways to. ". . . make these proceedings the last base rate cases the Companies will file for a number of years. . .". Explain what measures the Companies are willing to take in this regard.

A-235. As stated in Mr. Blake's testimony, the goal of the Companies' is to avoid base rate cases for the foreseeable future, but achieving that goal is dependent upon the satisfactory outcome of these cases. As further discussed in Mr. Blake's testimony, the Companies do not expect significant capital investment in the coming years because many large-scale capital projects are scheduled to be completed by the end of 2021. The Companies' objective is also to maintain operation and maintenance expenses at the same level that is included in the forecast test year. This will require the Companies to find efficiencies to offset inflation and other new costs of operation and other ways to offset the increased Plant in Service and higher depreciation expense.

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Question No. 236

Responding Witness: Lonnie E. Bellar

Q-236. Reference the Bellar testimony at 9: 1-9. Confirm that projected retirement dates for seven generating units have been moved forward, among them: (i) Mill Creek Unit 1 from 2034 to 2024; (ii) Brown Unit 3 from 2035 to 2028; and (iii) Mill Creek Unit 2 from 2034 to 2028. Given that the Companies will lose over 800 MW of capacity in less than ten years:

a. explain if there will be stranded costs for any of these units;

b. provide the Companies' projected reserve capacity margin for 2028 in light of these updated retirement dates; and

c. explain whether the Companies will need to procure additional generation capacity at some point in the next several years.

A-236. It is confirmed that the projected retirement years for seven units have been moved forward. However, Mr. Bellar’s testimony shows Mill Creek Unit 1 moving from 2032 to 2024.

a. Under the proposed retirement dates, the Companies do not expect stranded costs for any of these units.

b. See Table 4 on page 9 of Exhibit LEB-2, which shows that the reserve margin in 2028 would be 12.4% with the retirement of Mill Creek Units 1 and 2 and Brown Unit 3, without any replacement capacity.

c. These retirements would require the Companies to procure additional generation capacity by 2028.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 237

Responding Witness: Lonnie E. Bellar

Q-237. Reference the Bellar testimony at 10:21-11:1. Provide a copy of the referenced April 2020 Agreement with the Louisville Air Pollution Control Board.

A-237. See attached.

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ENFORCEABLE BOARD AGREEMENT

This Enforceable Board Agreement is entered into by and among Louisville Gas and Electric Company (LG&E), the Louisville Metro Air Pollution Control Board (Board), and the Louisville Metro Air Pollution Control District (District).

WHEREAS, the U.S. Environmental Protection Agency (EPA) on April 30, 2018, designated the Louisville Metropolitan Statistical Area (MSA), consisting of Jefferson, Bullitt, and Oldham Counties in Kentucky and Clark and Floyd Counties in Indiana, as non-attainment for the 2015 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 70 ppb; and

WHEREAS, District Regulation 3.01 Section 4 prohibits the emission of an air contaminant that would violate or interfere with the attainment or maintenance of, an ambient air quality standard; and

WHEREAS, ground level ozone is not emitted directly into the air, but is created by chemical reactions between oxides of nitrogen (NOx) and volatile organic compounds (VOC); and

WHEREAS, LG&E owns and operates the Mill Creek Electric Generating Station (Mill Creek), a coal-fired power plant, located at 14660 Dixie Hwy, Louisville, KY 40272, which emitted more than 7,958 tons of NOx in 2018, and is the largest single source of NOx emissions in the MSA; and

WHEREAS, the District has not determined which sources violate or interfere with the attainment or maintenance of an ambient air quality standard under District Regulation 3.01, but LG&E has agreed to take measures to reduce its emissions of NOx at Mill Creek consistent with the objectives of District Regulation 3.01;

NOW, THEREFORE, this Agreement reflects the commitment of LG&E and the approval of the Board and the District, to implement the following:

1. **Project Description**

From May 1, 2020, to October 31, 2020, the sum of Mill Creek Units 1, 2, 3 and 4 NOx emissions shall be equal to or less than 15 tons per calendar day. Compliance with the daily limit shall be determined through review of data generated by the plant's Continuous Emissions Monitoring System in accordance with 40 CFR Part 75.

This daily limit shall not apply to the following events in 1.A or 1.B:

A. To hours when Mill Creek Units 3 or 4 have experienced an outage, unit derate including operation of unit below minimum operating load for SCR operation, startup/shutdown, or SCR outage or derate at any time during the hour.

B. To hours when forecasted high demand due to extreme weather or system demand concurrent with other unit outages in the LG&E-KU system require, in the reasonable judgment of LG&E, Mill Creek Units 1 or 2 to operate at any time during the hour to ensure system reliability in accordance with North American Electric Reliability Corporation (NERC) requirements.

C. Nothing in this agreement shall obligate LG&E to purchase wholesale power from third-party power generation sources in response to the above events, but LG&E may undertake such purchases based on LG&E's determination of prudent utility practice.

For any calendar day when plant-wide emissions of NOx exceed 15 tons, including the hours specified in paragraph 1.A or 1.B, LG&E shall inform the District in writing within 24 hours, or the next business day if the due date falls on a weekend or holiday.

The written notification to the District shall include: (1) the reason for the event; (2) the anticipated duration; (3) all actions taken to prevent or minimize the delay or prevention of performance; (4) an explanation of why the delay or prevention of performance was necessary; and (5) the steps LG&E shall take to ensure that the performance of its obligations under this Agreement will be reinstituted as early as practicable after cessation of the event causing the dclay.

2. **Verification and Reporting**

Within 30 days after the end of thc calendar month, LG&E shall submit a monthly report to the District identifying daily plant-wide emissions of NOx. The reports shall be certified by a responsible official, as defined in Regulation 2.16 Title V Operating Permits, Section 1.35, at the facility. This certification shall include the statement, "Based on information and belief formed after reasonable inquiry, I certify that the statements and information in this document are true, accurate and complete." The District reserves its right to inspect the facility as provided in applicable law to verify compliance with LG&E's commitment set forth in Paragraph 1. All reporting and verification requirements under this agreement shall terminate upon submittal of the monthly report for October 2020.

3. **Effect on Permits**

Nothing in this Agreement affects, limits or waives any permitting requirement to which LG&E is subject. If any of the measures that LG&E has undertaken or will undertake in accordance with this Agreement are subject to any permit requirement under federal or state law or District regulations, such measures shall remain subject to such permitting requirements.

4. **Legal Effect of the Agreement**

LG&E agrees to fully implement the projects set forth in Paragraph 1 above. Nothing in this Agreement shall constitute evidence of any admission of liability, law or fact, a waiver of any right or defense, or estoppel against the parties to this Agreement.

5. Reservation of Rights and Legal Remedies

Nothing in this Agreement affects, limits or waives the District's legal rights, remedies or causes of action based on statutes, regulations or permit conditions within the jurisdiction of the District, and LG&E reserves its rights and defenses thereto. The District expressly reserves its right to seek enforcement of this Agreement or to take further action through administrative orders or other means at any time and to take any other action it deems necessary, including the right to order all necessary remedial measures and assess penalties for proven violations of applicable laws or regulations, and LG&E reserves its defenses thereto.

Nothing in this Agreement affects, limits or waives LG&E's legal rights, including LG&E's right to administrative or judicial review of any action by the District.

6. Amendments or Modifications

No modification or amendment to the terms or conditions of this Agreement shall be effective until reduced to writing and executed by LG&E and the Board.

Louisville Metro Air Pollution Control Board

By: Carl E. Hilton
Carl E. Hilton
Chairman

Date: 4/23/20

Louisville Gas and Electric Company

By: Lonnie E. Bellar
Lonnie E. Bellar
Chief Operating Officer

Date: 4/9/20

Louisville Metro Air Pollution Control District

By: K Talley Sr
Keith Talley, Sr.
Executive Director

Date: 4/15/2020

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 238

Responding Witness: Lonnie E. Bellar

Q-238. Reference the Bellar testimony at 10:15-19, in which he states neither Mill Creek Unit 1 nor Mill Creek Unit 2 are equipped with selective catalytic reduction ("SCR") technology. Explain whether Mill Creek Units 3 and 4 are equipped with SCR technology.

A-238. Mill Creek Units 3 and 4 are equipped with SCR technology.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 239

Responding Witness: Lonnie E. Bellar

Q-239. Reference the Bellar testimony at 11: 6-7. Provide the basis for the statement, ". . . it is reasonable to expect Jefferson County to be escalated to moderate non-attainment in 2021 . . ."

A-239. The attainment date for the 2015 Ozone National Ambient Air Quality Standard (NAAQS) of 70 ppb is August 3, 2021. On September 29, 2020, the Louisville Air Pollution Control District (APCD) held a virtual Clearing the Air Workshop on Ozone in Jefferson County[10]. APCD stated that Louisville had four exceedances in the 2020 ozone season and that Jefferson County would have an ozone 3-year design average value of 72 ppb (Clearing the Air Workshop, 2020, approximately 34 minutes into the video). APCD stated that EPA will be required to reclassify Jefferson County as moderate non-attainment within six months of the attainment deadline. 42 USC 181(b)(2) states that upon failure to attain a standard by the regulatory deadline, EPA will reclassify the area to the next higher classification. The next higher classification from marginal non-attainment is moderate non-attainment.

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[1] Louisville APCD. (2020, 09 29). *Clearing The Air Community Workshop Series*. Retrieved from Air Pollution Control District: https://louisvilleky.gov/government/air-pollution-control-district/clearing-air-community-workshop-series

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 240

Responding Witness: Lonnie E. Bellar

Q-240. Reference the Bellar testimony at 12: 5-13.

a. Explain whether the Companies have considered whether any modifications to their current outage and maintenance practices might make it cost-effective to extend the projected useful life of Brown Unit 3 beyond 2028. If so, identify such potential modifications.

b. Identify the nature of the $23.1 million capital investment that would have to be made on Brown Unit 3 if its useful life was extended beyond 2028.

c. Identify the nature of the $8 million in annual O&M costs that would be incurred if the useful life of Brown Unit 3 was extended beyond 2028.

A-240.

a. The Companies have not identified any potential cost savings that would make Brown Unit 3 cost-effective beyond 2028. However, the Companies have issued a request for proposals for additional capacity and energy resources to meet the capacity and energy shortfall that would result from the retirements of Mill Creek Units 1 and 2 and Brown Unit 3. The evaluation of these resources will provide a more definitive timeline for the remaining cost-effective life of Brown Unit 3.

b. Not applicable to LG&E.

c. Not applicable to LG&E.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 241

Responding Witness: Lonnie E. Bellar

Q-241. Reference the Bellar testimony at 12: 14-19. Explain whether any potential stranded costs were considered in the cost-benefit analysis of whether continued operation of Mill Creek Units 1 and 2, and Brown Unit 3 would be economical beyond their respective revised projected retirement dates? If not, why not?

A-241. The analysis considered all costs impacted by the retirement decision. No costs were assumed to be stranded. These units will be fully depreciated by the proposed retirement dates if the proposed depreciation rates are approved.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 242

Responding Witness: Daniel K. Arbough

Q-242. Reference the chart in the Bellar testimony found at pp. 13-14. Provide a detailed breakdown of these capital projects.

A-242. See attached for the LG&E information.

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Generation Reliability	159657	BRCT5 DC Battery Repl	$0.03
Generation Reliability	160820	BRCT6 & CT7 Flux Probe Install	$0.02
Generation Reliability	159659	BRCT6 DC Battery Repl	$0.02
Generation Reliability	159662	BRCT7 DC Battery Repl	$0.02
Generation Reliability	155158	BRCT7 Quench Cooler Nozzles	$0.05
Generation Reliability	162282	CR7 Auto Shutdown	$0.05
Generation Reliability	159032	CR7 Cir Wtr Pmp Mtr	$0.00
Generation Reliability	163553	CR7 Cooling Tower Motors	$0.01
Generation Reliability	152776	CR7 DCS Hardware Refresh	$0.04
Generation Reliability	154833	CR7 EQ OVERHAUL	$0.42
Generation Reliability	161058	CR7 Evap Cooling Pipe Repl	$0.04
Generation Reliability	162462	CR7 HRH1 Vlv Act Replace	$0.00
Generation Reliability	162211	CR7 R1 Static Seal	$0.06
Generation Reliability	161106	CR7 Raw Water Pump A 2019	$0.04
Generation Reliability	162810	CR7 Sludge Pump	$0.01
Generation Reliability	163315	CR7 Spare Cooling Twr Fan	$0.01
Generation Reliability	162287	CR7 ST SEE Replace	$0.16
Generation Reliability	162610	CR7 ST Turning Gear Motor	$0.01
Generation Reliability	152055	CR7 T3K Hardware Refresh	$0.13
Generation Reliability	163498	Deepwell Flush Drain System	$0.04
Generation Reliability	159990	Hydrocyclone Feed Pumps	$0.22
Generation Reliability	162603	MC 1 & 2 Fan Room Roof	$0.28
Generation Reliability	161630	MC 1 & 2 Wet/Dry Overlay	$0.08
Generation Reliability	162675	MC 1C BCP Motor Rewind	$0.03
Generation Reliability	163631	MC 1C BCP OVERHAUL	$0.13
Generation Reliability	154631	MC 1C BCP OVERHAUL 2022	$0.14
Generation Reliability	154632	MC 1C Recycle Pump OVERHAUL	$0.02
Generation Reliability	154633	MC 1E Recycle Pump OVERHAUL	$0.08
Generation Reliability	154643	MC 2D Recyc Pump OVERHAUL 2019	$0.01
Generation Reliability	154644	MC 2F Recyc Pump OVERHAUL 2020	$0.09
Generation Reliability	159962	MC 3A Hydrocycl Fd Pump	$0.02
Generation Reliability	157234	MC 3A Rec Pmp Overhaul 2021	$0.15
Generation Reliability	154649	MC 3C Recyc Pump OVERHAUL 2020	$0.07
Generation Reliability	154650	MC 3D Recyc Pump OVERHAUL 2020	$0.09
Generation Reliability	154651	MC 3E Recyc Pump OVERHAUL 2021	$0.09
Generation Reliability	159964	MC 4B Hydrocycl Fd Pump	$0.02
Generation Reliability	154657	MC 4D Recyc Pump OVERHAUL 2019	$0.01
Generation Reliability	154658	MC 4E Recyc Pump OVERHAUL 2022	$0.01
Generation Reliability	163145	MC B Clearwell Pump Ovhl	$0.10
Generation Reliability	143591	MC CH Railroad Track 2019	$0.16
Generation Reliability	147035	MC CH Railroad Track 2020	$0.17
Generation Reliability	151240	MC CH Railroad Track 2021	$0.17
Generation Reliability	160736	MC Clearwell Pump "A" 2019	($0.00)
Generation Reliability	151291	MC Coal Barge Unloader MCC	$0.32
Generation Reliability	139900	MC COAL BUCKET	$0.23
Generation Reliability	151262	MC Coal Handling Switchgear	$1.39
Generation Reliability	147068	MC Conveyor Belts 2020	$0.12
Generation Reliability	151284	MC Conveyor Belts 2021	$0.27

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Generation Reliability	158954	MC DCS Simulator	$1.58
Generation Reliability	132976	MC Dozer #1	$0.04
Generation Reliability	132980	MC Dozer #2	$2.30
Generation Reliability	162416	MC Gypsum Overland Belt 2020	$0.07
Generation Reliability	151243	MC Limestone Lining Screw A	$0.39
Generation Reliability	143592	MC Material Hndlg Chutes 2019	$0.27
Generation Reliability	147036	MC Matl Handling Chutes 2020	$0.31
Generation Reliability	151242	MC Matl Handling Chutes 2021	$0.29
Generation Reliability	147049	MC Misc Equipment 2020	$0.28
Generation Reliability	151265	MC Misc Equipment 2021	$1.08
Generation Reliability	147062	MC Misc Lab Equipment 2020	$0.01
Generation Reliability	151260	MC Misc Lab Equipment 2021	$0.07
Generation Reliability	151249	MC Plant Fire Protection	$0.40
Generation Reliability	156784	MC Process Wtr Sys Cap Spares	$0.24
Generation Reliability	159971	MC R Conveyor Upgrade	$0.12
Generation Reliability	161710	MC Reactant Feed Pump	$0.07
Generation Reliability	147070	MC Safety Equipment 2020	$0.03
Generation Reliability	151285	MC Safety Equipment 2021	$0.03
Generation Reliability	147069	MC Stacker/Reclaimer	$2.09
Generation Reliability	159982	MC1 Expansion Joints	$0.12
Generation Reliability	162205	MC1 Flyash Exhauster 2020	$0.01
Generation Reliability	151251	MC1 Turbine Room Roofing	$0.39
Generation Reliability	160005	MC2 Hot RH Wye	$0.46
Generation Reliability	159967	MC2 RH Spray Control Valves	$0.11
Generation Reliability	154593	MC2/MC3 Boiler Room Roof Drain	$0.17
Generation Reliability	159585	MC3 CT Drift Eliminators	$0.04
Generation Reliability	159983	MC3 Expansion Joints	$0.12
Generation Reliability	160968	MC3 Gen Bushing & CT Replace	$0.21
Generation Reliability	159898	MC3 PRECIP INT 21	$1.24
Generation Reliability	154659	MC3 TDBFP OVERHAUL 2019	$0.08
Generation Reliability	159949	MC3 Voltage Regulator	$0.30
Generation Reliability	160655	MC3 Water Coil Air Heater 2019	$0.21
Generation Reliability	161074	MC3 WFGD ABSORBER INLET	$0.29
Generation Reliability	160724	MC3A Agitator Gearbox	$0.01
Generation Reliability	160707	MC3B Cooling Tower Pump	$0.08
Generation Reliability	160757	MC3E Agitator Gearbox	$0.02
Generation Reliability	162613	MC4 Cooling Tower Bypass Valve	$0.05
Generation Reliability	159987	MC4 FGD IN SW CLAD	$0.13
Generation Reliability	159973	MC4 Turb Cntrl Hrdw Refr	$0.28
Generation Reliability	151980	OF DCS Conv/Upgrade	$2.42
Generation Reliability	160810	OF Trash Rack 2019	$0.16
Generation Reliability	144530	OF Trash Racks (multi-year)	$0.14
Generation Reliability	152649	OF Unit 9/10 Front Slabs	$0.26
Generation Reliability	161970	PR11 Battery Replace 20	$0.01
Generation Reliability	157167	PR13 Battery Replacement	$0.02
Generation Reliability	152056	PR13 T3K Hardware Refresh	$0.14
Generation Reliability	163632LGE	TC "C" COAL CONVEYOR BELT REPL	$0.07
Generation Reliability	163555LGE	TC "E" CONVEYOR BELT REPLACE	$0.12

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Generation Reliability	162760LGE	TC A TRAVELING WTR SCREEN	$0.05
Generation Reliability	162425LGE	TC AGITATOR BLADE REPLACE	$0.15
Generation Reliability	157302LGE	TC AMMONIA TANK WATER CURTAIN	$0.01
Generation Reliability	147470LGE	TC C COAL CONVEYOR SPARE MTR	$0.07
Generation Reliability	156635LGE	TC CBU BUCKETS & CHAINS 2018	$0.00
Generation Reliability	162429LGE	TC CHUTE REPLACEMENT	$0.13
Generation Reliability	162427LGE	TC CLEAN VAC PIPING	$0.08
Generation Reliability	161486LGE	TC COAL CONVEYOR BELTS 2020	$0.16
Generation Reliability	154729LGE	TC COAL CONVEYOR VFD UPGD	$0.00
Generation Reliability	157150LGE	TC COAL HAND BUILD ROOF REPL	$0.13
Generation Reliability	124526	TC COAL YARD BUILDING SIDING	$0.46
Generation Reliability	159520LGE	TC CONVEYOR BELT REPL 2019	$0.12
Generation Reliability	140619LGE	TC CONVEYOR BELT REPLACE	$0.15
Generation Reliability	157115LGE	TC CRITICAL HEAT UPGD	$0.09
Generation Reliability	160326LGE	TC CRITICAL HEAT UPGD 2019	$0.04
Generation Reliability	152009LGE	TC CT BULK CO STORAGE	($0.00)
Generation Reliability	153025LGE	TC CT CEM ANALYZER CHANGEOUT	$0.08
Generation Reliability	156885LGE	TC CT CEMs SHELTERS 5-6	$0.24
Generation Reliability	156863LGE	TC CT EMERSON PWCS	$0.07
Generation Reliability	152001LGE	TC CT EX2000 DIGITAL FE CT10	$0.06
Generation Reliability	152006LGE	TC CT EX2000 DIGITAL FE CT9	$0.07
Generation Reliability	139795LGE	TC CT FAST START CT6	$0.20
Generation Reliability	162712LGE	TC CT GAS HEATER PLC UPGD	$0.07
Generation Reliability	153095LGE	TC CT GFI UPGRADE	$0.04
Generation Reliability	159876LGE	TC CT GFI UPGRADE	$0.07
Generation Reliability	152032LGE	TC CT HMI UPGRADE	$0.23
Generation Reliability	159873LGE	TC CT HYDRAULIC PUMP UPG	$0.08
Generation Reliability	152007LGE	TC CT LUBE OIL PUMPS	$0.01
Generation Reliability	152015LGE	TC CT MARK VI UPGD CT9	$0.06
Generation Reliability	156875LGE	TC CT MKVIe PHASE 2-3 CT10	$0.16
Generation Reliability	156865LGE	TC CT MKVIe PHASE 2-3 CT5	$0.16
Generation Reliability	156867LGE	TC CT MKVIe PHASE 2-3 CT6	$0.16
Generation Reliability	156869LGE	TC CT MKVIe PHASE 2-3 CT7	$0.16
Generation Reliability	156871LGE	TC CT MKVIe PHASE 2-3 CT8	$0.16
Generation Reliability	156873LGE	TC CT MKVIe PHASE 2-3 CT9	$0.16
Generation Reliability	158328LGE	TC CT MULTILIN UPG 2018	$0.00
Generation Reliability	153070LGE	TC CT PEEC BATTERIES	$0.01
Generation Reliability	163273LGE	TC CT PLATFORM INSTALL	$0.03
Generation Reliability	156879LGE	TC CT PURGE CREDIT AIR CT10	$0.04
Generation Reliability	156877LGE	TC CT PURGE CREDIT AIR CT8	$0.04
Generation Reliability	160803LGE	TC CT REBUILD EXHST DUCT 5of6	$0.00
Generation Reliability	160887LGE	TC CT SITE HVAC REPLACEMENT	$0.03
Generation Reliability	162714LGE	TC CT SWITCHYARD RTU UPGD	$0.07
Generation Reliability	157299LGE	TC CT TURNING GEAR REFURB	$0.02
Generation Reliability	160814LGE	TC CT TURNING GEAR REFURB 2019	$0.00
Generation Reliability	154792LGE	TC CT WAREHOUSE	$0.19
Generation Reliability	160679LGE	TC DCS METERING SYST UPGD	$0.01
Generation Reliability	156846LGE	TC DCS METERING UPGD	$0.04

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Generation Reliability	156836LGE	TC DCS SIMULATOR	$0.05
Generation Reliability	161650LGE	TC ELECTROMECH RELAYS 2020	$0.11
Generation Reliability	155443LGE	TC F COAL CONV GALLERY REBLD	$1.89
Generation Reliability	156994LGE	TC F COAL CONV SPARE MOTOR	$0.04
Generation Reliability	156996LGE	TC FIRE SYSTEM UPG	$0.34
Generation Reliability	153028LGE	TC FUEL BLEND FEEDER REPL	$0.14
Generation Reliability	159690LGE	TC GAS LINE COMPNT UPG	$0.04
Generation Reliability	162683	TC HL1 INJECTION SYST REPL	$0.24
Generation Reliability	162813LGE	TC HVAC UNIT REPLACEMENT	$0.09
Generation Reliability	154762LGE	TC HVAC UPGD	$0.28
Generation Reliability	159254LGE	TC HVAC UPGD 2019	$0.03
Generation Reliability	162467LGE	TC HYDROCYCLONE UPGD	$0.12
Generation Reliability	160318LGE	TC IMPOUND IMPROVE 2019	$0.00
Generation Reliability	161496LGE	TC IMPOUND IMPROVE 2020	$0.01
Generation Reliability	155077LGE	TC INSIGHT CM VIB MONITOR	$0.01
Generation Reliability	162632LGE	TC INSTALL VIB MONITORING	$0.01
Generation Reliability	156980LGE	TC INVERTER UPG	$0.12
Generation Reliability	133627LGE	TC LAB EQUIP PURCHASES	$0.16
Generation Reliability	133622LGE	TC LAB PURCH MONITORS	$0.05
Generation Reliability	161707LGE	TC LAB RO SYSTEM UPGRADE	$0.03
Generation Reliability	159908LGE	TC LANDFILL IMPROVEMENT	$0.03
Generation Reliability	154759LGE	TC LED LIGHTING	$0.15
Generation Reliability	159937LGE	TC LIFT STATION REPL	$0.07
Generation Reliability	154803LGE	TC LIMESTONE FEEDER UPG	$0.14
Generation Reliability	162725LGE	TC LIMESTONE LBU UPGD	$0.28
Generation Reliability	162438LGE	TC LIMESTONE RECLAIM UPGD	$0.25
Generation Reliability	163317LGE	TC LIMESTONE RECLAIMER UPGD	$0.17
Generation Reliability	163420LGE	TC LIMESTONE SCALE UPGD	$0.01
Generation Reliability	162431LGE	TC MAGNETIC SEPARATOR	$0.21
Generation Reliability	161507LGE	TC MAT HANDLING STRUCT UPGD	$0.02
Generation Reliability	156848LGE	TC MATERIAL HAND OFFICE	$0.10
Generation Reliability	160337LGE	TC MATERIAL HAND STRUCT UPGD	$0.03
Generation Reliability	156830LGE	TC MATERIAL HDLG STRUCT UPGD	$0.11
Generation Reliability	156825LGE	TC MOORING CELL REFURB	$0.17
Generation Reliability	161494LGE	TC MOORING CELL UPGD 2020	$0.00
Generation Reliability	152693LGE	TC OFFICE UPGRADES	$0.21
Generation Reliability	152079LGE	TC OVATION SECUTY CENTER	$0.10
Generation Reliability	156838LGE	TC PLC CONVERSION	$0.11
Generation Reliability	133615LGE	TC PLT ENG/MTR RWNDS	$0.15
Generation Reliability	161489LGE	TC PREDICTIVE EQUIP 2020	$0.00
Generation Reliability	139682LGE	TC PREDICTIVE MAINT DEVICES	$0.04
Generation Reliability	162815LGE	TC PWS EQUIP MODIFICATION	$0.02
Generation Reliability	159864LGE	TC PWS EQUIP/MONITORS	$0.02
Generation Reliability	152097LGE	TC RAT RELAYS	$0.01
Generation Reliability	124518	TC RECYC PUMP PIPING ELBOW	$2.38
Generation Reliability	139769LGE	TC REPL FIRE SYSTEM CRUSHER HOUSE	$0.14
Generation Reliability	150049LGE	TC REPL LST TANK FLOORS	$0.21
Generation Reliability	150077LGE	TC REPL SEWAGE TREAT PLANT	$0.26

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Generation Reliability	152070LGE	TC SHUTTLE BARGE WINCH UPGD	$0.14
Generation Reliability	157122LGE	TC STACK ELEVATOR REFURB	$0.27
Generation Reliability	156850LGE	TC STACKER RECLAIM OH	$0.08
Generation Reliability	157072LGE	TC STATION AIR COMP OH	$0.06
Generation Reliability	162446LGE	TC SW PIPING INSTALL	$0.04
Generation Reliability	160569LGE	TC TROUGHING ROLL FRAME UPG	$0.00
Generation Reliability	150059LGE	TC UPG COAL HAND SAMPLER	$0.23
Generation Reliability	162440LGE	TC UPGD LIMESTONE SCALE	$0.04
Generation Reliability	161915LGE	TC UPGD SW PUMP TRAIN - C	$0.27
Generation Reliability	161013LGE	TC WIRELESS SENSOR INSTALL	$0.04
Generation Reliability	151000	TC1 & COMM 480V BREAK UPG	$0.03
Generation Reliability	160818	TC1 1A DEMISTER PUMP MTR RWD	$0.03
Generation Reliability	160646	TC1 1E COAL MILL GB OVERHAUL	$0.07
Generation Reliability	159389	TC1 A MILL HOT AIR GATE REPL	$0.03
Generation Reliability	160950	TC1 AGITATOR GEAR BOX OH	$0.08
Generation Reliability	159392	TC1 AIR HEATER SB CONT VLV	$0.01
Generation Reliability	154738	TC1 BATTERY REPLACEMENTS	$0.42
Generation Reliability	152667	TC1 BCWP OVERHAUL	$0.13
Generation Reliability	162352	TC1 BLEED PUMP MODIFICATION	$0.26
Generation Reliability	156486	TC1 BOILER RM ROOF EXHST 2018	$0.08
Generation Reliability	154761	TC1 BOILER ROOF EXHAUSTERS	$0.16
Generation Reliability	162458	TC1 COAL MILL INLET DUCT	$0.37
Generation Reliability	161909	TC1 COAL MILL SPRING CAN UPGD	$0.21
Generation Reliability	154743	TC1 COOLING TOWER PUMP OH	$0.30
Generation Reliability	159941	TC1 COOLING TWR CHEM INJ	$0.85
Generation Reliability	160597	TC1 COOLING TWR PUMP OH 2019	$0.24
Generation Reliability	159930	TC1 DCS SIMULATOR	$0.51
Generation Reliability	159914	TC1 DESP CONTROLLER UPG	$0.15
Generation Reliability	162647	TC1 DESP RAPPER CNTRL UPGD	$0.02
Generation Reliability	160732	TC1 DESP TR REFURB	$0.09
Generation Reliability	159913	TC1 DESP TRANSFORMERS	$0.25
Generation Reliability	151021	TC1 ELECTROMECH RELAYS	$0.13
Generation Reliability	160309	TC1 ELECTROMECH RELAYS*	$0.34
Generation Reliability	159936	TC1 ELEVATOR UPGRADE	$0.23
Generation Reliability	159882	TC1 FGD BLEED RECIRC	$0.13
Generation Reliability	159883	TC1 FGD NOZZLE REPL	$1.69
Generation Reliability	158623	TC1 FGD RECYCLE PUMP PIPING	$0.93
Generation Reliability	159884	TC1 FGD SULFITE PROBE	$0.17
Generation Reliability	156990	TC1 GSU COOLING UPG	$0.51
Generation Reliability	160316	TC1 HL AIR COMP REPL	$0.01
Generation Reliability	157246	TC1 MDBFP COOLER ADD	$0.22
Generation Reliability	134109	TC1 MDCT Fill & DE Replac	$0.68
Generation Reliability	161638	TC1 MDCT FILL & DRIFT ELIM	$0.25
Generation Reliability	160566	TC1 MILL DIFFUSER VALVES	$0.01
Generation Reliability	162735	TC1 PYRITE SUMP UPGD	$0.06
Generation Reliability	156821	TC1 SCR NOX ANALYZERS	$0.12
Generation Reliability	162460	TC1 SCRUB SRVC WTR PIPING	$0.22
Generation Reliability	156964	TC1 SDRS ME REMOVAL	$0.17

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Category	Project No.	Project Description	$M
Generation Reliability	162459	TC1 SPRING CAN UPGRADE	$0.55
Generation Reliability	160701	TC1 TDBFP SEAL CNTRL UPGD	$0.01
Generation Reliability	162904	TC1 TROLLEY SYSTEM	$0.03
Generation Reliability	153022LGE	TC2 A CEM ANALYZER CHANGEOUT	$0.06
Generation Reliability	157248LGE	TC2 ABB MAINS BREAKER UPGD	($0.01)
Generation Reliability	159910LGE	TC2 AMMONIA TANK UPGD	$0.02
Generation Reliability	160573LGE	TC2 CONDENSATE POLISH SUMP	$0.00
Generation Reliability	154744LGE	TC2 COOLING TOWER PUMP OH	$0.06
Generation Reliability	162359LGE	TC2 DYNAMIC CLASSIFIERS	$0.07
Generation Reliability	162355LGE	TC2 ECONOMIZER DRAIN UPG	$0.01
Generation Reliability	153055LGE	TC2 MDBFP START UPG	$0.00
Generation Reliability	159934LGE	TC2 MDBFP/ID FAN RELAY UPG	$0.01
Generation Reliability	162423LGE	TC2 PYRITE HOPPER	$0.05
Generation Reliability	162456LGE	TC2 RECYCLE PUMP PIPING	$0.05
Generation Reliability	163429LGE	TC2 SUBMERG SCRAPER DOOR	$0.01
Generation Reliability	160571LGE	TC2 TCS L&S CTRL UPG	$0.17
Generation Reliability Total			**$48.87**
Other	162546	1 AQCS Air Compressor O/H 21	$0.04
Other	GSCACONTL	ACCESS CONTROL OT	$0.01
Other	GSCASMGTL	ASSET MANGMT OT LGE	$0.32
Other	160913	BRCT 6&7 HVAC Repl	$0.01
Other	158941	BRCT GT24 Crane Controls Upgr	$0.01
Other	GSCCONFGL	CONFIGURATION OT LGE	$0.02
Other	163382	CR RIVERBANK STABILIZATION	$0.30
Other	163313	CR7 Air Compressor 2020	$0.01
Other	161900	CR7 Aux Stm Heater	$0.00
Other	159625	CR7 Clarifier Inlet Valve	$0.01
Other	162345	CR7 Condensor Clean	$0.03
Other	161877	CR7 Cool Towr Wall	$0.01
Other	160811	CR7 Emerson Start	$0.11
Other	161153	CR7 Emerson TREX Commun	$0.00
Other	159139	CR7 EQ BLDG SECUR	($0.00)
Other	161003	CR7 ICM Expansion 2019	$0.01
Other	160716	CR7 ISS Housing	$0.12
Other	162688	CR7 ISS Housing Rebuild	$0.06
Other	158876	CR7 Ket Boil Upgrade	$0.51
Other	159431	CR7 Lightning Arrestors	$0.00
Other	144531	CR7 Misc Project (multi-year)	$0.20
Other	163655	CR7 Plant Vehicle 2020	$0.07
Other	163523	CR7 Site Utility Vehicles 2020	$0.05
Other	162859	CR7 Spare CEM Analyzer	$0.01
Other	163508	CR7 Sump Pumps 2020	$0.02
Other	160765	CR7 Training Modules	$0.02
Other	160688	CR7 Training Simulation Bldg	$0.00
Other	154831	CR7 UV LIGHTING	$0.05
Other	161303	CR7 WARTY SHORTAGE LGE	$0.06
Other	158878	CR7 Waterbox Lining	$0.05
Other	160559	CR7 Wtrtrmt Catwalk	$0.01

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Category	Project No.	Project Description	$M
Other	161027	CSS Abrasive Wtr Jet	$0.26
Other	161029	CSS Blanche Grinder	$0.17
Other	162331	CSS CNC Lathe	$0.33
Other	161028	CSS Cont Milling Mach	$0.18
Other	162332	CSS Hexgon Arm	$0.10
Other	161030	CSS Horiz Boring Mill	$0.30
Other	162364	CSS Lift Truck	$0.04
Other	160973	CSS Port Pwr Dist	$0.02
Other	162333	CSS Pri P90 Ironworker	$0.07
Other	162366	CSS ROTARY AIR COMPRES	$0.06
Other	162330	CSS TPO Roofing System	$1.29
Other	162363	CSS Water Jet Drill Head	$0.02
Other	GSCDRBCL	DISASTER RECOVER OT LGE	$0.01
Other	133671	EFFLUENT WATER STUDY-MC	($5.44)
Other	133679	EFFLUENT WATER STUDY-TC LGE	($2.05)
Other	144514	GS CDM CIP Ver 8.0 LGE	$0.05
Other	148155	GS CDM CIP Ver 9.0	$0.06
Other	GSCIPV8L	GS CDM CIP Version 8 LGE	$0.04
Other	144503	GS CDM GMD Protection	$0.00
Other	161315LGE	GS CDM KIP Printer LGE	$0.01
Other	132931	GS CDM Lrg Format	$0.03
Other	161047	GS CDM MC GE SecST	$0.17
Other	GSCINV20L	GS CDM OT Inv Mgmt- 2020	$0.15
Other	161123	GS CDM Panduit Blcks	$0.02
Other	161236	GS CDM TCA Switch	$0.00
Other	157804	GS CR7 Bus Tie	$0.00
Other	148135	GS GE CV GIS	$0.08
Other	148132	GS GE CV Landfill Instrum	$0.04
Other	133076	GS GE Dam Impnd	$0.07
Other	132756	GS GE Lab Equip	$0.05
Other	GSSLLABEL	GS GE Lab Equip 2020	$0.06
Other	161121	GS GE M Spark OES	$0.02
Other	161111	GS GE M Viscometer	$0.02
Other	144494	GS GE PDM Equip Upgrade	$0.01
Other	136480	GS GE Test Equipment Pool LGE	$0.14
Other	GSMVMEL	GS GE Vibration Monitor Equip	$0.08
Other	155124	GS GenEng MHM Software	$0.23
Other	155127	GS GenEng Transformer Protection	$0.14
Other	155126	GS GenEng Vibration Monitor	$0.08
Other	160847	GS GL Coal Mstr Ash Anlzr	$0.04
Other	GSSLPWCRL	GS SL Ash Pond Wells - CR	$0.12
Other	GSSLBTUCL	GS SL BTU Calorimeter - LGE	$0.03
Other	157470CR	GS SL CCR WELL MONITOR CR 2019	$0.01
Other	157471CR	GS SL CCR WELL MONITOR CR 2020	$0.08
Other	157472CR	GS SL CCR WELL MONITOR CR 2021	$0.15
Other	160744	GS SL Discrete Analyzer	($0.02)
Other	GSSLRENOL	GS SL Lab Renovation 2021 LGE	$0.04
Other	160760	GS SL Mercury 1631	$0.00

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Category	Project No.	Project Description	$M
Other	160758	GS SL Office HVAC	($0.00)
Other	136565	GS SL Oil Dlctrc Test LGE	$0.03
Other	GSSLOPCTL	GS SL Oil Particle Counter-LGE	$0.02
Other	136566	GS SL Oil Pwr Fact Test LGE	$0.04
Other	GSSLRWTRL	GS SL Reagent Water Sys - LGE	$0.02
Other	GSSLALRML	GS SL Smart Alarms LGE	$0.01
Other	158929	GS Transformer prot CR7	$0.03
Other	161177	GS Transformer Prot MC2	$0.17
Other	158921	GS Transformer Prot TC1	$0.00
Other	162240	Gypsum PST Replacement	$2.98
Other	162782	KU SOLAR SHARE ARRAY 3	$0.13
Other	160714	MC #1 Fire Pump	$0.01
Other	161711	MC 1A Hydrocyclone Feed Pump	$0.08
Other	158560	MC Admin Bldg Card Readers	$0.04
Other	161069	MC Air Handling Unit #7	$0.07
Other	157239	MC Ammonia Fogging System	$0.00
Other	162607	MC Battery Room HVAC	$0.09
Other	158153	MC Beneficial Reuse RETIREMENT	($0.03)
Other	154547	MC Bottom Ash Hndlg Cap Spares	$0.28
Other	160794	MC C Coal Conv Belt Repl	$0.13
Other	161076	MC Carry Deck Crane 2019	$0.18
Other	156723	MC CH Diesel Fuel Tank	$0.17
Other	160558	MC CHG LIGHTING	$0.02
Other	159974	MC Cybersecurity 2020	$0.10
Other	160323	MC Elevator Controls	$0.30
Other	154324	MC Flyash Silo "A" Baghouse	$0.52
Other	154325	MC Flyash Silo "B" Baghouse	$0.58
Other	161310	MC Forklift 2019	$0.06
Other	161124	MC G1 Conv Blt Replace	$0.03
Other	154548	MC GPP Capital Spares	$0.28
Other	152330	MC Gypsum	$0.41
Other	151857	MC Landfill Closure	$1.52
Other	162328	MC Landfill Closure 2020	$0.31
Other	162419	MC PERSONEL CARRIER	$0.02
Other	160557	MC Screen Wash BP A&B	$0.01
Other	159692	MC Shipley Ln Prop	$0.16
Other	160956	MC Skid Steer Loader 2019	$0.05
Other	161263	MC Stacker/Reclaimer Boom Belt	$0.03
Other	158152	MC SynMat Plant RETIREMENT	($0.03)
Other	161075	MC Telehandler Forklift 2019	$0.12
Other	154388	MC Turbine Room LED Lighting	$0.09
Other	160994	MC Utility Vehicle 2019	$0.03
Other	161067	MC Vacuum Truck 2019	$0.38
Other	162604	MC Warehouse Dock Cover	$0.12
Other	159994	MC Xfrmr Fire Protection	$0.20
Other	162609	MC#1 Uninterruptable Power Sup	$0.05
Other	154389	MC1 Fire Protection	$0.15
Other	162556	MC1 Inst Air Compress OH 21	$0.04

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Category	Project No.	Project Description	$M
Other	154390	MC1 LED Lighting	$0.27
Other	154463	MC1 Turbine Room Roof Drains	$0.18
Other	161709	MC1&2 Absorber Mechanical Seal	$0.12
Other	162548	MC1A PJFF Air Compress OH 21	$0.03
Other	162549	MC1B PJFF Air Compress OH 21	$0.03
Other	162547	MC2 AQCS Air Compress OH 21	$0.04
Other	162608	MC2 Clg Twr Svc Bldg HVAC	$0.08
Other	154391	MC2 Fire Protection	$0.10
Other	159586	MC2 Hydro Feed Pump	$0.02
Other	154392	MC2 LED Lighting	$0.27
Other	154464	MC2 Turbine Room Roof Drains	$0.18
Other	162551	MC2B PJFF Air Compress OH 21	$0.03
Other	156717	MC3 Boiler Room Louvers	$0.18
Other	162521	MC3 Boiler Room Roofing	$0.39
Other	154393	MC3 Fire Protection	$0.15
Other	154394	MC3 LED Lighting	$0.30
Other	162866	MC3 Nox Probe Replacement 2021	$0.40
Other	156718	MC3 SCR Roofing	$0.03
Other	159996	MC3 Spare GSU Transformer	$1.50
Other	156665	MC3 TDBFP Fire Protection	$0.10
Other	154465	MC3 Turbine Room Roof Drains	$0.20
Other	159972	MC3 WATERWALL PANEL	$2.48
Other	161031	MC3E&G CT Fan Gearbox 2019	$0.06
Other	156719	MC4 Boiler Room Louvers	$0.18
Other	154396	MC4 Fire Protection	$0.15
Other	154397	MC4 LED Lighting	$0.60
Other	156722	MC4 SCR Roofing	($0.00)
Other	156667	MC4 TDBFP Fire Protection	$0.10
Other	159966	MC4 WATERWALL PANEL	$1.58
Other	161180	MC4A Mechanical Exhauster 2019	$0.07
Other	140342LGE	MISC TOOLS	$0.01
Other	GSCOTNWKL	NETWORK MONITORING OT LGE	$0.11
Other	GSCOTSEGL	NETWORK SEGMENTATION OT LGE	$0.17
Other	160907	OF Air Compressor	$0.03
Other	148083	OF Bridge Resurface	$1.34
Other	163152	OF Elev 408 Lighting	$0.13
Other	160755	OF Forklift	$0.00
Other	163149	OF Gen Protection Relay	$0.06
Other	161952	OF HEADWORKS CONCRET	$0.48
Other	160416	OF MASNRY AND TRASHRK UPGRADES	$12.84
Other	161948	OF PARKING EXPANSION	$0.02
Other	159438	OF Roof Replacement	$0.07
Other	163148	OF Service Water Intake Screen	$0.02
Other	162343	OF Site Paving	$0.26
Other	163150	OF Site Utility Vehicle	$0.01
Other	161062	OF Station Battery Charger	$0.03
Other	162344	OF Sump Oil Detection	$0.03
Other	163522	OF TRASH RACK GUIDES	$1.50

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Category	**Project No.**	**Project Description**	**$M**
Other	159440	PR11 Aux Breaker Replace	$0.06
Other	159441	PR12 Aux Breaker Replace	$0.06
Other	161155	PR13 CEMS Data Controller	$0.01
Other	159442	PR13A Aux Breaker Replace	$0.03
Other	159444	PR13B Aux Breaker Replace	$0.03
Other	163497	Screenhouse Bromide Conveyor	$0.02
Other	163269	SOLAR SHARE ARRAY 3	$0.31
Other	163276	SOLAR SHARE ARRAY 4 LGE	$0.37
Other	GSESPICTL	SPIR CT TRIMBLE COUNTY LGE	$0.00
Other	GSESPIOFL	SPIR OHIO FALLS LGE	$0.04
Other	GSESPIRTL	SPIR TRIMBLE COUNTY LGE	$0.00
Other	GSSLABTCL	SYSTEM LAB TRIMBLE COUNTY- LGE	$0.41
Other	158938LGE	TC 5TH FLR RESTROOM UPGRADE	$0.01
Other	160969LGE	TC ALL TERRAIN FORKLIFT	$0.05
Other	159296LGE	TC BREAKER TRAINING UPGD	$0.00
Other	154723LGE	TC COAL HANDLING D6 DOZER	$0.19
Other	162218LGE	TC CT INSTALL LED LIGHTING	$0.01
Other	153072LGE	TC FUEL HANDLING DOZER	$0.22
Other	161104LGE	TC GYPSUM LOADOUT TRANSFORMER	$0.02
Other	160741LGE	TC HAUL ROAD PAVING 2019	$0.17
Other	153056LGE	TC IMPOUNDMENT IMPROVEMENTS	$0.04
Other	159056LGE	TC LAB EQUIPMENT 2019	$0.03
Other	161463LGE	TC LAB EQUIPMENT 2020	$0.02
Other	161466LGE	TC LAB MONITORS 2020	$0.09
Other	159058LGE	TC LAB MONITORS-2019	$0.01
Other	159048LGE	TC LED LIGHTING 2019	$0.05
Other	161482LGE	TC LED LIGHTING 2020	$0.11
Other	160677LGE	TC MATERIAL HAND OFFICE UPGD	$0.04
Other	159172LGE	TC MOORING CELL REFURB 2019	$0.00
Other	162626LGE	TC MTCE CLEAN SHOP ADDITION	$0.04
Other	160575LGE	TC PRED MAINT DEVICE 2019	$0.05
Other	158836LGE	TC RESTROOM 3FL WOMEN	$0.00
Other	161484LGE	TC SAFETY & ERT 2020	$0.03
Other	133653LGE	TC SAFETY & ERT EQUIP	$0.03
Other	159065LGE	TC SAFETY ERT 2019	$0.07
Other	160972	TC VACCUM TRUCK	$0.38
Other	154753	TC VEHICLES	$0.10
Other	161488	TC VEHICLES 2020	$0.10
Other	159060LGE	TC WASTE SLUDGE PUMPS	$0.10
Other	160971	TC WATER TRUCK	$0.16
Other	160776LGE	TC WET PIT LIFT STATION UPGD	$0.10
Other	153009	TC1 CEM SHELTER REPL	$0.15
Other	GSETCMATL	TC1 MAT DGA monitor LGE	$0.07
Other	151005	TC1 OXIDATION AIR BLOWERS	$0.47
Other	138411	TC1 PULVERIZED GEAR BOX	$0.92
Other	139726	TC1 REPLACE BOILER ROOM ROOF	$0.52
Other	161478	TC1 SALE OF GEHL TELEHANDLER	($0.02)
Other	GSCVULMGL	VULNERABILITY MANGMT OT LGE	$0.02

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Category	Project No.	Project Description	$M
Other Total			**$42.03**
Outage for Coal Fired Units	161447	CR7 CCI Valves 2020	$0.09
Outage for Coal Fired Units	148096	CR7 NGCC STG	$0.23
Outage for Coal Fired Units	162222	CR7 ST Bearings	$0.04
Outage for Coal Fired Units	147078	MC 1&2 Reactant Supply Loop	$0.03
Outage for Coal Fired Units	161631	MC 1A BCP OVERHAUL 2020	$0.11
Outage for Coal Fired Units	154601	MC 1B Circ Wtr Pump Overhaul	$0.20
Outage for Coal Fired Units	154630	MC 1B MDBFP OVERHAUL 2021	$0.16
Outage for Coal Fired Units	154634	MC 2A BCP OVERHAUL 2020	$0.13
Outage for Coal Fired Units	154639	MC 2B CTP OVERHAUL 2020	$0.26
Outage for Coal Fired Units	154640	MC 2B MDBFP OVERHAUL 2020	$0.36
Outage for Coal Fired Units	154642	MC 2C BCP OVERHAUL 2019	$0.12
Outage for Coal Fired Units	147048	MC 3 and 4 Spare GSU Trans	$0.15
Outage for Coal Fired Units	147079	MC 3&4 Reactant Supply Loop	$1.10
Outage for Coal Fired Units	151585	MC 3A Burner Nozzles	$0.28
Outage for Coal Fired Units	151586	MC 3B Burner Nozzles	$0.28
Outage for Coal Fired Units	151255	MC 3B GSU Transformer Install	$0.45
Outage for Coal Fired Units	156664	MC 3B Mill Gearbox OVERHAUL 22	$0.38
Outage for Coal Fired Units	151587	MC 3C Burner Nozzles	$0.28
Outage for Coal Fired Units	139721	MC 3C GSU Transformer	$0.44
Outage for Coal Fired Units	151588	MC 3D Burner Nozzles	$0.28
Outage for Coal Fired Units	154654	MC 4B CTP OVERHAUL 2020	$0.15
Outage for Coal Fired Units	151574	MC1 Boiler Air Tips	$0.24
Outage for Coal Fired Units	132960	MC1 DCS 2019	($0.00)
Outage for Coal Fired Units	151784	MC1 DCS Hardware 2020	$0.10
Outage for Coal Fired Units	151246	MC1 Expansion Joints 2021	$0.10
Outage for Coal Fired Units	154554	MC1 Rear RH Weld Overlay	$1.58
Outage for Coal Fired Units	147056	MC2 Boiler Lower Slope	$3.78
Outage for Coal Fired Units	151276	MC2 CCWHE Yuba Coolers	$0.24
Outage for Coal Fired Units	147046	MC2 Cooling Tower Rebuild	$4.65
Outage for Coal Fired Units	157747	MC2 Feeders & Outlet Hoppers	$0.46
Outage for Coal Fired Units	156788	MC2 Precipitator	($0.00)
Outage for Coal Fired Units	132989	MC2 Relays	$0.53
Outage for Coal Fired Units	139889	MC3 AIR HTR BASKETS	$0.30
Outage for Coal Fired Units	151277	MC3 CCWHE Yuba Coolers	$0.89
Outage for Coal Fired Units	154408	MC3 Control Valve Steam Chest	$1.18
Outage for Coal Fired Units	153884	MC3 Cooling Tower Elect Cable	$0.74
Outage for Coal Fired Units	151283	MC3 Cooling Tower Structure	$0.93
Outage for Coal Fired Units	143605	MC3 DCS (2019)	$0.06
Outage for Coal Fired Units	147058	MC3 Econ Inlet Header	$0.56
Outage for Coal Fired Units	143601	MC3 Expansion Joints 2019	$0.09
Outage for Coal Fired Units	151247	MC3 Expansion Joints 2021	$0.10
Outage for Coal Fired Units	139892	MC3 FDWTR HTRS	$0.39
Outage for Coal Fired Units	151259	MC3 Field Instrumentation 2019	$0.01
Outage for Coal Fired Units	142399	MC3 Gen Stator Bar Install	$2.02
Outage for Coal Fired Units	154338	MC3 Hydrogen Coolers	$0.00
Outage for Coal Fired Units	139871	MC3 INT SH PENDANTS	$0.81
Outage for Coal Fired Units	156739	MC3 Lower IR Panels	$0.68

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Category	Project No.	Project Description	$M
Outage for Coal Fired Units	154395	MC3 O2 Probes	$0.10
Outage for Coal Fired Units	135124	MC3 PJFF Bags 2021	$1.67
Outage for Coal Fired Units	156789	MC3 Precipitator	$0.79
Outage for Coal Fired Units	147060	MC3 Rear Slope & Lower WW	$3.09
Outage for Coal Fired Units	156742	MC3 Reheat Outlet Partial	$0.99
Outage for Coal Fired Units	132996	MC3 Relays	$0.85
Outage for Coal Fired Units	136636	MC3 SCR Catalyst Layer 1	$0.32
Outage for Coal Fired Units	154541	MC3 Secondary Air Meters	$0.48
Outage for Coal Fired Units	162417	MC3 Sootblower Thrm Drain Vlvs	$0.11
Outage for Coal Fired Units	151266	MC3 Station Switchgear/MCC	$1.48
Outage for Coal Fired Units	160619	MC3 Turb HP-IP Buckets 2019	$0.60
Outage for Coal Fired Units	160620	MC3 Turb Shaft Packing 2019	$0.47
Outage for Coal Fired Units	160618	MC3 Turbine HP Snout Rings2019	$0.15
Outage for Coal Fired Units	143637	MC3 Turbine L-0 Buckets 2019	$0.89
Outage for Coal Fired Units	159969	MC4 Coal Fdrs 4D&E	$0.30
Outage for Coal Fired Units	143606	MC4 DCS 2022	$0.81
Outage for Coal Fired Units	139709	MC4 Dearator Heater	$0.29
Outage for Coal Fired Units	147043	MC4 Exp Joints 2020	$0.11
Outage for Coal Fired Units	154405	MC4 Hardware Refresh	$0.10
Outage for Coal Fired Units	154341	MC4 Hydrogen Coolers	$0.01
Outage for Coal Fired Units	139867	MC4 RH Outlet Partial	$0.32
Outage for Coal Fired Units	143595	MC4 SCR Catalyst L1 2020	$1.63
Outage for Coal Fired Units	156730	MC4 Service Water Valves 2020	$0.10
Outage for Coal Fired Units	156753	MC4 SH Outlet 2020	$4.71
Outage for Coal Fired Units	162418	MC4 Sootblower Thrm Drain Vlvs	$0.12
Outage for Coal Fired Units	147084	MC4 Voltage Regulator	$0.30
Outage for Coal Fired Units	156027	ST L-O BLADES LGE	($0.00)
Outage for Coal Fired Units	154704	TC1 BACKPASS FRONT WALL	$0.10
Outage for Coal Fired Units	160592	TC1 BCWP OVERHAUL 2019	$0.09
Outage for Coal Fired Units	151016	TC1 BURNERS (E,F ELEVAT)	$0.36
Outage for Coal Fired Units	155621	TC1 COAL CONDUITS 2021	$0.13
Outage for Coal Fired Units	156977	TC1 DA TRAY BOX REPL	$0.08
Outage for Coal Fired Units	137587	TC1 DCS UPGRADE	$0.07
Outage for Coal Fired Units	165001	TC1 DIVISION PANEL REPLAC	$0.20
Outage for Coal Fired Units	152081	TC1 EXP JOINTS	$0.27
Outage for Coal Fired Units	155600	TC1 EXP JOINTS 2021	$0.50
Outage for Coal Fired Units	156930	TC1 FRON RH BEN REP	$0.65
Outage for Coal Fired Units	165000	TC1 FRONT LOWER SLOPE	$0.74
Outage for Coal Fired Units	159918	TC1 FRONT RH BLEND REPL	$0.62
Outage for Coal Fired Units	131995	TC1 Generator Rewind	$2.91
Outage for Coal Fired Units	156978	TC1 HEATER CONTROLS UPGD	$0.46
Outage for Coal Fired Units	156999	TC1 HRH ELBOW REPLACE	$0.26
Outage for Coal Fired Units	139787	TC1 INSTALL EOD'S ON TDBFP TURBINES	$0.87
Outage for Coal Fired Units	154707	TC1 LOWER FURNACE WW REPL	$0.81
Outage for Coal Fired Units	154708	TC1 LOWER FURNACE WW REPL-	$0.50
Outage for Coal Fired Units	162699	TC1 LOWER SLOPE STEP PNL	$0.30
Outage for Coal Fired Units	153066	TC1 RE-INSULATE BOILER	$0.12
Outage for Coal Fired Units	137039	TC1 REPLACE AIR HEATER BASKETS	$0.43

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Outage for Coal Fired Units	139725	TC1 REPLACE TURBINE ROOM ROOF	$0.00
Outage for Coal Fired Units	162686	TC1 RRH KNUCK/SHDP SCS	$0.33
Outage for Coal Fired Units	156932	TC1 SB DRAIN PIPING OVERHAUL	$0.23
Outage for Coal Fired Units	162687	TC1 SC FLOOR PANELS	$0.37
Outage for Coal Fired Units	147455	TC1 SCAFFOLD DOOR UPGRADE	$0.30
Outage for Coal Fired Units	153077	TC1 SCR CATALYST L2 NEW	$0.46
Outage for Coal Fired Units	153078	TC1 SCR CATALYST L3 NEW	$2.21
Outage for Coal Fired Units	160674	TC1 SFC FLIGHT UPGD	$0.08
Outage for Coal Fired Units	138400	TC1 SH OUTLET TERM TUBES	$0.38
Outage for Coal Fired Units	154701	TC1 SSC CHAIN REPL	$0.22
Outage for Coal Fired Units	154702	TC1 SSC FLIGHT REPL	$0.20
Outage for Coal Fired Units	154703	TC1 SSC TILE REPL	$0.72
Outage for Coal Fired Units	155617	TC1 TDBFP OVERHAUL 2021	$0.22
Outage for Coal Fired Units	152670	TC1 TDBFP PUMP OVERHAULS	$0.25
Outage for Coal Fired Units	157785	TC1 TURBINE VALVE UPGRADE	$0.07
Outage for Coal Fired Units	150037	TC1 UPPER ARCH REPLACEMENT	$0.38
Outage for Coal Fired Units	135236	TC1_PJFF B&C	$1.51
Outage for Coal Fired Units	152683LGE	TC2 B BFP OVERHAUL	$0.15
Outage for Coal Fired Units	152665LGE	TC2 B FD FAN OVERHAUL	$0.00
Outage for Coal Fired Units	160911LGE	TC2 BOILER WATER WALL PANELS	$0.06
Outage for Coal Fired Units	150015LGE	TC2 BURNER REPL (B,E ROWS)	$0.00
Outage for Coal Fired Units	137585LGE	TC2 DCS UPDRADE	$0.01
Outage for Coal Fired Units	155651LGE	TC2 EXPANSION JOINTS	$0.03
Outage for Coal Fired Units	161146LGE	TC2 FINAL RH LEAD INLET LEG	$0.01
Outage for Coal Fired Units	159920LGE	TC2 FINAL SH INLET LEG	$0.02
Outage for Coal Fired Units	159922LGE	TC2 FINAL SH INLET LEG-2	$0.04
Outage for Coal Fired Units	153047LGE	TC2 FINAL SH REPL	$0.04
Outage for Coal Fired Units	152104LGE	TC2 LAST STAGE BUCKETS	$0.80
Outage for Coal Fired Units	157777LGE	TC2 LOWER SLOPE REPLACE	$0.01
Outage for Coal Fired Units	157191LGE	TC2 LOWER SLOPE WW REPL	$0.23
Outage for Coal Fired Units	161273LGE	TC2 MDBFP VOITH OH	$0.04
Outage for Coal Fired Units	152695LGE	TC2 MS TURBINE BYPASS VALVE	$0.04
Outage for Coal Fired Units	153060LGE	TC2 REPL AH CE BASKETS	$0.06
Outage for Coal Fired Units	160564LGE	TC2 RH ATTEMPERATORS-SPARE	$0.06
Outage for Coal Fired Units	159915LGE	TC2 SB CONTROL SYST UPG	$0.08
Outage for Coal Fired Units	153080LGE	TC2 SCR CATALYST L1	$0.12
Outage for Coal Fired Units	153081LGE	TC2 SCR CATALYST L2 NEW	$0.13
Outage for Coal Fired Units	162645LGE	TC2 SPARE ID FAN BLADES	$0.04
Outage for Coal Fired Units	152040LGE	TC2 SSC REPLACE CHAIN	$0.02
Outage for Coal Fired Units	150064LGE	TC2 SSC TILE	$0.01
Outage for Coal Fired Units	161276LGE	TC2 TD BFP RECIRC VALVES	$0.02
Outage for Coal Fired Units Total			**$67.19**
Outage for Combustion Turbines	157261	BRCT 6&7 SFC Controls Upgr	$0.36
Outage for Combustion Turbines	157263	BRCT6 AVR Upgrade	$0.09
Outage for Combustion Turbines	123906	BRCT6 C Inspection	$0.00
Outage for Combustion Turbines	155110	BRCT6 Gen Protect Relay Upgr	$0.05
Outage for Combustion Turbines	157265	BRCT7 AVR Upgrade	$0.09
Outage for Combustion Turbines	131972	BRCT7 C Inspection	$8.29

Louisville Gas & Electric Company

Category	Project No.	Project Description	$M
Outage for Combustion Turbines	155144	BRCT7 Gen Protect Relay Upgr	$0.04
Outage for Combustion Turbines	155150	BRCT7 GT Thermal Insulation	$0.36
Outage for Combustion Turbines	144542	CR7 NGCC HGP	$4.94
Outage for Combustion Turbines	132002	TC CT HGP Insp Unit 7	$0.01
Outage for Combustion Turbines	132004	TC CT HGP Insp Unit 8	$1.31
Outage for Combustion Turbines	132003	TC CT HGP Insp Unit 9	$1.73
Outage for Combustion Turbines	153083LGE	TC CT MAJOR INSPECTION #1	$3.04
Outage for Combustion Turbines Total			**$20.32**
Power Plant Demolition	156485	CANAL DEMOLITION	$11.28
Power Plant Demolition	162877	CANE RUN 11 DEMO	$0.39
Power Plant Demolition	148469	CR DEMO - PE ONLY	$4.21
Power Plant Demolition Total			**$15.88**
Grand Total			**$194.29**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 243

Responding Witness: Lonnie E. Bellar

Q-243. Reference the Bellar testimony beginning at p. 17. Explain whether the Companies are seeking any authorizations in the instant cases regarding the Southeast Energy Exchange Market.

A-243. No, the Companies are not seeking any authorizations in the instant cases regarding the Southeast Energy Exchange Market. At this time, the Companies do not anticipate the need to request approval from the Public Service Commission for participation in SEEM as there is no acquisition or transfer of control, or the right to control, of any assets that are owned by the Companies. KRS 278.218. See the response to PSC 2-33 for further information about the Southeast Energy Exchange Market.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 244

Responding Witness: Lonnie E. Bellar

Q-244. Reference the Bellar testimony at p. 40. Provide all workpapers associated with the development of the chart at the top of this page.

A-244. See attachment being provided in Excel format.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 245

Responding Witness: Lonnie E. Bellar

Q-245. Reference the Bellar testimony generally. List all transmission capital projects with an expense of greater than $10 million to occur within the next five years.

A-245. Below are the Transmission capital projects budgeted at greater than $10 million:

Project	$ millions
Elihu-Wofford Conductor Replacement	$39
Millersburg-Murphysville Conductor Replacement	$29
Hardin County Expansion	$23
Earlington North-Green River Steel 69kV Rebuild	$23
Davies Co-Hardin Co Pole Replacement	$22
Wofford-KU Park-Greasy Creek Conductor Replacement	$19
Farmers-Spencer Road Conductor Replacement	$13
Lebanon-Lebanon South	$13
Olin-Tip Top 69kV Static Replacement	$12
Dorchester-Pocket North Pole Replacement	$11
Spencer Road-Rodburn Pole Replacement	$11
Frankfort-Versailles W Conductor Replacement	$11
Brown North 345/138kV Transformer Addition	$11
Morganfield-Livingston Co Pole Replacement	$10

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 246

Responding Witness: Lonnie E. Bellar

Q-246. Reference the Bellar testimony at 38:19-21. Provide the costs for implementing Work Studio.

A-246.

	Total Capital	Test Year O&M
KU	$1,364,628	$57,200
LG&E	$1,116,510	$46,800
Total	$2,481,138	$104,000

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 247

Responding Witness: Lonnie E. Bellar

Q-247. Reference the Bellar testimony at 51: 14-19. Provide the costs for implementing the referenced GIS system, and explain whether it is required by any PHMSA regulations. If so, provide the citation to the appropriate regulation(s).

A-247. A Geographic Information System (GIS) is necessary to effectively complete work associated with PHMSA regulatory compliance. There are requirements to have records (including construction) to meet requirements of the regulation and have construction records, maps, and operating history available to appropriate personnel. The applicable regulations are 49 CFR 192.603(b) and 192.605(b)(3). System maps and records are also addressed in the Kentucky Administrative Regulations (KAR) Title 807 5:006 section 23. The functionality of the GIS is also critical to support other PHMSA and State regulations including but not limited to; leak surveys, patrolling, valve inspections damage prevention and integrity management programs.

New regulatory requirements which were created under the Mega Rule part 1 require LG&E to integrate data for analysis. Examples of sections of the regulations which do so include the following:

- §192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines
- §192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines
- §192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines
- §192.710 Transmission lines: Assessments outside of high consequence areas.

Regulatory requirements which were created under the Gas Distribution Pipeline Integrity Management regulations require LG&E to integrate data for analysis. Examples of sections of the regulations which do so include the following:

- §192.1007(5) Provide for the capture and retention of data on any new pipeline installed.

The GIS will be a platform used as a repository for gas facility attributes and information to facilitate data integration to comply with this regulation. The GIS is an enterprise solution for the companies and is being implemented in phases for electric transmission and distribution, gas, power generation and telecommunications. The total capital cost of the enterprise GIS project is $36.1 million, O&M expense of $1.9 million is included in the test year.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 248

Responding Witness: Lonnie E. Bellar

Q-248. Reference the chart in the Bellar testimony at p. 52. Provide a detailed explanation and breakout for each individual item of expense under the following categories:

a. $30 M for "Other," under "Enhance the Network"; and

b. $38.4 M "Other," under "Maintain the Network."

A-248.

a. Below is a breakdown of the projects that are included in the "Other" category under "Enhance the Network":

Enhance the Network - Other

Project	Number	$ thousands
ALPHA WAY	154231	$9
BALLARDSVILLE/MOODY LN	406000072	$99
Bare Steel Elimination 004060	406000035	$292
Bluelick Rd KYTC Relocation	406000030	$1,626
Cust Requested - 004060	CRCST406G	$354
EAST END REINFORCEMENT	152546	$2,165
Fisher Regulator Upgrade-2019	406000048	$273
FT CUSTOMER CONVERSIONS	CFTCUS450	$120
Gas Public Works - 004060	CPBWK406G	$3,047
Hwy 146 Relocation	406000084	$742
I65 Relocation PBWK	406000008	$8
KYTC REIMBURSABLE PUB WK GAS	CKYTCR406	$406
Louisville Airport West Runway	406000054	$6,704
Manslick Keys Ferry Crossing	160694	$280
Moisture Analyzer Eq at CG	450000017	$37
Old Henry KYTC	406000036	$491
Pleasureville HP Dist PL	160813	$131
Preston Hwy HP Reinforcement	406000079	$2,733
Regulator Assemblies 2020	406000052	$362

Regulator Assemblies 2021	406000056	$248
REPLACE PAD METERS 2019	406000004	$243
REPLACE PAD METERS 2020	406000005	$1,409
Replace Pad Meters 2021	406000055	$1,006
River Road Reinforcement - 1	406000046	$429
River Road reinforcement - 4	406000051	$502
Sys Enh - 004060	CSYSEN406	$2,293
US60 at Johnson PBWK	406000077	$166
VINE GROVE BACKUP FEED	149400	$553
WASTE MANAGEMENT GAS RELO	148081	-$39
WITHERSPOON REPLACEMENT	406000071	$3,386
Total		$30,074

b. Below is a breakdown of the projects included in “Other” category under “Maintain the Network”:

Maintain the Network - Other

Project	Number	$ thousands
SCADA HARDWARE RPLC	149422	$856
SCADA to SQL Database	450000024	$99
Upgrade CG Transmitters 2021	450000014	$30
OT/IT Gas Ops	450000025	$238
Enh Sec CG & Lrg Reg Sta 2021	450000018	$50
GAS REG CAPACITY PRO	CCAPAC451	$965
GAS REG FAC UPGRADE BLKT 2017	CREGFC451	$1,991
Repl Vlv at CG & Reg Fac 2021	451000011	$99
RET/REPL CONTR CG STA 2017	CCOCNT451	$118
UPGR FACIL CG STATION 2017	CCGUPG451	$102
UPGR FACIL DIST REG STATIONS	CREGST451	$160
Upgr Globe Valve Reg - 2021	451000018	$99
2019 PURCH ELEC RECORD GAUGES	152442	$40
AC_MITIGATION	CACMIT445	$1,816
ADD/REPLACE ENGINE COOLERS	447000016	-$37
BALLARDSVILLE DIGS-2020	406000013	$66
BALLARDSVILLE DIGS-2021	406000014	$302
Ballardsville Pig Launcher	414000011	$300
Calvary Anomaly Replacement	158443	$558
Canmer Valve Replacement	163648	$451
Center Cut Out	158237	$1,431
COMM HIGH PRES GAS SRV UPGR 17	CHPSRV451	$1,550

COMPRESSOR ENGINE AUTO EQUIP	152508	$21
CP IMPRESSED CUR SYS IMPROVE	CCPIMP445	$39
Demolish Amine Plants 1 & 2	448000042	$400
Doe Run Stor Piggability 2020	160555	$1,098
Doe Run Storage Piggability	447000001	$496
DRILL OBSV WELLS MULD 2018	149180	$143
DRILL WELLS CENTER 2018	149182	$245
DRILL WELLS MAG UPPER 2018	149185	$154
Eng & Compr Cooling Sys Upg	447000030	$1,407
ENG VALVE ACTUATOR REPL	162644	$576
ENGINE ROOM TRANSITE SIDING	152531	$122
ENGINE ROOM VENTILATION	144937	-$8
ENGINE VIBRATION EQUIP	152536	-$5
FERN VALLEY RD VLV ELIM	158955	-$6
H2S Scavenger Upgrades	448000029	$143
IMPROVE PIPELINES	138032	$1,406
Install Cntrl Vlvs Wells 2018	447500001	$265
Install Cntrl Vlvs Wells 2020	447500003	$269
Install Control Valves 2021	447500022	$804
IR DROP COUPON MON SYS 2019	152433	$348
IR Drop Coupon Mon Sys 2020	160260	$300
KOCH 1 EASEMENT	163263	$61
LP Dist Overpressure Protectio	158295	$67
MAG 16 CUT OUTS	161087	$2,391
MAG FAC IMP/EQ REPL	CDEFEQ448	$331
MAG STOR FIELD/TRANS BLKT	CSTOR448	$1,456
Magnolia Paving	448000011	-$8
MAGNOLIA STATION BLKT	CSTATN448	$216
Main Exposure - 2614 Hwy 22	406000085	$157
Main Exposure-Bardstown Sta	406000086	$132
MOIST REMOVAL UNIT	144857	$62
Mul Station Pipe Repl 2019	447000006	$517
Muld Compr Unit Surge Tank Rep	447000013	$162
MULD ENG & COMP UPGRADE	152505	$3
MULD STATION BLKT	CSTATN447	$1,388
Muld Station Control Rm Repl	447000002	$882
MULD STOR FIELD/TRANS BLKT	CSTOR447	$2,729
MULDR FAC IMP/EQ REPLACE	CDEFEQ447	$399
Muldraugh Piping Repl 2021	447000021	$1,676
ODORANT TANK LEVEL PROBES 2019	152524	$22
Penile to Paddy's	162319	$210

Piccadilly to Muld Cut Outs	158478	$366
PLUG GAS STOR WELLS COR CASE	CPLUG4475	$2,372
Purch Large Telehandler	448000056	$100
Purchase Regulators - 004190	CCAPR419	$381
Rectifier Upgrade	445000010	$690
REG FAC RET ELDER PARK	406000011	$386
REG FAC RET ZHALE SMITH-HWY 53	406000010	$5
RELINE GAS STORAGE WELLS 2016	CRELI4475	$808
Security Upg at Mag & Center	448000016	$10
Storage Field Barricades 2019	448000015	$61
Storage Fld Barricades 2020	448000032	$49
Tanks Stor & St Waste 2021	447000018	$65
UG Storage Asset-TaskOP	162676	$48
Upgrade CG Transmitters	450000005	$29
UPRG OBSOL ROTARY METERS	CROTAR451	$70
WK A CUT OUTS	161442	$327
WK B Cut Outs	161555	$313
Total		$38,440

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 249

Responding Witness: John K. Wolfe

Q-249. Reference Exhibit LEB-4. Confirm that beginning in 2024, KU will begin deploying a Distributed Energy Resource Management System (DERMS).

a. Provide any cost-benefit analyses the Companies may have conducted regarding a DERMS deployment.

b. Explain whether LG&E will begin deploying DERMS, and if so, when.

A-249.

a. The Companies have not completed a formal cost-benefit analyses on DERMS deployment.

b. As part of its 2021 Business Plan, LG&E and KU Electric Distribution allocated $1M in 2025 toward purchase, development and deployment of a DERMS. LG&E and KU recognize that deployment of this technology will be dependent on customer adoption rates of DER and availability of proven software and supporting technologies in the electric industry.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 250

Responding Witness: John K. Wolfe

Q-250. Reference the Wolfe testimony at 7: 12-18. Provide the expenses for deploying distribution SCADA software as part of the Distribution Automation project.

a. Provide a quantification of the costs and benefits of the Distribution Automation project from its inception to date.

A-250.

Please note all costs and benefits are as of December 31, 2020.

Distribution Automation - Project Costs / Year ($000)					
	2017	**2018**	**2019**	**2020**	**Total**
Construction - KU	**$3,399**	**$12,952**	**$17,006**	**$13,896**	**$47,253**
Construction - LKE	**$4,873**	**$12,174**	**$10,702**	**$6,638**	**$34,388**
Construction Subtotal:	**$8,272**	**$25,125**	**$27,709**	**$20,534**	**$81,640**
DMS/DSCADA - KU	**$1,417**	**$1,954**	**$2,569**	**$1,107**	**$7,047**
DMS/DSCADA - LGE	**$1,026**	**$1,415**	**$1,860**	**$817**	**$5,119**
DMS/DSCADA Subtotal:	**$2,443**	**$3,369**	**$4,430**	**$1,924**	**$12,166**
Project Total:	**$10,716**	**$28,495**	**$32,138**	**$22,458**	**$93,807**

Distribution Automation Benefits	
Total Customers on DA Circuits	700,401
Percentage of LKE Customers on DA Circuits	73.70%

Customer Minutes of Interruption (CMI) Avoided	32,670,033
Customer Interruptions (CI) Avoided	195,457
SAIDE Reduction (Minutes/Customer)	11.19
SAIFE Reduction (Interruptions/Customer)	195,457

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 251

Responding Witness: John K. Wolfe

Q-251. Reference the Wolfe testimony at 9: 4-12. Explain whether the Customers Experiencing Multiple Interruptions program is targeted toward customers on the ten worst performing circuits of both Companies. If not, would it be more cost-effective to do so?

A-251. Annually, the Companies allocate capital funding to address the worst performing circuits of both Companies. Often, associated projects address customers who have experienced the highest frequency of service interruptions. At times, however, individual or pockets of customers experience unacceptable outage frequencies on circuits that are not one of the ten worst performing circuits of both companies. It would be ineffective for the Companies to only target system improvements on the worst performing circuits because doing so would fail to address customers who are experiencing unacceptable reliability performance.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 252

Responding Witness: John K. Wolfe

Q-252. Reference the Wolfe testimony at 14: 15-21 through 15: 1-11. Explain whether 2-way flow is occurring on the Companies' distribution system today. If so, identify the circuits.

a. If no 2-way flow is occurring, explain why KU in 2024 will deploy a DERMS system, as depicted in Exhibit LEB-4.

A-252. Yes, 2-way power flow does occur today, however the 2-way power flow referenced in the Wolfe testimony refers to power flows at the customer interface. LG&E and KU currently have over 1200 customers with distributed generation that commonly experience 2-way power flows at the meter. 2-Way power flows at the circuit or substation level are not a common occurrence today, however the possibility for 2-way power flows does exist in the correct conditions. A list of circuits with customer owned distributed generation is attached.

a. 2-way power flow occurs on the system today, therefore the Companies do plan to implement a DERMS as indicated by exhibit LEB-4.

LOUISVILLE GAS & ELECTRIC UTILITES COMPANY

2- WAY FLOW CIRCUITS

FEEDER_ID	CO1197	FM1261	IN1290	ML1286	SO0422
AB1202	CS1260	FO0002	IN1291	ML1288	SO0453
AB1203	CS1262	FV1137	JT1121	NA1264	SP1115
AB1204	CW1222	FV1138	JT1122	NA1265	SP1116
AB1205	CW1224	FV1140	JT1123	NA1266	SW1184
AB1206	CW1225	FV1142	JT1124	NA1267	SW1187
AK1289	CW1226	FV1145	JT1125	NA1268	SW1190
AK1290	CW1227	FV1478	JT1126	OH1173	SY1250
AK1291	CW1228	GI0003	JT1127	OH1174	SY1252
AK1294	DA1237	GO0002	KE1156	OK1272	SY1253
BB1102	DA1238	GO0003	KE1159	OK1273	SY1255
BB1103	DA1239	HB1142	KE1161	OK1274	TA1105
BI1220	DA1240	HB1148	LG0001	OR0001	TA1106
BR1177	DA1241	HC1290	LG0002	OR0002	TA1130
BR1179	DA1242	HC1291	LG0004	OR0003	TA1133
BR1180	DA1243	HC1292	LN0001	OX1273	TA1134
BR1181	DX1222	HC1293	LN0003	OX1275	TA1173
BR1186	EI0002	HC1294	LN0004	OX1277	TE1242
BR1356	ET1167	HI1101	LO1190	OX1279	TE1243
BY1278	ET1171	HI1102	LO1192	PI0003	TE1244
BY1285	ET1172	HI1103	LO1193	PL1271	TE1245
CB0001	EW1241	HI1104	LS1244	PL1272	WO1177
CF1201	EW1242	HI1105	LS1245	PV1250	WO1178
CF1202	EW1243	HK1234	LY1111	PV1251	WO1179
CF1203	FA1214	HK1235	LY1112	PV1253	WO1183
CF1204	FA1215	HK1238	LY1163	PV1255	WO1184
CF1205	FH1210	HK1241	MC1261	PV1257	WT1151
CK0001	FH1213	HK1242	MD1457	SE0004	WT1152
CL1226	FH1214	HK1243	MG0452	SK1127	WT1154
CL1227	FH1216	HL1155	MK1290	SK1128	WT1155
CL1229	FH1217	HL1156	MK1292	SM1232	WT1209
CL1230	FM1256	HL1157	MK1295	SM1233	WT1210
CL1231	FM1257	HL1158	MK1299	SM1234	
CL1232	FM1259	HN1200	ML1283	SM1235	
CO1192	FM1260	HN1201	ML1284	SO0405	

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 253

Responding Witness: John K. Wolfe

Q-253. Reference the Wolfe testimony at 15: 12-24, regarding the Asset Investment Strategy (AIS) model and processes. Provide details regarding the benefit/cost analyses that the AIS prioritization algorithm conducts.

A-253. The project benefits are defined by point scores in reliability improvement, overload mitigation and O&M cost savings. The higher benefit / cost ratio equates to a higher valued project.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 254

Responding Witness: John K. Wolfe

Q-254. Reference the Wolfe testimony at 16: 1-8. Provide a detailed breakdown of the $40.4 million in distribution automation expense.

a. Provide copies of all benefit/cost analyses conducted through AIS regarding this expense.

b. Explain whether deployment of distribution automation on some or all of the Companies' ten worst-performing circuits has been given consideration. If so, provide any benefit/cost analyses associated with any such deployment.

A-254. The following chart provides a detailed breakdown of distribution automation costs from November 1, 2019 to December 31, 2021 (in millions).

Outside Services	$26.8
Materials	8.5
Labor	0.4
Burdens	4.7
Total	$40.4

a. The overall Distribution Automation program received CPCN approval in 2017 and started construction in July 2017 with an estimated completion date of December 2021. The $40.4 million in Distribution Automation expense between November 1, 2019 to December 31, 2021 is part of the overall program approved by the PSC. See the Company's response to AG 1-399 in Case No. 2016-00371: https://psc.ky.gov/pscecf/2016-00371/derek.rahn%40lge-ku.com/01252017015414/11-2016_AG_DR1_LGE_%28VOL_09_-_Q282-Q399%29.pdf

b. Yes. Consideration for deployment of distribution automation was given to all circuits that had ties to other distribution circuits to support the self-healing portion of the program. These circuits were part of the overall investment proposal and CPCN submission.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

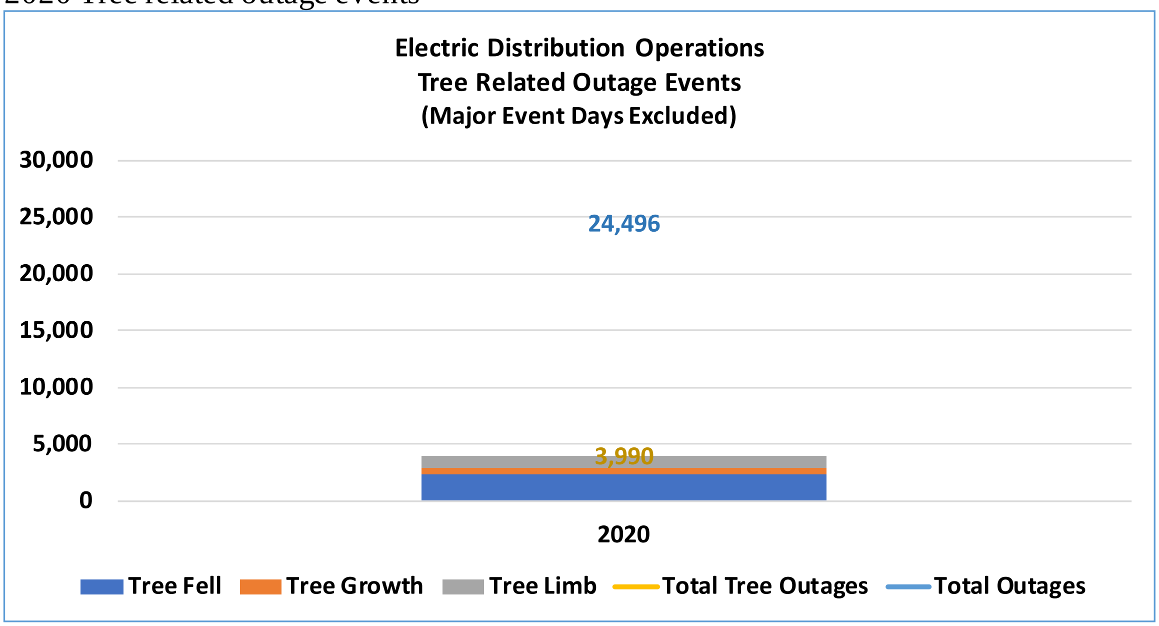
Question No. 255

Responding Witness: John K. Wolfe

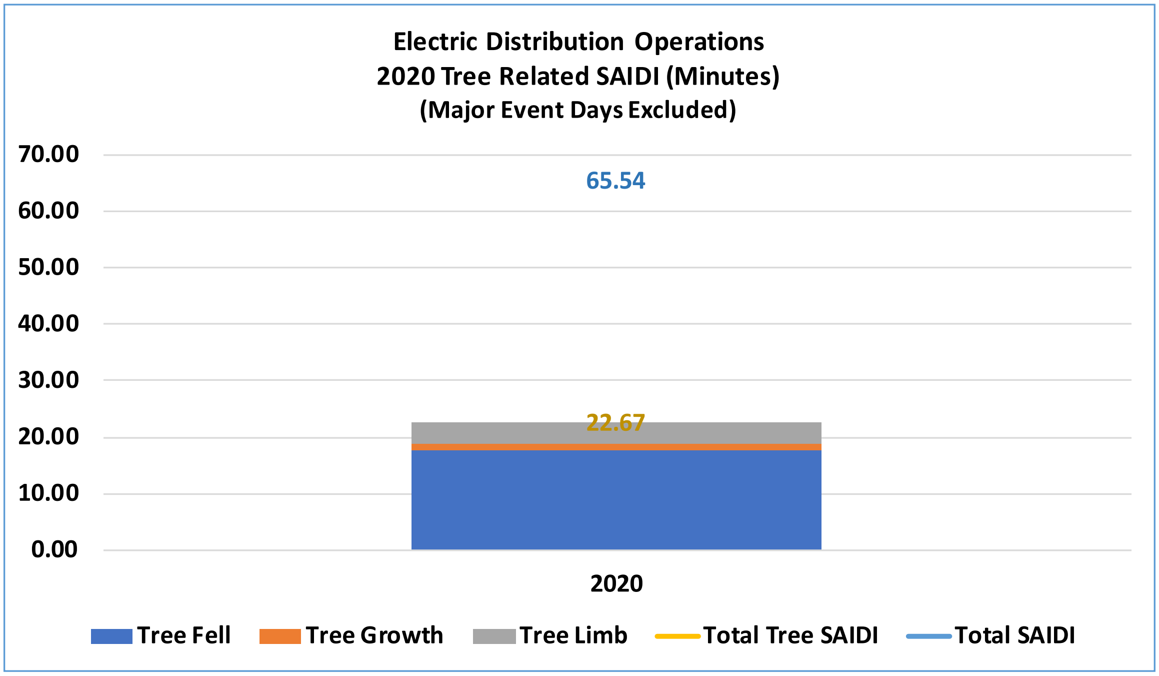
Q-255. Reference the Wolfe testimony, Exhibit JKW-1, Figures 11, 12 and 13 at pp. 29-30. In the same format as depicted in each of those Figures, provide the tree-related outages for calendar year 2020 to date.

A-255.

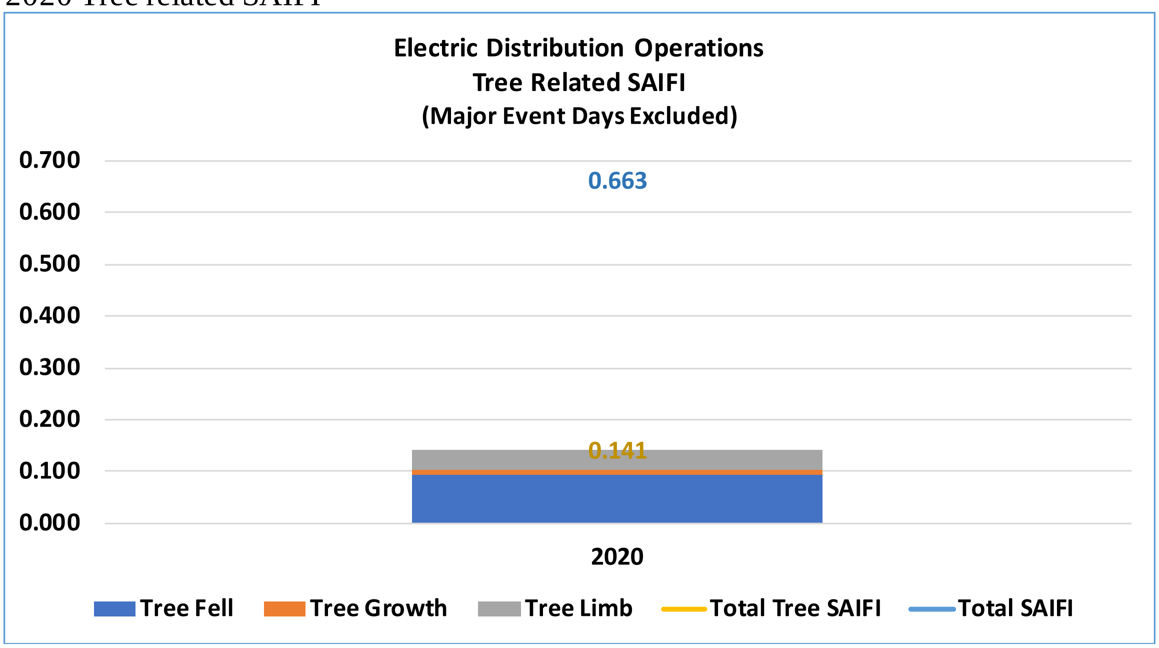
a. 2020 Tree related outage events



b. 2020 Tree related SAIDI



c. 2020 Tree related SAIFI



LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 256

Responding Witness: John K. Wolfe

Q-256. Reference the Wolfe testimony generally. Explain whether the Companies have conducted any studies or analyses of the potential for distributed energy resources on their grid. If so, provide copies of all such documents.

A-256. LG&E and KU Sales Analysis and Forecasting looks at customer adoption of various technologies including DER and provides a forecast. This forecast looks at historical DER adoption and considers current or proposed regulations that could affect DER adoption. The company-wide forecast was provided in Filing Req KU LGE Attach to Tab 16 - Section 16(7)(c) - Item C Electric Forecast.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 257

Responding Witness: John K. Wolfe

Q-257. Reference the Wolfe testimony generally. Provide a detailed analysis of vegetation management costs for the previous two years, together with forecasted costs for each of the next five (5) years.

A-257. The following chart provides vegetation management actual costs for 2019 and 2020 and forecasted costs from 2021-2025.

	2019	2020	2021	2022	2023	2024	2025
Hazard	1,483,110	1,670,879	951,000	979,000	1,008,105	1,037,602	1,068,508
Routine	6,505,221	6,530,069	7,725,120	7,954,550	8,190,559	8,432,440	8,682,449
Total	7,988,331	8,200,948	8,676,120	8,933,550	9,198,664	9,470,042	9,750,957

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021

Case No. 2020-00350

Question No. 258

Responding Witness: John K. Wolfe

Q-258. Reference the chart found in the Wolfe testimony at p. 16. Provide a detailed breakdown of all projected costs under "Enhance the Network," and "Maintain the Network," for both Companies.

a. Provide copies of all benefit/cost analyses conducted through AIS regarding each such expense.

A-258. The following chart provides a detailed breakdown of all projected costs under "Enhance the Network," and "Maintain the Network," for both Companies (in millions).

	KU	LGE	Total
Enhance the Network			
Circuit Hardening/Reliability	$ 36	$ 34	$ 70
Substation & Circuit Work Upgrades	34	17	51
N1DT	15	12	26
SCADA	12	2	14
Electric Public Works	4	4	7
Customer Requested Projects	3	1	4
IT - OT Security	1	1	2
SMAC	-	2	2
Other	6	5	11
Total Enhance the Network	$ 110	$ 77	$ 187
Maintain the Network			
Aging Infrastructure	$ 18	$ 55	$ 73
Repair/Replace Poles	14	17	31
Repair Defective Equipment - Overhead	16	12	28
Pole Inspection and Treatment	17	10	27
Repair/Replace Defective Street Lighting	11	9	20
Substation Maintenance	7	3	10
Capacitor/Regulator/Recloser Maintenance	5	3	9
Repair Defective Equipment - Underground	2	6	8
Vault Maintenance	-	3	3
Total Maintain the Network	$ 90	$ 119	$ 209

a. The Asset Investment Strategy (AIS) system utilizes a decision-support model that assists in the prioritization of distribution investment programs based on high-level benefits and estimated project costs. A priority ranking from this model allows distribution to establish 5-year capital plans for budgetary purposes. Before projects commence, a capital investment review process is followed to ensure each project is subject to the authority limit matrix for approval. See attached for last three years of AIS rankings.

		BP Year	2019

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2019	2020	2021	2022	2023	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2019	2019	Funded	0	Distribution Automation DMS/DSCADA IT	700	0	0	0	0	18572	0	940420	8175146	3884646	0	0	13000211	Enhance	Reliability Overhead	LGE	2019	Non-Discr	700
2019	2019	Funded	0	Distribution Automation KU	9020	7781	11421	9421	0	1679	0	3662327	7782875	3695364	0	0	15140566	Enhance	Reliability Overhead	KU	2019	Non-Discr	37643
2019	2019	Funded	0	Distribution Automation LGE	14280	12422	8781	2781	0	910	0	940420	8175146	3884646	0	0	13000211	Enhance	Reliability Overhead	LGE	2019	Non-Discr	38264
2019	2019	Funded	0	Distribution Capacitors KU	139	139	144	147	150	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	719
2019	2019	Funded	0	Distribution Capacitors LGE	150	154	158	162	166	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2019	Non-Discr	790
2019	2019	Funded	0	DSP Hoover 2 Substation Property	300	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	300
2019	2019	Funded	0	DSP Paynes Mill Road Distribution & Exit Feeders	1000	0	0	0	0	2443	0	0	80103	109294	0	0	189398	Enhance	System Enhancements	KU	2019	Non-Discr	1000
2019	2019	Funded	0	DSP Paynes Mill Road Substation Versailles	3512	0	0	0	0	2443	0	0	0	0	0	10832571	10832571	Enhance	System Enhancements	KU	2019	Non-Discr	3512
2019	2019	Funded	0	DSP Viley Distribution	938	0	0	0	0	36	0	0	18741	14626	0	0	33367	Enhance	System Enhancements	KU	2019	Non-Discr	938
2019	2019	Funded	0	DSP Vine St 4kV Distribution	1000	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	1000
2019	2019	Funded	0	DSP Vine St 4kV Substation	600	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	600
2019	2019	Funded	0	DSP Wise Substation Property	120	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	120
2019	2019	Funded	0	LEO Downtown Manhole Structural Repairs RAP	423	434	444	456	467	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	2223
2019	2019	Funded	0	LEO Downtown Network Vault Structural Repairs RAP	1700	1743	1786	857	878	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	6964
2019	2019	Funded	0	LEO Downtown Network Vent Type Protector Repl RAP	1426	1449	1472	566	580	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	5493
2019	2019	Funded	0	LEO Padmount Switchgear Repair/Replacement Program RAP	299	304	309	214	220	795	0	18622	78296	140932	0	0	237850	Maintain	Repair/Replace Defective Equipment-UG	LGE	2019	Non-Discr	1346
2019	2019	Funded	0	LEO PILC NW Cable Repl Curb to Curb Paving LGE STR	1100	1100	1100	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	3300
2019	2019	Funded	0	LEO PILC UG Network Cable Replacement Program LGE STR	10853	10553	11765	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	33171
2019	2019	Funded	0	LEO Substation Exit Cable Replacement LGE STR RAP	1602	1630	1660	689	710	139	0	0	38525	184894	0	0	223420	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	6291
2019	2019	Funded	0	LEO URD Cable Repl/Rejuv Program LGE STR	1700	1700	1700	1000	1030	646	853000	0	109295	136643	0	0	1098938	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	7130
2019	2019	Funded	0	LEX Vine to Race UG	715	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	715
2019	2019	Funded	0	N1DT Projects Funding by YEAR	15000	15000	13000	10000	10000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2019	Non-Discr	63000
2019	2019	Funded	0	Pole Inspection and Treatment KU STR	7367	7588	7816	8050	8292	177	0	449119	251958	604116	0	0	1305194	Maintain	Pole Inspection	KU	2019	Non-Discr	39113
2019	2019	Funded	0	Pole Inspection and Treatment LGE STR	4911	5058	5210	5367	5528	174	0	318703	106659	430329	0	0	855691	Maintain	Pole Inspection	LGE	2019	Non-Discr	26074
2019	2019	Funded	0	REL CEMI KU STR RAP	1534	1572	1612	1652	1693	8755	0	10190640	1606410	1632803	0	0	13429853	Enhance	Reliability Overhead	KU	2019	Non-Discr	8063
2019	2019	Funded	0	REL CEMI LGE STR RAP	780	800	819	840	861	8568	0	5105832	845028	731837	0	0	6682698	Enhance	Reliability Overhead	LGE	2019	Non-Discr	4100
2019	2019	Funded	0	REL KU CIFI STR YEARLY ND SPEND	2042	1500	1500	1538	1577	921	0	2789	1001188	876205	0	0	1880182	Enhance	Reliability Overhead	KU	2019	Non-Discr	8157
2019	2019	Funded	0	REL LGE CIFI STR YEARLY ND SPEND	1750	1250	1250	1281	1313	896	0	4829	1057415	505917	0	0	1568161	Enhance	Reliability Overhead	LGE	2019	Non-Discr	6844
2019	2019	Funded	0	REL System Hardening KU	3250	3714	4015	3603	3711	1409	0	2709379	539440	1330850	0	0	4579669	Enhance	Reliability Overhead	KU	2019	Non-Discr	18293
2019	2019	Funded	0	REL System Hardening LGE	3250	3713	4016	3604	3712	62	0	0	114929	87204	0	0	202133	Enhance	Reliability Overhead	LGE	2019	Non-Discr	18295
2019	2019	Funded	0	SCM 69:14KV 28 MVA TRANSFORMER	310	0	0	0	0	452	140000	0	0	0	0	0	140000	Maintain	Substation Maintenance	LGE	2019	Non-Discr	310
2019	2019	Funded	0	SCM DAN FAILED BREAKER/RECL RAP	87	89	91	94	96	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	457
2019	2019	Funded	0	SCM DAN MISC DIST CAPITAL SUB PROJ RAP	92	94	97	99	102	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	484
2019	2019	Funded	0	SCM DAN MISC NESC COMPLIANCE RAP	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	158
2019	2019	Funded	0	SCM DAN REPLACE SUBSTATION BATTERIES RAP - 2019	35	36	37	38	0	14539	0	0	87036	419637	0	0	506673	Maintain	Aging Infrastructure	KU	2019	Non-Discr	145
2019	2019	Funded	0	SCM DAN SUBSTN BUILDINGS & GNDS RAP	75	76	77	78	80	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	386
2019	2019	Funded	0	SCM EARL FAILED BREAKER/RECL PROJ RAP	238	244	250	150	263	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	1145
2019	2019	Funded	0	SCM EARL MISC DIST CAPITAL SUB PROJ RAP	224	230	235	241	247	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	1177
2019	2019	Funded	0	SCM EARL MISC NESC COMPLIANCE RAP	208	162	166	170	174	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	881
2019	2019	Funded	0	SCM EARL REPLACE SUBSTATION BATTERIES RAP	34	35	36	37	38	18020	0	0	218808	393855	0	0	612664	Maintain	Aging Infrastructure	KU	2019	Non-Discr	179
2019	2019	Funded	0	SCM EARL SUBSTN BUILDINGS & GNDS RAP	46	47	48	50	51	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	242
2019	2019	Funded	0	SCM ENHANCED SUBSTATION WILDLIFE PROTECTION	1250	1700	1700	0	0	9573	78000	0	1539881	10348313	0	0	11966194	Enhance	System Enhancements	KU	2019	Non-Discr	4650
2019	2019	Funded	0	SCM KU STR RAP REPL LTC/REG CONTROLS	111	114	117	120	123	379	0	0	28453	13658	0	0	42111	Maintain	Aging Infrastructure	KU	2019	Non-Discr	583
2019	2019	Funded	0	SCM KU WOOD POLE SUBSTATION UPGRADES RAP	650	666	683	700	717	413	0	0	78993	189583	0	0	268576	Maintain	Substation Maintenance	KU	2019	Non-Discr	3417
2019	2019	Funded	0	SCM LEX MISC DIST CAPITAL SUB PROJ RAP	184	189	193	198	203	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	967
2019	2019	Funded	0	SCM LEX MISC NESC COMPLIANCE RAP	160	113	157	118	121	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	670
2019	2019	Funded	0	SCM LEX REPLACE SUBSTATION BATTERIES RAP	68	70	71	73	75	15441	0	0	181034	868962	0	0	1049995	Maintain	Aging Infrastructure	KU	2019	Non-Discr	357
2019	2019	Funded	0	SCM LEX SUBSTATION BUILDINGS & GNDS RAP	125	128	131	135	138	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	657
2019	2019	Funded	0	SCM LGE MISC DIST CAPITAL SUB PROJ RAP	122	125	128	131	135	775	0	0	27802	66725	0	0	94527	Maintain	Substation Maintenance	LGE	2019	Non-Discr	641
2019	2019	Funded	0	SCM LGE MISC NESC COMPLIANCE RAP	55	56	58	59	61	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2019	Non-Discr	289
2019	2019	Funded	0	SCM LGE RAP CAP AND PIN INSULATOR UPGRADE	164	168	172	177	181	908	0	0	78338	70504	0	0	148842	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	862
2019	2019	Funded	0	SCM LGE RAP STR REPL LEGACY AIR MAG BREAKERS	409	419	430	440	451	1313	8000	0	155567	373361	0	0	536928	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	2150
2019	2019	Funded	0	SCM LGE REPLACE SUBSTATION BATTERIES RAP	103	106	108	111	114	6365	0	0	113038	542584	0	0	655622	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	541
2019	2019	Funded	0	SCM LGE SMAC PROJECT	1410	1699	0	0	0	35	50000	0	0	0	0	0	50000	Enhance	System Enhancements	LGE	2019	Non-Discr	3109
2019	2019	Funded	0	SCM LGE SUBSTN BUILDINGS & GNDS RAP	119	122	125	128	131	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2019	Non-Discr	625
2019	2019	Funded	0	SCM RAP DAN STR REPL LEGACY BREAKERS	248	254	261	267	274	705	0	0	51398	123355	0	0	174753	Maintain	Aging Infrastructure	KU	2019	Non-Discr	1304
2019	2019	Funded	0	SCM RAP KU LEGACY ARRESTER REPLACE	65	67	68	70	72	4100	5000	0	172050	89466	0	0	266516	Maintain	Aging Infrastructure	KU	2019	Non-Discr	342
2019	2019	Funded	0	SCM RAP KU OIL CONTAINMENT UPGRADES	272	279	286	293	300	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	1430
2019	2019	Funded	0	SCM RAP LEX REPL BREAKERS	141	145	148	152	156	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	741
2019	2019	Funded	0	SCM RAP LEX REPL BUSHINGS	112	115	118	121	124	12049	0	0	87630	1261872	0	0	1349502	Maintain	Substation Maintenance	KU	2019	Non-Discr	589
2019	2019	Funded	0	SCM RAP LEX REPL REGULATORS	88	90	92	95	97	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	463
2019	2019	Funded	0	SCM RAP LGE LEGACY ARRESTER REPLACE	65	67	68	70	72	4100	5000	0	172050	89466	0	0	266516	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	342
2019	2019	Funded	0	SCM RAP LGE OIL CONTAINMENT UPGRADES	111	114	117	120	123	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2019	Non-Discr	583
2019	2019	Funded	0	SCM RAP PINE FAILED BREAKER/RECL PROJ	116	119	122	125	128	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	610
2019	2019	Funded	0	SCM RAP PINE MISC DIST CAPITAL SUB PROJ	168	172	177	181	185	1096	0	0	40010	144037	0	0	184048	Maintain	Substation Maintenance	KU	2019	Non-Discr	883
2019	2019	Funded	0	SCM RAP PINE MISC NESC COMPLIANCE	75	77	79	81	83	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	394
2019	2019	Funded	0	SCM RAP PINE REPLACE SUBSTATION BATTERIES	34	35	36	37	38	107930	0	0	1776293	1893325	0	0	3669618	Maintain	Aging Infrastructure	KU	2019	Non-Discr	179
2019	2019	Funded	0	SCM RAP PINE STR REPL LEGACY BREAKERS	427	438	449	274	351	409	0	0	51398	123355	0	0	174753	Maintain	Aging Infrastructure	KU	2019	Non-Discr	1938
2019	2019	Funded	0	SCM RAP PINE SUBSTN BUILDINGS & GNDS	46	47	48	50	51	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2019	Non-Discr	242
2019	2019	Funded	0	SCM RAP STR DAN WILDLIFE PROTECTION	24	25	25	26	26	6898	0	0	48688	116852	0	0	165540	Enhance	System Enhancements	KU	2019	Non-Discr	126
2019	2019	Funded	0	SCM RAP STR EARL WILDLIFE PROTECTION	56	57	59	60	62	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Non-Discr	294
2019	2019	Funded	0	SCM RAP STR KU LEGACY RELAY REPL	129	131	135	138	139	2362	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	KU	2019	Non-Discr	672
2019	2019	Funded	0	SCM RAP STR LEX REPL LEGACY BREAKERS	456	467	479	491	503	397	0	0	51226	129860	0	0	181085	Maintain	Aging Infrastructure	KU	2019	Non-Discr	2397
2019	2019	Funded	0	SCM RAP STR LEX REPL LEGACY RTUS	220	226	231	237	243	513	0	0	70594	42357	0	0	112951	Maintain	Aging Infrastructure	KU	2019	Non-Discr	1156
2019	2019	Funded	0	SCM RAP STR LEX WILDLIFE PROTECTION	36	37	38	39	40	4709	4000	0	48688	116852	0	0	169540	Enhance	System Enhancements	KU	2019	Non-Discr	189
2019	2019	Funded	0	SCM RAP STR LGE LEGACY RELAY REPL	88	90	92	95	97	3462	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	463
2019	2019	Funded	0	SCM RAP STR LGE REPL LEGACY OIL BREAKERS	425	436	447	458	469	216	2000	0	26446	63471	0	0	91917	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	2234
2019	2019	Funded	0	SCM RAP STR LGE REPL LEGACY RTUS	110	113	116	118	121	730	0	0	50175	30093	0	0	80269	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	578
2019	2019	Funded	0	SCM RAP STR LGE REPLC ABB VHK MECH	81	83	85	87	89	1379	0	0	69788	41873	0	0	111661	Maintain	Aging Infrastructure	LGE	2019	Non-Discr	426
2019	2019	Funded	0	SCM RAP STR LGE WILDLIFE PROTECTION	83	85	87	89	92	5895	0	0	8584	480726	0	0	489310	Enhance	System Enhancements	LGE	2019	Non-Discr	436
2019	2019	Funded	0	SCM RAP STR LGE WILDLIFE PROTECTION	83	85	87	89	92	5895	0	0	8584	480726	0	0	489310	Enhance	System Enhancements	LGE	2019	Non-Discr	436

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		BP Year	**2019**

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2019	2020	2021	2022	2023	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2019	2019	Funded	0	SCM SUBSTATION SCADA EXPANSION STR	5045	5137	6208	0	0	3	0	0	7002	4201	0	0	11204	Enhance	System Enhancements	KU	2019	Non-Discr	16390
2019	2019	Funded	0	SHE Transmission Transfer Underbuilt Shelbyville East Cir 2522	250	30	0	0	0	0	0	0	0	0	0	0	0	Maintain	Other	KU	2019	Non-Discr	280
2019	2019	Funded	0	Transmission Line Clearance KU RAP	584	599	614	629	645	0	0	0	0	0	0	0	0	Maintain	Other	KU	2019	Non-Discr	3070
2019	2019	Funded	0	Transmission Line Clearance LGE RAP	203	208	213	219	224	0	0	0	0	0	0	0	0	Maintain	Other	LGE	2019	Non-Discr	1067
2019	2019	Funded	0	URD Cable Repl/Rejuv Program KU STR RAP	540	349	358	367	378	358	106000	0	38794	48519	0	0	193314	Maintain	Aging Infrastructure	KU	2019	Non-Discr	1992
2019	2019	Funded	1	DSP Versailles Bypass Circuit 0507 Breaker Replacement Project	150	0	0	0	0	3582401	0	0	0	0	0	537360131	537360131	Enhance	System Enhancements	KU	2019	Discretionary	150
2019	2019	Funded	2	DSP Lakeshore ckt 132 circuit upgrade - New School addition	460	0	0	0	0	17260	0	0	0	0	0	7939821	7939821	Enhance	System Enhancements	KU	2019	Discretionary	460
2020	2019	Funded Diff Year	3	DSP White Sulphur 138_12kV distribution	0	310	0	0	0	9431	0	0	11306	9091	0	0	20397	Enhance	System Enhancements	KU	2020	Discretionary	310
2019	2019	Funded	3	DSP White Sulphur 138_12kV substation	3325	3347	0	0	0	9431	0	12789	41971	39469	0	31244162	31338391	Enhance	System Enhancements	KU	2019	Discretionary	6672
2019	2019	Funded	4	DSP Fairfield Distribution	440	0	0	0	0	8383	0	3655945	0	32484	0	0	3688429	Enhance	System Enhancements	KU	2019	Discretionary	440
2019	2019	Funded	5	SCM RAP LGE LTC OIL FILTRATION ADDITIONS	59	60	62	64	65	5200	6000	0	39217	261592	0	0	306809	Maintain	Substation Maintenance	LGE	2019	Discretionary	310
2019	2019	Funded	6	SCM CAMPGROUND SUBSTATION EXPANSION	300	2000	6200	1000	0	4926	1400000	0	48558	29135	0	0	1477692	Maintain	Aging Infrastructure	LGE	2019	Discretionary	9500
2019	2019	Funded	7	DSP Lime Kiln Circuit Work	1500	1000	0	0	0	4162	0	0	47438	62217	0	0	109655	Enhance	System Enhancements	LGE	2019	Discretionary	2500
2019	2019	Funded	7	DSP Lime Kiln Substation	3000	4100	0	0	0	4162	0	0	0	0	0	27359145	27359145	Enhance	System Enhancements	LGE	2019	Discretionary	7100
2020	2019	Funded Diff Year	8	DSP Simpsonville 1 Distribution	0	400	0	0	0	4007	0	77885	4777	4265	0	0	86926	Enhance	System Enhancements	KU	2020	Discretionary	400
2019	2019	Funded	8	DSP Simpsonville 1 Substation	2700	2300	0	0	0	4007	0	0	0	0	0	10730686	10730686	Enhance	System Enhancements	KU	2019	Discretionary	5000
2019	2019	Funded	9	DSP La Grange East Distribution	900	0	0	0	0	2768	0	2463069	15434	12945	0	0	2491447	Enhance	System Enhancements	KU	2019	Discretionary	900
2019	2019	Funded	10	SCM RAP KU LTC OIL FILTRATION ADDITIONS	90	92	95	97	99	2081	8000	0	60910	118418	0	0	187327	Maintain	Substation Maintenance	KU	2019	Discretionary	473
2019	2019	Funded	11	DSP Shelbyville North Distribution	60	0	0	0	0	2051	0	103083	10803	9152	0	0	123038	Enhance	System Enhancements	KU	2019	Discretionary	60
2019	2019	Funded	12	DAN RECONDUCTOR CIRCUIT 0154 STANFORD TO HUSTONVILLE	88	0	0	0	0	1165	10000	0	58783	33184	0	0	101967	Enhance	System Enhancements	KU	2019	Discretionary	88
2019	2019	Funded	13	RIC Roundhill Line Deconstruction	60	0	0	0	0	833	50000	0	0	0	0	0	50000	Maintain	Aging Infrastructure	KU	2019	Discretionary	60
2019	2019	Funded	14	DSP Beechmont Substation Upgrade Project	550	0	0	0	0	712	0	694231	0	0	0	0	694231	Enhance	System Enhancements	KU	2019	Discretionary	550
2019	2019	Funded	15	DAN RECONDUCTOR CIRCUIT 2209 COLUMBIA SOUTH #6 CU	40	0	0	0	0	676	10000	11240	3117	2665	0	0	27022	Enhance	Reliability Overhead	KU	2019	Discretionary	40
2019	2019	Funded	16	DSP Beech Creek Distribution 4KV to 12KV Conversion Project.	104	0	0	0	0	643	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Discretionary	104
2019	2019	Funded	16	DSP Beech Creek Substation Upgrade Project	975	0	0	0	0	643	0	694231	0	0	0	0	694231	Enhance	System Enhancements	KU	2019	Discretionary	975
2019	2019	Funded	17	DAN REMOVE TEXAS TO PERRYVILLE LINE	95	95	0	0	0	526	50000	0	0	0	0	0	50000	Maintain	Repair/Replace Defective Equipment-OH	KU	2019	Discretionary	190
2019	2019	Funded	18	REL NOR Circuit Dwina 0691 Dry Fork Relocate	170	0	0	0	0	232	0	0	10506	29008	0	0	39514	Enhance	Reliability Overhead	KU	2019	Discretionary	170
2019	2019	Funded	19	Reconductor Irvine Broadway	150	0	0	0	0	179	0	0	12731	14173	0	0	26904	Enhance	System Enhancements	KU	2019	Discretionary	150
2019	2019	Funded	20	Irvine/Dark Hollow Tie	225	0	0	0	0	157	0	0	15168	20052	0	0	35220	Enhance	Reliability Overhead	KU	2019	Discretionary	225
2019	2019	Funded	21	REL LON Aisin - Circuit 4618 to Fariston Industrial Park	265	0	0	0	0	108	0	0	0	28642	0	0	28642	Enhance	System Enhancements	KU	2019	Discretionary	265
2019	2019	Funded	22	REL LON Hopewell Circuit 287 Extension/Tie to Circuit 285	400	0	0	0	0	75	0	0	17122	12684	0	0	29806	Enhance	Reliability Overhead	KU	2019	Discretionary	400
2019	2019	Funded	23	REL PIN Middlesboro 2 Circuit 355 Tie with Middlesboro 1 Circuit 364	52	0	0	0	0	50	0	0	1142	1467	0	0	2609	Enhance	Reliability Overhead	KU	2019	Discretionary	52
2019	2019	Funded	24	DSP Del Park to Canal Circuit Rebuild (2019 2020)	790	500	0	0	0	24	0	0	9802	9268	0	0	19070	Enhance	System Enhancements	LGE	2019	Discretionary	1290
2019	2019	Funded	25	REL PIN Middlesboro 2 Circuit 355 - Ambleside Tie	60	0	0	0	0	21	0	0	209	1054	0	0	1263	Enhance	Reliability Underground	KU	2019	Discretionary	60
2019	2019	Funded	26	DAN RECONDUCTOR CIRCUIT 2215 LEBANON SOUTH/CITY CONNECTION	123	0	0	0	0	19	0	0	882	1428	0	0	2310	Enhance	System Enhancements	KU	2019	Discretionary	123
2019	2019	Funded	27	REL NOR Circuit 0690 Dwina Rebuild	170	0	0	0	0	9	0	0	427	1055	0	0	1482	Enhance	Reliability Overhead	KU	2019	Discretionary	170
2019	2019	Funded	28	DSP American Ave Ckt 0008 Switchgear	150	0	0	0	0	7	0	0	532	505	0	0	1037	Enhance	System Enhancements	KU	2019	Discretionary	150
2019	2019	Funded	29	REL NOR Circuit 4704 Strawberry Patch Relocate	120	0	0	0	0	6	0	0	291	435	0	0	726	Enhance	Reliability Overhead	KU	2019	Discretionary	120
2019	2019	Funded	30	REL LON Williamsburg South- Circuit 0227 Upgrade Project	50	0	0	0	0	4	0	0	95	116	0	0	211	Enhance	Reliability Overhead	KU	2019	Discretionary	50
2019	2019	Funded	31	REL PIN Deer Branch Circuit 0320 Relocation	150	0	0	0	0	2	0	0	73	228	0	0	300	Enhance	Reliability Overhead	KU	2019	Discretionary	150
2019	2019	Funded	32	KU Direct Burial Replacement	1000	1000	2000	906	0	0	0	0	45	0	0	0	46	Enhance	Reliability Underground	KU	2019	Discretionary	4906
2019	2019	Funded	33	REL PIN Middlesboro 1 Circuit 0366 National Park main feed	100	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	Reliability Underground	KU	2019	Discretionary	100
2019	2019	Funded	34	DSP Beechmont Distribution 4KV to 12KV Conversion Project.	234	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Discretionary	234
2019	2019	Funded	35	LON Whitley City 0576 13.2 KV to 12.4 KV Conversion	150	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	Reliability Overhead	KU	2019	Discretionary	150
2019	2019	Funded	36	DSP Madisonville East Municipal Project-Distribution	165	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2019	Discretionary	165
2019	2019	Funded	37	REL PIN Middlesboro 1 Circuit 0366 National Park Alternate feed	70	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	Reliability Underground	KU	2019	Discretionary	70
2020	2020	Funded	1	DSP Tucker Station Circuit Work (2020_2021)	0	1500	1250	0	0	63950	0	0	45816	19769	0	345265872	345331457	Enhance	System Enhancements	LGE	2020	Discretionary	2750
2020	2020	Funded	1	DSP Tucker Station Substation (2020_2021)	0	3900	1800	0	0	63950	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2020	Discretionary	5700
2021	2020	Funded Diff Year	2	DSP Ashbottom Distribution	0	0	1000	0	0	52921	0	0	112915	136272	0	0	249187	Enhance	System Enhancements	LGE	2021	Discretionary	1000
2020	2020	Funded	2	DSP Ashbottom Substation	0	3600	1500	0	0	52921	0	0	0	0	0	190267353	190267353	Enhance	System Enhancements	LGE	2020	Discretionary	5100
2020	2020	Funded	3	RIC Circuit 2321 - Alternate Feed to Richmond Center	0	130	0	0	0	27219	0	3503043	9618	25864	0	0	3538525	Enhance	System Enhancements	KU	2020	Discretionary	130
2020	2020	Funded	6	DSP Hoover 2 Distribution	0	800	800	0	0	1404	0	0	21309	10453	0	0	31762	Enhance	System Enhancements	KU	2020	Discretionary	1600
2020	2020	Funded	6	DSP Hoover 2 Substation	0	2630	2500	0	0	1404	0	0	0	0	0	4785163	4785163	Enhance	System Enhancements	KU	2020	Discretionary	5130
2020	2020	Funded	7	REL NOR Circuit 4603 Thacker's Branch Relocate	0	80	0	0	0	7	10	0	314	231	0	0	554	Enhance	Reliability Overhead	KU	2020	Discretionary	80
2021	2021	Funded	1	RIC Battlefield Memorial HWY Reconductor	0	0	100	0	0	5184366	0	194861	2985	2321	0	518236434	518436602	Enhance	System Enhancements	KU	2021	Discretionary	100
2021	2021	Funded	2	DSP Lakeshore ckt 132 circuit upgrade - Blue Sky Parkway	0	0	1240	0	0	6403	0	0	0	0	0	7939821	7939821	Enhance	System Enhancements	KU	2021	Discretionary	1240
2021	2021	Funded	5	DSP Somerset North Substation PROPERTY	0	0	300	0	0	0	0	0	20	0	0	0	20	Enhance	System Enhancements	KU	2021	Discretionary	300
2021	2022	Funded Diff Year	1	DSP Aisin Substation Project	0	0	0	1477	1785	36117	0	0	0	0	0	53345443	53345443	Enhance	System Enhancements	KU	2021	Discretionary	3262
2023	2023	Funded	1	DSP Old Henry Substation (2023_2024)	0	0	0	0	3500	7747	0	0	0	0	0	27115493	27115493	Enhance	System Enhancements	LGE	2023	Discretionary	3500
2023	2023	Funded	2	DSP Buena Vista Upgrade	0	0	0	0	1822	5562	0	0	0	0	0	10134828	10134828	Enhance	System Enhancements	KU	2023	Discretionary	1822
2023	2023	Funded	5	DSP Paris 819-1 12kV Sub Bkr addition	0	0	0	0	150	191	0	0	13405	25685	0	0	39089	Enhance	System Enhancements	KU	2023	Discretionary	150
2023	2023	Funded	5	DSP Paris circuit 806 new circuit	0	0	0	0	260	191	0	0	13405	25685	0	0	39089	Enhance	System Enhancements	KU	2023	Discretionary	260
2022	2023	Funded Diff Year	6	DSP Fegenbush Circuit Work	0	0	0	0	1000	30	0	0	114212	20292	0	0	134505	Enhance	System Enhancements	LGE	2022	Discretionary	1000
2022	2023	Funded Diff Year	6	DSP Fegenbush Substation	0	0	0	0	3500	30	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2022	Discretionary	3500
2024	2023	Unfunded	7	DSP Somerset North Distribution	0	0	0	0	0	14	0	0	11483	13300	0	0	24784	Enhance	System Enhancements	KU	2024	Discretionary	0
2023	2023	Funded	7	DSP Somerset North Substation	0	0	0	0	1746	14	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2023	Discretionary	1746
2024	2023	Unfunded	8	DSP Middlesboro 1 4kV 124_5 Distribution Conversion	0	0	0	0	0	6	0	0	4406	2646	0	0	7052	Enhance	System Enhancements	KU	2024	Discretionary	0
2023	2023	Funded	8	DSP Middlesboro 1 4kV 124_5 Substation Conversion	0	0	0	0	1211	6	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2023	Discretionary	1211
2023	2023	Funded	9	DSP Old Henry Circuit Work (2023_2024)	0	0	0	0	1000	2	0	0	838	1022	0	0	1860	Enhance	System Enhancements	LGE	2023	Discretionary	1000

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	BP Year	2020

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2020	2021	2022	2023	2024	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2020	2020	Funded	0	Distribution Automation KU	9590	9590	0	0	0	1579	0	3662327	7782875	3695364	0	0	15140566	Enhance	Reliability Overhead	KU	2020	Non-Discr	19180
2020	2020	Funded	0	Distribution Automation LGE	14384	14384	0	0	0	904	0	940420	8175146	3884646	0	0	13000211	Enhance	Reliability Overhead	LGE	2020	Non-Discr	28768
2020	2020	Funded	0	Distribution Capacitors KU	139	144	147	150	154	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	734
2020	2020	Funded	0	Distribution Capacitors LGE	154	158	162	166	170	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2020	Non-Discr	810
2020	2020	Funded	0	DSP Del Park to Canal Circuit Rebuild (2019 2020)	500	0	0	0	0	38	0	0	9802	9268	0	0	19070	Enhance	System Enhancements	LGE	2020	Non-Discr	500
2020	2020	Funded	0	DSP Echols to Simmons Distribution Tie Circuit Project	466	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	466
2020	2020	Funded	0	DSP Echols/Simmons Substation Upgrade Project	1579	2134	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	3713
2020	2020	Funded	0	DSP Lime Kiln Circuit Work	1173	0	0	0	0	4516	0	0	47438	62217	0	0	109655	Enhance	System Enhancements	LGE	2020	Non-Discr	1173
2020	2020	Funded	0	DSP Lime Kiln Substation	4909	0	0	0	0	4516	0	0	0	0	0	27359145	27359145	Enhance	System Enhancements	LGE	2020	Non-Discr	4909
2020	2020	Funded	0	DSP Mount Sterling Substation project PROPERTY	300	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	300
2020	2020	Funded	0	DSP Paynes Mill Road Distribution Project	750	250	0	0	0	292197	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2020	Non-Discr	1000
2020	2020	Funded	0	DSP Paynes Mill Road Substation Project	750	0	0	0	0	292197	0	0	0	0	0	38294837	38294837	Enhance	System Enhancements	KU	2020	Non-Discr	750
2020	2020	Funded	0	DSP Uniontown 4KV to 12KV Distribution Conversion Project	160	33	0	0	0	237812	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2020	Non-Discr	193
2020	2020	Funded	0	DSP Uniontown Substation Upgrade Project	1522	1909	0	0	0	237812	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	3431
2020	2020	Funded	0	DSP Versailles Bypass 69kV Tap Upgrade Project	450	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	450
2020	2020	Funded	0	DSP White Sulphur 138_12kV Distribution	1096	0	0	0	0	8134	0	0	12231	18506	0	21411697	21442434	Enhance	System Enhancements	KU	2020	Non-Discr	1096
2020	2020	Funded	0	DSP White Sulphur 138_12kV substation	4176	0	0	0	0	8134	0	0	12231	18506	0	21411697	21442434	Enhance	System Enhancements	KU	2020	Non-Discr	4176
2020	2020	Funded	0	LEO Downtown Manhole Structural Repairs RAP	423	434	444	455	466	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	2222
2020	2020	Funded	0	LEO Downtown Network Vault Structural Repairs RAP	1700	1743	1786	1831	1876	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	8936
2020	2020	Funded	0	LEO Downtown Network Vent Type Protector Repl RAP	825	846	867	888	911	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	4336
2020	2020	Funded	0	LEO Padmount Switchgear Repair/Replacement Program RAP	304	312	319	327	336	782	0	18622	78296	140932	0	0	237850	Maintain	Repair/Replace Defective Equipment-UG	LGE	2020	Non-Discr	1598
2020	2020	Funded	0	LEO PILC NW Cable Repl Curb to Curb Paving LGE STR	1100	1100	0	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	2200
2020	2020	Funded	0	LEO PILC UG Network Cable Replacement Program LGE STR	10553	9163	0	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	19716
2020	2020	Funded	0	LEO Substation Exit Cable Replacement LGE STR RAP	1630	1671	1713	1755	1799	137	0	0	38525	184894	0	0	223420	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	8568
2020	2020	Funded	0	LEO URD Cable Replacement Program LGE STR	1700	1700	1000	1030	1056	399	432000	0	109295	136643	0	0	677938	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	6486
2020	2020	Funded	0	N1DT Projects Funding by YEAR	12000	12000	11000	10000	10000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2020	Non-Discr	55000
2020	2020	Funded	0	Pole Inspection and Treatment KU STR	7588	7816	8050	8292	8507	172	0	449119	251958	604116	0	0	1305194	Maintain	Pole Inspection	KU	2020	Non-Discr	40253
2020	2020	Funded	0	Pole Inspection and Treatment LGE STR	5058	5210	5367	5528	5666	169	0	318703	106659	430329	0	0	855691	Maintain	Pole Inspection	LGE	2020	Non-Discr	26829
2020	2020	Funded	0	REL CEMI KU STR RAP	1572	1612	1652	1693	1735	17038	0	20748689	2803806	3230896	0	0	26783390	Enhance	Reliability Overhead	KU	2020	Non-Discr	8264
2020	2020	Funded	0	REL CEMI LGE STR RAP	800	819	840	861	883	8353	0	5105832	845028	731837	0	0	6682698	Enhance	Reliability Overhead	LGE	2020	Non-Discr	4203
2020	2020	Funded	0	REL KU CIFI STR YEARLY ND SPEND	1500	1500	1538	1577	1616	962	0	2106	766600	673996	0	0	1442702	Enhance	Reliability Overhead	KU	2020	Non-Discr	7731
2020	2020	Funded	0	REL LGE CIFI STR YEARLY ND SPEND	1250	1250	1281	1313	1346	653	0	3131	580832	231826	0	0	815789	Enhance	Reliability Overhead	LGE	2020	Non-Discr	6440
2020	2020	Funded	0	SCM KU ENHANCED SUBSTATION WILDLIFE PROTECTION	1700	1700	0	0	0	7035	72000	0	1539881	10348313	0	0	11960194	Enhance	System Enhancements	KU	2020	Non-Discr	3400
2020	2020	Funded	0	SCM KU SIO BREAKERS	650	750	500	625	0	279	0	0	51226	129860	0	0	181085	Maintain	Aging Infrastructure	KU	2020	Non-Discr	2525
2020	2020	Funded	0	SCM KU SIO RELAYS	2500	2500	2500	2500	0	0	0	0	57	1	0	0	58	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	10000
2020	2020	Funded	0	SCM KU STR RAP REPL LTC/REG CONTROLS	114	117	120	123	126	369	0	0	28453	13658	0	0	42111	Maintain	Aging Infrastructure	KU	2020	Non-Discr	599
2020	2020	Funded	0	SCM KU SUBSTATION SCADA EXPANSION STR	4998	5085	0	0	0	2	0	0	7002	4201	0	0	11204	Enhance	System Enhancements	KU	2020	Non-Discr	10083
2020	2020	Funded	0	SCM LGE RAP CAP AND PIN INSULATOR UPGRADE	168	172	177	181	185	886	0	0	78338	70504	0	0	148842	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	883
2020	2020	Funded	0	SCM LGE SIO BREAKERS	650	750	500	625	0	2324	0	0	427459	1082896	0	0	1510355	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	2525
2020	2020	Funded	0	SCM LGE SIO RELAYS	2500	2500	2500	2500	0	0	0	0	74	1	0	0	74	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	10000
2020	2020	Funded	0	SCM LGE SMAC PROJECT	1699	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2020	Non-Discr	1699
2020	2020	Funded	0	SCM RAP DAN FAILED BREAKER/RECL PROJ	120	123	126	129	132	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	631
2020	2020	Funded	0	SCM RAP DAN MISC DIST CAPITAL SUB PROJ	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP DAN MISC NESC COMPLIANCE	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	158
2020	2020	Funded	0	SCM RAP DAN SUBSTN BUILDINGS & GRNDS	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP EARL FAILED BREAKER/RECL PROJ	120	123	126	129	132	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	631
2020	2020	Funded	0	SCM RAP EARL MISC DIST CAPITAL SUB PROJ	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP EARL MISC NESC COMPLIANCE	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	158
2020	2020	Funded	0	SCM RAP EARL SUBSTN BUILDINGS & GNDS	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP KU AND LGE REPLACE SUBSTATION BATTERIES	281	288	295	303	310	2333	0	0	113038	542584	0	0	655622	Maintain	Aging Infrastructure	KU	2020	Non-Discr	1477
2020	2020	Funded	0	SCM RAP KU LEGACY ARRESTER REPLACE	67	69	70	72	74	3978	5000	0	172050	89466	0	0	266516	Maintain	Aging Infrastructure	KU	2020	Non-Discr	352
2020	2020	Funded	0	SCM RAP KU LTC OIL FILTRATION ADDITIONS	92	94	97	99	102	2036	8000	0	60910	118418	0	0	187327	Maintain	Substation Maintenance	KU	2020	Non-Discr	484
2020	2020	Funded	0	SCM RAP KU NESC COMPLIANCE, MISC, BLDGS & GRNDS	1014	1039	1065	1092	1119	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	5330
2020	2020	Funded	0	SCM RAP KU OIL CONTAINMENT UPGRADES	279	286	293	300	308	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	1467
2020	2020	Funded	0	SCM RAP KU REPL BUSHINGS	115	118	121	124	127	11735	0	0	87630	1261872	0	0	1349502	Maintain	Substation Maintenance	KU	2020	Non-Discr	604
2020	2020	Funded	0	SCM RAP KU REPL REGULATORS	90	92	95	97	99	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	473
2020	2020	Funded	0	SCM RAP KU STR REPL LEGACY BREAKERS	1128	1156	1185	1215	1245	161	0	0	51226	129860	0	0	181085	Maintain	Aging Infrastructure	KU	2020	Non-Discr	5929
2020	2020	Funded	0	SCM RAP KU STR REPL LEGACY RTUS	224	230	235	241	247	504	0	0	70594	42357	0	0	112951	Maintain	Aging Infrastructure	KU	2020	Non-Discr	1177
2020	2020	Funded	0	SCM RAP KU WOOD POLE SUBSTATION UPGRADES	666	683	700	717	735	403	0	0	78993	189583	0	0	268576	Maintain	Substation Maintenance	KU	2020	Non-Discr	3501
2020	2020	Funded	0	SCM RAP LEX FAILED BREAKER/RECL PROJ	120	123	126	129	132	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	631
2020	2020	Funded	0	SCM RAP LEX MISC DIST CAPITAL SUB PROJ	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP LEX MISC NESC COMPLIANCE	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	158
2020	2020	Funded	0	SCM RAP LEX SUBSTATION BUILDINGS & GNDS	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP LGE LEGACY ARRESTER REPLACE	67	69	70	72	74	3978	5000	0	172050	89466	0	0	266516	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	352
2020	2020	Funded	0	SCM RAP LGE LTC OIL FILTRATION ADDITIONS	60	62	63	65	66	5113	6000	0	39217	261592	0	0	306809	Maintain	Substation Maintenance	LGE	2020	Non-Discr	315
2020	2020	Funded	0	SCM RAP LGE MISC DIST CAPITAL SUB PROJ	50	51	53	54	55	1891	0	0	27802	66725	0	0	94527	Maintain	Substation Maintenance	LGE	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP LGE MISC NESC COMPLIANCE	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2020	Non-Discr	158
2020	2020	Funded	0	SCM RAP LGE OIL CONTAINMENT UPGRADES	114	117	120	123	126	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2020	Non-Discr	599
2020	2020	Funded	0	SCM RAP LGE STR REPL LEGACY BREAKERS	936	959	983	1008	1033	96	0	0	26446	63471	0	0	89917	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	4920
2020	2020	Funded	0	SCM RAP LGE STR REPL LEGACY RTUS	113	116	119	122	125	710	0	0	50175	30093	0	0	80269	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	594
2020	2020	Funded	0	SCM RAP LGE SUBSTN BUILDINGS & GNDS	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP PINE FAILED BREAKER/RECL PROJ	120	123	126	129	132	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	631
2020	2020	Funded	0	SCM RAP PINE MISC DIST CAPITAL SUB PROJ	50	51	53	54	55	3681	0	0	40010	144037	0	0	184048	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP PINE MISC NESC COMPLIANCE	30	31	32	32	33	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	158
2020	2020	Funded	0	SCM RAP PINE SUBSTN BUILDINGS & GNDS	50	51	53	54	55	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2020	Non-Discr	263
2020	2020	Funded	0	SCM RAP STR DAN WILDLIFE PROTECTION	25	26	26	27	28	6622	0	0	48688	116852	0	0	165540	Enhance	System Enhancements	KU	2020	Non-Discr	131

	BP Year	2020

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2020	2021	2022	2023	2024	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2020	2020	Funded	0	SCM RAP STR EARL WILDLIFE PROTECTION	57	58	60	61	63	657	0	0	11008	26418	0	0	37426	Enhance	System Enhancements	KU	2020	Non-Discr	300
2020	2020	Funded	0	SCM RAP STR KU LEGACY RELAY REPL	130	133	137	140	144	2344	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	KU	2020	Non-Discr	683
2020	2020	Funded	0	SCM RAP STR LEX WILDLIFE PROTECTION	37	38	39	40	41	4582	4000	0	48688	116852	0	0	169540	Enhance	System Enhancements	KU	2020	Non-Discr	194
2020	2020	Funded	0	SCM RAP STR LGE LEGACY RELAY REPL	90	92	95	97	99	3385	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	473
2020	2020	Funded	0	SCM RAP STR LGE WILDLIFE PROTECTION	85	87	89	92	94	222	0	0	8584	10301	0	0	18886	Enhance	System Enhancements	LGE	2020	Non-Discr	447
2020	2020	Funded	0	SCM RAP STR PINE WILDLIFE PROTECTION	56	57	59	60	62	2996	0	0	49353	118448	0	0	167801	Enhance	System Enhancements	KU	2020	Non-Discr	294
2020	2020	Funded	0	SIO UG Fault Indicators KU	2250	2292	0	0	0	111	0	0	0	248981	0	0	248981	Enhance	Reliability Underground	KU	2020	Non-Discr	4542
2020	2020	Funded	0	SIO UG Fault Indicators LGE	2345	2410	0	0	0	111	0	0	0	260155	0	0	260155	Enhance	Reliability Underground	LGE	2020	Non-Discr	4755
2020	2020	Funded	0	Transmission Line Clearance KU RAP	2000	2000	2000	1000	1000	0	0	0	0	0	0	0	0	Maintain	Other	KU	2020	Non-Discr	8000
2020	2020	Funded	0	Transmission Line Clearance LGE RAP	1200	1200	1000	500	500	0	0	0	0	0	0	0	0	Maintain	Other	LGE	2020	Non-Discr	4400
2020	2020	Funded	0	URD Cable Replacement Program KU STR RAP	349	358	367	376	385	250	0	0	38794	48519	0	0	87314	Maintain	Aging Infrastructure	KU	2020	Non-Discr	1834
2020	2020	Funded	0	DSP Rogers Gap	750	100	0	0	0	0	0	0	0	0	0	0	0	#VALUE!	#VALUE!	#####	2020	Non-Discr	850
2020	2020	Funded	1	RIC Circuit 0334 Battlefield Memorial HWY Reconductor	425	0	0	0	0	2352968	0	5621	2610	3076	0	1000000000	1000011307	Enhance	Reliability Overhead	KU	2020	Discretionary	425
2020	2020	Funded	2	SCM KU ADD TRANSFORMER COOLING	100	100	100	0	0	823914	0	0	0	0	0	82391413	82391413	Enhance	System Enhancements	KU	2020	Discretionary	300
2020	2020	Funded	3	DAN RECONDUCTOR RUSSELL SPRINGS CIRCUIT 2222	160	0	0	0	0	1448	0	0	72638	50387	108621	0	231645	Enhance	System Enhancements	KU	2020	Discretionary	160
2020	2020	Funded	4	REL PIN Meldrum 0308 Hutch Re-route	85	0	0	0	0	616	0	47095	2783	2477	0	0	52355	Enhance	Reliability Overhead	KU	2020	Discretionary	85
2020	2020	Funded	5	SCM RAP LGE UPGRADE 14KV GND TRANSFORMERS	250	256	263	269	276	596	0	0	67682	81219	0	0	148901	Maintain	Aging Infrastructure	LGE	2020	Discretionary	1314
2020	2020	Funded	6	KU Direct Burial Replacement	1000	2000	906	0	0	495	0	334959	54834	105654	0	0	495447	Enhance	Reliability Underground	KU	2020	Discretionary	3906
2020	2020	Funded	7	MAY REL Circuit Butler 950 Hickory Grove Reconductor	95	0	0	0	0	491	0	9943	15182	21523	0	0	46648	Enhance	System Enhancements	KU	2020	Discretionary	95
2020	2020	Funded	8	SIO Fuse Savings LGE	350	490	0	0	0	444	0	0	46164	109406	0	0	155570	Enhance	Reliability Overhead	LGE	2020	Discretionary	840
2020	2020	Funded	9	SCM KU AND LGE SUBSTATION SECURITY	2000	4000	2000	0	0	388	1500000	0	25082	25082	0	0	1550164	Enhance	System Enhancements	KU	2020	Discretionary	8000
2020	2020	Funded	10	DAN RECONDUCTOR DANVILLE EAST TO BUENA VISTA CIRCUIT 2113 CON	250	0	0	0	0	327	0	0	26036	55655	0	0	81691	Enhance	System Enhancements	KU	2020	Discretionary	250
2020	2020	Funded	11	SIO Fuse Savings KU	150	210	0	0	0	290	0	0	17162	26357	0	0	43519	Enhance	Reliability Overhead	KU	2020	Discretionary	360
2020	2020	Funded	12	SCM LGE MAGAZINE SUBSTATION UPGRADE	5300	7300	4500	0	0	279	0	0	38075	45690	0	0	83764	Enhance	System Enhancements	LGE	2020	Discretionary	17100
2020	2020	Funded	13	DAN RECONDUCTOR CIRCUIT 2218 LEBANON SOUTH TO BRADFORDSVILL	285	0	0	0	0	264	0	0	33997	41112	0	0	75108	Enhance	System Enhancements	KU	2020	Discretionary	285
2020	2020	Funded	14	REL PIN Pineville 302 Relocate	85	0	0	0	0	237	0	15769	718	3631	0	0	20118	Enhance	Reliability Overhead	KU	2020	Discretionary	85
2020	2020	Funded	15	SCM KU CONVERT VERSAILLES 4KV SUBSTATION	1200	3000	0	0	0	198	0	0	34072	163546	0	0	197618	Enhance	System Enhancements	KU	2020	Discretionary	4200
2020	2020	Funded	16	REL LON Manchester 254 Greasy Reconductor	75	0	0	0	0	197	0	0	4873	9922	0	0	14795	Enhance	Reliability Overhead	KU	2020	Discretionary	75
2020	2020	Partially Funded	17	REL System Hardening	2652	3651	6707	7423	7604	183													
2021	2021	Funded	2	DSP Lakeshore ckt 132 circuit upgrade - Blue Sky Parkway	0	507	0	0	0	12167	0	0	0	0	0	6168689	6168689	Enhance	System Enhancements	KU	2021	Discretionary	507
2021	2021	Funded	3	DSP FMC 12kV Substation Expansion	0	2027	2200	0	0	11112	0	0	0	0	0	23080409	23080409	Enhance	System Enhancements	KU	2021	Discretionary	4227
2021	2021	Funded	3	DSP FMC 12kV Substation Expansion Distribution	0	50	150	0	0	11112	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Discretionary	200
2021	2021	Funded	4	DSP Bromley Substation Project	0	1169	1246	0	0	7495	0	0	0	0	0	8761338	8761338	Enhance	System Enhancements	KU	2021	Discretionary	2415
2021	2021	Funded	5	DSP Mount Sterling Substation Project	0	1993	2399	0	0	6380	0	0	0	0	0	13982381	13982381	Enhance	System Enhancements	KU	2021	Discretionary	4392
2021	2021	Funded	5	DSP Mount Sterling Substation Project Distribution	0	200	200	0	0	6380	0	0	5623	2687	0	0	8310	Enhance	System Enhancements	KU	2021	Discretionary	400
2021	2021	Funded	6	SCM RAP LGE UPGRADE 14KV GND FAULT SYSTEMS	0	150	154	158	162	1901	0	0	129584	155501	0	0	285086	Enhance	System Enhancements	LGE	2021	Discretionary	623
2021	2021	Funded	7	DSP Hoover 2 Distribution	0	700	700	0	0	843	0	0	11208	5947	0	0	17155	Enhance	System Enhancements	KU	2021	Discretionary	1400
2021	2021	Funded	7	DSP Hoover 2 Substation	0	3100	2600	0	0	843	0	0	0	0	0	3187286	3187286	Enhance	System Enhancements	KU	2021	Discretionary	5700
2022	2022	Funded	0	DSP Somerset North Substation PROPERTY	0	0	300	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2022	Non-Discr	300
2022	2022	Funded	1	DSP Ashbottom Substation	0	0	3200	1900	0	56338	0	0	0	0	0	180282857	180282857	Enhance	System Enhancements	LGE	2022	Discretionary	5100
2022	2022	Funded	1	SCM KU SIO WILDLIFE PROTECTION	0	0	1000	1000	0	11960	72000	0	1539881	10348313	0	0	11960194	Enhance	System Enhancements	KU	2022	Discretionary	2000
2022	2022	Funded	4	SCM KU SIO TXFMR UPGRADES	0	0	1500	1500	1500	417	0	0	184107	441856	0	0	625963	Enhance	System Enhancements	KU	2022	Discretionary	4500
2022	2022	Funded	8	SCM KU SIO SUBSTATION SCADA EXPANSION V2	0	0	1000	3400	4000	2	0	0	7002	4201	0	0	11204	Enhance	System Enhancements	KU	2022	Discretionary	8400
2023	2023	Funded	26	DSP Carlisle circuit 879 Upgrade	0	0	0	1500	0	24	0	0	6261	30333	0	0	36593	Enhance	System Enhancements	KU	2023	Discretionary	1500
2023	2023	Funded	0	SCM LGE CAMPGROUND SUBSTATION EXPANSION	0	0	0	300	4300	4592	1300000	0	48558	29135	0	0	1377692	Maintain	Aging Infrastructure	LGE	2023	Non-Discr	4600
2023	2023	Funded	1	DSP Horse Cave Industrial Substation Project	0	0	0	2425	2594	247165	0	0	0	0	0	199374590	199374590	Enhance	System Enhancements	KU	2023	Discretionary	5019
2023	2023	Funded	2	DSP Fariston 12KV Substation Upgrade Project	0	0	0	1863	1830	216895	0	0	0	0	0	4074854	4074854	Enhance	System Enhancements	KU	2023	Discretionary	3693
2023	2023	Funded	3	DSP Tucker Station Circuit Work (2023_2024)	0	0	0	1500	1250	57654	0	0	45816	19769	0	345265872	345331457	Enhance	System Enhancements	LGE	2023	Discretionary	2750
2023	2023	Funded	3	DSP Tucker Station Substation (2023_2024)	0	0	0	4500	4100	57654	0	0	0	0	0	593205	593205	Enhance	System Enhancements	LGE	2023	Discretionary	8600
2023	2023	Funded	4	DSP Crestwood 1229 Circuit Work (2023)	0	0	0	1800	0	2033	0	0	6359	3288	0	3650188	3659835	Enhance	System Enhancements	LGE	2023	Discretionary	1800
2023	2023	Funded	7	DSP Harrods Creek Circuit 1234	0	0	0	750	0	72	0	0	26710	27341	0	0	54051	Enhance	System Enhancements	LGE	2023	Discretionary	750
2023	2023	Funded	9	SIO Small Wire Removal LGE	0	0	0	1200	500	348													
2023	2023	Funded	10	SIO Small Wire Removal KU	0	0	0	1800	750	297													
2023	2023	Funded	24	DSP AND SCM DAN BEAR TRACK SUBSTATION UPGRADE	0	0	0	1664	1683	32	0	0	6523	46964	0	0	53486	Enhance	System Enhancements	KU	2023	Discretionary	3347
2023	2023	Funded	27	DAN RECONDUCTOR LEBANON EAST TO CITY CIRCUIT 2240 CONNECTION	0	0	0	225	0	21	0	254	1355	3067	0	0	4676	Enhance	System Enhancements	KU	2023	Discretionary	225
2023	2023	Funded	29	DSP Detroit Harvester 743-2 12kV Sub Bkr addition	0	0	0	150	0	16	0	0	5004	3559	0	0	8563	Enhance	System Enhancements	KU	2023	Discretionary	150
2023	2023	Funded	29	DSP Detroit Harvester 743-2 Circuit 801 new circuit	0	0	0	380	0	16	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2023	Discretionary	380
2024	2024	Funded	0	DSP Nicholasville Rd Substation Property	0	0	0	0	1000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2024	Non-Discr	1000
2024	2024	Funded	1	DSP Elizabethtown Industrial Substation Project	0	0	0	0	2185	183066	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2024	Discretionary	2185
2024	2024	Funded	1	DSP Horse Cave Industrial Distribution Exit Circuits Project	0	0	0	0	432	247165	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2024	Discretionary	432
2024	2024	Funded	2	DSP Fariston Distribution Circuit 0217 Reconductor Project	0	0	0	0	1900	216895	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2024	Discretionary	1900
2024	2024	Funded	2	DSP Old Henry Substation (2024_2025)	0	0	0	0	2500	10846	0	0	0	0	0	27115493	27115493	Enhance	System Enhancements	LGE	2024	Discretionary	2500
2024	2024	Funded	3	DSP Simpsonville 1 Distribution	0	0	0	0	400	3926	0	77885	4777	4265	0	0	86926	Enhance	System Enhancements	KU	2024	Discretionary	400
2024	2024	Funded	3	DSP Simpsonville 1 Substation	0	0	0	0	2300	3926	0	0	0	0	0	10514400	10514400	Enhance	System Enhancements	KU	2024	Discretionary	2300
2024	2024	Funded	7	DSP East Stone Gap 2 Cir 4721 Distribution	0	0	0	0	500	57	0	0	17161	11215	0	0	28376	Enhance	System Enhancements	KU	2024	Discretionary	500
2023	2024	Funded Diff Year	9	DSP Paris 819-1 12kV Sub Bkr addition	0	0	0	0	150	29	0	0	4975	10252	0	0	15226	Enhance	System Enhancements	KU	2023	Discretionary	150
2023	2024	Funded Diff Year	9	DSP Paris Circuit 806 new circuit	0	0	0	0	380	29	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2023	Discretionary	380
2023	2024	Funded Diff Year	22	DSP Sandy Ridge Substation Regs/Breaker	0	0	0	0	350	35	0	0	6803	5300	0	0	12103	Enhance	System Enhancements	KU	2023	Discretionary	350

	BP Year	2021

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2021	2022	2023	2024	2025	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2021	2021	Funded	0	Distribution Automation KU	3696	0	0	0	0	4096	0	3662327	7782875	3695364	0	0	15140566	Enhance	Reliability Overhead	KU	2021	Non-Discr	3696
2021	2021	Funded	0	Distribution Automation LGE	17278	0	0	0	0	752	0	940420	8175146	3884646	0	0	13000211	Enhance	Reliability Overhead	LGE	2021	Non-Discr	17278
2021	2021	Funded	0	Distribution Capacitors KU	146	149	152	155	159	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	761
2021	2021	Funded	0	Distribution Capacitors LGE	158	162	166	172	177	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2021	Non-Discr	835
2021	2021	Funded	0	DSP LaGrange Property	500	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	500
2021	2021	Funded	0	DSP Paynes Mill Road Distribution Project	250	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	250
2021	2021	Funded	0	DSP Rogers Gap Distribution	138	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	138
2021	2021	Funded	0	DSP Rogers Gap Substation	1971	0	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	1971
2021	2021	Funded	0	DSP Uniontown 4KV to 12KV Distribution Conversion Project	33	0	0	0	0	205233	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2021	Non-Discr	33
2021	2021	Funded	0	DSP Uniontown Substation Upgrade Project	1916	0	0	0	0	205233	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	1916
2021	2021	Funded	0	LED Conversion Pilot Program - KU	250	750	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Non-Discr	1000
2021	2021	Funded	0	LED Conversion Pilot Program - LGE	250	750	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2021	Non-Discr	1000
2021	2021	Funded	0	LEO Downtown Manhole Structural Repairs RAP	434	444	455	466	478	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	2277
2021	2021	Funded	0	LEO Downtown Network Vault Structural Repairs RAP - 2021	1750	1794	1500	1538	1576	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	8158
2021	2021	Funded	0	LEO Downtown Network Vent Type Protector Repl RAP - 2021	853	874	896	919	942	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	4484
2021	2021	Funded	0	LEO PILC NW Cable Repl Curb to Curb Paving LGE STR	1100	0	0	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	1100
2021	2021	Funded	0	LEO PILC UG Network Cable Replacement Program LGE STR	9263	0	0	0	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	9263
2021	2021	Funded	0	Magazine Distribution Lines Upgrades	2002	848	0	0	0	5431	0	0	6758325	4114568	0	0	10872893	Enhance	System Enhancements	LGE	2021	Non-Discr	2850
2021	2021	Funded	0	N1DT Projects Funding by YEAR	12000	11000	10000	10000	10000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2021	Non-Discr	53000
2021	2021	Funded	0	Pole Inspection and Treatment KU STR	7816	8050	8292	8507	8720	167	0	449119	251958	604116	0	0	1305194	Maintain	Pole Inspection	KU	2021	Non-Discr	41385
2021	2021	Funded	0	Pole Inspection and Treatment LGE STR	5210	5367	5528	5666	5808	164	0	318703	106659	430329	0	0	855691	Maintain	Pole Inspection	LGE	2021	Non-Discr	27579
2021	2021	Funded	0	SCM KU ENHANCED SUBSTATION WILDLIFE PROTECTION	1700	0	0	0	0	7017	40000	0	1539881	10348313	0	0	11928194	Enhance	System Enhancements	KU	2021	Non-Discr	1700
2021	2021	Funded	0	SCM KU SIO BREAKERS	753	515	625	0	0	240	0	0	51226	129860	0	0	181085	Maintain	Aging Infrastructure	KU	2021	Non-Discr	1893
2021	2021	Funded	0	SCM KU SIO RELAYS	2500	2500	2500	0	0	0	0	0	57	1	0	0	58	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	7500
2021	2021	Funded	0	SCM KU STR RAP REPL LTC/REG CONTROLS - 2021	118	121	124	127	130	357	0	0	28453	13658	0	0	42111	Maintain	Aging Infrastructure	KU	2021	Non-Discr	620
2021	2021	Funded	0	SCM KU SUBSTATION SCADA EXPANSION STR	5085	0	0	0	0	2	0	0	7002	4201	0	0	11204	Enhance	System Enhancements	KU	2021	Non-Discr	5085
2021	2021	Funded	0	SCM LGE MAGAZINE SUBSTATION UPGRADE	4610	5359	0	0	0	0	0	0	1032	103	0	0	1135	Enhance	System Enhancements	LGE	2021	Non-Discr	9969
2021	2021	Funded	0	SCM LGE RAP CAP AND PIN INSULATOR UPGRADE - 2021	176	180	185	0	0	846	0	0	78338	70504	0	0	148842	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	541
2021	2021	Funded	0	SCM LGE SIO BREAKERS	756	505	625	0	0	1998	0	0	427459	1082896	0	0	1510355	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	1886
2021	2021	Funded	0	SCM LGE SIO RELAYS	2500	2500	2500	0	0	0	0	0	74	1	0	0	74	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	7500
2021	2021	Funded	0	SCM RAP DAN FAILED BREAKER/RECL PROJ - 2021	125	128	131	135	138	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	657
2021	2021	Funded	0	SCM RAP DAN MISC DIST CAPITAL SUB PROJ - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP DAN MISC NESC COMPLIANCE - 2021	31	32	33	33	34	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP DAN SUBSTN BUILDINGS & GRNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP EARL FAILED BREAKER/RECL PROJ - 2021	125	128	131	135	138	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	657
2021	2021	Funded	0	SCM RAP EARL MISC DIST CAPITAL SUB PROJ - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP EARL MISC NESC COMPLIANCE - 2021	31	32	33	33	34	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP EARL SUBSTN BUILDINGS & GNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP KU AND LGE REPLACE SUBSTATION BATTERIES	288	295	303	310	318	2276	0	0	113038	542584	0	0	655622	Maintain	Aging Infrastructure	KU	2021	Non-Discr	1514
2021	2021	Funded	0	SCM RAP KU LEGACY ARRESTER REPLACE - 2021	140	144	147	151	155	1939	10000	0	172050	89466	0	0	271516	Maintain	Aging Infrastructure	KU	2021	Non-Discr	736
2021	2021	Funded	0	SCM RAP KU LTC OIL FILTRATION ADDITIONS - 2021	95	97	100	102	105	1974	8200	0	60910	118418	0	0	187527	Maintain	Substation Maintenance	KU	2021	Non-Discr	499
2021	2021	Funded	0	SCM RAP KU NESC COMPLIANCE, MISC, BLDGS & GRNDS - 2021	1055	1081	1108	1136	1165	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	5545
2021	2021	Funded	0	SCM RAP KU OIL CONTAINMENT UPGRADES - 2021	286	293	300	308	316	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	1503
2021	2021	Funded	0	SCM RAP KU REPL BUSHINGS - 2021	119	122	125	128	131	11340	0	0	87630	1261872	0	0	1349502	Maintain	Substation Maintenance	KU	2021	Non-Discr	626
2021	2021	Funded	0	SCM RAP KU REPL REGULATORS - 2021	92	95	97	99	102	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	485
2021	2021	Funded	0	SCM RAP KU STR REPL LEGACY BREAKERS - 2021	1186	1216	1246	1277	1309	153	0	0	51226	129860	0	0	181085	Maintain	Aging Infrastructure	KU	2021	Non-Discr	6234
2021	2021	Funded	0	SCM RAP KU STR REPL LEGACY RTUS - 2021	230	236	242	248	254	491	0	0	70594	42357	0	0	112951	Maintain	Aging Infrastructure	KU	2021	Non-Discr	1209
2021	2021	Funded	0	SCM RAP KU WOOD POLE SUBSTATION UPGRADES - 2021	683	700	717	735	754	393	0	0	78993	189583	0	0	268576	Maintain	Substation Maintenance	KU	2021	Non-Discr	3588
2021	2021	Funded	0	SCM RAP LEX FAILED BREAKER/RECL PROJ - 2021	124	127	130	134	137	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	652
2021	2021	Funded	0	SCM RAP LEX MISC DIST CAPITAL SUB PROJ - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP LEX MISC NESC COMPLIANCE - 2021	31	32	33	33	34	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP LEX SUBSTATION BUILDINGS & GNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP LGE LEGACY ARRESTER REPLACE - 2021	69	70	72	74	76	3883	5125	0	172050	89466	0	0	266641	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	361
2021	2021	Funded	0	SCM RAP LGE LTC OIL FILTRATION ADDITIONS - 2021	63	65	66	68	70	4872	6150	0	39217	261592	0	0	306959	Maintain	Substation Maintenance	LGE	2021	Non-Discr	331
2021	2021	Funded	0	SCM RAP LGE MISC DIST CAPITAL SUB PROJ - 2021	51	53	54	55	57	1844	0	0	27802	66725	0	0	94527	Maintain	Substation Maintenance	LGE	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP LGE MISC NESC COMPLIANCE - 2021	31	32	33	33	34	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP LGE OIL CONTAINMENT UPGRADES - 2021	117	120	123	126	129	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2021	Non-Discr	614
2021	2021	Funded	0	SCM RAP LGE REPL BUSHINGS - 2021	60	62	63	65	66	22492	0	0	87630	1261872	0	0	1349502	Maintain	Substation Maintenance	LGE	2021	Non-Discr	315
2021	2021	Funded	0	SCM RAP LGE STR REPL LEGACY BREAKERS - 2021	964	988	1013	1038	1064	93	0	0	26446	63471	0	0	89917	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	5067
2021	2021	Funded	0	SCM RAP LGE STR REPL LEGACY RTUS - 2021	118	121	124	127	130	680	0	0	50175	30093	0	0	80269	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	620
2021	2021	Funded	0	SCM RAP LGE SUBSTN BUILDINGS & GNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP PINE FAILED BREAKER/RECL PROJ - 2021	125	128	131	135	138	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	657
2021	2021	Funded	0	SCM RAP PINE MISC DIST CAPITAL SUB PROJ - 2021	51	53	54	55	57	3591	0	0	40010	144037	0	0	184048	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP PINE MISC NESC COMPLIANCE - 2021	31	32	33	33	34	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP PINE SUBSTN BUILDINGS & GNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	269
2021	2021	Funded	0	SCM RAP STR DAN WILDLIFE PROTECTION - 2021	27	28	28	29	30	6131	0	0	48688	116852	0	0	165540	Enhance	System Enhancements	KU	2021	Non-Discr	142
2021	2021	Funded	0	SCM RAP STR EARL WILDLIFE PROTECTION - 2021	60	62	63	65	66	624	0	0	11008	26418	0	0	37426	Enhance	System Enhancements	KU	2021	Non-Discr	315
2021	2021	Funded	0	SCM RAP STR KU LEGACY RELAY REPL - 2021	133	137	140	143	147	2286	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	KU	2021	Non-Discr	700
2021	2021	Funded	0	SCM RAP STR LEX WILDLIFE PROTECTION - 2021	39	40	41	42	43	4350	4100	0	48688	116852	0	0	169640	Enhance	System Enhancements	KU	2021	Non-Discr	205
2021	2021	Funded	0	SCM RAP STR LGE LEGACY RELAY REPL - 2021	95	97	100	102	105	3207	0	0	89610	215063	0	0	304672	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	499
2021	2021	Funded	0	SCM RAP STR LGE WILDLIFE PROTECTION - 2021	90	92	95	97	99	210	0	0	8584	10301	0	0	18886	Enhance	System Enhancements	LGE	2021	Non-Discr	473
2021	2021	Funded	0	SCM RAP STR PINE WILDLIFE PROTECTION - 2021	58	59	61	62	64	2893	0	0	49353	118448	0	0	167801	Enhance	System Enhancements	KU	2021	Non-Discr	305
2021	2021	Funded	0	SIO UG Fault Indicators KU	2292	0	0	0	0	109	0	0	0	248981	0	0	248981	Enhance	Reliability Underground	KU	2021	Non-Discr	2292
2021	2021	Funded	0	SIO UG Fault Indicators LGE	2410	0	0	0	0	108	0	0	0	260155	0	0	260155	Enhance	Reliability Underground	LGE	2021	Non-Discr	2410
2021	2021	Funded	0	Substation SCADA Upgrades - KU	3000	3000	3000	3000	0	159	0	0	363451	113857	0	0	477308	Enhance	System Enhancements	LGE	2021	Non-Discr	12000
2021	2021	Funded	0	Substation SCADA Upgrades - LGE	2000	2000	2000	2000	0	782	0	694348	736781	133403	0	0	1564531	Enhance	System Enhancements	LGE	2021	Non-Discr	8000
2021	2021	Funded	0	Transmission Line Clearance KU RAP	2500	2500	1000	1000	1000	0	0	0	0	0	0	0	0	Maintain	Other	KU	2021	Non-Discr	8000
2021	2021	Funded	0	Transmission Line Clearance LGE RAP	1500	1500	500	500	500	0	0	0	0	0	0	0	0	Maintain	Other	LGE	2021	Non-Discr	4500

	BP Year	2021

Year	Scheduled Year	Funding	Rank	AIS First Year Project Name	2021	2022	2023	2024	2025	Ratio	Financial	CEMI	CI	CMI	Complaints	Load	Total Project Score	Type	Code	Utility	Year	Discretionary	Funded Dollars Total
2021	2021	Funded	1	PIN Cumberland Express Circuit	180	0	0	0	0	1731676	0	0	6963	9431	0	311685207	311701601	Enhance	Reliability Overhead	KU	2021	Discretionary	180
2021	2021	Funded	2	DSP VERSAILLES DISTRIBUTION 4KV TO 12KV CONVERSION PROJECT	250	50	0	0	0	275998	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2021	Discretionary	300
2021	2021	Funded	2	SCM KU CONVERT VERSAILLES 4KV SUBSTATION	1200	3005	0	0	0	275998	0	0	34072	163546	0	0	197618	Enhance	System Enhancements	KU	2021	Discretionary	4205
2021	2021	Funded	3	SCM KU ADD TRANSFORMER COOLING	100	0	0	0	0	39511	0	0	0	0	0	3951101	3951101	Enhance	System Enhancements	KU	2021	Discretionary	100
2021	2021	Funded	4	DSP Detroit Harvester 743-2 Circuit 801 new circuit	182	0	0	0	0	22765	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Discretionary	182
2021	2021	Funded	4	DSP Detroit Harvester 743-2 Sub Bkr	150	0	0	0	0	22765	0	0	0	0	0	7558084	7558084	Enhance	System Enhancements	KU	2021	Discretionary	150
2021	2021	Funded	5	REL CEMI KU STR	1612	1652	1693	1735	1778	15430	0	17694302	3449189	3730232	0	0	24873723	Enhance	Reliability Overhead	KU	2021	Discretionary	8470
2021	2021	Funded	6	LEO Padmount Switchgear Repair/Replacement Program RAP - 2021	312	320	323	340	350	8349	0	72550	788492	1740643	0	0	2601685	Maintain	Repair/Replace Defective Equipment-UG	LGE	2021	Discretionary	1645
2021	2021	Funded	7	REL CEMI LGE STR	819	840	861	883	905	6901	0	4145217	855689	650674	0	0	5651580	Enhance	Reliability Overhead	LGE	2021	Discretionary	4308
2021	2021	Funded	8	LEO Substation Exit Cable Replacement LGE STR RAP	1660	1720	1500	1538	1576	5586	0	6488198	479972	2304037	0	0	9272206	Maintain	Aging Infrastructure	LGE	2021	Discretionary	7994
2021	2021	Funded	9	LEO URD Cable Replacement Program LGE STR	1700	1700	1030	1061	1093	4917	0	4925887	1330168	2102279	0	0	8358333	Maintain	Aging Infrastructure	LGE	2021	Discretionary	6584
2021	2021	Funded	10	DSP Mount Sterling Substation Project	2793	2709	0	0	0	4174	0	0	0	0	0	12493550	12493550	Enhance	System Enhancements	KU	2021	Discretionary	5502
2021	2021	Funded	10	DSP Mount Sterling Substation Project Distribution	200	200	0	0	0	4174	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Discretionary	400
2021	2021	Funded	11	SCM RAP LGE UPGRADE 14KV GND FAULT SYSTEMS	150	154	158	162	0	1901	0	0	129584	155501	0	0	285086	Enhance	System Enhancements	LGE	2021	Discretionary	623
2021	2021	Funded	12	SCM KU AND LGE SUBSTATION SECURITY	1000	1000	1000	0	0	1550	1500000	0	25082	25082	0	0	1550164	Enhance	System Enhancements	KU	2021	Discretionary	3000
2021	2021	Funded	13	LON Manchester 254 Greasy Reconductor	95	0	0	0	0	757	0	4401	34275	33264	0	0	71940	Enhance	Reliability Overhead	KU	2021	Discretionary	95
2021	2021	Funded	14	REL KU CIFI STR YEARLY ND SPEND	1500	1538	1577	1616	1656	752	0	13006	631322	483622	0	0	1127950	Enhance	Reliability Overhead	KU	2021	Discretionary	7887
2021	2021	Funded	15	REL LGE CIFI STR YEARLY ND SPEND	1250	1281	1313	1346	1380	742	0	2313	624943	299849	0	0	927106	Enhance	Reliability Overhead	LGE	2021	Discretionary	6570
2021	2021	Funded	16	SIO Small Wire Removal LGE	700	700	700	700	700	596	0	10013	229708	177753	0	0	417474	Enhance	Reliability Overhead	LGE	2021	Discretionary	3500
2021	2021	Funded	17	SIO Small Wire Removal KU	900	900	900	900	900	594	0	26893	219164	288327	0	0	534384	Enhance	Reliability Overhead	KU	2021	Discretionary	4500
2021	2021	Funded	18	SCM RAP LGE UPGRADE 14KV GND TRANSFORMERS - 2021	256	263	269	276	283	581	0	0	67682	81219	0	0	148901	Maintain	Aging Infrastructure	LGE	2021	Discretionary	1347
2021	2021	Funded	19	KU Direct Burial Replacement	1000	1000	1000	1000	1000	502	0	340255	54212	107670	0	0	502137	Enhance	Reliability Underground	KU	2021	Discretionary	5000
2021	2021	Funded	20	DAN RECONDUCTOR RUSSELL SPRINGS CIRCUIT 2222	170	0	0	0	0	499	0	0	46687	38188	0	0	84875	Enhance	System Enhancements	KU	2021	Discretionary	170
2021	2021	Funded	21	REL System Hardening LGE	1826	3354	3712	3802	3897	437	0	16016	580589	200490	0	0	797095	Enhance	Reliability Overhead	LGE	2021	Discretionary	16591
2021	2021	Funded	22	DAN RECONDUCTOR CIRCUIT 2218 LEBANON SOUTH TO BRADFORDSVILLE	215	0	0	0	0	403	0	0	35706	50862	0	0	86569	Enhance	System Enhancements	KU	2021	Discretionary	215
2021	2021	Funded	23	RIC REL 2304 Reconductor	250	0	0	0	0	356	0	0	34947	54065	0	0	89012	Enhance	Reliability Overhead	KU	2021	Discretionary	250
2021	2021	Funded	24	REL System Hardening KU	1826	3354	3712	3802	3897	335	0	89097	237571	284654	0	0	611321	Enhance	Reliability Overhead	KU	2021	Discretionary	16591
2021	2021	Funded	25	SCM LGE MAGAZINE 4KV SWITCHGEAR UPGRADE	300	1500	0	0	0	318	0	0	28024	67258	0	0	95282	Maintain	Aging Infrastructure	LGE	2021	Discretionary	1800
2021	2021	Funded	26	SIO Fuse Savings LGE	490	0	0	0	0	317	0	0	46164	109406	0	0	155570	Enhance	Reliability Overhead	LGE	2021	Discretionary	490
2021	2021	Funded	27	SCM KU VINE STREET 12KV SWITCHGEAR	1320	1200	0	0	0	257	300000	0	17768	21321	0	0	339089	Enhance	System Enhancements	KU	2021	Discretionary	2520
2021	2021	Funded	28	URD Cable Replacement Program KU STR RAP	358	367	378	388	389	244	0	0	38794	48519	0	0	87314	Maintain	Aging Infrastructure	KU	2021	Discretionary	1880
2021	2021	Funded	29	PIN Meldrum 0308 Hutch Re-route	250	0	0	0	0	242	0	41092	9366	9958	0	0	60416	Enhance	Reliability Overhead	KU	2021	Discretionary	250
2021	2021	Funded	30	LON Williamsburg South 225 to 226 Tie	80	0	0	0	0	210	0	0	7248	9514	0	0	16762	Enhance	Reliability Overhead	KU	2021	Discretionary	80
2021	2021	Funded	31	SIO Fuse Savings KU	210	0	0	0	0	207	0	0	17162	26357	0	0	43519	Enhance	Reliability Overhead	KU	2021	Discretionary	210
2021	2021	Funded	32	PIN Pineville 302 Relocate	120	0	0	0	0	184	0	15769	898	5446	0	0	22113	Enhance	Reliability Overhead	KU	2021	Discretionary	120
2021	2021	Funded	33	SCADA Voltage Control - KU	300	300	500	600	600	167	50000	0	0	0	0	0	50000	Enhance	System Enhancements	KU	2021	Discretionary	2300
2021	2021	Funded	34	SCADA Voltage Control - LGE	300	300	500	600	600	167	50000	0	0	0	0	0	50000	Enhance	System Enhancements	LGE	2021	Discretionary	2300
2021	2021	Funded	35	DSP MANNINGTON/CROFTON DISTRIBUTION SYSTEMS CONVERSION TO 12KV PRO	158	55	0	0	0	126	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2021	Discretionary	213
2021	2021	Funded	35	SCM KU CROFTON TRANSFORMER UPGRADE AND VOLTAGE CONVERSION	900	760	0	0	0	126	0	0	7297	126445	0	0	133742	Maintain	Aging Infrastructure	KU	2021	Discretionary	1660
2021	2021	Funded	37	DAN HARRODSBURG HITACHI UG PRIMARY LOOP UPGRADE	360	0	0	0	0	47	0	0	5697	11052	0	0	16749	Enhance	Reliability Underground	KU	2021	Discretionary	360
2022	2022	Funded	0	DSP Pavilion Dr Substation Property	0	600	0	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2022	Non-Discr	600
2022	2022	Funded	0	VVO Software Purchase	0	500	500	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2022	Non-Discr	1000
2022	2022	Funded	1	SCM KU SIO WILDLIFE PROTECTION	0	1000	1000	0	0	11960	72000	0	1539881	10348313	0	0	11960194	Enhance	System Enhancements	KU	2022	Discretionary	2000
2022	2022	Funded	2	DSP LaGrange Distribution	0	500	750	0	0	9491	0	0	22813	20932	0	14774307	14818052	Enhance	System Enhancements	KU	2022	Discretionary	1250
2022	2022	Funded	2	DSP LaGrange Substation Project	0	2618	2672	0	0	9491	0	0	0	0	0	14774307	14774307	Enhance	System Enhancements	KU	2022	Discretionary	5290
2022	2022	Funded	3	DSP Lakeshore ckt 132 circuit upgrade - Blue Sky Parkway	0	1240	0	0	0	6195	0	0	0	0	0	7681421	7681421	Enhance	System Enhancements	KU	2022	Discretionary	1240
2022	2022	Funded	4	DSP Harrods Creek Circuit 1234	0	300	0	0	0	867	0	70106	112169	77893	0	0	260168	Enhance	System Enhancements	LGE	2022	Discretionary	300
2022	2022	Funded	5	SCM KU SIO TXFMR UPGRADES	0	1000	1000	0	0	626	0	0	184107	441856	0	0	625963	Enhance	System Enhancements	KU	2022	Discretionary	2000
2022	2022	Funded	7	SCM KU SIO SUBSTATION SCADA EXPANSION V2	0	2000	2000	1000	1000	6	0	0	7002	4201	0	0	11204	Enhance	System Enhancements	KU	2022	Discretionary	6000
2023	2023	Funded	0	DSP Clinton St Substation Property	0	0	200	0	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2023	Non-Discr	200
2023	2023	Funded	0	SCM LGE CAMPGROUND SUBSTATION EXPANSION	0	0	300	4300	7000	3592	1000000	0	48558	29135	0	0	1077692	Maintain	Aging Infrastructure	LGE	2023	Non-Discr	11600
2024	2023	Funded Diff Year	1	DSP Horse Cave Industrial Distribution Exit Circuits Project	0	0	0	432	0	264027	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2024	Discretionary	432
2023	2023	Funded	1	DSP Horse Cave Industrial Substation Project	0	0	2483	2613	0	264027	0	0	0	0	0	255578143	255578143	Enhance	System Enhancements	KU	2023	Discretionary	5096
2023	2023	Funded	2	DSP Fariston 12KV Substation Upgrade Project	0	0	1852	1874	0	212179	0	0	0	0	0	5686309	5686309	Enhance	System Enhancements	KU	2023	Discretionary	3726
2023	2023	Funded	2	DSP Fariston Distribution Circuit 0217 Reconductor Project	0	0	60	150	0	212179	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2023	Discretionary	210
2023	2023	Funded	3	DSP Ashbottom Substation	0	0	3200	2700	0	124909	0	0	0	0	0	399708802	399708802	Enhance	System Enhancements	LGE	2023	Discretionary	5900
2023	2023	Funded	4	DSP Pavilion Dr Distribution	0	0	600	600	0	1188	0	0	12576	13134	0	0	25711	Enhance	System Enhancements	KU	2023	Discretionary	1200
2023	2023	Funded	4	DSP Pavilion Dr Substation	0	0	3200	2800	0	1188	0	0	0	0	0	4487862	4487862	Enhance	System Enhancements	KU	2023	Discretionary	6000
2025	2025	Funded	0	DERMS Software Upgrade	0	0	0	0	1000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2025	Non-Discr	1000
2026	2025	Unfunded	1	DSP Elizabethtown Industrial Distribution Circuit Project	0	0	0	0	0	183066	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2026	Discretionary	0
2025	2025	Funded	1	DSP Elizabethtown Industrial Substation Project	0	0	0	0	2185	183066	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2025	Discretionary	2185
2025	2025	Funded	2	DSP FMC 12kV Substation Expansion	0	0	0	0	2203	15070	0	0	0	0	0	34707273	34707273	Enhance	System Enhancements	KU	2025	Discretionary	2203
2025	2025	Funded	2	DSP FMC 12kV Substation Expansion Distribution	0	0	0	0	100	15070	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2025	Discretionary	100
2026	2025	Unfunded	3	DSP Lebanon South Substation Project	0	0	0	0	0	12845	0	0	0	0	0	19794898	19794898	Enhance	System Enhancements	KU	2026	Discretionary	0

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 259

Responding Witness: Eileen L. Saunders

Q-259. Reference the Saunders testimony at 23:8. Explain whether the word "absorbed" means that shareholders paid that amount as opposed to it being collected from ratepayers.

A-259. "Absorbed" as referenced in the above request for information does mean that the shareholders incurred that amount as opposed to it being collected from ratepayers because the amount was never in base rates.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 260

Responding Witness: Eileen L. Saunders

Q-260. Reference the Saunders testimony at 22-23. Discuss in detail the need for $86 M in facility improvements, including itemized workpapers supporting the proposed amounts.

A-260. As noted in Saunders testimony on page 23 for the period of November 1, 2019 to December 31, 2021, $41.8M spend is for improvements to or replacement of aging facilities that do not meet current codes and standards, replace outdated workspaces and create needed facilities for the utility operations. Itemized workpapers are attached.

The remaining $43.9M is needed for the following:

- address safety concerns, risks and potential hazards at aging work locations,
- Broadway Operations Center façade repairs due to aging facility issues, deteriorated masonry and water intrusion,
- KU General Office masonry and window replacement due to water intrusion,
- replace and update outdated mechanical and HVAC systems at company facilities,
- replace and update outdated lighting and electrical systems at company facilities,
- site and building envelope improvements to business offices, service centers and storeroom locations throughout the state (e.g. sidewalk repairs, rest room updates, transformer containment pad construction, dumpster pad improvements, drainage mitigation issues, parking lot repairs/replacements, siding/roof repairs, security gate repairs/improvements),
- office, common area, and meeting space renovations due to aging and inadequate workspaces,
- new facility construction in Kevil, KY to consolidate and replace inefficient facilities at KU's Barlow locations,

- planned property purchases in Carrollton and Elizabethtown to consolidate locations and optimize operations, and
- establishment of on-site medical clinics to provide primary care services to employees, spouses and dependents on the medical plan and occupational services to employees.

Description	Project #	Mid Point (Nov 2019 - Dec 2021)
Auburndale Operations Center ("AOC") Building Renovation	159545;00029FACL	$8,548,052
KU General Office ("KUGO") Building Renovation	00105FACK;00105FACL	$13,850,104
Limestone/Louden Operations Center Relocation	21BP064K	$10,964,229
South Operations Engineering Center Construction	00035FACL;161852KU;161852LGE	$8,443,089
	Sub-Total	**$41,805,474**
Broadway Operations Center ("BOC") Cooling Towers & Holding Tank / Chillers	00145FACL;00149FACL	$1,005,665
Earlington Business Office ("BO") Drive Thru Reconfiguration	163458	$70,033
AOC Office Renovation	158064;161176;162341;162758;00125FACL;00127FACL	$2,857,860
AOC Site & Building Envelope Improvement	161262;162340;163756;00015FACL	$1,088,845
BOC Annex Building Renovation	00067FACL;00067FACK	$2,432,569
KU Facility and Site Improvement Long Term Plan Budget	153019	$19,973
LGE Facility and Site Improvement Long Term Plan Budget	153018	$5,960
LGE Facility Equipment Long Term Plan Budget	153021	$78,648
KU Facility Equipment Long Term Plan Budget	153022	$8,384
Stone Rd Sprinkler System Preliminary Design	00080FACK	$23,178
2019 KU Facility Equipment Budget	152771	$96,246
2019 KU Furniture & Equipment Budget	152801	$29,132
2019 LG&E Furniture & Equipment Budget	152799	$46,022
2019 LGE Facility Equipment	152769	$19,419
2020 KU Furniture & Equipment Budget	153025	$131,394
2020 LGE Furniture & Equipment Budget	153024	$179,777
2021 KU Electrical & Lighting Repairs/Replacements Budget	00003FACK	$152,047
2021 KU Facility and Site Improvements Budget	00010FACK	$366,048
2021 KU Facility Equipment Budget	00043FACK	$109,835
2021 KU Furniture & Equipment Budget	00047FACK	$389,128
2021 LGE Electrical & Lighting Repairs/Replacements Budget	00004FACL	$153,060
2021 LGE Facility and Site Improvements Budget	00009FACL	$352,078
2021 LGE Facility Equipment Budget	00042FACL	$109,835
2021 LGE Furniture & Equipment Budget	00046FACL	$389,331
AOC Health Clinic Construction	161064;162732;162768KU;162768LGE	$1,583,988
AOC Mechanical System Improvements	161722	$89,019
AOC Warehouse Renovation	160893	$567,266
Audio Visual Equipment Replacements and Updates	00051FACK	$161,867
Big Stone Gap Storeroom Office Renovation	00093FACK	$107,834
BOC Building Façade Repairs	00076FACL	$1,500,654
BOC Health Clinic Construction	161157;162731;162764KU;162764LGE	$633,750
BOC HVAC Installation	156464;162724	$2,237,197
BOC Main Building Office Renovations	153561;153562;159699;162207;00066FACK;00066FACL;00072FACK;00072FACL;00073FACK;00073FACL;00107FACK;00107FACL;158624KU;158624LGE;160895KU;160895LGE;161254KU;161254LGE;161635KU;161635LGE;161723KU;161723LGE;162657KU;162657LGE	$3,882,404
BOC Mechanical System Improvements	163701;00053FACL;00054FACL;00075FACL	$244,957
BOC Site & Building Envelope Improvement	158598;159540;159787;159816;00040FACL	$1,737,492
Campbellsville Storeroom Emergency Transfer Switch Installation	160623	$23,476
Carrollton Operations Center Property Purchase	00164FACK	$500,076
Company Signage Replacement	155887;159295;159298;162808KU;162808LGE	$183,649
Danville Drainage Replacement	161109	$15,145
Danville Operations Center Office Renovations	00124FACK;00128FACK	$604,654
Danville Storeroom Renovation	163757	$189,007
Dawson Springs Storeroom HVAC & Lighting Upgrade	161136	$22,224
Earlington Concrete Ramp Repair	161211	$9,359
Earlington Meter Shop Window Replacement	161084	$5,628
Earlington Operations Center HVAC Upgrade	162605	$5,197
Earlington Operations Center Land Purchase	161061	$2,722
Earlington Storeroom Expansion	163050;00104FACK	$427,962
Earlington Storeroom Road Improvement	161474	$579,912
Earlington Storeroom Storm Shelter	161800	$31,398
Earlington Transformer Containment Construction	160645	$236
Earlington Wire Storage Shed Construction	161473;162643	$92,936
East Operations Center Renovation	161141;00031FACL;00139FACL	$216,615
East Operations Center Site & Building Envelope Improvement	159293;00078FACL;00079FACL	$711,858
Eddyville Storeroom Site Improvements	160491;161213	$140
Elizabethtown Purchase & Building Renovation	158181;21BP002K	$3,673,356
Elizabethtown Storeroom Renovation	159253	-$1,368
Elizabethtown Storeroom Site Drainage Improvements	161143;161149;161293;162921	$43,704
EOC Safety Training Building	00065FACL	$29,989
Georgetown BO Door Replacement	163610	$7,872
Greenville Containment Pad	160490	$65,626
Greenville Storeroom Renovation	00142FACK	$700,005
Greenville Storeroom Roof Replacement	00088FACK	$149,800
Harlan Storeroom Building Envelope Repair	163393	$49,118
Harlan Storeroom Site Improvements	163391	$49,004
Kevil Operations Center Construction	149991	$4,525,701

Description	Project #	Mid Point (Nov 2019 - Dec 2021)
KU GO Mechanical System Improvements	00076FACK;00082FACK	$1,520,782
KU GO Site & Building Envelope Improvement	159404;00013FACK	$1,351,789
KU GO Transmission Substations Office Renovation	158765KU;158765LGE	-$1,080
LG&E Center Office Renovations & Reconfigurations	139065;141389;141392;152805;00039FACK;00039FACL;158693KU;158693LGE;159676KU;159676LGE;160118KU;160118LGE;160432KU;160432LGE;160880LGE;160880KU;161005KU;161005LGE;162849KU;162849LGE	$133,005
Limestone Office Remodel 2019	00084FACK	$36
London Service Center Parking Lot Improvements	160077;160642;163758	$42,103
London Storeroom Fence Replacement	00095FACK	$25,133
London Storeroom Roof Replacement	161253	$25,070
Loudon Ice House Storage Area Renovation	161178	$52,455
Maysville BO Renovation	00150FACK	$524,878
Middlesboro BO Renovation	00100FACK	$796,917
Morehead BO Renovation	00146FACK	$100,218
Morganfield Operations Center Mechanical/Electrical Systems Improvements	160723;161035	$21,637
Morganfield Operations Center Parking Lot Improvements	161036;161734	$28,852
Norton Operations Center Construction	149992	$95,610
Norton Operations Center Easement Purchase	159069	$2,621
Norton Operations Center Mechanical/Electrical Systems Improvements	161209	$26,345
Norton Operations Center Site Improvements	161632	$14,262
Paris BO Roof Replacement	161770	$25,230
Pennington Gap BO Annex Renovation	00097FACK	$149,820
Pennington Gap Storeroom Relocation	00158FACK	$1,299,905
Pineville Operations Center Office Renovation	161144;161148	$61,283
Pineville Operations Center Site Improvement	160663;160886;161314	$56,893
Pineville Security Gate	162641	$6,580
Pineville Storage Building Construction	160704;163380	$28,589
Pineville Telecom Equipment Storage Relocation	161032	$25,081
Pineville Telecom Office Renovation	161033	$100,889
Richmond BO Drive Thru Reconfiguration	163694	$48,000
Richmond Service Center Parking Lot Repair	161459	$95
Richmond Storeroom Drainage Replacement	163609	$29,162
Richmond Storeroom Paving	161261	$53,991
Shelbyville Storeroom Drainage Replacement	161100	$7,572
Simpsonville Mechanical/Electrical System Improvements	162630;0050FACIK;0050FACIL;0050FACTK;0064FACIK;0064FACIL;0064FACTK;0064FACTL	$635,568
Simpsonville Office Renovations	159682KU;159682LGE;160957KU;160957LGE	$119,000
Simpsonville Site & Building Envelope Improvements	161054;161163KU;161163LGE	$32,041
Somerset BO Sidewalk Construction	163332	$11,000
Somerset Metal Storage Building	162635	$6,330
Somerset Pole Yard Security Gate Replacement	160892	$78,883
Somerset Storeroom Flooring Replacement	162880	$20,789
Somerset Storeroom Wire Shed Construction/Replacement	160594	$101,556
Somerst BO Renovation	160891;00023FACK	$144,193
South Service Center Exterior Improvements	161714	$6,326
South Service Center Office Renovation	156465	$112,381
Stone Road Entrance Paving	163457	$24,424
Stone Road Gate Replacement	161158	$31,900
Stone Road Site Improvement	160312	$131
Versailles BO Renovation & Roof Replacement	00148FACK	$199,798
Winchester Operations Center Preliminary Design	152388	$30,275
	Sub-Total	**$43,984,208**
	Total	**$85,789,682**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 261

Responding Witness: Eileen L. Saunders / John K. Wolfe

Q-261. Reference the Saunders testimony at pp. 35-36, in particular the chart on p. 36. Explain why for underground service, KU owns the service line but in the LG&E service territory, the customer owns the service line.

a. Explain whether the ownership of underground service lines is identical for all customer classes, or whether it is limited only to residential customers.

b. For each of the past five years, provide the sums KU has spent on maintenance and repair of underground service lines, broken down by class.

A-261. Ownership is different between the LG&E and KU as they are separately booked and established practices prior to their merger in 1998. The ownership of the underground service has remained consistent since that time.

a. The ownership of underground service lines varies for customer classes.

b. KU does not track maintenance and repair of underground customer service lines separately from company service lines therefore this information is not available.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

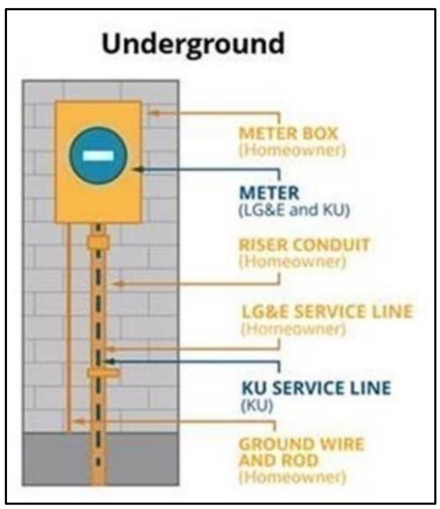
Case No. 2020-00350

Question No. 262

Responding Witness: Eileen L. Saunders

Q-262. Reference the Saunders testimony at pp. 37-38. Explain whether the proposed HomeServe warranty would cover maintenance and repair costs of underground service lines for both LG&E customers, and KU customers. If not, explain fully why not.

A-262. The proposed HomeServe warranty covers repair costs when the customer's underground service lines are no longer functioning. The homeowner responsibilities are different for LG&E and KU. For LG&E, the warranty would cover the service line, riser conduit, ground wire/rod and the meter box.



LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 263

Responding Witness: Kent W. Blake / Eileen L. Saunders

Q-263. Reference the Saunders testimony at p. 39, wherein she states, "The Companies aim to support economic development and growth in Kentucky interstate corridors by providing infrastructure necessary for the future of transportation and customer demands." Explain whether the companies' shareholders will be supporting the economic development, or the ratepayers.

A-263. Because all customers benefit from investment in economic development, these expenses should be included in base rates. When an existing Kentucky business expands or a new business locates in the state, significant economic benefits ensue for all customers. The creation of those new jobs bring payroll dollars, increased demand for housing, goods and services, greater capital investment, and a broader tax base, all of which spread throughout the economy.[11] This expansion of the economy and the additional revenue benefits all customers.

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[11] Just the Facts: Economic Impact of 100 Jobs, Think Kentucky, July 2018, https://ced.ky.gov/kyedc/pdfs/100jobs.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 264

Responding Witness: Eileen L. Saunders

Q-264. Reference the Saunders testimony generally. Provide copies of the contracts with Olameter, Scope Services, and Ops Plus.

A-264. 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.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021

Case No. 2020-00350

Question No. 265

Responding Witness: Eileen L. Saunders

Q-265. Reference the Saunders testimony at p. 40. Discuss the impact of the Energy and Environment Cabinet's Beneficiary Mitigation Plan, which can be found at https://eec.ky.gov/Documents/Final%20Mitigation%20Plan%20-%20june%202020.pdf on the proposal described by Saunders. Were the proposals approved or incorporated in the Beneficiary Mitigation Plan? Are these proposals still viable?

A-265. The Company intends to install infrastructure that meets or exceeds the requirements of the Energy and Environment Cabinet's (EEC) Beneficiary Mitigation Plan. The EEC has not yet solicited proposals for these funds, and thus no proposal has been submitted by the Company. It is the Company's understanding that funding from the Beneficiary Mitigation Plan is still viable.