

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 101

Responding Witness: Christopher M. Garrett

Q-101. Provide EEI's most recent IRS Form 990.

A-101. EEI's most recent IRS Form 990 is available through the IRS's Tax Exempt Organization Search at <https://apps.irs.gov/app/eos/>.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 102

Responding Witness: Robert M. Conroy

- Q-102. Do the Companies' EEI dues contribute to the salary, benefits and expenses of the EEI Executive Vice President for Public Policy and External Affairs, or any other EEI officer or employee who has led an effort EEI undertook to rebrand the utility industry?
- A-102. KU does not collect and retain the requested information for its corporate files. See the response to Question No. 93.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 103

Responding Witness: Christopher M. Garrett

- Q-103. Do any of the Companies' personnel actively participate on Committees and/or perform any other work for any Dues Requiring Organization or any other industry organization to which one or both Companies belong, including but not limited to EEI?
- a. If so, state specifically which employees participate, how they are compensated for their time (amount and source of compensation), and the purpose and accomplishments of any such association related work.
 - b. List any and all reimbursements received from industry associations, for work performed for such organizations by the Companies' employees.
- A-103. Company employees participate in various industry associations and organizations to gain knowledge, training, timely information and experience throughout the industry to allow for the Company to provide service to its customers in the most economical, cost effective, safe, and reliable manner. The gaining of industry knowledge through these associations benefits customers through the use of best practices in providing services. Since the conclusion of the Companies' 2018 rate cases, no employees have been compensated for their work for any Dues Requiring Organization or industry organization.

KENTUCKY UTILITIES COMPANY

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Dated January 8, 2021**

Case No. 2020-00349

Question No. 104

Responding Witness: Daniel K. Arbough

- Q-104. Provide all credit rating agency reports (Standard and Poor's, Moody's, Fitch) on LG&E and KU from January 2018 through the most recent month in 2021. Consider this an ongoing request such that when updated reports are filed, LG&E and KU will provide these updated reports.
- A-104. The KU credit rating agency reports from Standard and Poor's and Moody's are attached. S&P did not publish a report in 2018. Fitch no longer rates the debt of KU per the Company's request.

The LG&E credit rating agency reports are being provided in response to the same question in Case No. 2020-00350.



CREDIT OPINION
25 October 2018

Update

Rate this Research

RATINGS

Kentucky Utilities Co.

Domicile	Lexington, Kentucky, United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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EMEA	44-20-7772-5454

Kentucky Utilities Co.

Update to credit analysis

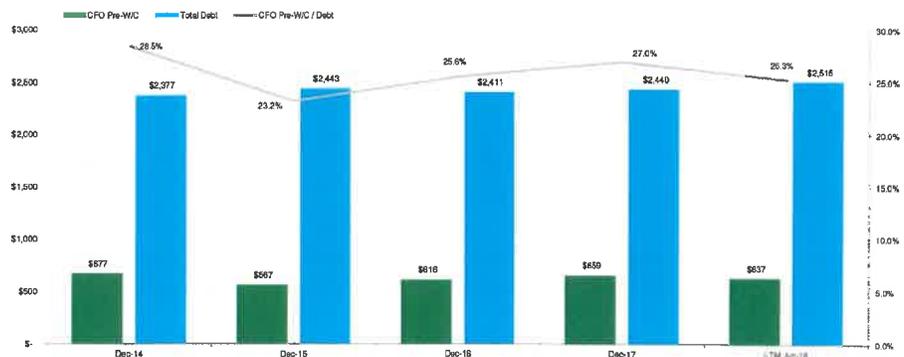
Summary

Kentucky Utilities' (KU) credit strengths include its constructive regulatory environments in Kentucky and Virginia where it has utility operations. KU has stable utility operations that produce relatively consistent credit metrics historically. KU represents approximately 22% of the cash flow to its ultimate parent company, PPL Corporation (PPL). These positive factors are somewhat offset by KU's large capital investment program, which may slightly pressure certain credit metrics, and to a lesser extent, a lack of fuel and geographic diversity.

The Kentucky and Virginia regulatory environments are supportive due to their transparent recovery framework. KU has been approved various tracker mechanisms by the regulatory commissions, providing a timely cost recovery. KU has been active in its general rate case filings. In September 2018, KU filed for an electric rate case requesting a \$112 million rate increase by the Kentucky Public Service Commission (KPSC). A final decision is expected by April 2019. Its last rate case in Kentucky concluded in June 2017.

We expect KU's ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt to range from 20% to 24%, which is weaker than its historical level.

Exhibit 1
Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt(\$MM)



Source: Moody's Financial Metrics

Credit strengths

- » Supportive regulatory environment in Kentucky and Virginia
- » Stable financial profile with transparent and predictable cash flows

Credit challenges

- » Large capital investment program
- » High coal concentration in its generation fuel mix
- » Elevated carbon transition risk

Rating outlook

The stable outlook reflects our expectation that the regulatory environments in Kentucky and Virginia will remain credit supportive for regulated utilities. The stable outlook also incorporates our view that KU will continue to generate stable cash flow and adequate financial metrics while it executes a large capital investment program, including a ratio of CFO pre-WC to debt in the 20%-24% range.

Factors that could lead to an upgrade

KU's rating could be upgraded if its financial metrics improve, including CFO pre-WC to debt at or above 26% on a sustained basis. An upgrade is also possible if KU's regulatory environment materially improves and provides more favorable regulatory recovery mechanisms. However, it is unlikely that KU's rating will be upgraded while the company executes on its large capital investment program and faces a slight negative impact in cash flows due to tax reform.

Factors that could lead to a downgrade

KU's ratings could be downgraded if there is a significant deterioration in the credit supportiveness of the regulatory environments. Additionally, KU's rating could be downgraded if its financial metrics deteriorate, such that CFO pre-WC to debt declines below 20% for an extended period of time.

Key indicators

Exhibit 2
Kentucky Utilities Co. [1]

	Dec-14	Dec-15	Dec-16	Dec-17	LTM Jun-18
CFO Pre-W/C + Interest / Interest	9.6x	7.8x	7.3x	7.8x	7.4x
CFO Pre-W/C / Debt	28.5%	23.2%	25.6%	27.0%	25.3%
CFO Pre-W/C – Dividends / Debt	22.2%	17.0%	15.3%	17.7%	15.3%
Debt / Capitalization	36.9%	36.2%	35.0%	37.7%	38.0%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Kentucky Utilities (KU) is a wholly owned regulated public utility subsidiary of LG&E and KU Energy LLC (LKE, Baa1 Stable) that is engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 525,000 customers in 77 counties of Kentucky and 28,000 customers in five counties of Virginia. KU is regulated by the Kentucky Public Service Commission and Virginia State Corporate Commission.

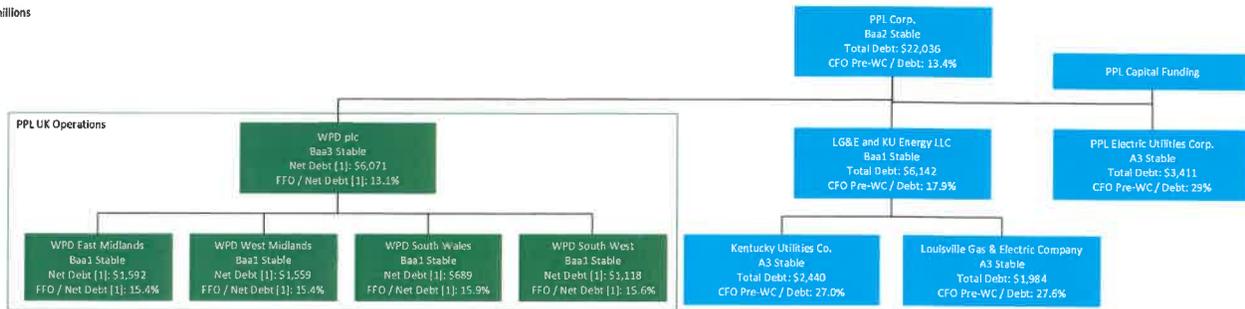
KU and its affiliate, Louisville Gas and Electric Company (LG&E, A3 Stable), are the two main operating entities of LKE. LKE is wholly owned by PPL Corporation (PPL, Baa2 Stable), a diversified utility holding company headquartered in Allentown, PA.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history

Exhibit 3

Organizational Structure
As of 12/31/2017

\$ In millions



[1] As of 3/31/2018; CFO Pre-WC to Debt is not a key metric we use for WPD and subsidiaries. WPD and subsidiaries are assessed under the Regulated Electric and Gas Networks Industry Grid

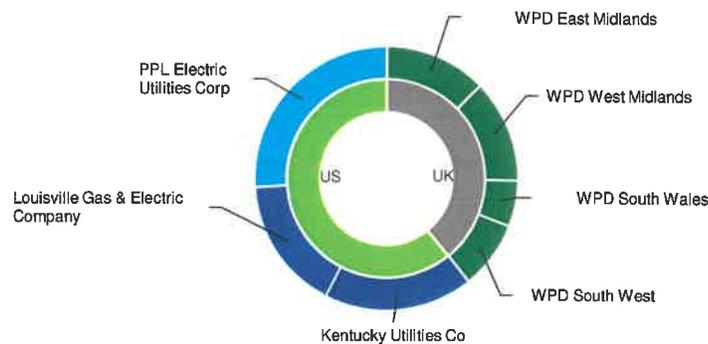
[2] Metrics are based on 'adjusted' financial data and incorporate Moody's Global Standard Adjustments for non-financial corporations.

Source: Moody's Financial Metrics

Exhibit 4

PPL's rate base breakdown between the US and UK jurisdictions

- Regulated network
- Regulated utility without generation
- Regulated utility with generation



Source: Company Reports

Detailed credit considerations

Supportive regulatory environment in Kentucky and Virginia

KU is a regulated electric and gas utility that has operations in Kentucky and Virginia and is regulated by the Kentucky Public Service Commission (KPSC) and the Virginia State Corporation Commission (SCC), respectively. We consider the regulatory environments in these states to be constructive for long-term credit quality. In Kentucky, the KPSC has approved various tracker mechanisms, allowing timely cost recovery for certain utility investments outside of a rate case, a credit positive. KU's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management (DSM) Cost Recovery Mechanism. KU does not have a decoupling mechanism in place, which subjects KU's revenue to some volatility. However, an impact on its revenue due to non-weather related demand fluctuations is minimized because of the DSM mechanism.

KU's last general rate rise in Kentucky concluded in June 2017 when a settlement was reached and approved. KU was authorized a \$52 million of revenue increase based on the approved settlement compared to its initial \$103 million increase request. The revenue increase was based on a 9.7% return on equity (ROE) but the settlement did not specify the allowed equity capitalization. In its order, the KPSC also excluded the recovery of certain costs for funding employee retirement plans.

In March 2018, the KPSC required KU's rates to be reduced by \$108 million over the period between April 2018 and April 2019 to account for the impact of the TCJA. In September 2018, the KPSC adopted a revised tax-related rate reduction of \$101 million for KU.

Also in September 2018, KU filed for its latest rate case with the KPSC, requesting a \$112 million electric rate increase based on a 10.42% ROE and equity layer of 52.84% with a capitalization for ratemaking value estimated around \$4.1 billion using a test year ending April 2020. The final decision is expected to be in April 2019.

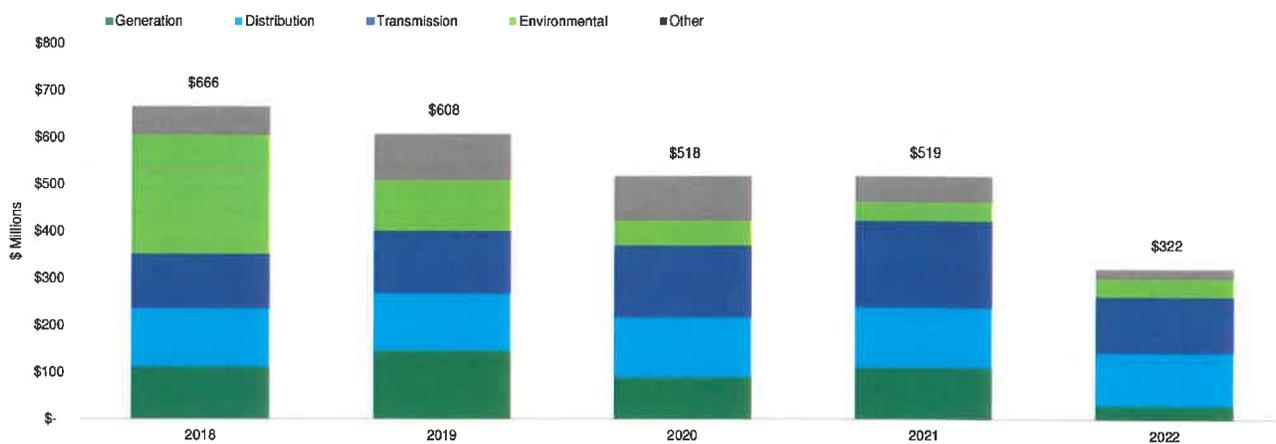
The last rate case in Virginia was filed in September 2017 and the new rates became effective in June 2018. A settlement was approved by the SCC and KU was authorized a \$1.8 million rate increase. KU had requested a \$6.7 million rate increase based on a 10.42% ROE and a 53.85% equity layer. The SCC staff had recommended a \$1.3 million rate increase based on a 9.2% ROE. Although the specifics of the settlement were not disclosed, the involved parties agreed that a ROE range of 9%-10% was reasonable. The primary reason for the filing was to recover costs related to environmental compliance. However, based on the settlement agreement reached, including the impact of the TCJA on rates, resulted with an outcome of a \$1.8 million rate increase.

Large capital investment plan over the next five years

Over the next five years, KU plans to spend approximately \$2.6 billion in capital expenditures, which is sizable considering the latest estimated value of its \$4 billion capitalization for ratemaking KU expects to invest. Approximately \$709 million will be spent on transmission facilities, \$615 million on distribution facilities, \$493 million on environmental, \$484 million on generating facilities, and \$332 million on other expenses. The total projected capital investment represents about 40% of KU's net book value of property, plant and equipment, which was about \$6.7 billion at the end of year end 2017.

Exhibit 5

Projected Capital Investment Plan



Source: Company Reports

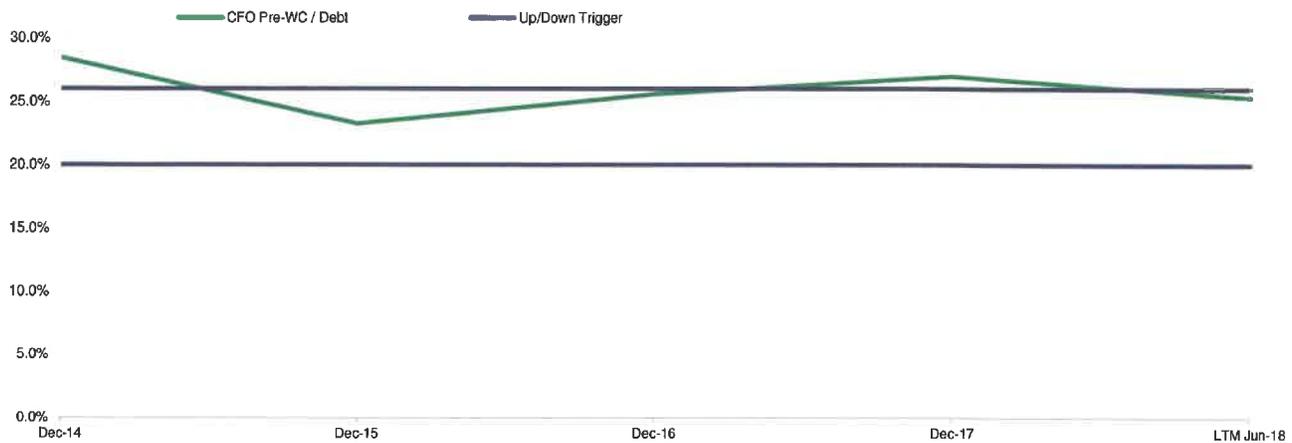
We expect the regulatory lag related to KU's large capital investment to be somewhat moderated by Kentucky's supportive regulatory environment, especially regarding the environmental expenditures through the ECR. The KPSC is also authorized to grant return on construction work in progress (CWIP) in rate case proceedings, a credit positive. Moreover, the ECR minimizes regulatory lag for investments associated with the coal combustion waste. The terms of the ECR allow KU to receive a return on and of investments two months after the capital is deployed. We view this to be credit supportive compared to the traditional rate-making process where there would be longer regulatory lag due to the length of the construction period and subsequent rate case proceedings.

Stable financial profile, but weakening credit metrics

KU has historically maintained a strong financial profile with its ratio of CFO pre-WC to debt in the mid-20% range. However, we expect metrics to slightly weaken to the low-20% range over the next 12-18 months. Metrics at these levels still position the company in-line with its credit profile. As of the last twelve months (LTM) period ending 30 June 2018, CFO pre-WC to debt was 25.3% and 25.1% on average for the past three years. The decline in metrics is caused by elevated capital investments as well as the negative impact of tax reform. However, prudent cost recovery mechanisms that are in place should result in timely recovery of investments and should help KU maintain its key credit metrics within the adequate ranges. Also, a capital contribution received from PPL of approximately \$45 million as of LTM 30 June 2018 has slightly helped mitigate the pressure on its cash flow.

Exhibit 6

KU's Historical CFO pre-WC to Debt vs Rating Triggers



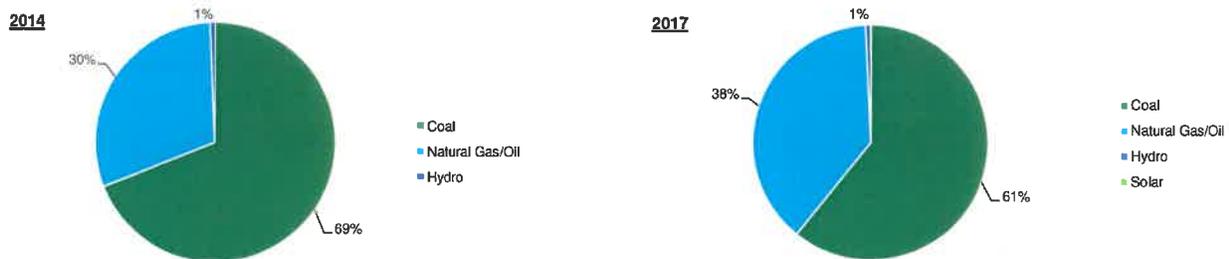
Source: Moody's Financial Metrics

Elevated carbon transition risk within the regulated utility sector

KU has elevated carbon transition risk within the US regulated utility sector because it is a vertically integrated utility that has a large, fossil based, installed generation capacity. Kentucky's political and regulatory environment is supportive of coal mining and related industries. KU has a total generation capacity of 5.1 GW, and 3.1 GW (61%) is coal-fired, which provides the majority (82%) of the electricity generation output. The remaining 18% of the generating capacity is comprised mainly of gas/oil-fired, hydro, and solar facilities. KU's generation fuel mix became more diversified when a new gas-fired power plant replaced its older coal-fired power plants. When Cane Run 7, a 660 MW power plant, became operational in June 2015. It replaced three older coal-fired plants which had a combined generating capacity of 797 MW.

Exhibit 7

KU Generation Mix (MW)



Source: Company reports

Fuel concentration in coal is typically considered to be a significant credit negative. However, we do not view KU's high reliance on coal to be as negative as some other companies because the state of Kentucky is very supportive of the coal industry. This support is evidenced by the ECR, which provides the company with credit supportive terms for its investments in coal-related environmental expenditures. However, KU is exposed to the risk of potentially needing to make a more rapid transition to clean energy in the future if carbon policies change.

Liquidity analysis

We expect KU to maintain an adequate but weakened liquidity profile over the next 12-18 months. KU has a P-2 short-term commercial program rating.

KU's liquidity is supported by a \$400 million syndicated credit facility that expires in January 2023 and a \$198 million letter of credit facility expiring in October 2020. As of 30 June 2018, the credit facility had \$267 million of available capacity. KU's credit facility

contains one financial covenant, a limitation on the ratio of debt to capitalization of 70%, which the company was in compliance with at the end of the second quarter of 2018. The facility does not contain a material adverse change clause.

Over the LTM period ending 30 June 2018, KU generated cash flow from operations of approximately \$661 million, spent about \$531 million in capital investments and paid \$252 million in dividends, resulting in a negative free cash flow of approximately \$122 million. The shortfall was partially financed with equity contributions from the parent. Due to the high level of planned capital investments, we expect KU to remain in a negative free cash flow position over the next 12-18 months.

KU's next long-term debt maturity is \$500 million of senior secured notes maturing in November 2020.

LG&E and KU Energy (LKE), the intermediate parent company of KU, manages the liquidity of its utility operations through its two subsidiaries on a consolidated basis, although each utility has a separate credit facility. Also, the \$75 million syndicated credit facility at LKE expires on 30 October 2018 and LG&E has a separate \$500 million syndicated credit facility maturing in January 2023. As of 30 June 2018, LG&E had \$317 million available. Also, LG&E's \$200 million term loan due October 2019 became current. LG&E's facility contains a financial covenant requiring that the companies' debt to total capitalization not exceed 70%. All entities were in compliance as of 30 June 2018.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors		Current LTM 6/30/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Kentucky Utilities Co. -Private					
Regulated Electric and Gas Utilities Industry Grid [1][2]					
Factor	Measure	Score	Measure	Score	
Factor 1 : Regulatory Framework (25%)					
a)	Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b)	Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)					
a)	Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b)	Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)					
a)	Market Position	Baa	Baa	Baa	Baa
b)	Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)					
a)	CFO pre-WC + Interest / Interest (3 Year Avg)	7.3x	Aa	6x - 7x	Aa
b)	CFO pre-WC / Debt (3 Year Avg)	25.1%	A	20% - 24%	Baa
c)	CFO pre-WC – Dividends / Debt (3 Year Avg)	15.8%	Baa	10% - 15%	Baa
d)	Debt / Capitalization (3 Year Avg)	35.9%	A	36% - 39%	A
Rating:					
Grid-Indicated Rating Before Notching Adjustment		A3		A3	
HoldCo Structural Subordination Notching		0		0	
a)	Indicated Rating from Grid	A3		A3	
b)	Actual Rating Assigned	A3		A3	

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 06/30/2018(L)

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Appendix

Exhibit 9

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-14	Dec-15	Dec-16	Dec-17	LTM Jun-18
As Adjusted					
FFO	679	641	652	689	667
+/- Other	(2)	(74)	(36)	(30)	(30)
CFO Pre-WC	677	567	616	659	637
+/- ΔWC	(102)	50	(1)	(15)	24
CFO	575	617	615	644	661
- Div	148	153	248	226	252
- Capex	613	528	359	442	531
FCF	(186)	(64)	8	(24)	(122)
(CFO Pre-W/C) / Debt	28.5%	23.2%	25.6%	27.0%	25.3%
(CFO Pre-W/C - Dividends) / Debt	22.2%	17.0%	15.3%	17.7%	15.3%
FFO / Debt	28.6%	26.3%	27.1%	28.2%	26.5%
RCF / Debt	22.3%	20.0%	16.8%	19.0%	16.5%
Revenue	1,737	1,728	1,749	1,744	1,786
Cost of Goods Sold	1,070	1,013	945	929	960
Interest Expense	78	84	98	97	99
Net Income	220	234	265	259	288
Total Assets	7,741	8,055	8,129	8,298	8,397
Total Liabilities	4,557	4,793	4,830	4,964	4,992
Total Equity	3,184	3,262	3,299	3,334	3,405

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 10

Peer Comparison Table [1]

(In US millions)	Kentucky Utilities Co.			Kentucky Power Company			Black Hills Power, Inc.			Empire District Electric Company (The)		
	A3 Stable			Baa2 Negative			A3 Stable			Baa1 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
	Dec-16	Dec-17	Jun-18	Dec-16	Dec-17	Jun-18	Dec-16	Dec-17	Jun-18	Dec-16	Dec-17	Jun-18
Revenue	1,749	1,744	1,786	655	643	659	268	288	293	613	627	682
CFO Pre-W/C	616	659	637	110	150	136	87	87	96	210	202	258
Total Debt	2,411	2,440	2,515	936	934	940	354	351	351	927	893	894
CFO Pre-W/C / Debt	25.6%	27.0%	25.3%	11.7%	16.1%	14.5%	24.5%	24.7%	27.5%	22.7%	22.7%	28.8%
CFO Pre-W/C - Dividends / Debt	15.3%	17.7%	15.3%	7.0%	12.3%	12.6%	9.6%	12.7%	12.7%	17.8%	18.6%	21.9%
Debt / Capitalization	35.0%	37.7%	38.0%	41.3%	46.8%	45.8%	37.4%	41.2%	41.4%	42.6%	44.9%	44.7%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
KENTUCKY UTILITIES CO.	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Bkd LT IRB/PC	A1
Commercial Paper	P-2
Bkd Other Short Term	P-2
ULT PARENT: PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
PARENT: LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1

Source: Moody's Investors Service

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454



CREDIT OPINION

25 October 2019

Update

Rate this Research

RATINGS

Kentucky Utilities Co.

Domicile	Lexington, Kentucky, United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Kentucky Utilities Co.

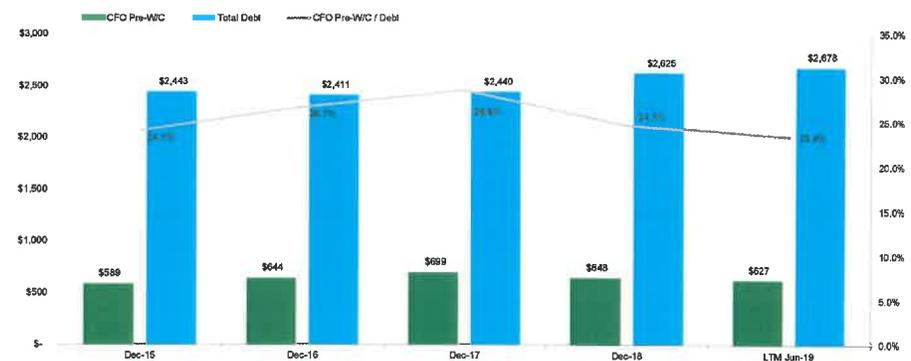
Update to credit analysis

Summary

Kentucky Utilities' (KU) credit reflects its supportive regulatory relationships in the states of Kentucky and Virginia, where it has utility operations. KU has stable utility operations that have produced relatively consistent credit metrics historically. KU represents approximately 23% of the cash flow to its ultimate parent company, PPL Corporation (PPL). Going forward, we believe that KU's large capital investment plan may pressure the ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt to a 22% to 24% range, which is slightly weaker than its historical level. To a lesser extent, KU's positive factors are also somewhat offset by a lack of fuel and geographic diversity.

The Kentucky and Virginia regulatory environments are supportive due to their transparent recovery framework. KU has been allowed various tracker mechanisms by the regulatory commissions, providing timely cost recovery, and has been active in its general rate case filings. In April 2019, KU reached a settlement in an electric rate case for a \$56 million rate increase by the Kentucky Public Service Commission (KPSC). In July 2019, KU filed for an electric rate case in Virginia, requesting a \$13 million rate increase. Its last rate case in Virginia concluded in May 2018. The final decision from the Virginia State Corporation Commission (SCC) is expected by April 2020.

Exhibit 1
Historical CFO pre-WC, Total Debt and CFO pre-WC to Debt(\$MM)



Source: Moody's Financial Metrics

Credit strengths

- » Supportive regulatory environment in Kentucky and Virginia
- » Stable financial profile with transparent and predictable cash flows

Credit challenges

- » Slightly pressured credit metrics due to large capital investment program
- » High coal concentration in its generation fuel mix
- » Elevated carbon transition risk relative to its peers

Rating outlook

The stable outlook reflects our expectation that the regulatory environments in Kentucky and Virginia will remain consistent and supportive. The stable outlook also incorporates our view that KU will continue to generate stable cash flow and adequate financial metrics while it executes a large capital investment program, including a ratio of CFO pre-WC to debt in the 22%-24% range.

Factors that could lead to an upgrade

KU's rating could be upgraded if its financial metrics increase, including CFO pre-WC to debt at or above 26% on a sustained basis. An upgrade is also possible if KU's regulatory environment materially improves, providing more favorable regulatory recovery mechanisms. However, it is unlikely that KU's rating will be upgraded while the company executes on its large capital investment program.

Factors that could lead to a downgrade

KU's ratings could be downgraded if there is a significant deterioration in the credit supportiveness of the regulatory environments. Additionally, KU's rating could be downgraded if its financial metrics weaken, such that CFO pre-WC to debt declines below 20% for an extended period of time.

Key indicators

Kentucky Utilities Co. [1]

	Dec-15	Dec-16	Dec-17	Dec-18	LTM Jun-19
CFO Pre-W/C + Interest / Interest	8.1x	7.6x	8.2x	7.4x	6.9x
CFO Pre-W/C / Debt	24.1%	26.7%	28.6%	24.7%	23.4%
CFO Pre-W/C – Dividends / Debt	17.9%	16.4%	19.4%	15.3%	15.9%
Debt / Capitalization	36.2%	35.0%	37.7%	38.7%	38.3%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Kentucky Utilities (KU) is a wholly owned regulated public utility subsidiary of LG&E and KU Energy LLC (LKE, Baa1 stable) that is engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 527,000 customers in 77 counties of Kentucky and 28,000 customers in five counties of Virginia. KU is regulated by the Kentucky Public Service Commission and the Virginia State Corporate Commission.

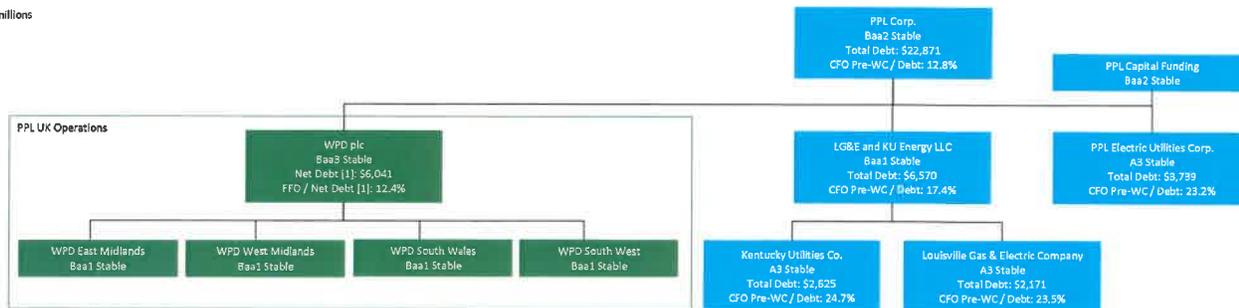
KU and its affiliate, Louisville Gas and Electric Company (LG&E, A3 stable), are the two main operating entities of LKE. LKE is wholly owned by PPL Corporation (PPL, Baa2 stable), a diversified utility holding company headquartered in Allentown, PA.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moody's.com for the most updated credit rating action information and rating history.

Exhibit 3

Organizational structure
As of 12/31/2018

\$ in millions



[1] As of 3/31/2019; CFO Pre-WC to Debt is not a key metric we use for WPD and subsidiaries. WPD and subsidiaries are assessed under the Regulated Electric and Gas Networks Industry Grid.

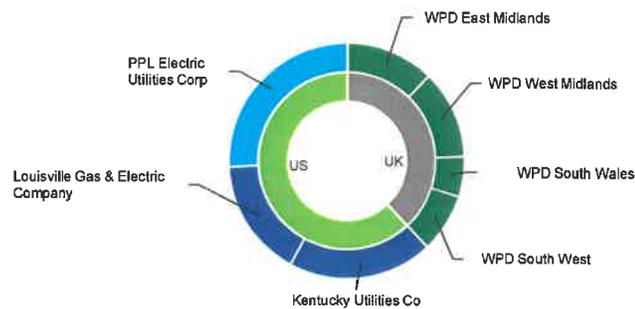
[2] Metrics are based on 'adjusted' financial data and incorporate Moody's Global Standard Adjustments for non-financial corporations.

Source: Moody's Financial Metrics

Exhibit 4

PPL's rate base breakdown between the US and UK jurisdictions

- Regulated network
- Regulated utility without generation
- Regulated utility with generation



Source: Company Reports

Detailed credit considerations

Robust regulatory activities continue supportive regulatory environment in Kentucky and Virginia

KU is a regulated electric and gas utility that has operations in Kentucky and Virginia and is regulated by the KPSC and the SCC, respectively. We view the regulatory frameworks provided by Kentucky and Virginia to be constructive and supportive. In Kentucky, the KPSC has approved various tracker mechanisms, allowing timely cost recovery of certain utility investments outside of a rate case, a credit positive. KU's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management (DSM) Cost Recovery Mechanism. KU does not have a decoupling mechanism in place, which subjects KU's revenue to some volatility. However, the impact on its revenue due to non-weather related demand fluctuations is minimized because of the DSM mechanism.

KU's latest electric rate case in Kentucky concluded in April 2019 when a settlement was reached and approved. The settlement authorized a \$56 million revenue increase compared to its initial \$112 million increase requested in September 2018. The revenue increase was based on a 9.73% return on equity (ROE) versus the initial request of 10.42%. The settlement did not specify the allowed equity layer.

In March 2018, the KPSC required KU's rates to be reduced by \$108 million over the period between April 2018 and April 2019 to account for the impact of the federal tax reform. In September 2018, the KPSC adopted a revised tax-related rate reduction of \$101 million for KU. In the latest Kentucky rate case filing, KU was also looking to terminate the Tax Cuts and Jobs Act (TCJA) bill credit

mechanism once new rates were in effect. The termination was approved, which represented a total annual revenue increase of \$114 million at KU, effective as of May 2019.

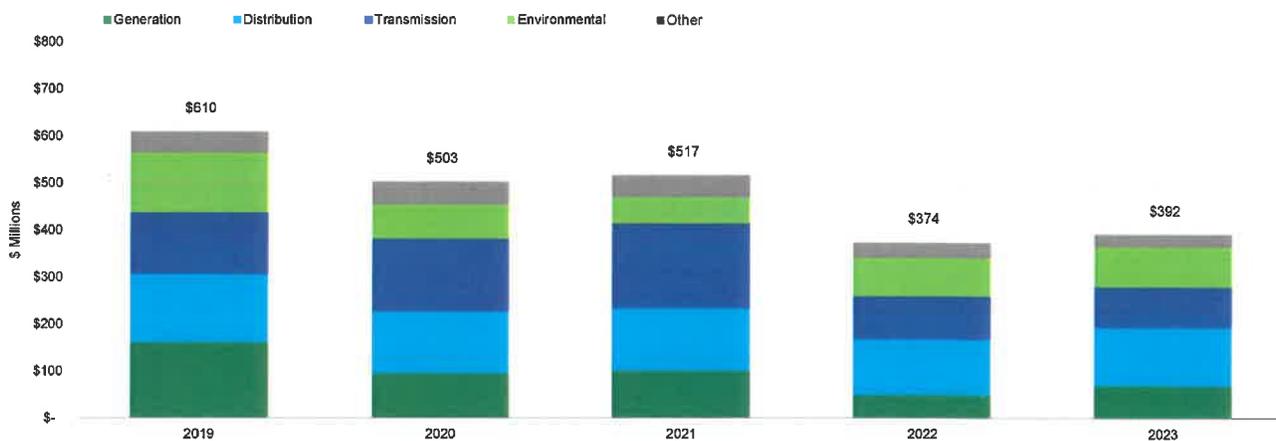
In July 2019, KU filed for an electric rate case in Virginia, requesting a revenue increase of approximately \$13 million. KU is also requesting an allowed ROE of 10.5% and an equity layer of 54.04%. The final decision is expected by April 2020. The last rate case in Virginia was filed in September 2017 and the latest rates became effective in June 2018 when a settlement of \$1.75 million was approved by the SCC. KU had requested a \$6.7 million rate increase based on a 10.42% ROE and a 53.85% equity layer. The SCC staff had recommended a \$1.3 million rate increase based on a 9.2% ROE. Although the specifics of the settlement were not disclosed, the involved parties agreed that a ROE range of 9%-10% was reasonable.

Large capital investment plan in the near-term

KU is currently in the midst of a large capital investment plan and expects to spend approximately \$2.4 billion, including capital expenditure under mechanisms over the next five years. KU's latest estimated value of its capitalization for ratemaking purpose excluding the amount mechanism capitalization was approximately \$4 billion. Approximately \$650 million will be spent on transmission facilities, \$651 million on distribution facilities, \$421 million on environmental, \$474 million on generating facilities, and \$200 million on other expenses. The total projected capital investment represents about 34% of KU's net book value of property, plant and equipment, which was about \$7 billion at the end of 2018.

Exhibit 5

Projected Capital Investment Plan



Source: Company Reports

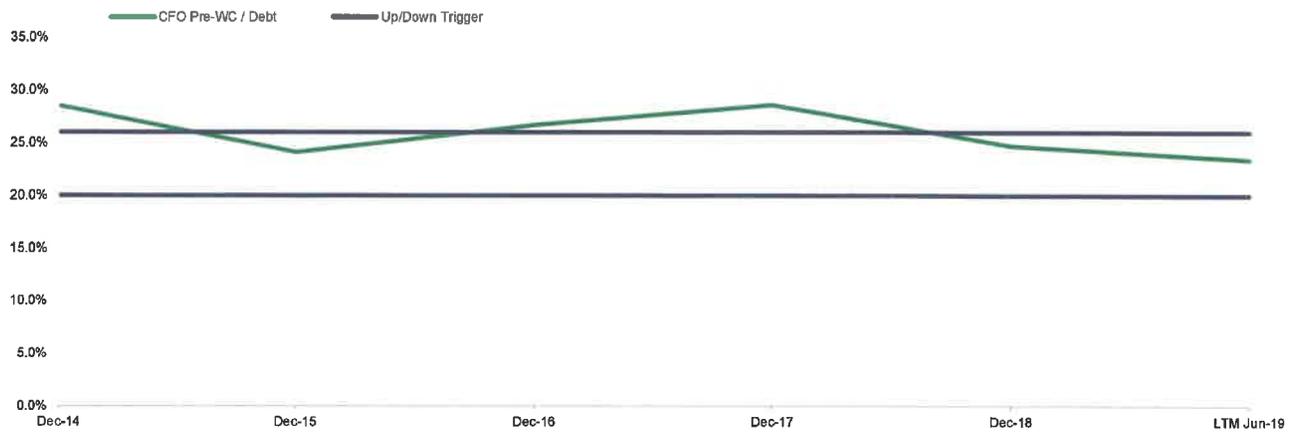
We expect regulatory lag related to KU's large capital investment to be somewhat moderated by Kentucky's supportive regulatory environment, especially regarding environmental expenditures through the ECR. The KPSC is also authorized to grant a return on construction work in progress (CWIP) in rate case proceedings, a credit positive. Moreover, the ECR minimizes regulatory lag for investments associated with the coal combustion waste. The terms of the ECR allow KU to receive a return on and of investments two months after the capital is deployed. We view this to be credit supportive compared to the traditional rate-making process where there would be longer regulatory lag due to the length of the construction period and subsequent rate case proceedings.

Stable financial profile, but credit metrics slightly pressured

KU has historically maintained a strong financial profile with its ratio of CFO pre-WC to debt in the mid to high 20% range. However, we expect metrics to slightly weaken to the low to mid 20% range over the next 12-18 months. KU's metrics are currently and will remain appropriately positioned its credit profile. As of the last twelve month (LTM) period ending 30 June 2019, CFO pre-WC to debt was 23.4% and 26.2% on average for the past three years. The decline in metrics is caused by elevated capital investments as well as the negative impact of tax reform. However, prudent cost recovery mechanisms that are in place should result in timely recovery of investments and should help KU maintain its key credit metrics within the adequate ranges. Also, capital contributions received from LKE of approximately \$68 million as of LTM 30 June 2019 has slightly helped mitigate the pressure on its cash flow.

Exhibit 6

KU's Historical CFO pre-WC to Debt vs Financial Metric Upgrade/Downgrade Thresholds



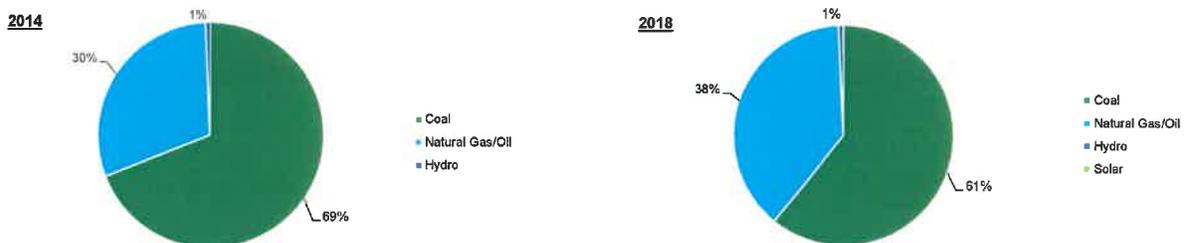
Source: Moody's Financial Metrics

Environmental, social and governance considerations

KU has elevated carbon transition risk within the US regulated utility sector because it is a vertically integrated utility that has a large, fossil based generation capacity. Kentucky's political and regulatory environment is supportive of coal mining and related industries. KU has a total generation capacity of 5.1 GW, and 3.1 GW (61%) is coal-fired, which provides the majority (77%) of the electricity generation output. The remaining 23% of the generating capacity is comprised mainly of gas/oil-fired, hydro, and solar facilities. KU's generation fuel mix became more diversified when a new gas-fired power plant replaced some older coal-fired power plants. When Cane Run 7, a 660 MW power plant, became operational in June 2015, it replaced three older coal-fired plants which had a combined generating capacity of 797 MW. Due to environmental requirements and energy efficiency measures, KU retired two older coal units at the E.W Brown plant in the first quarter of 2019 with a combined capacity of ~300 MW.

Exhibit 7

KU Generation Mix (MW)



Source: Company reports

Fuel concentration in coal is typically considered to be a significant credit negative. However, we do not view KU's high reliance on coal to be as negative as some other companies because the state of Kentucky is very supportive of the coal industry. This support is evidenced by the ECR, which provides the company with credit supportive terms for its investments in coal-related environmental expenditures. However, KU is exposed to the risk of potentially needing to make a more rapid transition to clean energy in the future if carbon policies change.

Liquidity analysis

We expect KU to maintain an adequate liquidity profile over the next 12-18 months. Although the utility has an elevated capital investment program over the next few years, we anticipate its liquidity will be supported by relatively stable and predictable cash flows and good access to capital markets.

KU's liquidity is supported by a \$400 million syndicated credit facility that expires in January 2024. As of 30 June 2019, the credit facility had \$400 million of available capacity. KU's credit facility contains one financial covenant, a limitation on the ratio of debt to capitalization of 70%, which the company was in compliance with at the end of the second quarter of 2019. The facility does not contain a material adverse change clause.

Over the LTM period ending 30 June 2019, KU generated cash flow from operations of approximately \$577 million, spent about \$601 million in capital investments and paid \$201 million in dividends, resulting in a negative free cash flow of approximately \$225 million. The shortfall was partially financed with equity contributions from the parent. Due to the high level of planned capital investments, we expect KU to remain in a negative free cash flow position over the next 12-18 months.

KU's next long-term debt maturity is \$500 million of senior secured notes maturing in November 2020.

LG&E and KU Energy (LKE), the intermediate parent company of KU, manages the liquidity of its two subsidiaries on a consolidated basis, although each utility has a separate credit facility. LG&E has a separate \$500 million syndicated credit facility maturing in January 2024. As of 30 June 2019, LG&E had \$404 million available. LG&E's facility contains a financial covenant requiring that the companies' debt to total capitalization not exceed 70%. All entities were in compliance as of 30 June 2019.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 6/30/2019	Moody's 12-18 Month Forward View As of Date Published [3]
Factor 1 : Regulatory Framework (25%)	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A
b) Consistency and Predictability of Regulation	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)		
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa
b) Sufficiency of Rates and Returns	A	A
Factor 3 : Diversification (10%)		
a) Market Position	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa
Factor 4 : Financial Strength (40%)		
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.6x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	26.2%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	17.1%	A
d) Debt / Capitalization (3 Year Avg)	37.1%	A
Rating:		
Scorecard-Indicated Outcome Before Notching Adjustment	A2	A3
HoldCo Structural Subordination Notching	0	0
a) Scorecard-Indicated Outcome	A2	A3
b) Actual Rating Assigned	A2	A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 06/30/2019 (L)

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Appendix

Exhibit 9
Cash Flow and Credit Metrics [1]

CF Metrics	Dec-15	Dec-16	Dec-17	Dec-18	LTM Jun-19
As Adjusted					
FFO	641	652	687	649	677
+/- Other	(52)	(8)	12	(1)	(50)
CFO Pre-WC	589	644	699	648	627
+/- ΔWC	50	(1)	(13)	47	31
CFO	639	643	686	695	658
- Div	153	248	226	246	201
- Capex	528	359	442	572	611
FCF	(42)	36	18	(123)	(154)
(CFO Pre-W/C) / Debt	24.1%	26.7%	28.6%	24.7%	23.4%
(CFO Pre-W/C - Dividends) / Debt	17.9%	16.4%	19.4%	15.3%	15.9%
FFO / Debt	26.3%	27.1%	28.1%	24.7%	25.3%
RCF / Debt	20.0%	16.8%	18.9%	15.4%	17.8%
Revenue	1,728	1,749	1,744	1,760	1,731
Cost of Good Sold	1,013	945	928	967	930
Interest Expense	84	98	97	102	106
Net Income	234	265	259	286	280
Total Assets	8,055	8,129	8,298	8,588	8,691
Total Liabilities	4,793	4,830	4,964	5,167	5,151
Total Equity	3,262	3,299	3,334	3,421	3,540

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 10
Peer Comparison Table [1]

(In US millions)	Kentucky Utilities Co.			Kentucky Power Company			Black Hills Power, Inc.			Empire District Electric Company (The)		
	A3 Stable			Baa3 Stable			A3 Stable			Baa1 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
	Dec-17	Dec-18	Jun-19	Dec-17	Dec-18	Mar-19	Dec-17	Dec-18	Jun-19	Dec-17	Dec-18	Jun-19
Revenue	1,744	1,760	1,731	643	642	635	288	298	302	627	698	662
CFO Pre-W/C	699	648	627	150	95	97	87	95	90	202	265	239
Total Debt	2,440	2,625	2,678	934	951	959	364	438	403	893	912	908
CFO Pre-W/C / Debt	28.6%	24.7%	23.4%	16.1%	10.0%	10.1%	23.8%	21.7%	22.4%	22.7%	29.0%	26.3%
CFO Pre-W/C - Dividends / Debt	19.4%	15.3%	15.9%	12.3%	10.0%	10.1%	12.3%	13.5%	19.9%	18.6%	18.6%	17.5%
Debt / Capitalization	37.7%	38.7%	38.3%	46.8%	45.6%	45.3%	42.1%	45.9%	42.5%	44.9%	44.9%	44.6%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
KENTUCKY UTILITIES CO.	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Bkd LT IRB/PC	A1
Commercial Paper	P-2
Bkd Other Short Term	P-2
ULT PARENT: PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
PARENT: LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1

Source: Moody's Investors Service

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Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454



CREDIT OPINION

23 October 2020

Update

Rate this Research

RATINGS

Kentucky Utilities Co.

Domicile	Lexington, Kentucky, United States
Long Term Rating	A3
Type	iT issuer Rating
Outlook	Stable

Please see the [ratings section](#) at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Kentucky Utilities Co.

Update to credit analysis

Summary

Kentucky Utilities' (KU) credit strengths include its supportive regulatory environments in the states of Kentucky and Virginia. Historically, KU has produced relatively consistent credit metrics due to stable utility operations, and represents approximately 22% of the cash flow of its ultimate parent company, PPL Corporation (PPL). Going forward, we believe that KU's large capital investment plan will pressure the ratio of cash flow from operations before changes in working capital (CFO pre-WC) to debt to the 22% to 24% range, which is weaker than its historical level. To a lesser extent, KU's positive credit factors are also somewhat offset by a lack of fuel and geographic diversity.

The supportive regulatory environments of Kentucky and Virginia have a transparent recovery framework. The regulatory commissions have allowed KU various tracker mechanisms, providing timely cost recovery, and KU has been active in its general rate case filings over the last two years. In July 2019, KU filed for an electric rate case in Virginia, requesting a \$13 million rate increase. The Virginia State Corporation Commission (SCC) authorized a \$9 million rate increase in April 2020. Its last rate case in Virginia concluded in May 2018.

Recent developments

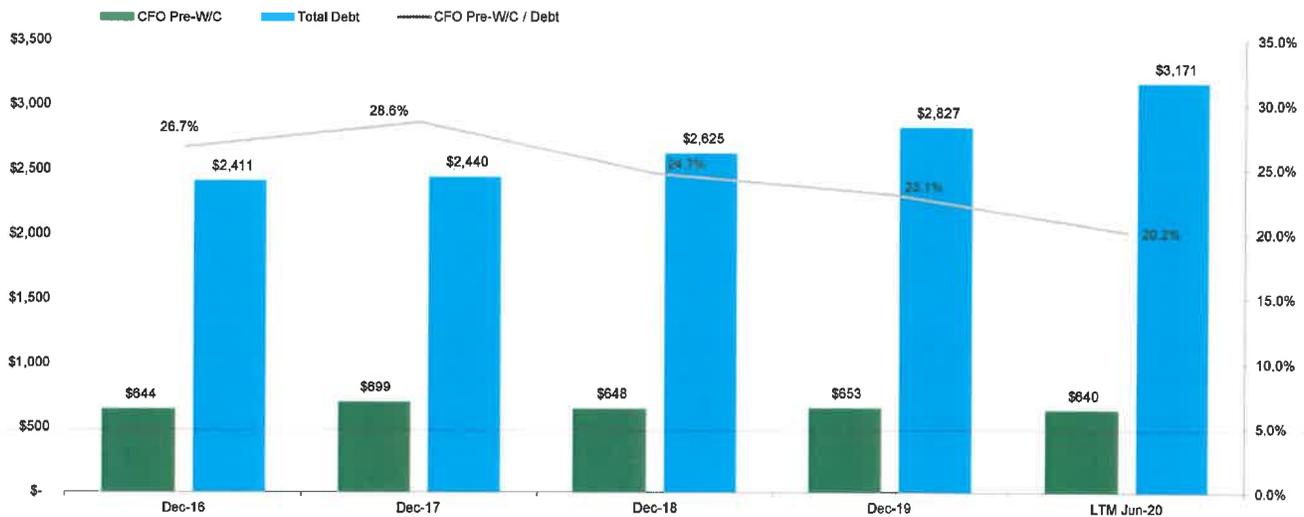
In August 2020, PPL, KU's parent company, announced that it had initiated a process to sell its utility assets in the United Kingdom that have a total estimated rate base of around \$10 billion and approximately \$8 billion of debt. If PPL is successful in divesting its UK assets, we estimate its Kentucky operations will proportionally increase to more than half of rate base from around 37%. Due to their vertically integrated utility business models with coal as the primary fuel source for its generation in Kentucky, we would view PPL's overall business risk to be higher.

The rapid spread of the coronavirus outbreak, severe global economic shock and asset price volatility are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented. We regard the coronavirus outbreak as a social risk under our ESG framework, given the substantial implications for public health and safety.

We expect KU to be relatively resilient to recessionary pressures related to the coronavirus because of its rate regulated business model and timely cost recovery mechanisms. Nevertheless, we are watching for electricity usage declines, utility bill payment delinquency, and the regulatory response to counter these effects on earnings and cash flow. As events related to the coronavirus continue, we are taking into consideration a wider range of potential outcomes, including more severe downside scenarios. The effects of the pandemic

could result in financial metrics that are weaker than expected; however, we see these issues as temporary and not reflective of the long-term financial profile or credit quality of KU.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt (\$ MM)

Source: Moody's Financial Metrics

Credit strengths

- » Supportive regulatory frameworks in Kentucky and Virginia
- » Overall stable profile with transparent and predictable cash flows

Credit challenges

- » Slightly pressured credit metrics due to large capital investment program
- » High coal concentration in its generation fuel mix
- » Elevated carbon transition risk relative to its peers

Rating outlook

KU's stable outlook reflects our expectation that the regulatory environments in Kentucky and Virginia will remain consistent and supportive. The stable outlook also incorporates our view that KU will continue to generate stable cash flow and adequate financial metrics while it executes a large capital investment program.

Factors that could lead to an upgrade

KU's rating could be upgraded if its financial metrics increase, including CFO pre-WC to debt at or above 26% on a sustained basis. An upgrade is also possible if KU's regulatory environment materially improves, providing more favorable regulatory recovery mechanisms. However, it is unlikely that KU's rating will be upgraded while the company is in the midst of a large capital investment program.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moody's.com for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

KU's ratings could be downgraded if there is a significant deterioration in the credit supportiveness of the regulatory environments. Additionally, KU's rating could be downgraded if its financial metrics weaken, such that CFO pre-WC to debt declines below 20% for an extended period of time.

Key indicators

Exhibit 2

Kentucky Utilities Co. [1]

	Dec-16	Dec-17	Dec-18	Dec-19	LTM Jun-20
CFO Pre-W/C + Interest / Interest	7.6x	8.2x	7.4x	6.9x	6.6x
CFO Pre-W/C / Debt	26.7%	28.6%	24.7%	23.1%	20.2%
CFO Pre-W/C – Dividends / Debt	16.4%	19.4%	15.3%	15.0%	13.0%
Debt / Capitalization	35.0%	37.7%	38.7%	39.4%	41.6%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Financial Metrics™

Source: Moody's Financial Metrics

Profile

Kentucky Utilities (KU) is a wholly owned regulated public utility subsidiary of LG&E and KU Energy LLC (LKE, Baa1 stable) that is engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 530,000 customers in 77 counties of Kentucky and 28,000 customers in five counties of Virginia. KU is regulated by the Kentucky Public Service Commission (KPSC) and the Virginia State Corporate Commission (VSCC).

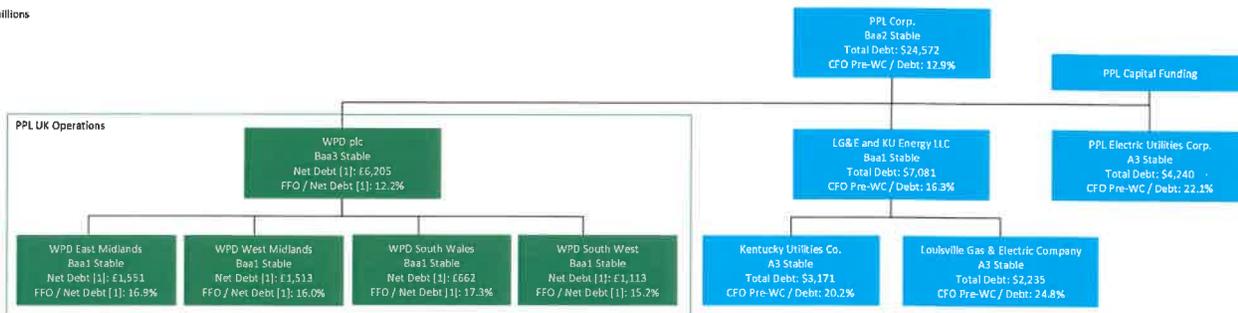
KU and its affiliate, Louisville Gas and Electric Company (LG&E, A3 stable), are the two main operating entities of LKE. LKE is wholly owned by PPL Corporation (PPL, Baa2 stable), a diversified utility holding company headquartered in Allentown, PA.

Exhibit 3

Organizational structure

As of LTM 6/30/2020

\$ in millions



[1] As of 3/31/2020; CFO Pre-WC to Debt is not a key metric we use for WPD and subsidiaries. WPD and subsidiaries are assessed under the Regulated Electric and Gas Networks Industry Grid.

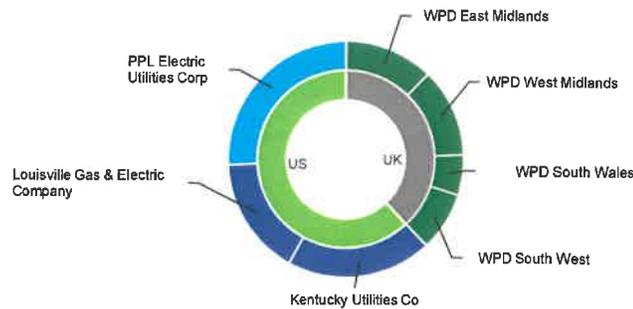
[2] Metrics are based on 'adjusted' financial data and incorporate Moody's Global Standard Adjustments for non-financial corporations.

Source: Moody's Financial Metrics

Exhibit 4

PPL's rate base breakdown between the US and UK jurisdictions

- Regulated network
- Regulated utility without generation
- Regulated utility with generation



Source: Company Reports

Detailed credit considerations

Supportive regulatory environments in Kentucky and Virginia

We view the regulatory frameworks provided by Kentucky, where it has most of its operations, and Virginia to be supportive. The KPSC has approved various tracker mechanisms that provide timely recovery of costs outside of a general rate case. Some of the authorized tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR), and a Demand-Side Management (DSM) Cost Recovery Mechanism. The Kentucky operating utilities do not have decoupling mechanisms in place, which subjects KU's revenue to some volatility. However, the impact of non-weather related demand fluctuations on its revenue is minimized because of the DSM mechanism.

KU's latest electric rate case in Kentucky concluded in April 2019 when a settlement was reached and approved. The settlement authorized a \$56 million revenue increase compared to the initial \$112 million increase requested in September 2018. The revenue increase was based on a 9.725% return on equity (ROE) versus the initial request of 10.42%. Also, the KPSC approved the termination of the Tax Cuts and Jobs Act (TCJA) bill credit mechanism, which was used to reduce both electric rates to reflect the impact of the tax reform. With the new rates from the latest rate case implemented, the termination was implemented. This represented a total annual revenue increase of \$114 million for KU, effective as of May 2019.

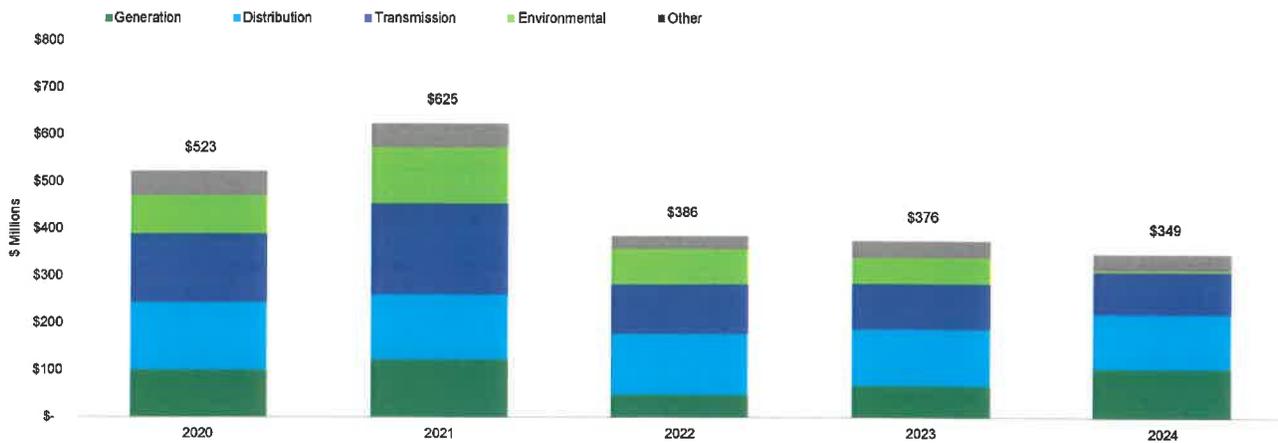
In July 2019, KU filed for an electric rate case in Virginia where it has a smaller operation. The company requested a revenue increase of approximately \$13 million based on an allowed ROE of 10.5% and an equity layer of 54.04%. In April 2020, the VSCC authorized a rate increase of \$9 million as a result of an approved settlement. The settlement did not specify the allowed ROE and equity layer. Although the specifics of the settlement were not disclosed, the parties involved agreed that a ROE range of 9%-10% was reasonable.

Large capital investment plan in the near-term

KU is currently in the midst of a large capital investment plan and expects to spend approximately \$2.3 billion, including capital expenditure under cost recovery mechanisms, over the next five years. Approximately \$632 million will be spent on transmission facilities, \$648 million on distribution facilities, \$335 million on environmental, \$441 million on generating facilities, and \$203 million on other expenses. The total projected capital investment represents about 32% of KU's net book value of property, plant and equipment, which was about \$7.3 billion at the end of 2019.

Exhibit 5

Projected Capital Investment Plan



Source: Company Reports

We expect regulatory lag related to KU's capital investments to be somewhat moderated by Kentucky's supportive regulatory environment, especially regarding environmental investments through the ECR. The KPSC is also authorized to grant a return on construction work in progress (CWIP) in rate case proceedings, a credit positive. Moreover, the ECR minimizes regulatory lag for investments associated with the coal combustion waste. The terms of the ECR allow KU to receive a return on and of investments two months after the capital is deployed. We view this to be credit supportive compared to the traditional ratemaking process where there would be longer regulatory lag due to the length of the construction period and subsequent rate case proceedings.

Adequate overall financial profile, but credit metrics slightly pressured

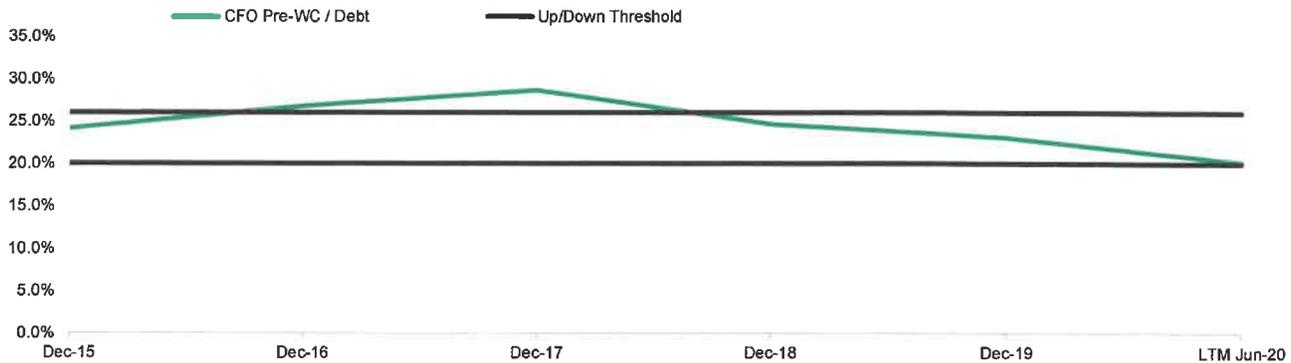
Historically, KU has maintained a strong financial profile with its ratio of CFO pre-WC to debt in the mid to high 20% range. However, we expect metrics to slightly weaken to the low to mid 20% range over the next 12-18 months. Furthermore, it is possible that metrics may weaken further due to the negative impact of the COVID pandemic. However, we do not expect the impact to be material because the utility experienced an increase in residential usage while commercial and industrial customer usage declined. In 2019, residential sales generated approximately 40% of KU's total revenue while commercial and industrial sales contributed the remainder.

KU's metrics are currently and will remain appropriately positioned its credit profile. As of the last twelve month (LTM) period ending 30 June 2020, CFO pre-WC to debt was 20.2%, or 23.7% on average for the past three years. KU's debt level in the first half of 2020 was higher due to the early refinancing of a 2020 maturity. In June 2020, KU issued \$500 million of first mortgage bonds in advance to fund its \$500 million first mortgage bond maturing in November 2020. The series that was to mature in November was redeemed at par in August 2020.

We expect KU's metrics to be pressured due to elevated capital investments over the next 18 - 24 months. However, prudent cost recovery mechanisms that are in place should result in timely recovery of investments and should help KU maintain key credit metrics within the adequate ranges. Also, capital contributions received from LKE of approximately \$37 million as of LTM 30 June 2020 has modestly helped mitigate the pressure on its cash flow.

Exhibit 6

KU's Historical CFO pre-WC to Debt vs Financial Metric Upgrade/Downgrade Thresholds



The financial metric threshold indicated are one of several factors that could result in an upgrade or downgrade of the ratings if they are above or below that level for a sustained period. Source: Moody's Financial Metrics

ESG considerations

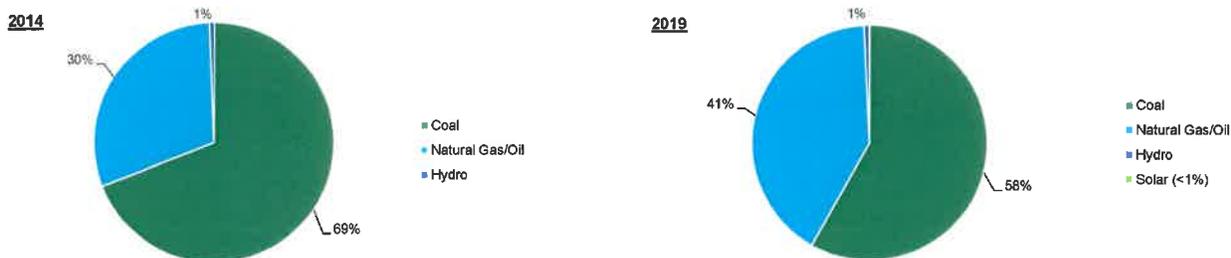
Environmental

KU has elevated carbon transition risk within the US regulated utility sector because it is a vertically integrated utility that has a large, fossil based generation capacity. Kentucky's political and regulatory environment is supportive of coal mining and related industries. KU has a total generation capacity of 4.8 GW, and 2.8 GW (58%) is coal-fired, which provides the majority (73%) of the electricity generation output. The remaining 27% of the generating capacity is comprised mainly of gas/oil-fired, hydro, and solar facilities. KU's generation fuel mix became more diversified when a new gas-fired power plant, the 660 MW Cane Run 7 plant, became operational in June 2015. It replaced three older coal-fired plants which had a combined generating capacity of 797 MW. Due to environmental requirements and energy efficiency measures, KU retired two older coal units at the E.W Brown plant in the first quarter of 2019 with a combined capacity of 272 MW.

KU and LG&E received approval from the KPSC to develop a 4 MW solar facility to service a solar share program. The solar share program is a voluntary program that allows customers to subscribe capacity in the solar share facility. In January 2020, KU and LG&E requested approval from the KSPC for the purchase of 100 MW of solar power in connection with the green tariff option established in the most recent Kentucky rate cases. KSPC has approved the solar contract subject to changes. LG&E and KU will purchase the initial 20 years of output of a proposed third-party solar generation facility and resell the majority of the power as renewable energy to two large industrial customers and use the remaining power for other customers.

Exhibit 7

KU Generation Mix (MW)



Source: Company reports

Fuel concentration in coal is typically considered to be a significant credit negative. However, we do not view KU's high reliance on coal to be as negative as some other companies because the state of Kentucky is very supportive of the coal industry. This support is evidenced by the ECR, which provides the company with credit supportive terms for its investments in coal-related environmental

expenditures. However, KU is exposed to the risk of potentially needing to make a more rapid transition to clean energy in the future if carbon policies change.

PPL has enhanced transparency and disclosure, especially related to its environmental risks, over the last three years. PPL has published a 2019 sustainability report and has also set a more aggressive carbon reduction goal of at least 80% from 2010 levels by 2050 and has accelerated its previous 70% goal by 10 years to 2040. It also reiterated the assessment outcome for considering a two-degree scenario analysis based on the recommendations of the Task Force on Climate-Related Financial Disclosure (TCFD). Under these carbon regulation policy scenarios, PPL's analysis indicated that the CO2 emissions from the company's Kentucky utilities' generation assets would be reduced 45-90% from 2005 levels by 2050.

Social

Social risks are primarily related to KU's customer and regulatory relations as well as demographic and societal trends. KU's regulatory environment as well as its interaction with the KPSC and SCC are important in considering the company's social risk. Also, the safety and reliability of its operations are extremely important social considerations. Given recent developments related to the COVID-19 pandemic, there is a possibility of increasing social risk longer term as the affordability of the utility bill and prolonged recessionary impact have a negative impact on KU.

Governance

As a subsidiary of PPL, corporate governance considerations include the financial policy and risk management of its parent company. We note that a stable financial position is an important characteristic for managing environmental and social risks.

Liquidity analysis

We expect KU to maintain an adequate liquidity profile over the next 12-18 months. Although the utility has an elevated capital investment program over the next few years, we anticipate its liquidity will be supported by relatively stable and predictable cash flow and good access to capital markets.

KU's liquidity is supported by a \$400 million syndicated credit facility that expires in January 2024. As of 30 June 2020, the credit facility had \$400 million of available capacity. KU's credit facility contains one financial covenant, a limitation on the ratio of debt to capitalization of 70%, which the company was in compliance with at the end of the second quarter of 2020. The facility does not contain a material adverse change clause.

Over the LTM period ending 30 June 2020, KU generated cash flow from operations of approximately \$640 million, spent about \$581 million in capital investments and paid \$227 million in dividends, resulting in a negative free cash flow of approximately \$168 million. The shortfall was partially financed with equity contributions from the parent. Due to the high level of planned capital investments, we expect KU to remain in a negative free cash flow position over the next 12-18 months.

KU's next long-term debt puts are \$132 million of revenue bonds with a mandatory purchase in June 2021.

LG&E and KU Energy (LKE), the intermediate parent company of KU, manages the liquidity of its two subsidiaries on a consolidated basis, although each utility has a separate credit facility. LG&E has a separate \$500 million syndicated credit facility maturing in January 2024. As of 30 June 2020, LG&E had \$500 million available. LG&E's facility contains a financial covenant requiring that the companies' debt to total capitalization not exceed 70%. All entities were in compliance as of 30 June 2020.

Rating methodology and scorecard factors

Exhibit 8

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 6/30/2020		Moody's 12-18 Month Forward View As of Date Published [3]	
	Measure	Score	Measure	Score
Factor 1 : Regulatory Framework (25%)				
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.2x	Aa	6.5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	23.7%	A	22% - 24%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.6%	Baa	12% - 16%	Baa
d) Debt / Capitalization (3 Year Avg)	39.5%	A	37% - 40%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.

[2] As of 06/30/2020 (L)

[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

Source: Moody's Financial Metrics

Appendix

Exhibit 9
Cash Flow and Credit Metrics [1]

CF Metrics	Dec-16	Dec-17	Dec-18	Dec-19	LTM Jun-20
As Adjusted					
FFO	652	687	622	665	652
+/- Other	(8)	12	26	(12)	(12)
CFO Pre-WC	644	699	648	653	640
+/- ΔWC	(1)	(13)	47	(26)	-
CFO	643	686	695	627	640
- Div	248	226	246	229	227
- Capex	359	442	572	622	581
FCF	36	18	(123)	(224)	(168)
(CFO Pre-W/C) / Debt	26.7%	28.6%	24.7%	23.1%	20.2%
(CFO Pre-W/C - Dividends) / Debt	16.4%	19.4%	15.3%	15.0%	13.0%
FFO / Debt	27.1%	28.1%	23.7%	23.5%	20.6%
RCF / Debt	16.8%	18.9%	14.3%	15.4%	13.4%
Revenue	1,749	1,744	1,760	1,740	1,704
Cost of Good Sold	945	928	967	892	848
Interest Expense	98	97	102	110	113
Net Income	265	259	286	293	284
Total Assets	8,129	8,298	8,588	8,825	9,243
Total Liabilities	4,830	4,964	5,167	5,270	5,607
Total Equity	3,299	3,334	3,421	3,555	3,636

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 10
Peer Comparison Table [1]

(In US millions)	Kentucky Utilities Co.			Kentucky Power Company			Black Hills Power, Inc.			Empire District Electric Company (The)		
	A3 Stable			Baa3 Stable			A3 Stable			Baa1 Stable		
	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM	FYE	FYE	LTM
	Dec-18	Dec-19	Jun-20	Dec-18	Dec-19	Jun-20	Dec-18	Dec-19	Jun-20	Dec-18	Dec-19	Jun-20
Revenue	1,760	1,740	1,704	642	619	579	298	291	277	698	644	602
CFO Pre-W/C	648	653	640	95	93	97	95	89	88	265	211	209
Total Debt	2,625	2,827	3,171	951	1,037	1,088	398	447	483	912	898	898
CFO Pre-W/C / Debt	24.7%	23.1%	20.2%	10.0%	8.9%	8.9%	23.9%	19.9%	18.1%	29.0%	23.5%	23.3%
CFO Pre-W/C - Dividends / Debt	15.3%	15.0%	13.0%	10.0%	8.4%	8.9%	14.9%	19.9%	14.0%	18.6%	20.2%	21.6%
Debt / Capitalization	38.7%	39.4%	41.6%	45.6%	46.4%	47.0%	43.6%	44.4%	46.2%	44.9%	42.8%	42.5%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
KENTUCKY UTILITIES CO.	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Bkd LT IRB/PC	A1
Commercial Paper	P-2
Bkd Other Short Term	P-2
ULT PARENT: PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
PARENT: LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1

Source: Moody's Investors Service

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Kentucky Utilities Co.

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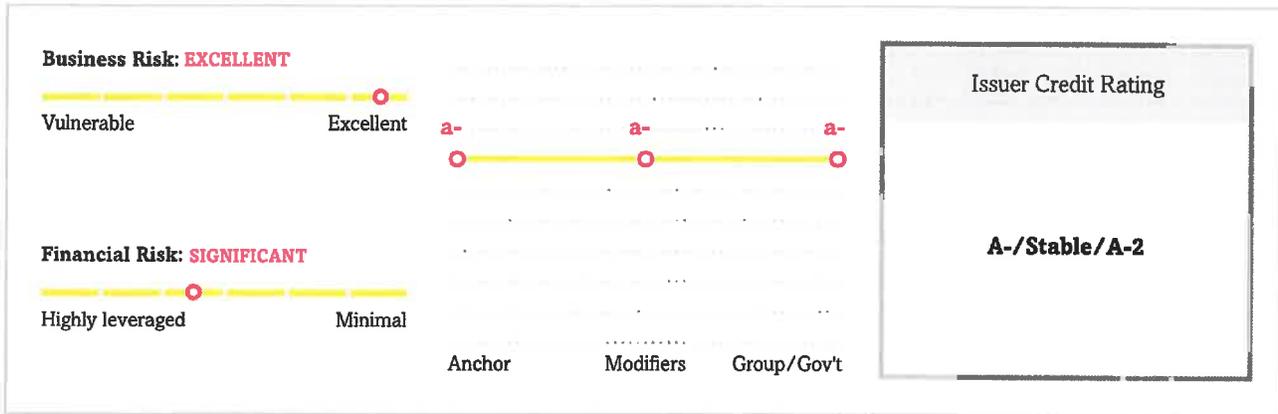
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Ratings Score Snapshot

Related Criteria

Kentucky Utilities Co.



Credit Highlights

Overview	
Key strengths	Key risks
Fully regulated vertically integrated electric utility.	Limited geographic diversity and relatively small customer base.
Constructive and credit supportive regulatory framework.	Moderate operational and environmental risk relating to coal-fired generation.
Strengthening financial measures in 2019 benefiting from various cost recovery mechanisms.	Negative discretionary cash flow, in part reflecting greater capital spending.

Kentucky Utilities Co. (KU) operates under credit-supportive framework. Kentucky has a constructive regulatory framework that provides for the timely recovery of approved capital expenditures, as well as pass-through fuel cost mechanisms and various operating expenses recoveries.

Debt leverage remains modest for regulated utilities overall. Over the next few years, debt leverage, as indicated by debt to EBITDA, is expected to remain in the mid- to high-3x range, modest for regulated utilities, in part from timely cost recovery.

Capital spending has remained elevated as a result of environmental compliance. The company has had higher capital spending to comply with the Environmental Protection Agency's (EPA's) Clean Air Act rules for coal combustion waste and byproducts created through coal-fired generation. KU is entitled to cost recovery through an environmental cost recovery mechanism.

Outlook: Stable

The stable rating outlook on KU reflects S&P Global Ratings' outlook on its parent, PPL Corp. (PPL).

This stable outlook over the next 24 months is based on the company's excellent business risk profile, which we view to be at the upper end of the range, and significant financial risk profile, which is at the lower end of the range. Under our base-case scenario, we expect that adjusted funds from operations (FFO) to debt will range from 13%-14%, while adjusted debt to EBITDA will remain elevated at over 5x.

Downside scenario

We could lower the ratings over the next 24 months on PPL and its subsidiaries if core credit ratios weakened enough that adjusted FFO to debt fell below 13% on a consistent basis while still at the current level of business risk.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings on PPL and its subsidiaries during the outlook period. However, higher ratings would largely depend on PPL consistently achieving FFO to debt of more than 18% over the next 12-18 months, while maintaining the current level of business risk.

Our Base-Case Scenario

Assumptions	Key Metrics
-------------	-------------

- Gross margin growth in 2019 driven by modest volume growth and ongoing rate recovery for capital spending including on environmental-compliance equipment;
- High average capital spending of \$585 million per year for upgrading generation infrastructure to meet environmental standards and for improvements to transmission and distribution assets; and
- All debt maturities refinanced.

	2018E	2019E	2020E
Adjusted FFO to debt (%)	19-21	19-21	21-23
Adjusted FFO cash interest coverage (X)	6.7-7.3	6.5-7.1	7.2-7.8
Adjusted debt to EBITDA	3.6-4.0	3.6-4.0	3.2-3.6

E--Estimate. FFO--Funds from operations.

Base-case projections

- After dividends and elevated capital spending, discretionary cash flow that is negative will be largely debt funded.
- Adjusted FFO to debt around 20%, but improving over time after incremental cost recovery; and

- Debt leverage, as indicated by debt to EBITDA, remains in the 3x-4x area.

Company Description

KU is a vertically integrated electric utility providing service to about 550,000 customers that are mostly in Kentucky.

Business Risk: Excellent

We assess KU's business risk profile based on the company's regulated integrated utility operations under Kentucky's generally constructive regulatory framework, which provides for the timely recovery of approved capital expenditures.

KU has moderate scale with 550,000 customers and limited geographic diversity since it operates almost entirely in Kentucky. The customer mix is mostly residential and commercial, which can insulate the company from fluctuations in electricity demand and also supports relatively stable operating cash flow.

The company has generation capacity of about 5,000 megawatts, including sizeable coal-fired capacity. However, KU has been upgrading its coal units to comply with environmental regulations. KU can recover the costs for these upgrades through an environmental cost recovery mechanism, which limits regulatory lag and supports the credit profile. Under Kentucky Public Service Commission regulation, the company benefits from other recovery mechanisms such as a pass-through fuel cost and a purchased power cost recovery rider. These mechanisms help stabilize the company's operating cash flow. Moreover, the company's low-cost, coal-fired generation and efficient operations contribute to competitive rates for customers.

Peer comparison

KU is in line with peers such as Kentucky Power, Appalachian Power, and Louisville Gas & Electric (LG&E) given the similar coal-fired generation profiles and environmental compliance spending obligations. KU has approximately 550,000 customers, which compares more favorably to Kentucky Power (which has 170,000) and LG&E (which has 400,000), but it is smaller than Appalachian Power, which has one million customers. Kentucky Power has greater industrial customer exposure with about one-half of energy sales coming from industrial customers. Whereas KU benefits from a higher level of residential and commercial customers, which contributes to steadier cash flows. All companies use regulatory mechanisms to recover environmental spending costs, pass through fuel costs, and for purchased power cost recovery. The mechanisms contribute to more robust operating cash flow and more predictable returns.

Table 2

Peer Metrics				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric
Long-term (foreign currency)	A-/Stable	A-/Stable	A-/Stable	A-/Stable
Short-term (foreign currency)	A-2		A-2	A-2
Business risk profile	Excellent	Strong	Excellent	Excellent
Financial risk profile	Significant	Significant	Significant	Significant
Anchor	a-	bbb	a-	a-

Table 2

Peer Metrics (cont.)				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric
Capital structure	Neutral	Neutral	Neutral	Neutral
Liquidity	Adequate	Adequate	Adequate	Adequate
Financial policy	Neutral	Neutral	Neutral	Neutral
Management/governance	Satisfactory	Satisfactory	Satisfactory	Satisfactory
Comparable rating analysis	Neutral	Neutral	Neutral	Neutral
Stand-alone credit profile	a-	a-	a-	a-
GRM adjustment	0	+2	0	0
Issuer credit rating	A-	A-	A-	A-

GRM--Group rating methodology.

Table 2

Peer Comparison				
Industry sector: electric				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric Co.
Rating as of Jan. 15, 2019	A-/Stable/A-2	A-/Stable/--	A-/Stable/A-2	A-/Stable/A-2
--Fiscal year ended Dec. 31, 2017--				
(Mil. \$)				
Revenues	1,744.0	642.8	2,901.9	1,453.0
EBITDA	808.8	185.2	1,085.2	650.4
FFO	683.6	145.4	868.2	551.9
Net income from continuing operations	259.0	35.2	331.3	213.0
Cash flow from operations	647.1	134.6	874.8	537.2
Capital expenditures	432.5	94.5	812.8	459.2
Free operating cash flow	214.6	40.1	62.0	78.0
Discretionary cash flow	(11.4)	5.1	(58.0)	(114.0)
Cash and short-term investments	15.0	0.9	2.9	15.0
Debt	2,728.4	934.7	4,152.6	2,154.8
Equity	3,357.0	670.3	3,804.5	2,527.0
Adjusted ratios				
EBITDA margin (%)	46.4	28.8	37.4	44.8
Return on capital (%)	7.2	4.6	7.1	7.6
EBITDA interest coverage (x)	6.9	3.8	5.4	7.2
FFO cash interest coverage (X)	8.7	4.4	5.7	9.9
Debt/EBITDA (x)	3.4	5.0	3.8	3.3
FFO/debt (%)	25.1	15.6	20.9	25.6
Cash flow from operations/debt (%)	23.7	14.4	21.1	24.9
Free operating cash flow/debt (%)	7.9	4.3	1.5	3.6

Table 2

Peer Comparison (cont.)				
Industry sector: electric				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric Co.
Discretionary cash flow/debt (%)	(0.4)	0.5	(1.4)	(5.3)

FFO--Funds from operations.

Financial Risk: Significant

Under our base-case scenario, we project that KU's adjusted FFO to debt will be in the 19%-21% range, near the upper end the benchmark range. Bolstering the financial risk profile determination is the supplemental ratio of adjusted FFO cash interest coverage in the 6.5x-7.5x range. Over the next few years, we expect credit measures to benefit from the use of regulatory mechanisms to recover its invested capital cost. We expect continued capital spending averaging \$585 million per year, when combined with the utility's dividend, will result in discretionary cash flow that is negative. To offset the negative cash flow, we expect external funding such as debt issuances and cash injections within the PPL group. We do expect debt leverage to be relatively modest for a regulated utility as indicated by debt to EBITDA averaging about 3.5x over the next few years.

We assess KU's financial risk profile as significant using our medial table financial benchmarks, which are more moderate than the typical corporate issuer, accounting for the company's low-risk regulated electric utility operations, steady cash flow, and effective regulatory risk management.

Table 3

Financial Summary					
Industry sector: electric					
	--Fiscal year ended Dec. 31--				
	2017	2016	2015	2014	2013
Rating history	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2	BBB/Watch Pos/A-2	BBB/Stable/A-2
(Mil. \$)					
Revenues	1,744.0	1,749.0	1,728.0	1,737.0	1,635.0
EBITDA	808.8	807.3	719.4	662.2	651.1
FFO	683.6	648.0	637.9	658.3	500.8
Net income from continuing operations	259.0	265.0	234.0	220.0	228.0
Cash flow from operations	647.1	616.3	612.8	566.5	515.4
Capital expenditures	432.5	350.5	519.4	604.0	855.0
Free operating cash flow	214.6	265.8	93.4	(37.5)	(339.6)
Discretionary cash flow	(11.4)	17.8	(59.6)	(185.5)	(463.6)
Cash and short-term investments	15.0	7.0	11.0	11.0	21.0
Debt	2,728.4	2,725.1	2,777.7	2,604.3	2,457.7
Equity	3,357.0	3,323.0	3,287.0	3,206.0	3,044.0

Table 3

Financial Summary (cont.)					
Industry sector: electric					
	--Fiscal year ended Dec. 31--				
	2017	2016	2015	2014	2013
Adjusted ratios					
EBITDA margin (%)	46.4	46.2	41.6	38.1	39.8
Return on capital (%)	7.2	7.5	6.9	7.0	7.7
EBITDA interest coverage (x)	6.9	6.6	6.9	6.8	8.1
FFO cash interest coverage (x)	8.7	8.6	9.9	10.3	9.5
Debt/EBITDA (x)	3.4	3.4	3.9	3.9	3.8
FFO/debt (%)	25.1	23.8	23.0	25.3	20.4
Cash flow from operations/debt (%)	23.7	22.6	22.1	21.8	21.0
Free operating cash flow/debt (%)	7.9	9.8	3.4	(1.4)	(13.8)
Discretionary cash flow/debt (%)	(0.4)	0.7	(2.1)	(7.1)	(18.9)

FFO—Funds from operations.

Liquidity: Adequate

We assess KU's standalone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. We view KU as having sound bank relationships, the ability to absorb high-impact, low probability events without the need for refinancing, and a satisfactory standing in credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
<ul style="list-style-type: none"> • Cash and liquid investments of about \$30 million • Revolving credit facility availability of \$400 million • Estimated cash FFO of \$615 million 	<ul style="list-style-type: none"> • Debt maturities of about \$95 million • Capital spending of about \$475 million • Dividends of \$230 million

Debt maturities

- 2019: \$96 million
- 2020: \$500 million
- 2021: \$0 million
- 2022: \$0 million

Covenant Analysis

Compliance expectations

As of Sept. 30, 2018, KU was in compliance with the financial covenants in its credit facilities and had sufficient cushion. Under our base-case scenario, we expect KU will remain in compliance with these covenants, especially given the stability of regulated utility operations. We expect that even if forecast EBITDA declined 10% the company would remain in compliance with the covenants.

Requirements

- Total debt-to-capitalization ratio of 70% or less.
- The covenant thresholds remain unchanged through the credit facility's expiration in January of 2023.

Environmental, Social, And Governance

Environmental factors are material in our rating analysis, while social and governance factors are not.

Most of the total generation capacity--about 5,000 megawatts--is coal-fired, representing an environmental risk factor. By 2050, PPL intends to reduce its carbon footprint by 70%. In Kentucky, the company is seeking a green energy tariff that would help grow renewable energy. The company expects to replace much of its coal-based generation with a combination of natural gas and renewables.

Social factors are neutral to our ESG assessment and are consistent with what we see across the industry for other publicly traded utilities. By pursuing greater renewable generation, the company is meeting customer demand for greener energy. Governance factors are also neutral to our ESG assessment and its governance practices are consistent with what we see across the industry for other publicly traded utilities.

Group Influence

Under our group rating methodology we consider KU a core subsidiary of parent PPL, reflecting our view that KU is unlikely to be sold, is integral to the group's overall strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. As a result, the issuer credit rating on KU is 'A-', in line with the group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

The short-term rating on KU is 'A-2', based on the issuer credit rating.

Issue Ratings - Recovery Analysis

Key analytical factors

KU's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Reconciliation

Table 4

Reconciliation Of Kentucky Utilities Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. \$)

--Rolling 12 months ended Sept. 30, 2018--

Kentucky Utilities Co. reported amounts.

	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	EBITDA	Cash flow from operations	Dividends paid	Capital expenditures
	2,448	3,431	1,773	758	483	98	758	618	251	554
S&P Global Ratings' adjustments										
Interest expense (reported)	--	--	--	--	--	--	(98)	--	--	--
Interest income (reported)	--	--	--	--	--	--	--	--	--	--
Current tax expense (reported)	--	--	--	--	--	--	(25)	--	--	--
Operating leases	33	--	--	10	2	2	7	7	--	--
Postretirement benefit obligations/deferred compensation	54	--	--	3	3	1	1	(0)	--	--
Surplus cash	(18)	--	--	--	--	--	--	--	--	--
Power purchase agreements	32	--	--	3	2	2	0	0	--	0
Asset retirement obligations	166	--	--	11	11	11	(3)	20	--	--
Nonoperating income (expense)	--	--	--	--	1	--	--	--	--	--
Debt - accrued interest not included in reported debt	37	--	--	--	--	--	--	--	--	--
Debt - issuance cost	14	--	--	--	--	--	--	--	--	--
EBITDA - other income/(expense)	--	--	--	4	4	--	4	--	--	--
EBITDA - other	--	--	--	(1)	(1)	--	(1)	--	--	--
D&A - other	--	--	--	--	(4)	--	--	--	--	--
Interest expense - other	--	--	--	--	--	2	(2)	--	--	--
Total adjustments	318	0	0	29	18	19	(116)	27	0	0

Table 4

Reconciliation Of Kentucky Utilities Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. \$) (cont.)

S&P Global Ratings' adjusted amounts

Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Funds from Operations	Cash flow from operations	Dividends paid	Capital expenditures
2,766	3,431	1,773	787	501	117	642	645	251	554

D&A—Depreciation and amortization.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers,

Ratings Detail (As Of February 8, 2019) (cont.)

Louisville Gas & Electric Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
<i>Local Currency</i>	A-2
Senior Secured	A

PPL Capital Funding Inc.

Issuer Credit Rating	A-/Stable/A-2
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PPL Corp.

Issuer Credit Rating	A-/Stable/A-2
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PPL Electric Utilities Corp.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
<i>Local Currency</i>	A-2
Senior Secured	A

Western Power Distribution (East Midlands) PLC

Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	A-

Western Power Distribution PLC

Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	BBB+

Western Power Distribution (South Wales) PLC

Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	A-

Western Power Distribution (South West) PLC

Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	A-

Western Power Distribution (West Midlands) PLC

Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	A-

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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Kentucky Utilities Co.

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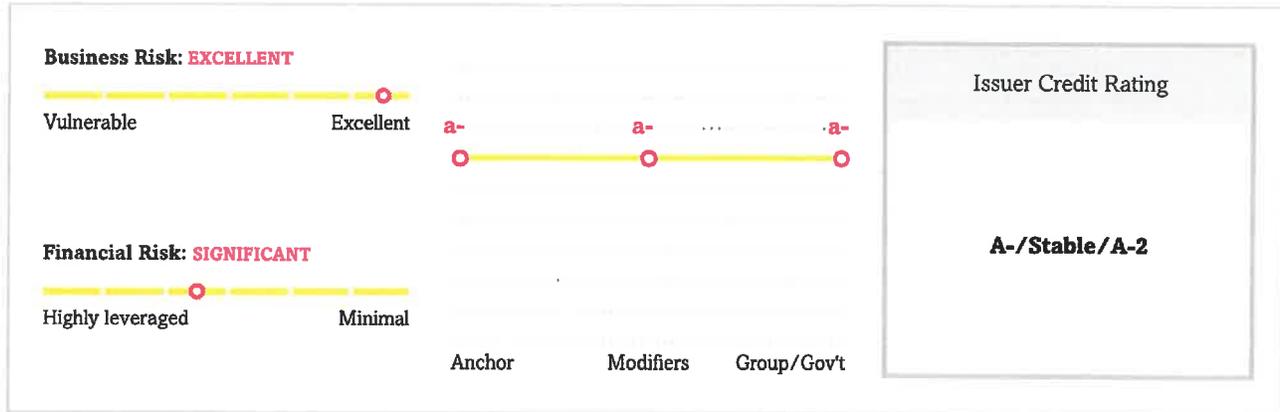
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Related Criteria

Kentucky Utilities Co.



Credit Highlights

Overview	
Key strengths	Key risks
Fully regulated vertically integrated electric utility.	Limited geographic diversity and relatively small customer base.
Constructive and credit supportive regulatory framework.	Moderate operational and environmental risk relating to coal-fired generation.
Financial measures in 2020 benefiting from timely cost recovery mechanisms.	Negative discretionary cash flow, in part reflecting greater capital spending.

Kentucky Utilities Co. (KU) operates under a credit-supportive framework. Kentucky Utilities Co. has a constructive regulatory framework that provides for the timely recovery of approved capital expenditures, as well as pass-through fuel cost mechanisms and various operating expenses recoveries.

Debt leverage remains modest for regulated utilities overall. Over the next few years, we expect debt leverage, as indicated by debt to EBITDA, to remain in the mid- to high-3x range, modest for regulated utilities, in part from timely cost recovery.

Capital spending has remained elevated as a result of environmental compliance. In order to comply with the Environmental Protection Agency's (EPA's) Clean Air Act rules for coal combustion waste and byproducts, we foresee the company continuing into 2020 with slightly lower capital spending than previous years. KU is entitled to cost recovery through an environmental cost recovery mechanism.

Outlook: Stable

The stable rating outlook on KU reflects that of its parent PPL Corp. (PPL) over the next 24 months. We base the outlook on our assessment of PPL's excellent business risk profile, which is at the upper end of the range, and significant financial risk profile, which is at the lower end of the range. Under S&P Global Ratings' base case scenario, PPL's adjusted funds from operations (FFO) to debt will average about 14%, and adjusted debt to EBITDA will remain elevated at about 5x.

Downside scenario

We could lower the ratings over the next 24 months on PPL and its subsidiaries if core credit ratios weakened such that adjusted FFO to debt consistently stays below 13% and business risk remains unchanged.

Upside scenario

Given our assessment of business risk and our base case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, we could raise our ratings if PPL achieves adjusted FFO to debt of more than 18% on a consistent basis while maintaining the current level of business risk.

Our Base-Case Scenario

Assumptions	Key Metrics			
<ul style="list-style-type: none"> Gross margin growth in 2020 driven by modest volume growth and ongoing rate recovery for capital spending including on environmental-compliance equipment; High average capital spending of \$560 million per year for upgrading generation infrastructure to meet environmental standards and for improvements to transmission and distribution assets; and All debt maturities refinanced. 		2020e	2021f	2022f
	Adjusted FFO to debt (%)	22-24	19-21	19-21
	Adjusted FFO cash interest coverage (X)	6.8-7.2	6.2-6.6	6.0-6.4
	Adjusted debt to EBITDA	3.5-3.9	3.5-3.9	3.7-4.1

e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

KU is a vertically integrated electric utility providing service to about 550,000 customers that are mostly in Kentucky.

Business Risk: Excellent

We assess KU's business risk profile based on the company's regulated integrated utility operations under Kentucky's generally constructive regulatory framework, which provides for the timely recovery of approved capital expenditures.

KU has moderate scale with 550,000 customers and limited geographic diversity because it operates almost entirely in Kentucky. The customer mix is mostly residential and commercial, which can insulate the company from fluctuations in electricity demand and also supports relatively stable operating cash flow.

The company has generation capacity of about 5,000 MW, including sizeable coal-fired capacity. However, KU has been upgrading its coal units to comply with environmental regulations. KU can recover the costs for these upgrades through an environmental cost recovery mechanism, which limits regulatory lag and supports the credit profile. Under Kentucky Public Service Commission regulation, the company benefits from other recovery mechanisms such as a pass-through fuel cost and a purchased-power cost-recovery rider. These mechanisms help stabilize the company's operating cash flow. Moreover, the company's low-cost, coal-fired generation and efficient operations contribute to competitive rates for customers.

Table 1

Kentucky Utilities Co.--Peer Comparison				
Industry sector: electric				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric Co.
Ratings as of March 4, 2020	A-/Stable/A-2	A-/Stable/--	A-/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--
(Mil. \$)				
Revenue	1,760.0	642.1	2,934.8	1,496.0
EBITDA	774.8	203.0	903.2	618.9
Funds from operations (FFO)	650.2	165.8	729.6	533.7
Interest expense	118.6	41.9	206.1	93.8
Cash interest paid	99.5	40.4	186.7	78.2
Cash flow from operations	589.2	118.2	826.7	454.7
Capital expenditure	562.5	134.8	772.3	555.2
Free operating cash flow (FOCF)	26.7	(16.6)	54.4	(100.5)
Discretionary cash flow (DCF)	(219.3)	(16.6)	(105.6)	(256.5)
Cash and short-term investments	14.0	1.2	4.2	10.0
Debt	2,817.7	938.0	4,192.6	2,297.0
Equity	3,442.0	732.9	4,006.1	2,687.0
Adjusted ratios				
EBITDA margin (%)	44.0	31.6	30.8	41.4

Table 1

Kentucky Utilities Co.--Peer Comparison (cont.)				
Industry sector: electric				
	Kentucky Utilities Co.	Kentucky Power Co.	Appalachian Power Co.	Louisville Gas & Electric Co.
Ratings as of March 4, 2020	A-/Stable/A-2	A-/Stable/--	A-/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--	--Fiscal year ended Dec. 31, 2018--
Return on capital (%)	7.8	6.5	6.3	8.0
EBITDA interest coverage (x)	6.5	4.8	4.4	6.6
FFO cash interest coverage (x)	7.5	5.1	4.9	7.8
Debt/EBITDA (x)	3.6	4.6	4.6	3.7
FFO/debt (%)	23.1	17.7	17.4	23.2
Cash flow from operations/debt (%)	20.9	12.6	19.7	19.8
FOCF/debt (%)	0.9	(1.8)	1.3	(4.4)
DCF/debt (%)	(7.8)	(1.8)	(2.5)	(11.2)

Source: S&P Global Ratings, company data.

Financial Risk: Significant

Under our base case scenario, we project that KU's adjusted FFO to debt will be in the 22%-24% range, near the upper end the benchmark range. Bolstering the financial risk profile determination is the supplemental ratio of adjusted FFO cash interest coverage in the 6.2x-6.6x range. Over the next few years, we expect credit measures to benefit from the use of regulatory mechanisms to recover its invested capital cost. We expect continued capital spending averaging \$560 million per year, when combined with the utility's dividend, will result in discretionary cash flow that is negative. We do expect debt leverage to be relatively modest for a regulated utility as indicated by debt to EBITDA averaging about 3.6x over the next few years.

We assess KU's financial risk profile using our medial volatility table financial benchmarks, which are more relaxed than those used for a the typical corporate issuer. This reflects KU's low-risk regulated electric utility operations, steady cash flow, and effective regulatory risk management.

Table 3

Kentucky Utilities Co.--Financial Summary					
Industry sector: electric					
	--Fiscal year ended Dec. 31--				
	2018	2017	2016	2015	2014
(Mil. \$)					
Revenue	1,760.0	1,744.0	1,749.0	1,728.0	1,737.0
EBITDA	774.8	808.8	807.3	719.4	662.2

Table 3

Kentucky Utilities Co.--Financial Summary (cont.)

Industry sector: electric

	--Fiscal year ended Dec. 31--				
	2018	2017	2016	2015	2014
Funds from operations (FFO)	650.2	678.2	700.5	723.7	586.9
Interest expense	118.6	115.5	117.6	101.5	91.1
Cash interest paid	99.5	96.6	93.8	79.7	75.3
Cash flow from operations	589.2	641.6	613.5	615.5	573.2
Capital expenditure	562.5	432.5	350.5	519.4	604.0
Free operating cash flow (FOCF)	26.7	209.1	263.0	96.1	(30.8)
Discretionary cash flow (DCF)	(219.3)	(16.9)	15.0	(56.9)	(178.8)
Cash and short-term investments	14.0	15.0	7.0	11.0	11.0
Gross available cash	14.0	15.0	7.0	11.0	11.0
Debt	2,817.7	2,698.4	2,694.1	2,761.7	2,593.3
Equity	3,442.0	3,357.0	3,323.0	3,287.0	3,206.0
Adjusted ratios					
EBITDA margin (%)	44.0	46.4	46.2	41.6	38.1
Return on capital (%)	7.8	8.8	9.1	8.1	8.1
EBITDA interest coverage (x)	6.5	7.0	6.9	7.1	7.3
FFO cash interest coverage (x)	7.5	8.0	8.5	10.1	8.8
Debt/EBITDA (x)	3.6	3.3	3.3	3.8	3.9
FFO/debt (%)	23.1	25.1	26.0	26.2	22.6
Cash flow from operations/debt (%)	20.9	23.8	22.8	22.3	22.1
FOCF/debt (%)	0.9	7.8	9.8	3.5	(1.2)
DCF/debt (%)	(7.8)	(0.6)	0.6	(2.1)	(6.9)

Sources: S&P Global Ratings, company data

Liquidity: Adequate

We assess KU's stand-alone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. We view KU as having sound bank relationships, the ability to absorb high-impact, low probability events without the need for refinancing, and a satisfactory standing in credit markets.

Principal Liquidity Sources

- Revolving credit facility availability of \$400 million
- Estimated cash FFO of \$600 million

Principal Liquidity Uses

- Debt maturities of about \$500 million
- Capital spending of about \$560 million
- Dividends of about \$280 million

Environmental, Social, And Governance

Environmental factors are material in our rating analysis, while social and governance factors are not.

Most of the total generation capacity--about 5,000 megawatts--is coal-fired, representing an environmental risk factor. By 2050, PPL intends to reduce its carbon footprint by 70%. In Kentucky, the company is seeking a green energy tariff that would help grow renewable energy. The company expects to replace much of its coal-based generation with a combination of natural gas and renewables. Social factors are neutral to our ESG assessment and are consistent with what we see across the industry for other publicly traded utilities. Governance factors are also neutral to our ESG assessment and its governance practices are consistent with what we see across the industry for other publicly traded utilities.

Group Influence

Under our group rating methodology we consider KU a core subsidiary of parent PPL, reflecting our view that KU is unlikely to be sold, is integral to the group's overall strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. As a result, the issuer credit rating on KU is 'A-', in line with the group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

The short-term rating on KU is 'A-2', based on the issuer credit rating.

Issue Ratings - Recovery Analysis

Key analytical factors

KU's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Reconciliation

Table 3

Reconciliation Of Kentucky Utilities Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. \$)

Reconciliation Of Kentucky Utilities Co. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. \$)

--Fiscal year ended Dec. 31, 2018--

Kentucky Utilities Co. reported amounts							
	Debt	EBITDA	Operating income	Interest expense	S&P Global Ratings' adjusted EBITDA	Cash flow from operations	Capital expenditure
	2,556.0	747.0	468.0	100.0	774.8	581.0	562.0
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	(25.0)	--	--
Cash taxes paid: Other	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	(95.0)	--	--
Operating leases	32.0	10.0	2.3	2.3	(2.3)	7.7	--
Postretirement benefit obligations/deferred compensation	24.5	--	--	--	--	--	--
Accessible cash and liquid investments	(14.0)	--	--	--	--	--	--
Power purchase agreements	32.4	2.8	2.3	2.3	(2.3)	0.5	0.5
Asset retirement obligations	152.5	12.0	12.0	12.0	--	--	--
Nonoperating income (expense)	--	--	(5.6)	--	--	--	--
Debt: Other	34.4	--	--	--	--	--	--
EBITDA: Other income/(expense)	--	3.0	3.0	--	--	--	--
Depreciation and amortization: Other	--	--	(3.0)	--	--	--	--
Interest expense: Other	--	--	--	2.1	--	--	--
Total adjustments	261.7	27.8	11.0	18.6	(124.5)	8.2	0.5
S&P Global Ratings' adjusted amounts							
	Debt	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	2,817.7	774.8	479.0	118.6	650.2	589.2	562.5

Sources: S&P Global Ratings, company data.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- Country risk: Very low

- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of March 20, 2020)*

Kentucky Utilities Co.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A

Issuer Credit Ratings History

01-Jun-2015	A-/Stable/A-2
10-Jun-2014	BBB/Watch Pos/A-2
15-Apr-2011	BBB/Stable/A-2

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Kentucky Utilities Co. Bond Ratings Lowered To 'A' From 'AA/A-1+' (Recovery Rating: '1+'); Short-Term Ratings Removed

September 3, 2019

NEW YORK (S&P Global Ratings) Sept. 3, 2019--S&P Global Ratings today lowered its issue-level rating to 'A' from 'AA/A-1+', removed the short-term ratings, and assigned its '1+' recovery rating to obligor Kentucky Utilities Co.'s (KU; A-/Stable/A-2) remarketed secured debt issues:

- \$12.9 million solid waste disposal facility revenue bonds 2000 Series A due May 1, 2023 (issued through the County of Mercer, Ky.).
- \$77,947,405 environmental facilities revenue bonds 2008 Series A due Feb. 1, 2032 (issued through the County of Carroll, Ky.).
- \$50 million environmental facilities revenue bonds 2004 Series A due Oct. 1, 2034 (issued through the County of Carroll, Ky.).
- \$54 million environmental facilities revenue refunding bonds 2006 Series B due Oct. 1, 2034 (issued through the County of Carroll, Ky.).

The bonds, historically supported by letters of credit (LOCs), are being reoffered without LOCs. Therefore, the rating on these bonds without the enhancement reflects the rating on KU's first mortgage bonds (FMBs) since these issues are secured with KU's FMBs. KU's FMBs benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of more than 1.5x supports a '1+' recovery rating and an issue-level rating one notch above the issuer credit rating.

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013

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- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

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RatingsDirect®

Summary:

Kentucky Utilities Co.

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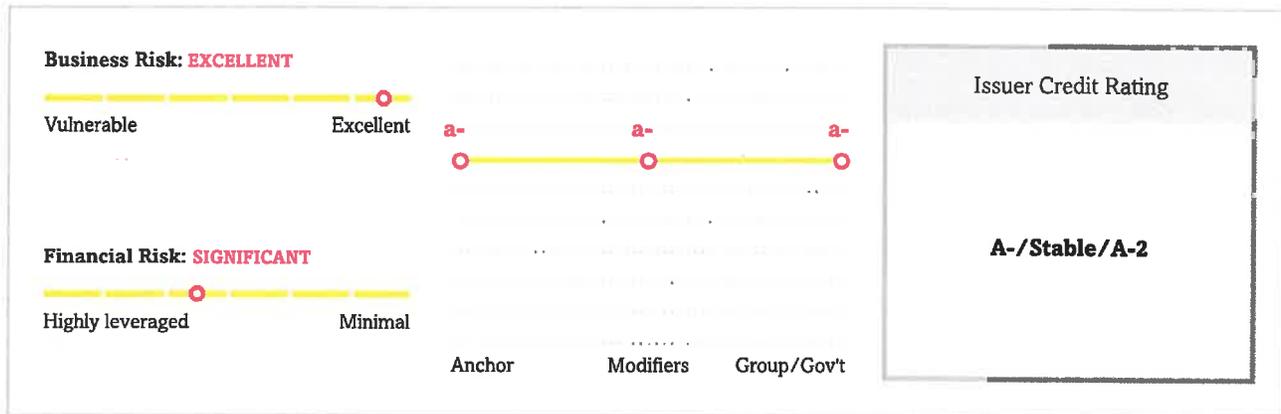
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Summary:

Kentucky Utilities Co.



Credit Highlights

Overview	
Key strengths	Key risks
Fully regulated vertically-integrated electric utility.	Limited geographic diversity and relatively small customer base.
Constructive and credit supportive regulatory framework.	Moderate operational and environmental risk relating to coal-fired generation.
Strengthening financial measures in 2019 benefiting from various cost recovery mechanisms.	Negative discretionary cash flow, in part reflecting greater capital spending.

Kentucky Utilities Co. (KU) operates under credit-supportive framework.

Kentucky has a constructive regulatory framework that provides for the timely recovery of approved capital expenditures, as well as pass-through fuel cost mechanisms and various operating expenses recoveries.

Debt leverage remains modest for regulated utilities overall.

Over the next few years, debt leverage, as indicated by debt to EBITDA, is expected to remain in the mid- to high-3x range, modest for regulated utilities, in part from timely cost recovery.

Capital spending has remained elevated as a result of environmental compliance.

The company has had higher capital spending to comply with the Environmental Protection Agency's (EPA's) Clean Air Act rules for coal combustion waste and byproducts created through coal-fired generation. KU is entitled to cost recovery through an environmental cost recovery mechanism.

Outlook: Stable

The stable rating outlook on KU reflects S&P Global Ratings' outlook on its parent, PPL Corp. (PPL).

This stable outlook over the next 24 months is based on the company's excellent business risk profile, which we view to be at the upper end of the range, and significant financial risk profile, which is at the lower end of the range. Under our base-case scenario, we expect that adjusted funds from operations (FFO) to debt will range from 13%-14%, while adjusted debt to EBITDA will remain elevated at over 5x.

Downside scenario

We could lower the ratings over the next 24 months on PPL and its subsidiaries if core credit ratios weakened enough that adjusted FFO to debt fell below 13% on a consistent basis while still at the current level of business risk.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings on PPL and its subsidiaries during the outlook period. However, higher ratings would largely depend on PPL consistently achieving FFO to debt of more than 18% over the next 12-18 months, while maintaining the current level of business risk.

Our Base-Case Scenario

Assumptions	Key Metrics		
-------------	-------------	--	--

- Gross margin growth in 2019 driven by modest volume growth and ongoing rate recovery for capital spending including on environmental-compliance equipment;
- High average capital spending of \$585 million per year for upgrading generation infrastructure to meet environmental standards and for improvements to transmission and distribution assets; and
- All debt maturities refinanced.

	2018E	2019E	2020E
Adjusted FFO to debt (%)	19-21	19-21	21-23
Adjusted FFO cash interest coverage (X)	6.7-7.3	6.5-7.1	7.2-7.8
Adjusted debt to EBITDA	3.6-4.0	3.6-4.0	3.2-3.6

E--Estimate. FFO--Funds from operations.

Base-case projections

- After dividends and elevated capital spending, discretionary cash flow that is negative will be largely debt funded.
- Adjusted FFO to debt around 20%, but improving over time after incremental cost recovery; and

- Debt leverage, as indicated by debt to EBITDA, remains in the 3x-4x area.

Company Description

KU is a vertically integrated electric utility providing service to about 550,000 customers that are mostly in Kentucky.

Business Risk: Excellent

We assess KU's business risk profile based on the company's regulated integrated utility operations under Kentucky's generally constructive regulatory framework, which provides for the timely recovery of approved capital expenditures.

KU has moderate scale with 550,000 customers and limited geographic diversity since it operates almost entirely in Kentucky. The customer mix is mostly residential and commercial, which can insulate the company from fluctuations in electricity demand and also supports relatively stable operating cash flow.

The company has generation capacity of about 5,000 megawatts, including sizeable coal-fired capacity. However, KU has been upgrading its coal units to comply with environmental regulations. KU can recover the costs for these upgrades through an environmental cost recovery mechanism, which limits regulatory lag and supports the credit profile. Under Kentucky Public Service Commission regulation, the company benefits from other recovery mechanisms such as a pass-through fuel cost and a purchased power cost recovery rider. These mechanisms help stabilize the company's operating cash flow. Moreover, the company's low-cost, coal-fired generation and efficient operations contribute to competitive rates for customers.

Peer comparison

KU is in line with peers such as Kentucky Power, Appalachian Power, and Louisville Gas & Electric (LG&E) given the similar coal-fired generation profiles and environmental compliance spending obligations. KU has approximately 550,000 customers, which compares more favorably to Kentucky Power (which has 170,000) and LG&E (which has 400,000), but it is smaller than Appalachian Power, which has one million customers. Kentucky Power has greater industrial customer exposure with about one-half of energy sales coming from industrial customers. Whereas KU benefits from a higher level of residential and commercial customers, which contributes to steadier cash flows. All companies use regulatory mechanisms to recover environmental spending costs, pass through fuel costs, and for purchased power cost recovery. The mechanisms contribute to more robust operating cash flow and more predictable returns.

Financial Risk: Significant

Under our base-case scenario, we project that KU's adjusted FFO to debt will be in the 19%-21% range, near the upper end the benchmark range. Bolstering the financial risk profile determination is the supplemental ratio of adjusted FFO cash interest coverage in the 6.5x-7.5x range. Over the next few years, we expect credit measures to benefit from the use of regulatory mechanisms to recover its invested capital cost. We expect continued capital spending averaging \$585 million per year, when combined with the utility's dividend, will result in discretionary cash flow that is negative.

To offset the negative cash flow, we expect external funding such as debt issuances and cash injections within the PPL group. We do expect debt leverage to be relatively modest for a regulated utility as indicated by debt to EBITDA averaging about 3.5x over the next few years.

We assess KU's financial risk profile as significant using our medial table financial benchmarks, which are more moderate than the typical corporate issuer, accounting for the company's low-risk regulated electric utility operations, steady cash flow, and effective regulatory risk management.

Liquidity: Adequate

We assess KU's standalone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. We view KU as having sound bank relationships, the ability to absorb high-impact, low probability events without the need for refinancing, and a satisfactory standing in credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
<ul style="list-style-type: none"> • Cash and liquid investments of about \$30 million • Revolving credit facility availability of \$400 million • Estimated cash FFO of \$615 million 	<ul style="list-style-type: none"> • Debt maturities of about \$95 million • Capital spending of about \$475 million • Dividends of \$230 million

Debt maturities

- 2019: \$96 million
- 2020: \$500 million
- 2021: \$0 million
- 2022: \$0 million

Covenant Analysis

Compliance expectations

As of Sept. 30, 2018, KU was in compliance with the financial covenants in its credit facilities and had sufficient cushion. Under our base-case scenario, we expect KU will remain in compliance with these covenants, especially given the stability of regulated utility operations. We expect that even if forecast EBITDA declined 10% the company would remain in compliance with the covenants.

Requirements

- Total debt-to-capitalization ratio of 70% or less.
- The covenant thresholds remain unchanged through the credit facility's expiration in January of 2023.

Environmental, Social, And Governance

Environmental factors are material in our rating analysis, while social and governance factors are not.

Most of the total generation capacity--about 5,000 megawatts--is coal-fired, representing an environmental risk factor. By 2050, PPL intends to reduce its carbon footprint by 70%. In Kentucky, the company is seeking a green energy tariff that would help grow renewable energy. The company expects to replace much of its coal-based generation with a combination of natural gas and renewables.

Social factors are neutral to our ESG assessment and are consistent with what we see across the industry for other publicly traded utilities. By pursuing greater renewable generation, the company is meeting customer demand for greener energy. Governance factors are also neutral to our ESG assessment and its governance practices are consistent with what we see across the industry for other publicly traded utilities.

Group Influence

Under our group rating methodology we consider KU a core subsidiary of parent PPL, reflecting our view that KU is unlikely to be sold, is integral to the group's overall strategy, possesses a strong long-term commitment from senior management, and is closely linked to the parent's name and reputation. As a result, the issuer credit rating on KU is 'A-', in line with the group credit profile of 'a-'.

Issue Ratings - Subordination Risk Analysis

The short-term rating on KU is 'A-2', based on the issuer credit rating.

Issue Ratings - Recovery Analysis

Key analytical factors

KU's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property, owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 105

Responding Witness: Daniel K. Arbough

- Q-105. Refer to Mr. Arbough's Direct Testimony. Provide all cost of capital exhibits from the J Schedules and associated work papers and supporting documentation in spreadsheet format with cell formulas intact. Include LG&E's and KU's weighted average cost of debt and all supporting work papers.
- A-105. See the file named "2020_Att_KU_PSC_1-56_Sch_J.xlsx" (Att-PSC1-56-File34) provided in response to PSC 1-56.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 106

Responding Witness: Christopher M. Garrett

Q-106. Provide the earned return on equity for LG&E and KU for the calendar years 2015 - 2019. Provide all supporting work papers and documentation, including spreadsheets with cell formulas intact.

A-106. See the attachment being provided in Excel format for the KU information.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 107

Responding Witness: Daniel K. Arbough

- Q-107. Provide the historical capital structures for LG&E and KU for the calendar years 2015 - 2019. Provide supporting work papers and documentation, including spreadsheets with cell formulas intact.
- A-107. See attachment to PSC 1-22 for the historical capital structure. See attached for KU's supporting documentation.

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2019 and 2018

Assets	This Year	Last Year	Liabilities and Proprietary Capital	This Year	Last Year
Utility Plant			Proprietary Capital		
Utility Plant at Original Cost.....	\$ 10,376,419,763.68	\$ 10,062,539,120.04	Common Stock.....	\$ 308,139,977.56	\$ 308,139,977.56
Less: Reserves for Depreciation and Amortization.....	3,464,339,890.51	3,429,322,259.30	Less: Common Stock Expense.....	321,288.87	321,288.87
Total.....	6,912,079,873.17	6,633,216,860.74	Paid-In Capital.....	696,858,083.00	628,858,083.00
Investments			Other Comprehensive Income.....	0.01	0.01
Ohio Valley Electric Company.....	250,000.00	250,000.00	Retained Earnings.....	1,962,485,401.63	1,898,449,904.18
Nonutility Property-Less Reserve.....	657,564.21	612,836.40	Total Proprietary Capital.....	2,967,162,173.33	2,835,126,675.88
Special Fund.....	30,690,207.86	0.12	Other Long-Term Debt.....	2,639,740,708.43	2,333,824,307.54
Total.....	31,597,772.07	862,836.52	Total Long-Term Debt.....	2,639,740,708.43	2,333,824,307.54
Current and Accrued Assets			Total Capitalization.....	5,606,902,881.76	5,168,950,983.42
Cash.....	9,892,423.13	12,672,900.30	Current and Accrued Liabilities		
Temporary Cash Investments.....	2,285,926.76	960,025.04	Notes Payable.....	149,934,886.67	235,079,778.13
Accounts Receivable-Less Reserve.....	253,830,891.42	254,823,909.05	Accounts Payable.....	122,060,065.12	181,324,060.75
Accounts Receivable from Associated Companies.....	569.53	2.00	Accounts Payable to Associated Companies.....	51,685,326.75	53,103,480.00
Materials and Supplies-At Average Cost			Customer Deposits.....	31,492,744.58	31,967,926.04
Fuel.....	63,279,740.92	56,182,929.17	Taxes Accrued.....	26,106,353.51	23,887,525.87
Plant Materials and Operating Supplies.....	60,430,620.04	55,639,904.66	Interest Accrued.....	19,982,288.24	16,266,827.16
Stores Expense.....	4,274,232.32	9,836,644.82	Miscellaneous Current and Accrued Liabilities.....	33,692,842.17	23,228,801.36
Emission Allowances.....	125,577.77	127,771.13	Total.....	445,944,507.05	564,759,299.31
Prepayments.....	19,121,366.69	16,889,823.66	Deferred Credits and Other		
Miscellaneous Current and Accrued Assets.....	700,740.00	-	Accumulated Deferred Income Taxes.....	1,105,135,642.01	1,067,025,666.90
Total.....	413,942,088.58	407,133,909.83	Investment Tax Credit.....	90,078,098.37	91,624,049.57
Deferred Debits and Other			Regulatory Liabilities.....	745,640,720.17	770,939,989.66
Unamortized Debt Expense.....	18,127,139.79	16,624,734.63	Customer Advances for Construction.....	4,891,558.70	1,343,082.17
Unamortized Loss on Bonds.....	9,294,441.28	8,498,363.99	Asset Retirement Obligations.....	141,909,342.55	199,407,980.99
Accumulated Deferred Income Taxes.....	313,445,797.64	327,076,777.55	Other Deferred Credits.....	117,420.42	1,347,032.38
Deferred Regulatory Assets.....	426,210,642.14	446,191,302.90	Miscellaneous Long-Term Liabilities.....	26,070,252.47	2,956,059.25
Other Deferred Debits.....	62,237,659.02	55,949,793.74	Accum Provision for Pension & Postretirement Benefits....	20,244,990.19	32,200,381.25
Total.....	829,315,679.87	859,340,917.81	Total.....	2,134,088,024.88	2,166,844,242.17
Total Assets.....	\$ 8,186,935,413.69	\$ 7,900,554,524.90	Total Liabilities and Stockholders Equity.....	\$ 8,186,935,413.69	\$ 7,900,554,524.90

January 27, 2020

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2017 and 2016

Assets	<u>This Year</u>	<u>Last Year</u>	Liabilities and Proprietary Capital	<u>This Year</u>	<u>Last Year</u>
Utility Plant			Proprietary Capital		
Utility Plant at Original Cost.....	\$ 9,598,351,833.34	\$ 9,266,547,925.93	Common Stock.....	\$ 308,139,977.56	\$ 308,139,977.56
Less: Reserves for Depreciation and Amortization.....	<u>3,238,141,781.83</u>	<u>3,051,197,812.18</u>	Less: Common Stock Expense.....	321,288.87	321,288.87
Total.....	<u>6,360,210,051.51</u>	<u>6,215,350,113.75</u>	Paid-In Capital.....	583,858,083.00	583,858,083.00
Investments			Other Comprehensive Income.....	0.01	(1,813,203.72)
Electric Energy, Inc.....	-	-	Retained Earnings.....	<u>1,857,820,153.08</u>	<u>1,826,711,396.78</u>
Ohio Valley Electric Company.....	250,000.00	250,000.00	Total Proprietary Capital.....	<u>2,749,496,924.78</u>	<u>2,716,574,964.75</u>
Nonutility Property-Less Reserve.....	<u>178,713.89</u>	<u>971,313.10</u>	Other Long-Term Debt.....	<u>2,342,209,368.15</u>	<u>2,341,674,017.12</u>
Total.....	<u>428,713.89</u>	<u>1,221,313.10</u>	Total Long-Term Debt.....	<u>2,342,209,368.15</u>	<u>2,341,674,017.12</u>
Current and Accrued Assets			Total Capitalization.....	<u>5,091,706,292.93</u>	<u>5,058,248,981.87</u>
Cash.....	12,877,873.43	7,343,610.10	Current and Accrued Liabilities		
Temporary Cash Investments.....	1,864,128.22	142,502.24	Notes Payable.....	<u>44,957,426.11</u>	<u>15,999,230.01</u>
Accounts Receivable-Less Reserve.....	272,519,622.89	225,673,073.32	Accounts Payable.....	150,204,014.46	90,647,649.83
Accounts Receivable from Associated Companies.....	-	(38,000.73)	Accounts Payable to Associated Companies.....	53,209,388.21	56,193,623.00
Materials and Supplies-At Average Cost			Customer Deposits.....	30,584,515.17	28,877,637.76
Fuel.....	62,248,036.43	98,479,707.05	Taxes Accrued.....	18,835,542.00	45,124,109.95
Plant Materials and Operating Supplies.....	49,287,221.38	44,941,734.36	Interest Accrued.....	16,161,239.77	16,021,675.40
Stores Expense.....	11,598,192.93	10,876,430.46	Miscellaneous Current and Accrued Liabilities.....	<u>22,780,946.37</u>	<u>22,444,763.30</u>
Emission Allowances.....	131,237.73	135,180.30	Total.....	<u>345,823,072.09</u>	<u>275,308,588.95</u>
Prepayments.....	<u>16,269,726.44</u>	<u>16,185,362.57</u>	Deferred Credits and Other		
Total.....	<u>426,796,039.45</u>	<u>403,739,599.67</u>	Accumulated Deferred Income Taxes.....	1,053,661,822.45	1,489,601,766.50
Deferred Debits and Other			Investment Tax Credit.....	93,857,853.57	95,774,039.57
Unamortized Debt Expense.....	<u>18,055,102.03</u>	<u>19,221,807.12</u>	Regulatory Liabilities.....	744,309,850.76	145,201,850.99
Unamortized Loss on Bonds.....	<u>8,826,063.15</u>	<u>9,436,062.85</u>	Customer Advances for Construction.....	842,195.92	1,521,114.39
Accumulated Deferred Income Taxes.....	262,271,175.46	219,266,223.71	Asset Retirement Obligations.....	234,928,553.13	288,674,251.98
Deferred Regulatory Assets.....	416,947,624.84	443,231,694.58	Other Deferred Credits.....	1,381,941.38	1,542,816.97
Other Deferred Debits.....	<u>51,082,349.23</u>	<u>53,815,745.05</u>	Miscellaneous Long-Term Liabilities.....	3,421,396.66	1,989,404.19
Total.....	<u>857,282,314.71</u>	<u>845,071,543.31</u>	Accum Provision for Pension & Postretirement Benefits....	<u>74,784,140.67</u>	<u>107,519,754.42</u>
Total Assets.....	<u>\$ 7,644,717,119.56</u>	<u>\$ 7,465,382,569.83</u>	Total.....	<u>2,207,187,754.54</u>	<u>2,131,824,999.01</u>
			Total Liabilities and Stockholders Equity.....	<u>\$ 7,644,717,119.56</u>	<u>\$ 7,465,382,569.83</u>

January 25, 2018

Case No. 2020-00349

Attachment to Response to AG-KIUC-1 Question No. 107

Page 2 of 3

Arbough

Kentucky Utilities Company
Comparative Balance Sheets as of December 31, 2015 and 2014

Assets	This Year	Last Year	Liabilities and Proprietary Capital	This Year	Last Year
Utility Plant			Proprietary Capital		
Utility Plant at Original Cost.....	\$ 9,082,008,901.23	\$ 8,667,708,179.24	Common Stock.....	\$ 308,139,977.56	\$ 308,139,977.56
Less: Reserves for Depreciation and Amortization.....	2,849,851,989.11	2,798,968,737.30	Less: Common Stock Expense.....	321,288.87	321,288.87
Total.....	<u>6,232,156,912.12</u>	<u>5,868,739,441.94</u>	Paid-In Capital.....	563,858,083.00	563,858,083.00
			Other Comprehensive Income.....	(1,627,215.32)	(1,232,509.32)
			Retained Earnings.....	1,809,303,187.19	1,728,986,178.85
			Unappropriated Undistributed Subsidiary Earnings.....	-	-
Investments			Total Proprietary Capital.....	<u>2,679,352,743.56</u>	<u>2,599,430,441.22</u>
Electric Energy, Inc.....	-	-	Other Long-Term Debt.....	<u>2,341,130,601.99</u>	<u>2,090,768,151.28</u>
Ohio Valley Electric Company.....	250,000.00	250,000.00	Total Long-Term Debt.....	<u>2,341,130,601.99</u>	<u>2,090,768,151.28</u>
Nonutility Property-Less Reserve.....	971,313.10	971,313.10			
Special Fund.....	-	-	Total Capitalization.....	<u>5,020,483,345.55</u>	<u>4,690,198,592.50</u>
Total.....	<u>1,221,313.10</u>	<u>1,221,313.10</u>	Current and Accrued Liabilities		
			ST Notes Payable to Associated Companies.....	-	-
Current and Accrued Assets			Notes Payable.....	<u>47,997,120.00</u>	235,592,322.03
Cash.....	7,202,017.55	7,069,896.19	Accounts Payable.....	<u>108,367,451.69</u>	153,042,157.99
Special Deposits.....	-	-	Accounts Payable to Associated Companies.....	39,179,663.47	46,590,075.29
Temporary Cash Investments.....	4,253,005.98	4,066,766.38	Customer Deposits.....	26,249,503.24	27,255,893.31
Accounts Receivable-Less Reserve.....	205,696,526.12	222,270,038.81	Taxes Accrued.....	20,427,557.49	13,974,039.11
Accounts Receivable from Associated Companies.....	847,986.14	59,765,612.63	Interest Accrued.....	15,760,841.12	11,624,315.19
Notes Receivable from Associated Companies.....	-	-	Dividends Declared.....	-	-
Materials and Supplies-At Average Cost			Miscellaneous Current and Accrued Liabilities.....	<u>23,097,128.83</u>	<u>58,617,072.54</u>
Fuel.....	97,051,050.68	99,282,055.68	Total.....	<u>281,074,267.84</u>	<u>546,695,875.46</u>
Plant Materials and Operating Supplies.....	41,183,222.05	38,655,516.05	Deferred Credits and Other		
Stores Expense.....	9,371,629.69	10,574,015.53	Accumulated Deferred Income Taxes.....	1,404,626,225.28	1,104,287,220.74
Emission Allowances.....	140,355.60	158,872.09	Investment Tax Credit.....	93,018,937.57	94,865,139.57
Prepayments.....	7,513,311.96	7,629,373.84	Regulatory Liabilities.....	153,390,896.28	136,098,871.38
Miscellaneous Current and Accrued Assets.....	-	-	Customer Advances for Construction.....	1,968,685.25	2,218,445.28
Total.....	<u>373,259,105.77</u>	<u>449,472,147.20</u>	Asset Retirement Obligations.....	362,143,424.48	210,966,863.53
			Other Deferred Credits.....	8,679,929.34	38,495,003.59
Deferred Debits and Other			Miscellaneous Long-Term Liabilities.....	2,343,039.61	2,049,991.68
Unamortized Debt Expense.....	<u>20,924,669.19</u>	18,614,826.72	Accum Provision for Pension & Postretirement Benefits..	<u>93,702,288.92</u>	<u>117,607,469.93</u>
Unamortized Loss on Bonds.....	<u>8,907,227.76</u>	9,590,735.30	Total.....	<u>2,119,873,426.73</u>	<u>1,706,589,005.70</u>
Accumulated Deferred Income Taxes.....	358,038,655.59	221,690,913.50	Total Liabilities and Stockholders Equity.....	<u>\$ 7,421,431,040.12</u>	<u>\$ 6,943,483,473.66</u>
Deferred Regulatory Assets.....	379,151,145.16	329,468,702.21			
Other Deferred Debits.....	<u>47,772,011.43</u>	<u>44,685,393.69</u>			
Total.....	<u>814,793,709.13</u>	<u>624,050,571.42</u>			
Total Assets.....	<u>\$ 7,421,431,040.12</u>	<u>\$ 6,943,483,473.66</u>			

January 27, 2016

Case No. 2020-00349

Attachment to Response to AG-KIUC-1 Question No. 107

Page 3 of 3

Arbough

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 108

Responding Witness: Adrien M. McKenzie

- Q-108. Refer to Exhibit No. 8 attached to the Direct Testimony of Mr. McKenzie.
- a. Provide the source documents for the allowed return on equity by year.
 - b. Provide updated allowed ROEs through 2020 using the latest available data. Provide this data by rate case decision.
- A-108.
- a. Please refer to the file “WP-36”, which is included in Mr. McKenzie’s workpapers provided in response to PSC 2-61.
 - b. As indicated at footnote (a) to page 3 of Exhibit No. 8, Mr. McKenzie’s application of the risk premium approach relies on the annual average allowed ROE for electric utilities in “general” rate cases, as reported in RRA Regulatory Focus. RRA Regulatory Focus has not yet published comparable data for 2020. See the response to PSC 2-63(b) for an excerpt from the October 20, 2020 edition of RRA Regulatory Focus listing the results of individual rate cases through the end of September 30, 2020.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 109

Responding Witness: Daniel K. Arbough

- Q-109. Provide any analyses performed by Mr. McKenzie, Mr. Arbough, or other persons at LG&E and KU that quantify the credit metrics used by Standard and Poor's and/or Moody's showing that Mr. McKenzie's recommended ROE is necessary to maintain the Companies' financial integrity and its current credit ratings. If no such analyses were performed, please so state. If such analyses were performed, please provide all associated spreadsheets and supporting documentation.
- A-109. The credit metrics for the Company, and the supporting calculations have been provided in the response to DOD-FEA 1-40. The requested ROE is not set based on the credit metric impacts, but rather is set based on what is a fair, just, and reasonable return that allows the Company to attract the necessary equity capital in the market. However, the ROE is a key component impacting the credit metrics of the Company.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 110

Responding Witness: Adrien M. McKenzie

- Q-110. Please provide all work papers and supporting documentation used by Mr. McKenzie in the preparation of his Direct Testimony and Exhibits. Please include the analyses Mr. McKenzie used to select the proxy group, the companies excluded from the group, and the basis for such exclusion.
- A-110. See the response to PSC 2-61 for all workpapers and supporting documentation used by Mr. McKenzie, except for court and regulatory orders, which are publicly available from the respective authorities. With respect to the determination of the proxy group, please refer to the tab labelled "Proxy Group Criteria" in the Excel file "2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsx" in response to PSC 1-56.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 111

Responding Witness: Adrien M. McKenzie

- Q-111. Refer to page 22, lines 6 through 13 of Mr. McKenzie's Direct Testimony. If not provided previously, please provide the supporting analysis, work papers, and documentation for the increase in beta values for the proxy group and LG&E/KU.
- A-111. Please refer to the tab labelled "Proxy Group Risk Measures" in the Excel file provided as "2020_Att_KU_LGE_PSC_1-56_Exhibit_McKenzie_2-12.xlsm" in response to PSC 1-56 which contains the tabulation and calculation of the average beta values for the proxy group. Please refer to the file "WP-29" provided in response to PSC 2-61 for the Value Line source documents supporting the average beta of 0.87. Please refer to the file "WP 40" provided in response to PSC 2-61 for the Value Line source documents supporting the average beta of 0.56. Please refer to the file "WP-41" provided in response to PSC 2-61 for the Value Line source documents supporting the 0.70 and 1.10 beta values for LGE/KU's parent, PPL.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 112

Responding Witness: Robert M. Conroy / William Steven Seelye

- Q-112. Reference the Conroy testimony generally. Explain whether the EV charging classes are being subsidized by the other classes. If so, provide the amount of the subsidy through the forecast test period.
- A-112. No, the EV charging classes are not being subsidized by the other classes. See the testimonies of Mr. Conroy at page 18 and Mr. Seelye at page 65.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC

Dated January 8, 2021

Case No. 2020-00349

Question No. 113

Responding Witness: David S. Sinclair

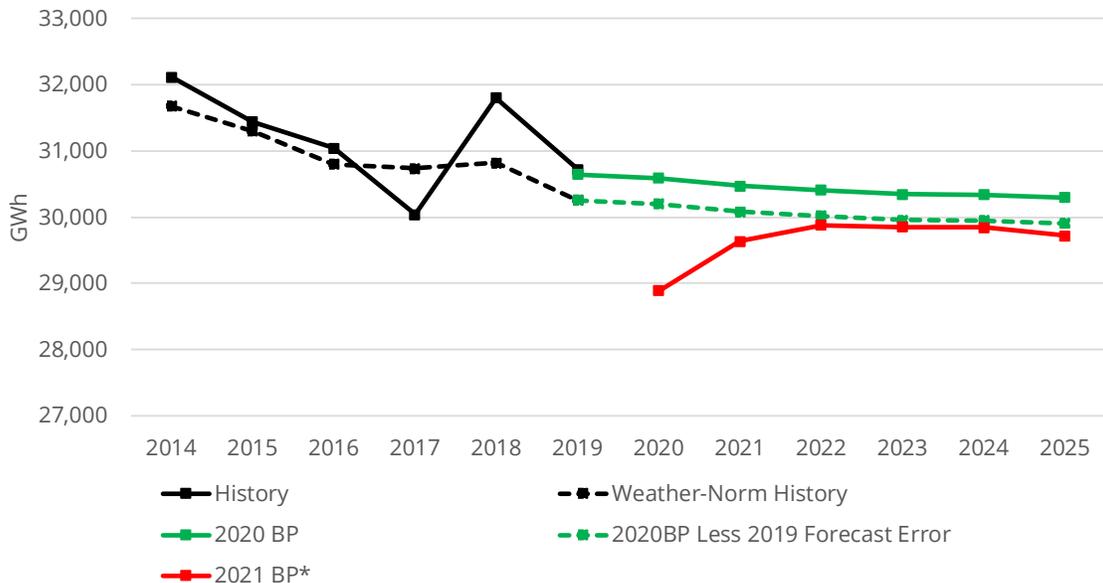
- Q-113. With regard to the direct testimony of David Sinclair generally, please explain if the COVID pandemic has skewed or altered the sales and load forecasts for KU, LG&E electric, and/or LG&E gas. If the answer is affirmative, please quantify the adjustments (alterations) due to COVID by Company and rate schedule. If the answer is negative, please explain why recognition was not given to the COVID pandemic within the Companies' sales and load forecasts.
- A-113. The impacts of the COVID pandemic on the sales and load forecasts are discussed in Mr. Sinclair's testimony on pages 6 through 9. The forecast was not "skewed or altered" to reflect the pandemic but rather incorporates the economic and usage implications of the pandemic directly in the forecast process as discussed in Mr. Sinclair's testimony.

As discussed by Mr. Sinclair, there is no doubt that the pandemic has had a real impact on the Companies' sales, some of which will likely dissipate over time and others that could be long-lasting. The Companies have not quantified this impact by company and rate. A way to approximate the pandemic impacts on the total sales forecast is to adjust the 2021 BP forecast for the error in the 2020 BP forecast for the year 2019. The table below contains the Companies' actual and forecasted sales as presented in Figure 2 on page 8 of Mr. Sinclair's testimony. In 2019, weather-normalized actual sales were 390 GWh lower than the 2020BP forecast. Holding the 2019 forecast error constant and assuming the only reason the 2021 BP forecast differs from the 2020 BP forecast is due to COVID (which is not likely), then an estimate of the impact of the COVID pandemic on the 2021BP forecast is created by subtracting this difference from the plan-over-plan forecast differences (2021BP less 2020BP). Using this approach, the likely impact of the pandemic largely disappears by 2022.

Historical and Forecasted Billed Sales (GWh, Combined Companies)**

	[A]	[B]	[C]	[D]	[E]	[E]-[D]
Year	History	Weather-Norm History	2020 BP	2020 BP [C] Less 2019 Forecast Error	2021 BP*	Est. COVID Impact
2014	32,115	31,681				
2015	31,445	31,301				
2016	31,046	30,798				
2017	30,043	30,736				
2018	31,808	30,818				
2019	30,725	30,255	30,645	30,255		
2020			30,594	30,204	28,893	-1,311
2021			30,476	30,086	29,638	-448
2022			30,411	30,021	29,882	-140
2023			30,350	29,960	29,852	-108
2024			30,342	29,952	29,847	-105
2025			30,302	29,912	29,718	-193

Historical and Forecasted Billed Sales (GWh, Combined Companies)**



*2020 value includes 5 months of actual sales and 7 months of forecasted sales.

**Data excludes sales to departed municipal customers.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 114

Responding Witness: David S. Sinclair / William Steven Seelye

- Q-114. With regard to the forecasted electric hourly energy sales by class as referenced in the direct testimony of witness David Sinclair, page 12, lines 1-6, please provide each forecasted hourly energy (MWH) sales for:
- a. each KY Jurisdictional retail tariff rate schedule for KU;
 - b. each KY Jurisdictional retail special contract for KU;
 - c. VA Jurisdictional (total) for KU;
 - d. FERC Jurisdictional for KU;
 - e. KU unaffiliated (non-LG&E) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
 - f. KU sales to LG&E;
 - g. each KY Jurisdictional retail tariff rate schedule for LG&E;
 - h. each KY Jurisdictional retail special contract for LG&E;
 - i. FERC Jurisdictional for LG&E;
 - j. LG&E unaffiliated (non-KU) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
 - k. LG&E sales to KU; and,
 - l. total system (KU and LG&E combined).

In this response, indicate if each hourly energy amount in (a) through (l) is measured at generation or at meter. If hourly amounts in (a) through (l) are

measured at meter, please provide loss factors for each item in (a) through (l). Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

- A-114. See attachment being provided in Excel format. These items are measured at generation.

There are no data to provide for items (b) and (i).

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 115

Responding Witness: David S. Sinclair / William Steven Seelye

- Q-115. For each of the last two years (or the most recent 24 months available), provide the following MWH sales (loads) for every hour during the 24-month period:
- a. each KY Jurisdictional retail tariff rate schedule for KU;
 - b. each KY Jurisdictional retail special contract for KU;
 - c. VA Jurisdictional (total) for KU;
 - d. FERC Jurisdictional for KU;
 - e. KU unaffiliated (non-LG&E) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
 - f. KU sales to LG&E;
 - g. each KY Jurisdictional retail tariff rate schedule for LG&E;
 - h. each KY Jurisdictional retail special contract for LG&E;
 - i. FERC Jurisdictional for LG&E;
 - j. LG&E unaffiliated (non-KU) off-system sales (sales for resale) delineated for each type of off-system sales as shown in the Company's FERC Form 1 (e.g., RQ, OS, SF, etc.);
 - k. LG&E sales to KU; and,
 - l. total system (KU and LG&E combined).

In this response, indicate if each hourly energy amount in (a) through (l) is measured at generation or at meter. If hourly amounts in (a) through (l) are measured at meter, please provide loss factors for each item in (a) through (l).

Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

A-115. Items (a), (c-d), and (g-h): See attachment being provided in Excel format. These items are measured at generation. The attachment contains class hourly loads for the 12-months including January 2019, February 2020, and March 2019 to December 2019. The Companies have not estimated class hourly loads for the 12 months prior to January 2019.

Items (e-f) and (j-l): See attachment being provided in Excel format. These items are measured at generation.

There are no data to provide for items (b) and (i).

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 116

Responding Witness: Christopher M. Garrett

- Q-116. For the most recent 36-month period, please provide monthly number of customers and kWh sales by jurisdictional rate schedule separately for KU and LG&E electric.
- A-116. See the responses to Question No. 180, part a for kWh sales by jurisdictional rate schedule and Question No. 180, part c for monthly numbers of customers for KU.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 117

Responding Witness: David S. Sinclair

Q-117. With regard to the generation, sales for resale and purchased power forecasts referenced in the direct testimony of witness David Sinclair, pages 23-28, please provide:

- a. forecasted hourly (MWH) generation output by unit;
- b. forecasted hourly KU purchased power from unaffiliated companies;
- c. forecasted hourly KU purchased power from LG&E;
- d. forecasted hourly LG&E purchased power from unaffiliated companies;
- e. forecasted hourly LG&E purchased power from KU; and,
- f. forecasted curtailed hourly (MW or MWH) load (at generation).

Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

A-117. See attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 118

Responding Witness: David S. Sinclair

- Q-118. For each of the last two years (or the most recent 24 months available), provide the following:
- a. hourly (MWH) generation output by unit;
 - b. hourly KU purchased power from unaffiliated companies;
 - c. hourly KU purchased power from LG&E;
 - d. hourly LG&E purchased power from unaffiliated companies;
 - e. hourly LG&E purchased power from KU; and,
 - f. curtailed hourly (MW or MWH) load (at generation).

Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.

- A-118. See attachment being provided in Excel format.

For part (a), the net generation volumes for Trimble County Units 1 and 2 reflect the Companies' collective 75 percent ownership share of these units.

For part (f), the attachment includes the load curtailed during this period from testing the Companies' direct load control ("DLC") system. There were no actual DLC events or physical curtailments of customers participating in the Companies' curtailable service rider tariffs during this period.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 119

Responding Witness: David S. Sinclair

- Q-119. With regard to forecasted wholesale market electricity prices discussed in the Attachment to Filing Requirement Tab 16 – 807 KAR 5:001 Sec. 16(7)(c) G [Generation Forecast Process], please provide hourly wholesale electricity prices as utilized in the Companies' Generation Forecast Process. Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.
- A-119. See attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 120

Responding Witness: David S. Sinclair

- Q-120. For each of the last two years (or most recent 24 months available), provide actual hourly wholesale market electricity prices consistent with the PJM-South Import pricing point as discussed in the Attachment to Filing Requirement Tab 16 – 807 KAR 5:001 Sec. 16(7)(c) G [Generation Forecast Process]. Provide in executable electronic (Excel, Microsoft Access or ASCII comma-delimited) format.
- A-120. See attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 121

Responding Witness: David S. Sinclair / William Steven Seelye

- Q-121. With regard to Mr. Seelye's LOLP study, provide a detailed explanation along with all mathematical formulae showing how hourly LOLP was calculated. In this response, specifically explain how off-system sales, wholesale purchases of power, curtailment capabilities, reserve margin requirements, and outage rates are considered, evaluated, and quantified in developing hourly LOLP.
- A-121. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

No off-system sales and wholesale purchases of power were modeled in the LOLP study. In addition to the Companies' firm supply-side capacity resources, the analysis assumed that the Companies could curtail up to 127 MW of CSR-related load. The generation resources in the LOLP study reflect the characteristics of the Companies' existing resources that were acquired to meet the Companies' forecasted load obligations, based on the reserve margin target range developed in the Companies' 2018 Integrated Resource Plan ("IRP"). Forecasted outage rates are included in the generating unit characteristics considered in the LOLP analysis.

The entire attachment is
Confidential and
provided separately
under seal.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 122

Responding Witness: David S. Sinclair / William Steven Seelye

Q-122. With regard to Mr. Seelye's LOLP study, provide all analyses, workpapers, spreadsheets, etc. showing the following:

- a. forecasted hourly system Loss of Load Probability;
- b. forecasted hourly system load (MW);
- c. forecasted hourly forced outage MW (by unit as available);
- d. forecasted hourly planned outage MW (by unit as available);
- e. forecasted available generation production from KU/LG&E-owned facilities;
- f. forecasted wholesale sales (if applicable or utilized in determining hourly LOLP);
- g. forecasted wholesale purchased power (if applicable or utilized in determining hourly LOLP); and,
- h. forecasted required reserve margin (percent or MW as applicable).

In this response, provide all data and formulae necessary to replicate each hourly system Loss of Load Probability. Provide all data in executable electronic (Excel) format. If data is not available in Excel format, provide ASCII comma-delimited format with all fields defined.

A-122.

- a. See attachment being provided in Excel format.
- b. See the response to part (a).
- c. PROSYM's process for calculating LOLP does not simulate forced outages for each unit on an hourly basis.

- d. Planned outages were not considered in the LOLP calculation.
- e. See attachments being provided in Excel format. Note that maximum capacity in the outage rate table varies by month.
- f. See the response to Question No. 121.
- g. See the response to Question No. 121.
- h. See the response to Question No. 123(a).

In addition, a number of PROSYM files are being provided in response to this request. The Company is providing them on the Company's HighQ site subject to a motion to deviate because the files cannot be uploaded to the Commission's website. Access to the HighQ site will be available to the Commission and all parties to the case.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 123

Responding Witness: David S. Sinclair

- Q-123. Provide LG&E and KU individual and combined generation reserve margins for the following period:
- a. fully forecasted test year;
 - b. most recent actual period during 2020;
 - c. actual as of year-end 2019; and,
 - d. actual as of year-end 2018.
- A-123. The Companies develop a target reserve margin range for planning sufficient supply resources to reliably meet the combined Companies' anticipated peak hour load obligation and account for resource outage risk and load variability at every moment of the year. At any point in time, the Companies take actions to address momentary demand and system operational issues. The planning reserve margin is designed to allow the combined Companies to reliably address these uncertainties at the lowest reasonable cost. For further information regarding the development of the Companies' target reserve margin, see the Companies' 2018 Integrated Resource Plan. Because the Companies jointly plan the combined system, the Companies do not develop a target reserve margin range or a planning reserve margin for each individual company on a standalone basis. Although a comparison of each company's allocated supply resources and forecasted summer peak load can be performed, there is no target reserve margin range to which these figures can be compared.
- a. The planning reserve margin for the forecasted test period is 24.4 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years is higher than the forecasted summer peak demand in the forecasted test period by 41.8 percent for KU and by 0.4 percent for LG&E.
 - b. The planning reserve margin for 2020 was 28.5 percent for the combined Companies, which is based on the Companies' 2021 Business Plan peak load

forecast reflecting the impact of COVID-19 in 2020. The capacity of the supply resources that have been allocated to each company over the years was higher than the 2020 forecasted summer peak by 47.8 percent for KU and by 3.2 percent for LG&E.

- c. The planning reserve margin for 2019 was 23.5 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years was higher than the 2019 forecasted summer peak demand by 33.5 percent for KU and by 9.7 percent for LG&E.
- d. The planning reserve margin for 2018 was 24.7 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years was higher than the 2018 forecasted summer peak by 30.3 percent for KU and by 16.4 percent for LG&E.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 124

Responding Witness: William Steven Seelye

Q-124. Provide all workpapers, analyses, spreadsheets, etc. showing the development of each class' weighted LOLP as shown in Exhibit WSS-21. Provide in executable electronic (Excel) format.

A-124. See attachment provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 125

Responding Witness: David S. Sinclair

- Q-125 With regard to the Companies' 2018 Integrated Resource Plan ("IRP"),⁹ please provide an unredacted copy of Table 8-6 (page 8-11 of Report).
- A-125. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to the Commission's November 16, 2018 Order in Case No. 2018-00348.

⁹ In Re: *Electronic 2018 Joint Integrated Resource Plan Of Louisville Gas And Electric Company And Kentucky Utilities Company*, Case No. 2018-00348

CONFIDENTIAL INFORMATION REDACTED

Table 8-6: Cost of Fuel (\$/MMBtu)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bluegrass/EKPC																
Brown 1																
Brown 2																
Brown 3																
Brown 5																
Brown 6																
Brown 7																
Brown 8																
Brown 9																
Brown 10																
Brown 11																
Brown Solar																
Cane Run 7																
Cane Run 11																
Dix Dam 1-3																
Ghent 1																
Ghent 2																
Ghent 3																
Ghent 4																
Haefling 1-2																
Mill Creek 1																
Mill Creek 2																
Mill Creek 3																
Mill Creek 4																
Ohio Falls 1-8																
Paddy's Run 11																
Paddy's Run 12																
Paddy's Run 13																
Trimble County 1																
Trimble County 2																
Trimble County 5																
Trimble County 6																
Trimble County 7																
Trimble County 8																
Trimble County 9																
Trimble County 10																
Zorn 1																
Solar Share																

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. KU does not maintain gross investment information in the forecasted test period at generating unit level.
- e. KU does not maintain depreciation reserve information in the forecasted test period at a generating unit level.
- f. KU 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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		

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 the attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. Note that KU serves these customers through contracts filed with and approved by the Federal Energy Regulatory Commission. Therefore, the costs and revenues associated with these customers are not included in the costs and revenues at issue in this proceeding.

- a. KU's sale for resale customers are Bardstown Municipal Light & Water and Nicholasville City Utilities.
- b. KU provides partial requirements service to each of these customers through contracts filed with and approved by the Federal Energy Regulatory Commission.
- c. Neither customer has a contractually limited contract demand. See the attachment for the peak demands in the forecasted test year. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
- d. The current demand charges are \$15.101/kW and \$15.016/kW for Bardstown and Nicholasville, respectively.
- e. The current energy charges are \$0.0320402/kWh and \$0.0320085/kWh for Bardstown and Nicholasville, respectively.
- f. Each customer has a monthly fixed Direct Assignment Charge, which are \$15,120.31 and \$740.06 for Bardstown and Nicholasville, respectively.
- g. Each customer pays the current OATT transmission rate for Network Integration Transmission Service rate for the amount of transmission they use each month.
- h. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
- i. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
- j. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
- k. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.
- l. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The attachments are
Confidential and
provided separately
under seal in PDF
and Excel format.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. This question is not applicable to KU.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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, subtransmission, 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU information.

Kentucky Utilities Company
Case No. 2020-00349
Curtailable Service Rider

	<u>Curtailable Demand, kVA</u>
<u>CSR-1 Primary Voltage Service</u>	
Time-of-Day Primary (TODP)	65,695
<u>CSR-2 Transmission Voltage Service</u>	
Retail Transmission Service (RTS)	573,919
Fluctuating Load Service (FLS)	2,409,406
<u>CSR-2 Primary Voltage Service</u>	
Time-of-Day Primary (TODP)	135,835

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. KU 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 KU 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	140,490
2	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	30,575
3	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	58,079
4	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	117,805
5	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	1,163,549
6	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	388,742
7	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	78,433
8	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	104,141
9	01/04/2018 08:00	01/04/2018 22:00	14	Buy Through Option	121,502
1	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	139,797
2	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	63,750
3	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	90,407
4	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	118,013
5	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	1,094,278
6	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	357,123
7	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	45,016
8	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	108,238
9	01/05/2018 09:00	01/05/2018 23:00	14	Buy Through Option	153,582
1	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	67,139
2	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	61,445
3	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	93,292
4	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	108,804
5	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	1,134,875
6	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	351,710
7	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	41,404
8	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	101,388
9	01/16/2018 10:00	01/16/2018 23:00	13	Buy Through Option	141,299
1	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	72,519
2	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	63,400
3	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	84,511
4	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	117,115
5	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	1,195,301
6	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	395,315

Customer	Start Date/Time	End Date/Time	Hours	Type	kWh billed during Buy Through Period
7	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	45,296
8	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	105,809
9	01/17/2018 09:00	01/17/2018 23:00	14	Buy Through Option	153,821
1	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	101,525
2	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	47,229
3	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	81,161
4	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	84,735
5	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	813,402
6	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	316,737
7	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	38,264
8	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	75,367
9	12/14/2018 10:00	12/14/2018 20:00	10	Buy Through Option	122,853
1	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	51,647
2	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	33,541
3	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	74,315
4	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	84,083
5	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	651,758
6	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	319,453
7	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	38,894
8	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	76,682
9	12/17/2018 10:00	12/17/2018 20:00	10	Buy Through Option	127,233
1	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	68,198
2	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	68,832
3	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	109,750
4	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	108,985
5	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	945,626
6	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	412,533
7	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	51,422
8	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	93,698
9	03/05/2019 09:00	03/05/2019 22:00	13	Buy Through Option	125,197
1	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	124,673
2	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	62,641
3	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	86,980

Customer	Start Date/Time	End Date/Time	Hours	Type	kWh billed during Buy Through Period
4	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	63,959
5	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	655,819
6	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	339,269
7	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	76,863
8	10/29/2020 09:00	10/29/2020 20:00	11	Buy Through Option	71,885
1	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	100,907
2	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	39,381
3	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	75,427
4	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	28,092
5	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	702,486
6	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	282,734
7	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	62,335
8	10/30/2020 09:00	10/30/2020 18:00	9	Buy Through Option	57,110
1	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	104,213
2	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	56,145
3	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	80,242
4	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	30,915
5	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	909,954
6	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	310,807
7	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	68,083
8	11/03/2020 10:00	11/03/2020 20:00	10	Buy Through Option	61,900

Notes: KU Customer #9's CSR 2 rider ended Sept 2019. All times are EST.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. KU and LG&E 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU loss factors.

Company	Voltage Level of Service	Energy Loss Factor	Demand Loss Factor
KU	Transmission	1.02827	1.03295
KU	Primary Substation	1.03382	1.03883
KU	Primary	1.05011	1.06632
KU	Secondary	1.07651	1.09017

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. See attachment being provided in Excel format.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. This request is not applicable to KU.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 144

Responding Witness: William Steven Seelye

Q-144. With regard to the Company's KU CCOSS, explain why Rate PS-Secondary, Rate TODSecondary, 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 145

Responding Witness: N/A

Q-145. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-145. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 146

Responding Witness: N/A

Q-146. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-146. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU TE devices was 1,112, and the number of unmetered KU TE devices was 273.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU LE devices was 160, and the number of unmetered KU LE devices was 4.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 1,385 KU TE bills rendered in the month of December 2020.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 164 KU LE bills rendered in the month of December 2020.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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_Forecasted.zip" and
"2020_Att_LGE_PSC_1-56_ElecScheduleM_Forecasted.xlsx".

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 2-30.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 2-30.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 2-30. 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 155

Responding Witness: N/A

Q-155. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-155. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 156

Responding Witness: N/A

Q-156. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-156. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 157

Responding Witness: N/A

Q-157. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-157. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 158

Responding Witness: N/A

Q-158. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-158. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 159

Responding Witness: N/A

Q-159. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-159. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 160

Responding Witness: N/A

Q-160. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-160. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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. This customer takes service on the KU Time-of-Day Primary rate. Based upon the Companies' understanding, the timeline for the Phoenix Paper expansion is uncertain. The Companies developed their forecast for Phoenix Paper based on discussions with them. To view this forecast, 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.

The attachment is
Confidential and
provided separately
under seal in Excel
format.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 is not different from the 2021 Business Plan Electric Forecast.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 purchase¹) 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 rate³ 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 cost⁵

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.

Attachment 2 is
Confidential and
provided separately
under seal in Excel
format.

Kentucky Utilities Company

P.S.C. No. 19, First Revision of Original Sheet No. 55
Canceling P.S.C. No. 19, Original Sheet No. 55

Standard Rate Rider

SQF

Small Capacity Cogeneration and Small Power Production Qualifying Facilities

APPLICABLE

In all territory served.

AVAILABILITY

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
Lexington, Kentucky

KENTUCKY PUBLIC SERVICE COMMISSION
Kent A. Chandler Executive Director 
EFFECTIVE 6/30/2020 PURSUANT TO 807 KAR 5:011 SECTION 9 (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

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						



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 Kentucky Utilities Company Purchase Rates for Small Capacity Cogeneration and Small Power Production Qualifying Facilities*

Dear Mr. Chandler:

Kentucky Utilities Company ("KU") files herewith revised sheets of its Tariff P.S.C. No. 19 Original Sheet Nos. 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.

KU 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

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State Regulation and Rates
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Mr. Kent A. Chandler
May 28, 2020

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 KU's Small Capacity Cogeneration and Small Power Production Qualifying Facilities, better estimating the operational impact of these facilities to KU'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,

A handwritten signature in black ink, appearing to read "Michael E. Hornung", with a long horizontal flourish extending to the right.

Michael E. Hornung

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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

**KU 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



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 – KU

Dear Mr. Conroy:

Transmitted herewith are the results of the 2010 Analysis of System Losses for LG&E and KU Services Company's Kentucky Utilities (KU) 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 KU and LG&E 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 KU 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,

A handwritten signature in cursive script that reads "Paul M. Normand".

Paul M. Normand
Principal

Enclosure
PMN/tjp

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

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Appendix A – Results of LG&E (KU and LG&E) Transmission System 2010 Loss Analysis

Appendix B – Results of KU 2010 Loss Analysis

Appendix C – Discussion of Hoebel Coefficient



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

1.0 EXECUTIVE SUMMARY

This report presents KU 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 KU. 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 – KU Power System

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

<u>Voltage Level of Service</u>	<u>Total KU</u> (a)	<u>Delivery System (Excludes Transmission)</u> (b)	<u>Recalculated Total KU With Appendix A Transmission Losses</u> (c) (d) = 1/(c)	
<u>Demand (kW)</u>				
Transmission ¹	1.03295	1.00000	1.02805	0.97272
Primary Substation	1.03883	1.00569	1.03390	0.96721
Primary	1.06632	1.03230	1.06126	0.94228
Secondary	1.09017	1.05539	1.08499	0.92167
<u>Energy (kWh)</u>				
Transmission ¹	1.02827	1.00000	1.02271	0.97779
Primary Substation	1.03382	1.00540	1.02823	0.97255
Primary	1.05011	1.02124	1.04444	0.95745
Secondary	1.07651	1.04692	1.07069	0.93398
Losses – Net System Input ²	5.75% MWh 7.12% MW			
Losses – Net System Output ³	6.10% MWh 7.67% 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 LG&E 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 KU 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 1.05539 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.



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

The net system input shown in Table 1 represents the MWh losses of 5.75% for the total KU load using calculated losses divided by the associated input energy to the system. The 7.12% represents the MW losses also using system input as a reference. The net system output reference shown in Table 1 represents MWh losses of 6.10% and MW losses of 7.17%. 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.

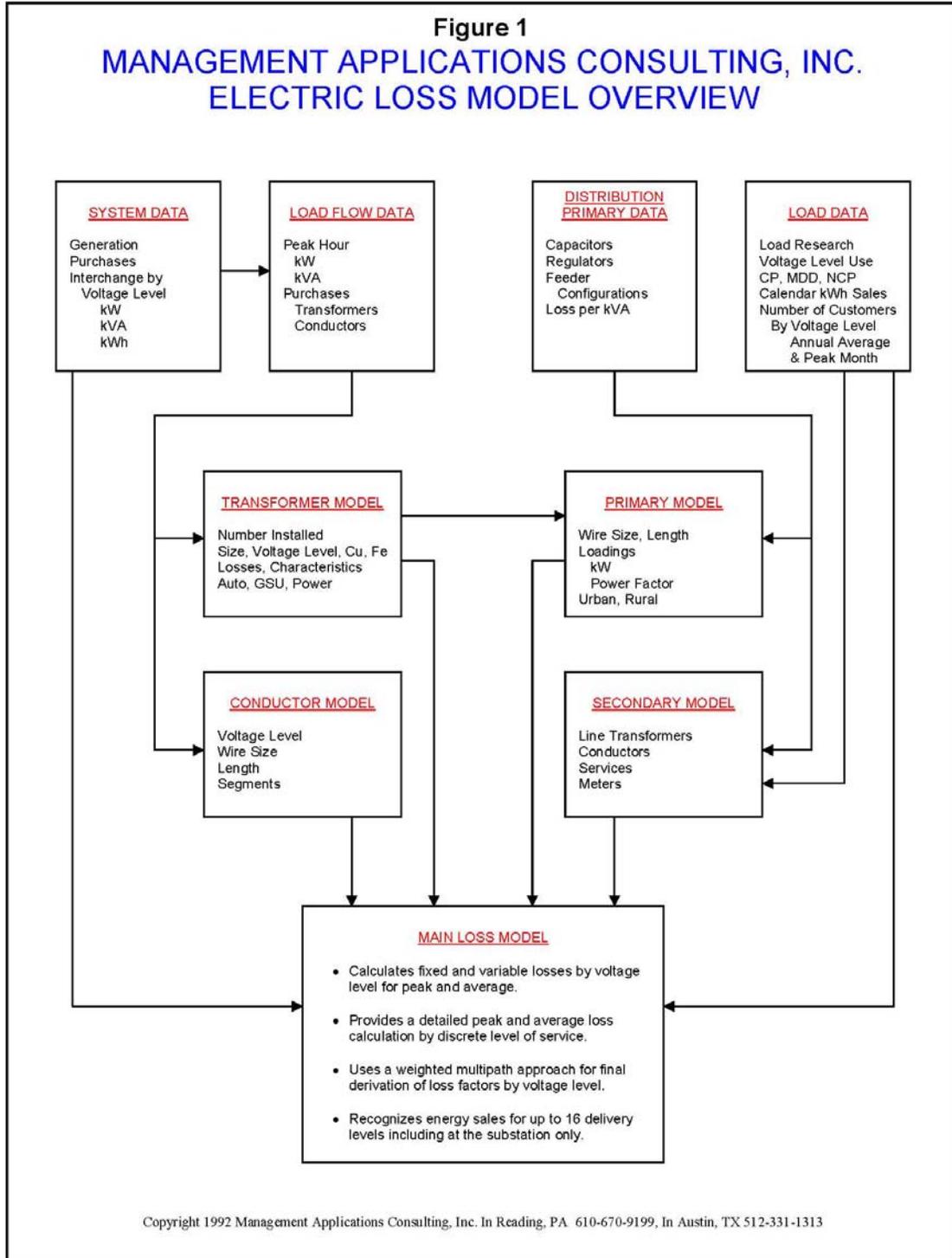
The derivation of the cumulative loss factors (Appendix B) shown in Table 1 (columns (a) and (b)) have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service 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.

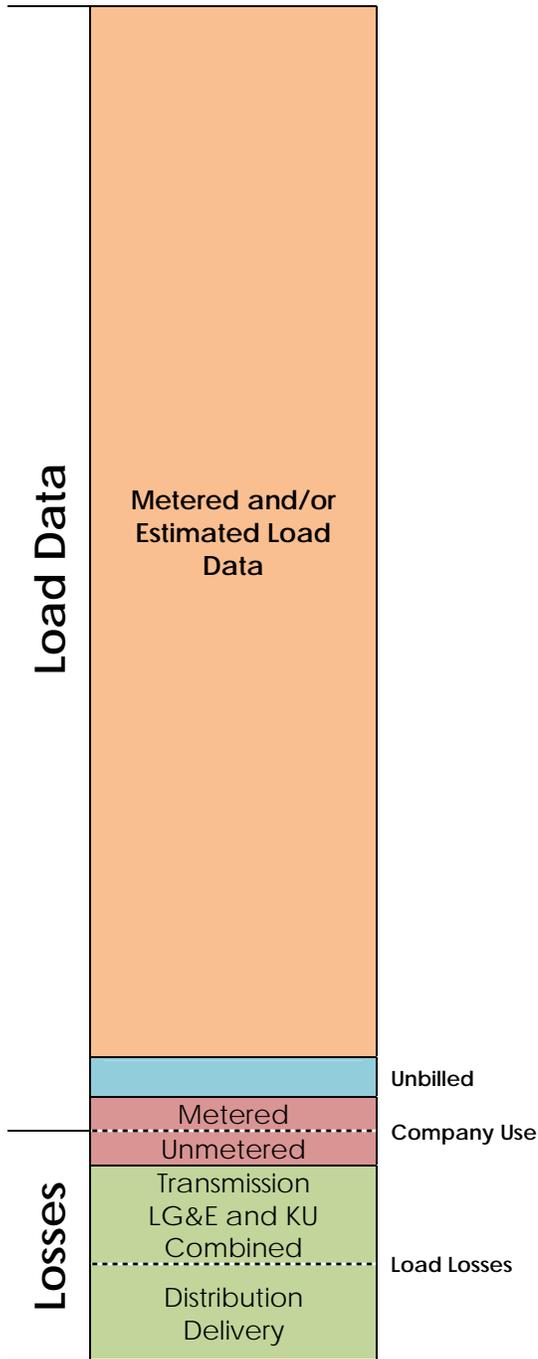


LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – KU Power System



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

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



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

2.0 INTRODUCTION

This report of the 2010 Analysis of System Losses for the KU 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 model⁴ 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).

⁴Copyright by Management Applications Consulting, Inc.



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

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.



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

- 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 LG&E 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 KU 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 KU power system.

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

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

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.



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

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 KU'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.



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

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.

Distribution Substations

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.

Primary Lines

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.



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



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

4.0 DISCUSSION OF RESULTS

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

Exhibit 1 – Summary of Company Data

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.

Exhibit 2 – Summary of Conductor Information

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.

Exhibit 3 – Summary of Transformer Information

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.

Exhibit 4 – Summary of Losses Diagram (2 Pages)

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.

Exhibit 5 – Summary of Sales and Calculated Losses

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.



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

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 KU 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.



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

Appendix A

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



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

Pages 1-2	Index
Schedule 1, Page 3	<p>Presents the summary loss results of the calculated hourly losses for the Company's LGE and KU control areas at the annual peak hour and for the annual average losses for all hours of the year.</p> <p>Calculated loss factors are applicable to the metered (output) sales level.</p> <p>All data is from Schedule 2.</p> <p>Section I - Summarizes the transmission loss results with GSU losses included.</p> <p>Section II - Summarizes GSU only losses.</p> <p>Section III - Summarizes the transmission only losses excluding GSU losses.</p>
Schedule 1A, Page 4	<p>Presents the summary loss results of the calculated hourly losses for the Company's LGE control areas at the annual peak hour and for the annual average losses for all hours of the year.</p>
Schedule 1B, Page 5	<p>Presents the summary loss results of the calculated hourly losses for the Company's KU control areas at the annual peak hour and for the annual average losses for all hours of the year.</p>
Schedule 2, Page 6	<p>Summary of the summer and winter peak hour MW and annual MWH losses for LGE and KU and the total system.</p> <p>Results are detailed by segment and season: Summer (June, July, August, and September), Winter (all months excluding Summer months).</p> <p>Loss data is from Schedule 3.</p>
Schedule 3, Page 7	<p>Summary of MW and MWH loss results for each control area by season and voltage level.</p>
Schedule 4, Page 8	<p>Summary of seasonal peak hour MW and average MWH loss results for LGE by season and voltage level.</p>

**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.

Page 16 3 - Corona Loss Calculations
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.

Seelye

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

I TRANSMISSION LOSSES WITH GSU		LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
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)		
A. GSU LOSSES (2)		FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
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
III TRANSMISSION ONLY LOSSES		LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
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

I TRANSMISSION LOSSES WITH GSU

	LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
A. DEMAND					
<u>Peak (MW) Summer (June - September)</u>					
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					
<u>Annual MWH</u>					
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

II TRANSMISSION GSU LOSSES

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

III TRANSMISSION ONLY LOSSES

	LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
A. DEMAND LOSSES					
<u>Peak (MW) Summer (June - September)</u>					
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					
<u>Annual MWH</u>					
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

Seelye

KU 2011 TRANSMISSION LOSS ANALYSIS

I TRANSMISSION LOSSES WITH GSU

	LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
A. DEMAND					
<u>Peak (MW) Summer (June - September)</u>					
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					
<u>Annual MWH</u>					
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

II TRANSMISSION GSU LOSSES

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

III TRANSMISSION ONLY LOSSES

	LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)	
A. DEMAND LOSSES					
<u>Peak (MW) Summer (June - September)</u>					
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					
<u>Annual MWH</u>					
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

Seelye

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

TRANSMISSION LOSSES WITH GSU	PEAK (SUMMER)		PEAK (OTHER)		ANNUAL	
	Total (MW)	% of Total System Losses	Total (MW)	% of Total System Losses	Total Annual (MWH)	% of Total System Losses
<u>LGE</u>						
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%	
<u>KU</u>						
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%	
<u>TOTAL LGE & KU</u>						
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 2/11/11 8:00 February-11	SUMMER 7/11/11 16:00 July-11	OTHER	SUMMER
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	<u>4,911</u>	<u>4,662</u>	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	<u>249</u>	<u>204</u>	249.00	204.00
17 BTM (0.5%) - OMU Network Load	112	182		
18 BTM (0.5%) - KMPA Gen	-	49		
19 Total BTM	<u>112</u>	<u>231</u>		
20 Losses at 0.5%	0.560	1.155	5,160.00	4,866.00
21 Losses from Schedule 5, Lines 1 and 8			-198.71	-151.41
22 Peak MW Load			<u>4,961.29</u>	<u>4,714.59</u>

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	<u>1,791</u>	<u>2,737</u>	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	<u>309</u>	<u>303</u>	309.00	303.00
31 LGE to KU	1,228	1,020	1,228.00	1,020.00
			<u>3,328.00</u>	<u>4,060.00</u>
32 Losses from Schedule 4, Lines 1 and 8			-27.75	-57.95
33 Peak MW Load			<u>3,300.25</u>	<u>4,002.05</u>

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

	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	Other	Summer
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

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

Appendix B

Results of KU
2010 Loss Analysis



KENTUCKY UTILITIES

Seelye
EXHIBIT 1SUMMARY OF COMPANY DATA

ANNUAL PEAK	4,354 MW
ANNUAL SYSTEM INPUT	23,358,179 MWH
ANNUAL SALES	22,015,243 MWH
SYSTEM LOSSES @ INPUT	1,342,936 or 5.75%
SYSTEM LOAD FACTOR	61.2%

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	% TOTAL	--- MWH ---	% TOTAL
		Input		Input	
TRANS	500,345,138 69	138.9	44.78%	642,185	47.82%
		3.19%		2.75%	
PRIM SUBS	33,12,1	20.6	6.64%	102,336	7.62%
		0.47%		0.44%	
PRIMARY	33,12,1	91.5	29.49%	267,414	19.91%
		2.10%		1.14%	
SECONDARY	120/240,to,477	59.2	19.09%	331,001	24.65%
		1.36%		1.42%	
TOTAL		310.2	100.00%	1,342,936	100.00%
		7.12%		5.75%	

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS			
		DEMAND (Peak)		ENERGY (Annual)	
		d	1/d	e	1/e
TOT TRANS	500,345,138 69	1.03295	0.96810	1.02827	0.97251
PRIM SUBS	33,12,1	1.03883	0.96262	1.03382	0.96728
PRIMARY	33,12,1	1.06632	0.93781	1.05011	0.95228
SECONDARY	120/240,to,477	1.09017	0.91729	1.07651	0.92892

SUMMARY OF CONDUCTOR INFORMATION

DESCRIPTION	CIRCUIT MILES	LOADING % RATING	----- MW LOSSES ----- LOAD NO LOAD TOTAL
--- BULK ----- 500 KV OR GREATER -----			
TIE LINES	0.0	0.00%	0.000 0.000 0.000
<u>BULK TRANS</u>	<u>0.0</u>	<u>0.00%</u>	<u>0.000</u> <u>0.000</u> <u>0.000</u>
SUBTOT	0.0		0.000 0.000 0.000
--- TRANS ----- 138 KV TO 500.00 KV -----			
TIE LINES	0	0.00%	0.000 0.000 0.000
TRANS1	345 KV	0.0	0.000 0.000 0.000
<u>TRANS2</u>	<u>138 KV</u>	<u>0.0</u>	<u>0.000</u> <u>0.000</u> <u>0.000</u>
SUBTOT	0.0		0.000 0.000 0.000
--- SUBTRANS ----- 35 KV TO 138 KV -----			
TIE LINES	0	0.00%	0.000 0.000 0.000
SUBTRANS1	KV	0.0	0.000 0.000 0.000
SUBTRANS2	KV	0.0	0.000 0.000 0.000
<u>SUBTRANS3</u>	<u>KV</u>	<u>0.0</u>	<u>0.000</u> <u>0.003</u> <u>0.003</u>
SUBTOT	0.0		0.000 0.003 0.003
PRIMARY LINES	16,372		80.472 4.246 84.718
SECONDARY LINES	3,708		4.160 0.000 4.160
SERVICES	7,637		9.210 1.131 10.341
TOTAL	27,717		93.843 5.380 99.223

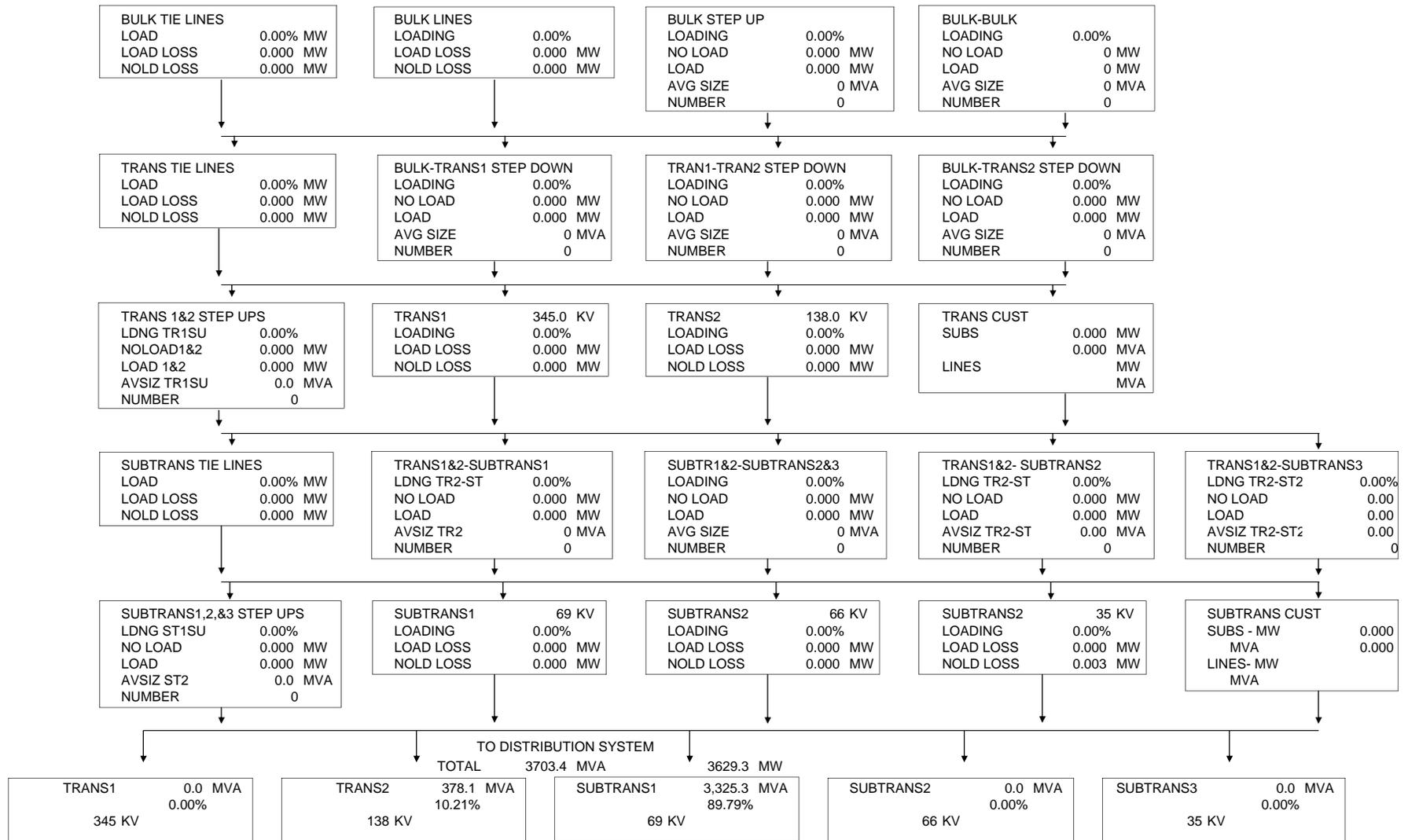
----- MWH LOSSES ----- LOAD NO LOAD TOTAL
0 0 0
<u>0</u> <u>0</u> <u>0</u>
0 0 0
0 0 0
<u>0</u> <u>0</u> <u>0</u>
0 0 0
0 0 0
<u>0</u> <u>26</u> <u>26</u>
0 26 26
230,573 37,193 267,766
11,528 0 11,528
29,961 9,910 39,872
272,062 47,130 319,192

SUMMARY OF TRANSFORMER INFORMATION

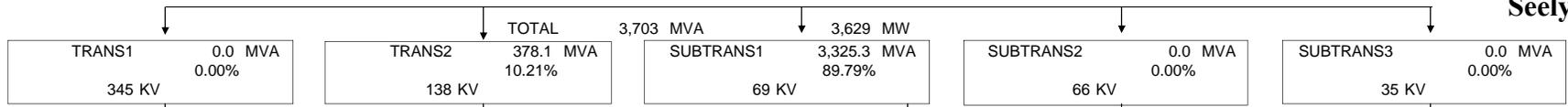
DESCRIPTION	KV CAPACITY		NUMBER TRANSFRM	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES			MWH LOSSES			
	VOLTAGE	MVA					LOAD	NO LOAD	TOTAL	LOAD	NO LOAD	TOTAL	
BULK STEP-UP	500	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0	
BULK - BULK		0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0	
BULK - TRANS1	345	0.0	0	0.0	0.00%	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	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	138	12	704.7	28	25.2	53.66%	378	0.878	0.836	1.715	3,041	6,042	9,083
TRANS2 -	138	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	279.0	18	15.5	39.75%	111	0.226	0.301	0.527	784	2,257	3,041
SUBTRAN1-	69	12	4,973.6	374	13.3	55.44%	2,758	7.347	6.518	13.865	25,435	47,736	73,171
SUBTRAN1-	69	1	957.4	164	5.8	47.72%	457	1.412	1.610	3.022	4,888	12,550	17,439
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			147.6	50	3.0	44.74%	66	0.198	0.200	0.398	686	1,750	2,437
LINE TRANSFRMR			9,359.1	229,808	40.7	31.58%	2,956	11.556	28.926	40.482	27,494	253,394	280,888
TOTAL			16,421	230,442				21.617	38.391	60.008	62,328	323,729	386,058

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK

4354 MW



FROM HIGH VOLTAGE SYSTEM



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	0	378	0	111	2,758	457	0	0	0	0	0	0
% SYS TOT	0.00%	0.00%	0.00%	0.00%	10.21%	0.00%	2.99%	74.46%	12.34%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.000	0.000	0.000	0.000	0.836	0.000	0.301	6.518	1.610	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.000	0.000	0.000	0.000	0.878	0.000	0.226	7.347	1.412	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	0.0	0.0	0.0	0.0	25.2	0.0	15.5	13.3	5.8	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	0	0	0	0	28	0	18	374	164	0	0	0	0	0	0
DIVERSITY RATIO	0.000	0.000	0.000	0.000	1.000	0.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES

LOADING	3538.386 MW
@ SYS PF	3610.598 MVA
LOAD LOSS	80.472 MW
NOLD LOSS	4.246 MW
TOT LOSS	84.718 MW

PRIM/PRIM TRANSF

LOADING	66.024 MW
NOLD LOSS	0.200 MW
LOAD LOSS	0.198 MW
AVG SIZE	2.95
NUMBER	50

PRIM CUST LOADS

NO LINES	0.000 MW
CUST SUB	0.000 MVA
NO LINES	71.500 MW
CO. SUB	72.959 MVA
PRIM WITH	750.000 MW
LINES	815.217 MVA

LINE TRANSFORMERS

LOADING	2703.270 MW	MVA	2996.392
NOLD LOSS	28.926	MW	
LOAD LOSS	11.556	MW	
AVG SIZE	40.7	KVA	
NUMBER	229808		

SECONDARY LINES

LOAD	851.123 MW
LOAD LOSS	4.160 MW
NOLD LOSS	0.000 MW
TOT LOSS	4.160 MW

NO SECONDARY LINES

LOAD	1811.665 MW
------	-------------

SERVICES

LOAD	2658.627 MW
LOAD LOSS	9.210 MW
NOLD LOSS	1.131 MW
TOT LOSS	10.341 MW

CUSTOMER SECONDARY LOAD

	2648.286 MW
--	-------------

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	0.000000	0.000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
6 TRANS GSU	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
7 TRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
TOTAL TRAN	4,354.0	7.58	131.32	138.90	1.032953	1.032953	23,358,179	59,557	582,628	642,185	1.0282702	1.0282702
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000		0	0	0	0	0.000000	
22 TOT TRANS LOSS FAC	4,354.0	7.58	131.32	138.90	1.032953	1.032953	23,358,179	59,557	582,628	642,185	1.028270	1.0282702
DISTRIBUTION SUBST												
TRANS1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
TRANS2	370.5	0.84	0.88	1.71	1.004649	0.000000	1,945,541	6,042	3,041	9,083	1.0046905	0.000000
SUBTR1	3,258.8	8.43	8.99	17.41	1.005372	0.000000	17,111,051	62,543	31,107	93,650	1.0055032	0.000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.000000	0.000000
WEIGHTED AVERAGE	3,629.3	9.26	9.86	19.13	1.005298	1.038426	19,056,592	68,585	34,148	102,733	1.0054202	1.0338436
PRIMARY INTRCHNGE	0.0				0.000000		0				0.000000	
PRIMARY LINES	3,538.2	4.25	80.67	84.92	1.024590	1.063961	17,239,383	37,193	231,259	268,453	1.0158184	1.0501973
LINE TRANSF	2,703.3	28.93	11.56	40.48	1.015203	1.080136	13,498,846	253,394	27,494	280,888	1.0212504	1.0725145
SECONDARY	2,662.8	0.00	4.16	4.16	1.001565	1.081827	13,217,958	0	11,528	11,528	1.0008729	1.0734507
SERVICES	2,658.6	1.13	9.21	10.34	1.003905	1.086051	13,206,431	9,910	29,961	39,872	1.0030283	1.0767013
TOTAL SYSTEM		=====	=====	=====				=====	=====	=====		
		51.15	246.78	297.93				428,640	917,018	1,345,658		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK EXPANSION FACTORS	
	a	b	c	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	574.0	18.9	592.9	1.03295	0.96810
PRIM SUBS	71.5	2.7	74.2	1.03843	0.96300
PRIM LINES	750.0	48.0	798.0	1.06396	0.93988
SECONDARY	<u>2,648.3</u>	<u>227.9</u>	<u>2,876.2</u>	1.08605	0.92077
TOTALS	4,043.8	297.5	4,341.3		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNUAL EXPANSION FACTORS	
	a	b	c	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	3,663,030	103,554	3,766,584	1.02827	0.97251
PRIM SUBS	1,713,570	57,993	1,771,563	1.03384	0.96726
PRIM LINES	3,472,084	174,289	3,646,373	1.05020	0.95220
SECONDARY	<u>13,166,559</u>	<u>1,009,893</u>	<u>14,176,452</u>	1.07670	0.92876
TOTALS	22,015,243	1,345,730	23,360,973		

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	592.91	3,766,584
PRIM SUBS	74.25	1,771,563
PRIM LINES	797.97	3,646,373
SECONDARY	2,876.17	14,176,452
SUBTOTAL	4,341.31	23,360,973
ACTUAL ENERGY	4,354.00	23,358,179
MISSMATCH	(12.69)	2,794
% MISSMATCH	-0.29%	0.01%

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	574.0	0.0	18.9	592.9	1.03295	0.96810
PRIM SUBS	71.5	0.0	2.8	74.3	1.03883	0.96262
PRIM LINES	750.0	0.0	49.7	799.7	1.06632	0.93781
SECONDARY	<u>2,648.3</u>	<u>0.0</u>	238.8	<u>2,887.1</u>	1.09017	0.91729
			310.2			
TOTALS	4,043.8	0.0	310.2	4,354.0		

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	3,663,030	0	103,554	3,766,584	1.02827	0.97251
PRIM SUBS	1,713,570	0	57,958	1,771,528	1.03382	0.96728
PRIM LINES	3,472,084	0	174,001	3,646,085	1.05011	0.95228
SECONDARY	<u>13,166,559</u>	<u>0</u>	1,007,420	<u>14,173,979</u>	1.07651	0.92892
			1,342,934			
TOTALS	22,015,243	0	1,342,936	23,358,177		

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	592.91	3,766,584
PRIM SUBS	74.28	1,771,528
PRIM LINES	799.74	3,646,085
SECONDARY	2,887.07	14,173,979
	4,354.00	23,358,177
ACTUAL ENERGY	4,354.00	23,358,179
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	10.34	10.31	39,872	39,876
Secondary Losses	4.16	4.15	11,528	11,529
Line Transformer Losses	40.48	40.38	280,888	280,916
Primary Line Losses	84.92	84.70	268,453	268,480
Distribution Substation Losses	19.13	19.08	102,733	102,744
<u>Transmission System Losses</u>	<u>138.90</u>	<u>138.90</u>	<u>642,185</u>	<u>642,185</u>
Total	297.93	297.52	1,345,658	1,345,730

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	-0.83	158
Secondary Losses	-0.33	46
Line Transformer Losses	-3.23	1,116
Primary Line Losses	-6.78	1,066
Distribution Substation Losses	-1.53	408
<u>Transmission System Losses</u>	<u>0.00</u>	<u>0</u>
Total	-12.69	2,794

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	11.14	3.6%	39,718	3.0%
Secondary Losses	4.48	1.4%	11,483	0.9%
Line Transformer Losses	43.61	14.1%	279,800	20.8%
Primary Line Losses	91.48	29.5%	267,414	19.9%
Distribution Substation Losses	20.61	6.6%	102,336	7.6%
<u>Transmission System Losses</u>	<u>138.90</u>	<u>44.8%</u>	<u>642,185</u>	<u>47.8%</u>
Total	310.21	100.0%	1,342,936	100.0%

Loss Factors by Segment

	MW	MWH	
Retail Sales from Service Drops	2,648.286	13,166,559	
<u>Adjusted Service Drop Losses</u>	<u>11.140</u>	<u>39,718</u>	
Input to Service Drops	2,659.426	13,206,277	
Service Drop Loss Factor	1.00421	1.00302	
Output from Secondary	2,659.426	13,206,277	
<u>Adjusted Secondary Losses</u>	<u>4.482</u>	<u>11,483</u>	
Input to Secondary	2,663.908	13,217,760	
Secondary Conductor Loss Factor	1.00169	1.00087	
Output from Line Transformers	2,663.908	13,217,760	
<u>Adjusted Line Transformer Losses</u>	<u>43.609</u>	<u>279,800</u>	
Input to Line Transformers	2,707.517	13,497,560	
Line Transformer Loss Factor	1.01637	1.02117	
Retail Sales from Primary	750.000	3,472,084	
Req. Whls Sales from Primary	0.000	0	
<u>Input to Line Transformers</u>	<u>2,707.517</u>	<u>13,497,560</u>	
Output from Primary Lines	3,457.517	16,969,644	
<u>Adjusted Primary Line Losses</u>	<u>91.477</u>	<u>267,414</u>	
Input to Primary Lines	3,548.994	17,237,058	
Primary Line Loss Factor	1.02646	1.01576	
Output PI from Distribution Substations	3,548.994	17,237,058	
Req. Whls Sales from Substations	0.000	0	
Retail Sales from Substations	71.500	1,713,570	
Total Output from Distribution Substations	3,620.494	18,950,628	
<u>Adjusted Distribution Substation Losses</u>	<u>20.606</u>	<u>102,336</u>	
Input to Distribution Substations	3,641.100	19,052,964	
Distribution Substation Loss Factor	1.00569	1.00540	
Retail Sales at from SubTransmission	574.000	3,663,030	
Req. Whls Sales from SubTransmission	0.000	0	
Non-Req. Whls Sales from SubTransmission	0.000	0	
Losses	0.000	0	4457
<u>Input to Distribution Substations</u>	<u>3,641.100</u>	<u>19,052,964</u>	
Output from SubTransmission	4,215.100	22,715,994	4,354.000
<u>SubTransmission System Losses</u>	<u>138.900</u>	<u>642,185</u>	<u>138.900</u>
Input to Transmission	4,354.000	23,358,179	138.900
TotTransmission System Loss Factor	1.03295	1.02827	138.900

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DEMAND MW		SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE						EXHIBIT 9
SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	SERVICES							
2	SALES	2,648.3		2,648.3				
3	LOSSES		11.1	11.1				
4	INPUT			2,659.4				
5	EXPANSION FACTOR	1.00421						
6	SECONDARY							
7	SALES							
8	LOSSES		4.5	4.5				
9	INPUT			2,663.9				
10	EXPANSION FACTOR	1.00169						
11	LINE TRANSFORMER							
12	SALES							
13	LOSSES		43.6	43.6				
14	INPUT			2,707.5				
15	EXPANSION FACTOR	1.01637						
16	PRIMARY							
17	SECONDARY			2,707.5				
18	SALES	750.0			750.0			
19	LOSSES		91.5	71.6	19.8			
20	INPUT			2,779.2	769.8			
21	EXPANSION FACTOR	1.02646						
22	SUBSTATION							
23	PRIMARY			2,779.2	769.8			
24	SALES	71.5				71.5		
25	LOSSES		20.6	15.8	4.4	0.4		
26	INPUT			2,795.0	774.2	71.9		
27	EXPANSION FACTOR	1.00569						
28	SUB-TRANSMISSION							
29	DISTRIBUTION SUBS							
30	SALES							
31	LOSSES							
32	INPUT							
33	EXPANSION FACTOR							
34	TRANSMISSION							
35	SUBTRANSMISSION							
36	DISTRIBUTION SUBS			2,795.0	774.2	71.9		
37	SALES	574.0						574.0
38	LOSSES		138.9	92.1	25.5	2.4		18.9
39	INPUT			2,887.1	799.7	74.3		592.9
40	EXPANSION FACTOR	1.03295						
41	TOTALS		310.2	238.8	49.7	2.8		18.9
42	% OF TOTAL		100%	76.97%	16.03%	0.90%		6.10%
43	SALES	4,043.8		2,648.3	750.0	71.5		574.0
44	% OF TOTAL	100.00%		65.49%	18.55%	1.77%		14.19%
45	INPUT	4,354.0		2,887.1	799.7	74.3		592.9
46	CUMMULATIVE EXPANSION LOSS FACTORS			1.09017	1.06632	1.03883		1.03295
	(from meter to system input)							

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Seelye

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	13,166,559		13,166,559				
3	LOSSES		39,718	39,718				
4	INPUT			13,206,277				
5	EXPANSION FACTOR	1.00302						
6	SECONDARY							
7	SALES							
8	LOSSES		11,483	11,483				
9	INPUT			13,217,760				
10	EXPANSION FACTOR	1.00087						
11	LINE TRANSFORMER							
12	SALES							
13	LOSSES		279,800	279,800				
14	INPUT			13,497,560				
15	EXPANSION FACTOR	1.02117						
16	PRIMARY							
17	SECONDARY			13,497,560				
18	SALES	3,472,084.000			3,472,084			
19	LOSSES		267,414	212,699	54,714			
20	INPUT			13,710,259	3,526,798			
21	EXPANSION FACTOR	1.01576						
22	SUBSTATION							
23	PRIMARY			13,710,259	3,526,798			
24	SALES	1,713,570				1,713,570		
25	LOSSES		102,336	74,037	19,045	9,253		
26	INPUT			13,784,297	3,545,844	1,722,823		
27	EXPANSION FACTOR	1.00540						
28	SUB-TRANSMISSION							
29	DISTRIBUTION SUBS							
30	SALES							
31	LOSSES							
32	INPUT							
33	EXPANSION FACTOR							
34	TRANSMISSION							
35	SUBTRANSMISSION							
36	DISTRIBUTION SUBS			13,784,297	3,545,844	1,722,823		
37	SALES	3,663,030					3,663,030	
38	LOSSES		642,185	389,684	100,242	48,705	103,554	
39	INPUT			14,173,981	3,646,085	1,771,528	3,766,584	
40	EXPANSION FACTOR	1.02827						
41	TOTALS		1,342,936	1,007,422	174,001	57,958	103,554	
42	% OF TOTAL		100%	75.02%	12.96%	4.32%	7.71%	
43	SALES	22,015,243		13,166,559	3,472,084	1,713,570	3,663,030	
44	% OF TOTAL	100.00%		59.81%	15.77%	7.78%	16.64%	
45	INPUT	23,358,179		14,173,981	3,646,085	1,771,528	3,766,584	
46	CUMMULATIVE EXPANSION LOSS FACTORS (from meter to system input)			1.07651	1.05011	1.03382	1.02827	

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

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:

$$\frac{(1) F_{LS} \cdot A_{LS}}{P_{LS}} \quad \text{where: } F_{LS} = \text{Loss Factor}$$

$$A_{LS} = \text{Average Losses}$$

$$P_{LS} = \text{Peak Losses}$$

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:

$$\frac{(2) F_{LD} \cdot A_{LD}}{P_{LD}} \quad \text{where: } F_{LD} = \text{Load Factor}$$

$$A_{LD} = \text{Average Load}$$

$$P_{LD} = \text{Peak Load}$$

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:

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

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):

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

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:

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

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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
- 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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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		

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU 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 lines.

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 2-137.
 - b. See the response to PSC 2-137.
 - c. See the response to PSC 2-137.
 - d. See the response to PSC 2-137.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 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 FLS tariff.

Date	Est. Time (EST)	Event	Response			FLS load before curtailment (MW)
			Spinning Reserves	Fast Start CT	Automatic Reserve Sharing	
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			FLS load before curtailment (MW)
			Spinning Reserves	Fast Start CT	Automatic Reserve Sharing	
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			FLS load before curtailment (MW)
			Spinning Reserves	Fast Start CT	Automatic Reserve Sharing	
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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 <ul style="list-style-type: none"> 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 <ul style="list-style-type: none"> 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	<p>Annual review</p> <ul style="list-style-type: none"> 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 	<p>C. Freibert</p> <p>C. Freibert</p> <p>C. Freibert</p> <p>M. Dalloul</p>	<p>January 31st, 2012</p>
6	<p>Annual review</p> <ul style="list-style-type: none"> Updated Attachment A to reflect 2012 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC 	<p>S. Homberg</p>	<p>January 31st, 2013</p>
7	<ul style="list-style-type: none"> Update Attachment A to reflect EKPC withdrawal for the TEE-RSG, reallocation of Contingency Reserve Requirements among members 	<p>S. Homberg</p>	<p>June 1st, 2013</p>
8	<p>Annual review</p> <ul style="list-style-type: none"> Updated Attachment A to reflect 2013 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC 	<p>S. Homberg</p>	<p>January 31st, 2014</p>
9	<p>Interim changes (Section 2.6.1.2, 2.6.1.3, add 2.7.2.1)</p> <ul style="list-style-type: none"> 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 	<p>S. Homberg</p>	<p>October 1st, 2014</p>
10	<p>Annual review</p> <ul style="list-style-type: none"> Updated Attachment A to reflect 2014 peak load data, and reallocation of Contingency Reserve Requirements, reviewed MSSC 	<p>S. Homberg</p>	<p>January 31st, 2015</p>

11	Annual review <ul style="list-style-type: none"> • 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 <ul style="list-style-type: none"> • 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 <ul style="list-style-type: none"> • 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 <ul style="list-style-type: none"> • 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 31 st , 2019
15	Annual Review <ul style="list-style-type: none"> • Grammatical clean-up (Reserves to Reserve) throughout • Section 2.3.1 – Removed reference to spinning reserve adjustment • Added Attachment C 	C. Lawson	January 31 st , 2020
16	Annual Review <ul style="list-style-type: none"> • Updated Attachment A • Updated Attachment C 	C. Lawson	January 31 st , 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 TCRSG Disturbances

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 within 60 minutes 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 ("T₀") 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 redispach 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. A voided 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

G. Wayne Talley
Manager, Transmission & Interchange Services
Phone: (423)751-6172
gwталley@tva.gov

Alternate

William George
Sr Specialist, Transmission & Interchange
Phone: (423)697-4124
wmgeorg2@tva.gov

For TVA:

Representative

Phillip Wiginton
Sr Prog Mgr, NERC TOCE
Phone: (423)751-4182
prwiginton@tva.gov

Alternate

Cameron Lawson
Manager, Balancing Authority
Phone: (423)751-4250
cclawson@tva.gov

For LGEE:

Representative

Charlie Martin
Manager, Generation Dispatch and Trading
Phone: (502)627-4242
Charlie.Martin@lge-ku.com

Alternate

Linn Oelker
Manager, Market Compliance
Phone: (502)627-3245
Linn.Oelker@lge-ku.com

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 \$0.031615/kWh for TODP and \$0.031008/kWh for RTS. The Company proposed an Energy charge of \$0.03161/kWh for TODP and \$0.03101/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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 189.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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	KU Share
AR Upload Process	\$ 13,121
Automate Cash receipts for AR process	\$ 13,378
Oracle eBusiness Suite Access Removal	\$ 14,466
Data to Identify Preliminary Retirements	\$ 10,348
Transmission Journal Entry	\$ 10,996
Zero Balance Account Reconciliations	\$ 10,703

c. The RPA assets at KU are included in the depreciation group KU-130300 – Misc. Intangible Plant which has an amortization life of approximately five years.

- d. For KU the salary and benefits associated with one full time headcount in 2019 was approximately \$54,872.
- e. For KU the salary associated with three interns in 2019 was approximately \$32,352, there are no benefits associated with interns.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 \$1,926,790 for KU.
- b. The amount of Depreciation – Existing Meters incorporated for the test year in this rate case is \$2,243,488 for KU.
- c. The amount of New Meters incorporated into the revenue requirement calculations for the test year is \$842,985 for KU. 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 KU. 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 \$20,625 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 \$596,553 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 \$10,491,567 for KU.
- h. The amount of Field Services incorporated for the test year in this rate case is \$8,436,171 for KU.
- i. The amount of Property Taxes – Existing Meters incorporated for the test year in this rate case is \$451.102 for KU.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.
- b. 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. Only the meter reading and field service implementation period savings are included within “Regulatory Liability Amortization” at an amount needed to bring the combined revenue requirement for AMI relative to the status quo to zero for the first 5 years post-implementation with the balance then returned to customers in post-implementation year 6. The “Reversal of ADIT – Retired

& Replaced Meters” is shown on page 4 of Exhibit KWB-2 and generally follows the amortization of the Regulatory Asset for retired and replaced meters as the tax basis of those assets would be zero, so the ADIT reverse as the remaining book value is amortized. The ADIT buildup for the AMI meters during the implementation period is included within Change in ADIT on page 4 of Exhibit KWB-2.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 199

Responding Witness: N/A

Q-199. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-199. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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 by year for each of the five years indicated in this schedule. Be sure to include, 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				
			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
Note	Project						
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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 in Excel
format.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 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)."

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 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 2012-0042810, 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.

¹⁰ https://psc.ky.gov/order_vault/orders_2016/201200428_04132016.pdf.

Year	Manufacturer	Model	Phase	Type	Count
2015	Asea Brown Boveri (ABB)	AB1	Single-Phase	Electromechanical	339
2015	Asea Brown Boveri (ABB)	AB1R	Single-Phase	Electromechanical	85
2015	Duncan	MKS	Single-Phase	Electromechanical	457
2015	Duncan	MQS	Single-Phase	Electromechanical	142
2015	Duncan	MS	Single-Phase	Electromechanical	493
2015	Duncan	MSII	Single-Phase	Electromechanical	3
2015	Duncan	MT14S	Three-Phase	Electromechanical	4
2015	Duncan	MT15S	Three-Phase	Electromechanical	4
2015	Elster	ABS3	Three-Phase	Electromechanical	3
2015	Elster	ABS7	Three-Phase	Electromechanical	8
2015	General Electric	I210	Single-Phase	Electronic	96
2015	General Electric	I-210	Single-Phase	Electronic	2
2015	General Electric	I50A	Single-Phase	Electromechanical	14
2015	General Electric	I50S	Single-Phase	Electromechanical	80
2015	General Electric	I55A	Single-Phase	Electromechanical	4
2015	General Electric	I55S	Single-Phase	Electromechanical	62
2015	General Electric	I-55S	Single-Phase	Electromechanical	1
2015	General Electric	I60S	Single-Phase	Electromechanical	609
2015	General Electric	I-60S	Single-Phase	Electromechanical	7
2015	General Electric	I70A	Single-Phase	Electromechanical	1
2015	General Electric	I70S	Single-Phase	Electromechanical	1598
2015	General Electric	I-70S	Single-Phase	Electromechanical	24
2015	General Electric	I70S2	Single-Phase	Electromechanical	14
2015	General Electric	IM50A	Single-Phase	Electromechanical	8
2015	General Electric	IM50S	Single-Phase	Electromechanical	32
2015	General Electric	IM60S	Single-Phase	Electromechanical	3
2015	General Electric	IM70A	Single-Phase	Electromechanical	2
2015	General Electric	IM70S	Single-Phase	Electromechanical	575
2015	General Electric	IM-70S	Single-Phase	Electromechanical	1
2015	General Electric	IMW70S	Single-Phase	Electromechanical	1
2015	General Electric	KV2C	Single-Phase	Electronic	4
2015	General Electric	EV4	Three-Phase	Electronic	3
2015	General Electric	EV-4	Three-Phase	Electronic	1
2015	General Electric	EV5	Three-Phase	Electronic	9
2015	General Electric	EV6	Three-Phase	Electronic	2
2015	General Electric	KV	Three-Phase	Electronic	10
2015	General Electric	KV2C	Three-Phase	Electronic	57
2015	General Electric	KV2CE	Three-Phase	Electronic	1
2015	General Electric	V3A	Three-Phase	Electromechanical	1
2015	General Electric	V612S	Three-Phase	Electromechanical	63
2015	General Electric	V62S	Three-Phase	Electromechanical	33
2015	General Electric	V63A	Three-Phase	Electromechanical	24
2015	General Electric	V63S	Three-Phase	Electromechanical	5
2015	General Electric	V64S	Three-Phase	Electromechanical	1

Year	Manufacturer	Model	Phase	Type	Count
2015	General Electric	V65A	Three-Phase	Electromechanical	4
2015	General Electric	V65S	Three-Phase	Electromechanical	95
2015	General Electric	V-65S	Three-Phase	Electromechanical	2
2015	General Electric	V66A	Three-Phase	Electromechanical	8
2015	General Electric	V66S	Three-Phase	Electromechanical	274
2015	General Electric	V-66S	Three-Phase	Electromechanical	2
2015	General Electric	VM612S	Three-Phase	Electromechanical	12
2015	General Electric	VM62S	Three-Phase	Electromechanical	12
2015	General Electric	VM63A	Three-Phase	Electromechanical	89
2015	General Electric	VM-63A	Three-Phase	Electromechanical	1
2015	General Electric	VM63S	Three-Phase	Electromechanical	20
2015	General Electric	VM64A	Three-Phase	Electromechanical	39
2015	General Electric	VM-64A	Three-Phase	Electromechanical	1
2015	General Electric	VM64S	Three-Phase	Electromechanical	104
2015	General Electric	VM65A	Three-Phase	Electromechanical	82
2015	General Electric	VM-65A	Three-Phase	Electromechanical	3
2015	General Electric	VM65S	Three-Phase	Electromechanical	310
2015	General Electric	VM-65S	Three-Phase	Electromechanical	1
2015	General Electric	VM66A	Three-Phase	Electromechanical	41
2015	General Electric	VM66S	Three-Phase	Electromechanical	313
2015	General Electric	VMW63S	Three-Phase	Electromechanical	3
2015	General Electric	VMW64S	Three-Phase	Electromechanical	4
2015	General Electric	VMW65S	Three-Phase	Electromechanical	7
2015	General Electric	VW63S	Three-Phase	Electromechanical	1
2015	Itron	C1S	Single-Phase	Electronic	165
2015	Itron	C1SD	Single-Phase	Electronic	50
2015	Itron	C1SR	Single-Phase	Electronic	21
2015	Itron	CN1SD	Three-Phase	Electronic	1
2015	Itron	CP1SD	Three-Phase	Electronic	32
2015	Itron	SS2S	Three-Phase	Electronic	1
2015	Itron	SS3S1D	Three-Phase	Electronic	3
2015	Itron	SS4S1D	Three-Phase	Electronic	20
2015	Itron	SS5S1D	Three-Phase	Electronic	3
2015	Itron	SV4S	Three-Phase	Electronic	4
2015	Landis + Gyr	AL	Single-Phase	Electronic	2
2015	Landis + Gyr	ALF	Single-Phase	Electronic	1
2015	Landis + Gyr	ALF4S	Single-Phase	Electronic	1
2015	Landis + Gyr	AX	Single-Phase	Electronic	10
2015	Landis + Gyr	AXR	Single-Phase	Electronic	4
2015	Landis + Gyr	AXS4	Single-Phase	Electronic	2
2015	Landis + Gyr	DXMS	Single-Phase	Electromechanical	35
2015	Landis + Gyr	DXMX	Single-Phase	Electromechanical	9
2015	Landis + Gyr	MS	Single-Phase	Electromechanical	9
2015	Landis + Gyr	MSII	Single-Phase	Electromechanical	48

Year	Manufacturer	Model	Phase	Type	Count
2015	Landis + Gyr	MX	Single-Phase	Electromechanical	295
2015	Landis + Gyr	OMRMX	Single-Phase	Electromechanical	6
2015	Landis + Gyr	AXLS4	Three-Phase	Electronic	35
2015	Landis + Gyr	AXRS4	Three-Phase	Electronic	115
2015	Landis + Gyr	AXS4	Three-Phase	Electronic	122
2015	Landis + Gyr	DXS2	Three-Phase	Electronic	12
2015	Landis + Gyr	RDS3	Three-Phase	Electronic	4
2015	Landis + Gyr	RXRS4	Three-Phase	Electronic	14
2015	Landis + Gyr	RXRS4e	Three-Phase	Electronic	1
2015	Landis + Gyr	RXS4	Three-Phase	Electronic	13
2015	Landis + Gyr	SSM2	Three-Phase	Electronic	3
2015	Sangamo	C1S	Single-Phase	Electronic	18
2015	Sangamo	C1SD	Single-Phase	Electronic	77
2015	Sangamo	C1SR	Single-Phase	Electronic	52
2015	Sangamo	J3MS	Single-Phase	Electromechanical	1
2015	Sangamo	J3MS11	Single-Phase	Electromechanical	7
2015	Sangamo	J3S	Single-Phase	Electromechanical	1
2015	Sangamo	J4EDS	Single-Phase	Electromechanical	1
2015	Sangamo	J4ES	Single-Phase	Electromechanical	2
2015	Sangamo	J4S	Single-Phase	Electromechanical	382
2015	Sangamo	J5DS	Single-Phase	Electromechanical	3
2015	Sangamo	J5S	Single-Phase	Electromechanical	1244
2015	Sangamo	J5SD	Single-Phase	Electromechanical	1
2015	Sangamo	CN1SD	Three-Phase	Electronic	3
2015	Sangamo	P20DA	Three-Phase	Electromechanical	2
2015	Sangamo	P20DAY	Three-Phase	Electromechanical	1
2015	Sangamo	P20DS	Three-Phase	Electromechanical	3
2015	Sangamo	P20S	Three-Phase	Electromechanical	5
2015	Sangamo	P30DA	Three-Phase	Electromechanical	1
2015	Sangamo	P30S	Three-Phase	Electromechanical	1
2015	Sangamo	S12S	Three-Phase	Electromechanical	6
2015	Sangamo	S2S	Three-Phase	Electromechanical	1
2015	Sangamo	S4DS	Three-Phase	Electromechanical	3
2015	Sangamo	S4S	Three-Phase	Electronic	7
2015	Sangamo	S5DS	Three-Phase	Electromechanical	2
2015	Sangamo	S5S	Three-Phase	Electromechanical	6
2015	Sangamo	S6DA	Three-Phase	Electromechanical	1
2015	Sangamo	S6DS	Three-Phase	Electromechanical	1
2015	Sangamo	S6S	Three-Phase	Electromechanical	2
2015	Sangamo	SL12S	Three-Phase	Electromechanical	22
2015	Sangamo	SS4S1D	Three-Phase	Electronic	66
2015	Sangamo	SS4S2D	Three-Phase	Electronic	2
2015	Sangamo	SV2SD	Three-Phase	Electronic	9
2015	Sangamo	SV3SD	Three-Phase	Electronic	18

Year	Manufacturer	Model	Phase	Type	Count
2015	Sangamo	SV4SD	Three-Phase	Electronic	214
2015	Sangamo	SV4ST	Three-Phase	Electronic	1
2015	Siemens	AX	Single-Phase	Electronic	23
2015	Siemens	AXR	Single-Phase	Electronic	1
2015	Westinghouse	D4S	Single-Phase	Electromechanical	638
2015	Westinghouse	D4SM	Single-Phase	Electromechanical	17
2015	Westinghouse	D5S	Single-Phase	Electromechanical	32
2015	Westinghouse	D5SM	Single-Phase	Electromechanical	1
2015	Westinghouse	D2A7M	Three-Phase	Electromechanical	1
2015	Westinghouse	D4S2M	Three-Phase	Electromechanical	1
2015	Westinghouse	D4S3	Three-Phase	Electromechanical	3
2015	Westinghouse	D4S3M	Three-Phase	Electromechanical	2
2015	Westinghouse	D4S5	Three-Phase	Electromechanical	1
2015	Westinghouse	D4S7M	Three-Phase	Electromechanical	2
2015	Westinghouse	D4S8	Three-Phase	Electromechanical	1
2015	Westinghouse	D4S8M	Three-Phase	Electromechanical	8
2015	Westinghouse	D5A3M	Three-Phase	Electromechanical	1
2015	Westinghouse	D5S3M	Three-Phase	Electromechanical	1
2015	Westinghouse	D5S7	Three-Phase	Electromechanical	1
2015	Westinghouse	D5S7M	Three-Phase	Electromechanical	2
2015	Westinghouse	D5S8	Three-Phase	Electromechanical	3
2016	Asea Brown Boveri (ABB)	AB1	Single-Phase	Electromechanical	92
2016	Asea Brown Boveri (ABB)	AB1R	Single-Phase	Electromechanical	73
2016	Duncan	MQS	Single-Phase	Electromechanical	129
2016	Duncan	MS	Single-Phase	Electromechanical	533
2016	Duncan	MSII	Single-Phase	Electromechanical	1
2016	Elster	ABS3	Three-Phase	Electromechanical	1
2016	General Electric	I210	Single-Phase	Electronic	108
2016	General Electric	I-210	Single-Phase	Electronic	1
2016	General Electric	I50A	Single-Phase	Electromechanical	26
2016	General Electric	I50S	Single-Phase	Electromechanical	84
2016	General Electric	I55A	Single-Phase	Electromechanical	2
2016	General Electric	I55S	Single-Phase	Electromechanical	62
2016	General Electric	I60S	Single-Phase	Electromechanical	589
2016	General Electric	I-60S	Single-Phase	Electromechanical	9
2016	General Electric	I70A	Single-Phase	Electromechanical	1
2016	General Electric	I70S	Single-Phase	Electromechanical	1646
2016	General Electric	I-70S	Single-Phase	Electromechanical	3
2016	General Electric	I70S2	Single-Phase	Electromechanical	10
2016	General Electric	IM50A	Single-Phase	Electromechanical	35
2016	General Electric	IM50S	Single-Phase	Electromechanical	22
2016	General Electric	IM-50S	Single-Phase	Electromechanical	1
2016	General Electric	IM70A	Single-Phase	Electromechanical	3
2016	General Electric	IM70S	Single-Phase	Electromechanical	317

Year	Manufacturer	Model	Phase	Type	Count
2016	General Electric	IM-70S	Single-Phase	Electromechanical	1
2016	General Electric	KV2C	Single-Phase	Electronic	5
2016	General Electric	EV4	Three-Phase	Electronic	8
2016	General Electric	EV5	Three-Phase	Electronic	30
2016	General Electric	EV6	Three-Phase	Electronic	13
2016	General Electric	I210+N	Three-Phase	Electronic	2
2016	General Electric	KV	Three-Phase	Electronic	17
2016	General Electric	KV2C	Three-Phase	Electronic	45
2016	General Electric	KV2CE	Three-Phase	Electronic	3
2016	General Electric	V612S	Three-Phase	Electromechanical	23
2016	General Electric	V62A	Three-Phase	Electromechanical	2
2016	General Electric	V62S	Three-Phase	Electromechanical	7
2016	General Electric	V63A	Three-Phase	Electromechanical	1
2016	General Electric	V65A	Three-Phase	Electromechanical	1
2016	General Electric	V65S	Three-Phase	Electromechanical	7
2016	General Electric	V66A	Three-Phase	Electromechanical	7
2016	General Electric	V66S	Three-Phase	Electromechanical	18
2016	General Electric	VM612S	Three-Phase	Electromechanical	6
2016	General Electric	VM63A	Three-Phase	Electromechanical	102
2016	General Electric	VM63S	Three-Phase	Electromechanical	23
2016	General Electric	VM64A	Three-Phase	Electromechanical	95
2016	General Electric	VM64S	Three-Phase	Electromechanical	148
2016	General Electric	VM-64S	Three-Phase	Electromechanical	1
2016	General Electric	VM65A	Three-Phase	Electromechanical	177
2016	General Electric	VM-65A	Three-Phase	Electromechanical	16
2016	General Electric	VM65S	Three-Phase	Electromechanical	245
2016	General Electric	VM66A	Three-Phase	Electromechanical	158
2016	General Electric	VM66S	Three-Phase	Electromechanical	277
2016	General Electric	VM-66S	Three-Phase	Electromechanical	2
2016	General Electric	VW66A	Three-Phase	Electromechanical	1
2016	Itron	C1S	Single-Phase	Electronic	222
2016	Itron	C1SD	Single-Phase	Electronic	128
2016	Itron	C1SL	Single-Phase	Electronic	3
2016	Itron	C1SR	Single-Phase	Electronic	27
2016	Itron	CN1S	Three-Phase	Electronic	4
2016	Itron	CP1SD	Three-Phase	Electronic	19
2016	Itron	SS3S1D	Three-Phase	Electronic	4
2016	Itron	SS4S	Three-Phase	Electronic	1
2016	Itron	SS4S1D	Three-Phase	Electronic	6
2016	Landis + Gyr	AL	Single-Phase	Electronic	9
2016	Landis + Gyr	ALF	Single-Phase	Electronic	6
2016	Landis + Gyr	ALF4S	Single-Phase	Electronic	2
2016	Landis + Gyr	AX	Single-Phase	Electronic	15
2016	Landis + Gyr	AXR	Single-Phase	Electronic	5

Year	Manufacturer	Model	Phase	Type	Count
2016	Landis + Gyr	DXMS	Single-Phase	Electromechanical	31
2016	Landis + Gyr	DXMX	Single-Phase	Electromechanical	10
2016	Landis + Gyr	MS	Single-Phase	Electromechanical	9
2016	Landis + Gyr	MSII	Single-Phase	Electromechanical	38
2016	Landis + Gyr	MX	Single-Phase	Electromechanical	273
2016	Landis + Gyr	OMRMX	Single-Phase	Electromechanical	11
2016	Landis + Gyr	AXLS4	Three-Phase	Electronic	2
2016	Landis + Gyr	AXRS4	Three-Phase	Electronic	61
2016	Landis + Gyr	AXS4	Three-Phase	Electronic	111
2016	Landis + Gyr	DXS2	Three-Phase	Electronic	6
2016	Landis + Gyr	RDS3	Three-Phase	Electronic	2
2016	Landis + Gyr	RXRS4	Three-Phase	Electronic	29
2016	Landis + Gyr	RXRS4e	Three-Phase	Electronic	3
2016	Landis + Gyr	RXS4	Three-Phase	Electronic	17
2016	Landis + Gyr	SSM2	Three-Phase	Electronic	3
2016	Sangamo	C1S	Single-Phase	Electronic	21
2016	Sangamo	C1SD	Single-Phase	Electronic	72
2016	Sangamo	C1SR	Single-Phase	Electronic	68
2016	Sangamo	J3DS	Single-Phase	Electromechanical	2
2016	Sangamo	J4DS	Single-Phase	Electromechanical	1
2016	Sangamo	J4EDS	Single-Phase	Electromechanical	5
2016	Sangamo	J4ES	Single-Phase	Electromechanical	3
2016	Sangamo	J4S	Single-Phase	Electromechanical	422
2016	Sangamo	J4SA	Single-Phase	Electromechanical	2
2016	Sangamo	J5S	Single-Phase	Electromechanical	1378
2016	Sangamo	CN1SD	Three-Phase	Electronic	8
2016	Sangamo	P20DA	Three-Phase	Electromechanical	1
2016	Sangamo	P20S	Three-Phase	Electromechanical	1
2016	Sangamo	P30DA	Three-Phase	Electromechanical	1
2016	Sangamo	S12S	Three-Phase	Electromechanical	2
2016	Sangamo	S4DS	Three-Phase	Electromechanical	1
2016	Sangamo	S4S	Three-Phase	Electronic	15
2016	Sangamo	S5DA	Three-Phase	Electromechanical	2
2016	Sangamo	SL12S	Three-Phase	Electromechanical	7
2016	Sangamo	SL4DS	Three-Phase	Electromechanical	1
2016	Sangamo	SM5SD	Three-Phase	Electromechanical	1
2016	Sangamo	SS3S1D	Three-Phase	Electronic	2
2016	Sangamo	SS4S1D	Three-Phase	Electronic	124
2016	Sangamo	SS4S1T	Three-Phase	Electronic	1
2016	Sangamo	SS4S2D	Three-Phase	Electronic	9
2016	Sangamo	SV2SD	Three-Phase	Electronic	2
2016	Sangamo	SV3SD	Three-Phase	Electronic	14
2016	Sangamo	SV4SD	Three-Phase	Electronic	207
2016	Sangamo	SV4ST	Three-Phase	Electronic	1

Year	Manufacturer	Model	Phase	Type	Count
2016	Siemens	AX	Single-Phase	Electronic	13
2016	Siemens	AX2SE	Single-Phase	Electronic	15
2016	Siemens	AXR	Single-Phase	Electronic	1
2016	Westinghouse	D2A	Single-Phase	Electromechanical	2
2016	Westinghouse	D2AM	Single-Phase	Electromechanical	4
2016	Westinghouse	D4S	Single-Phase	Electromechanical	624
2016	Westinghouse	D4SM	Single-Phase	Electromechanical	23
2016	Westinghouse	D5S	Single-Phase	Electromechanical	47
2016	Westinghouse	D4A3M	Three-Phase	Electromechanical	11
2016	Westinghouse	D4A7M	Three-Phase	Electromechanical	1
2016	Westinghouse	D4S3	Three-Phase	Electromechanical	3
2016	Westinghouse	D4S3M	Three-Phase	Electromechanical	7
2016	Westinghouse	D4S5	Three-Phase	Electromechanical	1
2016	Westinghouse	D4S7M	Three-Phase	Electromechanical	3
2016	Westinghouse	D4S8M	Three-Phase	Electromechanical	4
2016	Westinghouse	D5A2M	Three-Phase	Electromechanical	1
2016	Westinghouse	D5A3M	Three-Phase	Electromechanical	5
2016	Westinghouse	D5S2M	Three-Phase	Electromechanical	1
2016	Westinghouse	D5S3M	Three-Phase	Electromechanical	1
2016	Westinghouse	D5S7M	Three-Phase	Electromechanical	3
2017	Asea Brown Boveri (ABB)	AB1	Single-Phase	Electromechanical	103
2017	Asea Brown Boveri (ABB)	AB1R	Single-Phase	Electromechanical	86
2017	Duncan	MQS	Single-Phase	Electromechanical	135
2017	Duncan	MS	Single-Phase	Electromechanical	537
2017	Duncan	MSII	Single-Phase	Electromechanical	2
2017	Duncan	RDDMS	Single-Phase	Electromechanical	1
2017	Elster	ABS7	Three-Phase	Electromechanical	1
2017	General Electric	I210	Single-Phase	Electronic	155
2017	General Electric	I50A	Single-Phase	Electromechanical	16
2017	General Electric	I50S	Single-Phase	Electromechanical	70
2017	General Electric	I55A	Single-Phase	Electromechanical	7
2017	General Electric	I55S	Single-Phase	Electromechanical	59
2017	General Electric	I60S	Single-Phase	Electromechanical	726
2017	General Electric	I-60S	Single-Phase	Electromechanical	2
2017	General Electric	I70A	Single-Phase	Electromechanical	3
2017	General Electric	I70S	Single-Phase	Electromechanical	1656
2017	General Electric	I-70S	Single-Phase	Electromechanical	3
2017	General Electric	I70S2	Single-Phase	Electromechanical	19
2017	General Electric	IM50A	Single-Phase	Electromechanical	5
2017	General Electric	IM50S	Single-Phase	Electromechanical	14
2017	General Electric	IM60S	Single-Phase	Electromechanical	1
2017	General Electric	IM70A	Single-Phase	Electromechanical	6
2017	General Electric	IM70S	Single-Phase	Electromechanical	355
2017	General Electric	KV2C	Single-Phase	Electronic	12

Year	Manufacturer	Model	Phase	Type	Count
2017	General Electric	EV4	Three-Phase	Electronic	7
2017	General Electric	EV5	Three-Phase	Electronic	19
2017	General Electric	EV6	Three-Phase	Electronic	10
2017	General Electric	KV	Three-Phase	Electronic	18
2017	General Electric	KV2C	Three-Phase	Electronic	87
2017	General Electric	KV2CE	Three-Phase	Electronic	1
2017	General Electric	V612S	Three-Phase	Electromechanical	26
2017	General Electric	V-612-S	Three-Phase	Electromechanical	1
2017	General Electric	V62S	Three-Phase	Electromechanical	31
2017	General Electric	V65S	Three-Phase	Electromechanical	7
2017	General Electric	V66A	Three-Phase	Electromechanical	1
2017	General Electric	V66S	Three-Phase	Electromechanical	8
2017	General Electric	VM612S	Three-Phase	Electromechanical	7
2017	General Electric	VM62S	Three-Phase	Electromechanical	6
2017	General Electric	VM63A	Three-Phase	Electromechanical	18
2017	General Electric	VM63S	Three-Phase	Electromechanical	7
2017	General Electric	VM64A	Three-Phase	Electromechanical	45
2017	General Electric	VM64S	Three-Phase	Electromechanical	27
2017	General Electric	VM65A	Three-Phase	Electromechanical	106
2017	General Electric	VM65S	Three-Phase	Electromechanical	156
2017	General Electric	VM66A	Three-Phase	Electromechanical	71
2017	General Electric	VM66S	Three-Phase	Electromechanical	152
2017	General Electric	VM-66S	Three-Phase	Electromechanical	1
2017	General Electric	VMW63S	Three-Phase	Electromechanical	1
2017	General Electric	VMW64S	Three-Phase	Electromechanical	1
2017	Itron	C1S	Single-Phase	Electronic	197
2017	Itron	C1SD	Single-Phase	Electronic	134
2017	Itron	C1SL	Single-Phase	Electronic	1
2017	Itron	C1SR	Single-Phase	Electronic	23
2017	Itron	CN1S	Three-Phase	Electronic	3
2017	Itron	CN1SD	Three-Phase	Electronic	1
2017	Itron	CP1SD	Three-Phase	Electronic	38
2017	Itron	CP2SOAS	Three-Phase	Electronic	1
2017	Itron	SS3S1D	Three-Phase	Electronic	5
2017	Itron	SS4S	Three-Phase	Electronic	3
2017	Itron	SS4S1D	Three-Phase	Electronic	15
2017	Itron	SS4S2L	Three-Phase	Electronic	1
2017	Itron	SS5S1D	Three-Phase	Electronic	4
2017	Itron	SV4S	Three-Phase	Electronic	1
2017	Landis + Gyr	AL	Single-Phase	Electronic	10
2017	Landis + Gyr	ALF	Single-Phase	Electronic	2
2017	Landis + Gyr	AX	Single-Phase	Electronic	9
2017	Landis + Gyr	AXR	Single-Phase	Electronic	1
2017	Landis + Gyr	AXS4	Single-Phase	Electronic	1

Year	Manufacturer	Model	Phase	Type	Count
2017	Landis + Gyr	DXMS	Single-Phase	Electromechanical	22
2017	Landis + Gyr	DXMX	Single-Phase	Electromechanical	37
2017	Landis + Gyr	Focus AXR-Mesh	Single-Phase	Electronic	1
2017	Landis + Gyr	MS	Single-Phase	Electromechanical	20
2017	Landis + Gyr	MSII	Single-Phase	Electromechanical	37
2017	Landis + Gyr	MX	Single-Phase	Electromechanical	271
2017	Landis + Gyr	AXLS4	Three-Phase	Electronic	2
2017	Landis + Gyr	AXRS4	Three-Phase	Electronic	18
2017	Landis + Gyr	AXS4	Three-Phase	Electronic	107
2017	Landis + Gyr	DXS2	Three-Phase	Electronic	24
2017	Landis + Gyr	RDS3	Three-Phase	Electronic	3
2017	Landis + Gyr	RXRS3	Three-Phase	Electronic	1
2017	Landis + Gyr	RXRS4	Three-Phase	Electronic	42
2017	Landis + Gyr	RXRS4e	Three-Phase	Electronic	4
2017	Landis + Gyr	RXS4	Three-Phase	Electronic	21
2017	Sangamo	C1S	Single-Phase	Electronic	20
2017	Sangamo	C1SD	Single-Phase	Electronic	81
2017	Sangamo	C1SR	Single-Phase	Electronic	66
2017	Sangamo	J4EDS	Single-Phase	Electromechanical	4
2017	Sangamo	J4ES	Single-Phase	Electromechanical	1
2017	Sangamo	J4S	Single-Phase	Electromechanical	467
2017	Sangamo	J5S	Single-Phase	Electromechanical	1328
2017	Sangamo	J5SD	Single-Phase	Electromechanical	6
2017	Sangamo	CN1SD	Three-Phase	Electronic	3
2017	Sangamo	S12S	Three-Phase	Electromechanical	7
2017	Sangamo	S4S	Three-Phase	Electronic	2
2017	Sangamo	S5DS	Three-Phase	Electromechanical	1
2017	Sangamo	SL12S	Three-Phase	Electromechanical	4
2017	Sangamo	SS2S1T	Three-Phase	Electronic	1
2017	Sangamo	SS3S1D	Three-Phase	Electronic	5
2017	Sangamo	SS4S1D	Three-Phase	Electronic	50
2017	Sangamo	SS4S1T	Three-Phase	Electronic	2
2017	Sangamo	SS4S2D	Three-Phase	Electronic	3
2017	Sangamo	SS4S2L	Three-Phase	Electronic	1
2017	Sangamo	SV2SD	Three-Phase	Electronic	5
2017	Sangamo	SV3SD	Three-Phase	Electronic	1
2017	Sangamo	SV4SD	Three-Phase	Electronic	174
2017	Sangamo	SV4ST	Three-Phase	Electronic	2
2017	Siemens	AX	Single-Phase	Electronic	12
2017	Siemens	AX2SE	Single-Phase	Electronic	2
2017	Siemens	AXR	Single-Phase	Electronic	1
2017	Westinghouse	D2A	Single-Phase	Electromechanical	1
2017	Westinghouse	D4S	Single-Phase	Electromechanical	579
2017	Westinghouse	D4SM	Single-Phase	Electromechanical	7

Year	Manufacturer	Model	Phase	Type	Count
2017	Westinghouse	D5S	Single-Phase	Electromechanical	22
2017	Westinghouse	D2A2	Three-Phase	Electromechanical	1
2017	Westinghouse	D4A3M	Three-Phase	Electromechanical	1
2017	Westinghouse	D4S3M	Three-Phase	Electromechanical	1
2018	Asea Brown Boveri (ABB)	AB1	Single-Phase	Electromechanical	9067
2018	Asea Brown Boveri (ABB)	AB1R	Single-Phase	Electromechanical	77
2018	Duncan	BMS	Single-Phase	Electromechanical	1
2018	Duncan	MQS	Single-Phase	Electromechanical	157
2018	Duncan	MS	Single-Phase	Electromechanical	565
2018	Duncan	MSII	Single-Phase	Electromechanical	1
2018	Elster	ABS7	Three-Phase	Electromechanical	3
2018	General Electric	I210	Single-Phase	Electronic	102
2018	General Electric	I-210	Single-Phase	Electronic	53
2018	General Electric	I50S	Single-Phase	Electromechanical	62
2018	General Electric	I-50S	Single-Phase	Electromechanical	9
2018	General Electric	I55S	Single-Phase	Electromechanical	63
2018	General Electric	I-55S	Single-Phase	Electromechanical	14
2018	General Electric	I60S	Single-Phase	Electromechanical	532
2018	General Electric	I-60S	Single-Phase	Electromechanical	196
2018	General Electric	I70S	Single-Phase	Electromechanical	956
2018	General Electric	I-70S	Single-Phase	Electromechanical	555
2018	General Electric	I70S2	Single-Phase	Electromechanical	15
2018	General Electric	IM-50A	Single-Phase	Electromechanical	2
2018	General Electric	IM-50S	Single-Phase	Electromechanical	12
2018	General Electric	IM-70A	Single-Phase	Electromechanical	1
2018	General Electric	IM-70S	Single-Phase	Electromechanical	247
2018	General Electric	KV2C	Single-Phase	Electronic	5
2018	General Electric	EV-4	Three-Phase	Electronic	4
2018	General Electric	EV-5	Three-Phase	Electronic	6
2018	General Electric	EV-6	Three-Phase	Electronic	12
2018	General Electric	I-210+N	Three-Phase	Electronic	2
2018	General Electric	KV	Three-Phase	Electronic	7
2018	General Electric	KV2C	Three-Phase	Electronic	63
2018	General Electric	V-612-S	Three-Phase	Electromechanical	44
2018	General Electric	V-62S	Three-Phase	Electromechanical	28
2018	General Electric	V-63A	Three-Phase	Electromechanical	1
2018	General Electric	V-65S	Three-Phase	Electromechanical	2
2018	General Electric	V-66S	Three-Phase	Electromechanical	16
2018	General Electric	VM-612-S	Three-Phase	Electromechanical	7
2018	General Electric	VM-62S	Three-Phase	Electromechanical	4
2018	General Electric	VM-63A	Three-Phase	Electromechanical	3
2018	General Electric	VM-63S	Three-Phase	Electromechanical	7
2018	General Electric	VM-64A	Three-Phase	Electromechanical	15
2018	General Electric	VM-64S	Three-Phase	Electromechanical	52

Year	Manufacturer	Model	Phase	Type	Count
2018	General Electric	VM-65A	Three-Phase	Electromechanical	67
2018	General Electric	VM-65S	Three-Phase	Electromechanical	179
2018	General Electric	VM-66A	Three-Phase	Electromechanical	41
2018	General Electric	VM-66S	Three-Phase	Electromechanical	199
2018	General Electric	VMW-64S	Three-Phase	Electromechanical	1
2018	Itron	C1S	Single-Phase	Electronic	241
2018	Itron	C1SD	Single-Phase	Electronic	192
2018	Itron	C1SL	Single-Phase	Electronic	1
2018	Itron	C1SR	Single-Phase	Electronic	62
2018	Itron	C2SOS	Single-Phase	Electronic	1
2018	Itron	CN1S	Three-Phase	Electronic	5
2018	Itron	CN1SD	Three-Phase	Electronic	12
2018	Itron	CP1SD	Three-Phase	Electronic	34
2018	Itron	SS2S	Three-Phase	Electronic	1
2018	Itron	SS3S	Three-Phase	Electronic	4
2018	Itron	SS4S	Three-Phase	Electronic	63
2018	Itron	SS4S1D	Three-Phase	Electronic	6
2018	Itron	SS5S	Three-Phase	Electronic	1
2018	Itron	SV2S	Three-Phase	Electronic	6
2018	Itron	SV3S	Three-Phase	Electronic	3
2018	Itron	SV4S	Three-Phase	Electronic	194
2018	Landis + Gyr	AL	Single-Phase	Electronic	1
2018	Landis + Gyr	ALF	Single-Phase	Electronic	4
2018	Landis + Gyr	AX	Single-Phase	Electronic	9
2018	Landis + Gyr	AXS4	Single-Phase	Electronic	1
2018	Landis + Gyr	DXMS	Single-Phase	Electromechanical	10
2018	Landis + Gyr	DXMX	Single-Phase	Electromechanical	1
2018	Landis + Gyr	Focus AXR-Mesh	Single-Phase	Electronic	1
2018	Landis + Gyr	MS	Single-Phase	Electromechanical	18
2018	Landis + Gyr	MSII	Single-Phase	Electromechanical	43
2018	Landis + Gyr	MX	Single-Phase	Electromechanical	329
2018	Landis + Gyr	OMRMX	Single-Phase	Electromechanical	12
2018	Landis + Gyr	RDDMS	Single-Phase	Electromechanical	1
2018	Landis + Gyr	AXLS4	Three-Phase	Electronic	4
2018	Landis + Gyr	AXRS4	Three-Phase	Electronic	9
2018	Landis + Gyr	AXS4	Three-Phase	Electronic	121
2018	Landis + Gyr	DXS2	Three-Phase	Electronic	8
2018	Landis + Gyr	RXRS4	Three-Phase	Electronic	31
2018	Landis + Gyr	RXRS4e	Three-Phase	Electronic	1
2018	Landis + Gyr	RXS4	Three-Phase	Electronic	9
2018	Landis + Gyr	SSM2	Three-Phase	Electronic	1
2018	Sangamo	C1S	Single-Phase	Electronic	12
2018	Sangamo	C1SR	Single-Phase	Electronic	50
2018	Sangamo	J3DS	Single-Phase	Electromechanical	1

Year	Manufacturer	Model	Phase	Type	Count
2018	Sangamo	J4EDS	Single-Phase	Electromechanical	1
2018	Sangamo	J4ES	Single-Phase	Electromechanical	5
2018	Sangamo	J4S	Single-Phase	Electromechanical	375
2018	Sangamo	J5S	Single-Phase	Electromechanical	1341
2018	Sangamo	P20DS	Three-Phase	Electromechanical	1
2018	Sangamo	P20S	Three-Phase	Electromechanical	1
2018	Sangamo	S12S	Three-Phase	Electromechanical	3
2018	Sangamo	S4S	Three-Phase	Electronic	1
2018	Sangamo	S5DS	Three-Phase	Electromechanical	1
2018	Sangamo	SL12S	Three-Phase	Electromechanical	4
2018	Siemens	AX	Single-Phase	Electronic	7
2018	Siemens	AX2SE	Single-Phase	Electronic	2
2018	Siemens	AXR	Single-Phase	Electronic	18
2018	Westinghouse	D4S	Single-Phase	Electromechanical	530
2018	Westinghouse	D4S-M	Single-Phase	Electromechanical	5
2018	Westinghouse	D5S	Single-Phase	Electromechanical	30
2018	Westinghouse	D2S7	Three-Phase	Electromechanical	1
2018	Westinghouse	D4A7M	Three-Phase	Electromechanical	2
2018	Westinghouse	D4S-2M	Three-Phase	Electromechanical	1
2018	Westinghouse	D4S-5M	Three-Phase	Electromechanical	1
2018	Westinghouse	D5S-7M	Three-Phase	Electromechanical	1
2019	Aclara	KV2C-METRUM	Three-Phase	Electronic	2
2019	Asea Brown Boveri (ABB)	AB1	Single-Phase	Electromechanical	190
2019	Asea Brown Boveri (ABB)	AB1R	Single-Phase	Electromechanical	49
2019	Duncan	MQS	Single-Phase	Electromechanical	110
2019	Duncan	MS	Single-Phase	Electromechanical	1222
2019	Duncan	MSII	Single-Phase	Electromechanical	7
2019	Elster	ABS7	Three-Phase	Electromechanical	1
2019	General Electric	EV-4	Three-Phase	Electronic	4
2019	General Electric	EV-5	Three-Phase	Electronic	6
2019	General Electric	EV-6	Three-Phase	Electronic	9
2019	General Electric	I-210	Single-Phase	Electronic	129
2019	General Electric	I-210+N	Three-Phase	Electronic	5
2019	General Electric	I-50A	Single-Phase	Electromechanical	16
2019	General Electric	I-50S	Single-Phase	Electromechanical	56
2019	General Electric	I-55S	Single-Phase	Electromechanical	57
2019	General Electric	I-60S	Single-Phase	Electromechanical	1193
2019	General Electric	I-70S	Single-Phase	Electromechanical	2821
2019	General Electric	IM-50A	Single-Phase	Electromechanical	1
2019	General Electric	IM-50S	Single-Phase	Electromechanical	20
2019	General Electric	IM-70A	Single-Phase	Electromechanical	5
2019	General Electric	IM-70S	Single-Phase	Electromechanical	71
2019	General Electric	KV	Three-Phase	Electronic	10
2019	General Electric	kV2c	Single-Phase	Electronic	5

Year	Manufacturer	Model	Phase	Type	Count
2019	General Electric	kV2c	Three-Phase	Electronic	93
2019	General Electric	V-612-S	Three-Phase	Electromechanical	56
2019	General Electric	V-62S	Three-Phase	Electromechanical	19
2019	General Electric	V-65S	Three-Phase	Electromechanical	3
2019	General Electric	V-66A	Three-Phase	Electromechanical	1
2019	General Electric	V-66S	Three-Phase	Electromechanical	19
2019	General Electric	VM-63A	Three-Phase	Electromechanical	18
2019	General Electric	VM-63S	Three-Phase	Electromechanical	14
2019	General Electric	VM-64A	Three-Phase	Electromechanical	21
2019	General Electric	VM-64S	Three-Phase	Electromechanical	79
2019	General Electric	VM-65A	Three-Phase	Electromechanical	146
2019	General Electric	VM-65S	Three-Phase	Electromechanical	95
2019	General Electric	VM-66A	Three-Phase	Electromechanical	45
2019	General Electric	VM-66S	Three-Phase	Electromechanical	98
2019	General Electric	VMW-64S	Three-Phase	Electromechanical	2
2019	General Electric	VMW-65A	Three-Phase	Electromechanical	1
2019	General Electric	VMW-65S	Three-Phase	Electromechanical	1
2019	Itron	C1S	Single-Phase	Electronic	273
2019	Itron	C1SD	Single-Phase	Electronic	217
2019	Itron	C1SL	Single-Phase	Electronic	3
2019	Itron	C1SR	Single-Phase	Electronic	149
2019	Itron	C2SOS	Single-Phase	Electronic	71
2019	Itron	CN1S	Three-Phase	Electronic	4
2019	Itron	CN1SD	Three-Phase	Electronic	12
2019	Itron	CP1SD	Three-Phase	Electronic	39
2019	Itron	CP1STR2	Three-Phase	Electronic	1
2019	Itron	CP2SOAS	Single-Phase	Electronic	1
2019	Itron	CP2SOAS	Three-Phase	Electronic	1
2019	Itron	J4S	Single-Phase	Electromechanical	1
2019	Itron	J5S	Single-Phase	Electromechanical	3
2019	Itron	Q200	Three-Phase	Electromechanical	1
2019	Itron	SS3S	Three-Phase	Electronic	6
2019	Itron	SS4S	Three-Phase	Electronic	232
2019	Itron	SS4S1D	Three-Phase	Electronic	1
2019	Itron	SS5S	Three-Phase	Electronic	4
2019	Itron	SV2S	Three-Phase	Electronic	1
2019	Itron	SV3S	Three-Phase	Electronic	3
2019	Itron	SV4S	Three-Phase	Electronic	173
2019	Itron	SV5S	Three-Phase	Electronic	1
2019	Landis + Gyr	AL	Single-Phase	Electronic	3
2019	Landis + Gyr	ALF	Single-Phase	Electronic	11
2019	Landis + Gyr	AX	Single-Phase	Electronic	7
2019	Landis + Gyr	AXLS4	Three-Phase	Electronic	6
2019	Landis + Gyr	AXR	Single-Phase	Electronic	1

Year	Manufacturer	Model	Phase	Type	Count
2019	Landis + Gyr	AXRS4	Three-Phase	Electronic	1
2019	Landis + Gyr	AXS4	Three-Phase	Electronic	99
2019	Landis + Gyr	DXMS	Single-Phase	Electromechanical	6
2019	Landis + Gyr	DXMX	Single-Phase	Electromechanical	2
2019	Landis + Gyr	DXS2	Three-Phase	Electronic	13
2019	Landis + Gyr	Focus AXR - Mesh	Single-Phase	Electronic	2
2019	Landis + Gyr	Focus AXRe-SD Mes	Three-Phase	Electronic	5
2019	Landis + Gyr	MS	Single-Phase	Electromechanical	29
2019	Landis + Gyr	MSII	Single-Phase	Electromechanical	99
2019	Landis + Gyr	MX	Single-Phase	Electromechanical	296
2019	Landis + Gyr	OMRMX	Single-Phase	Electromechanical	8
2019	Landis + Gyr	RXRS4	Three-Phase	Electronic	85
2019	Landis + Gyr	RXRS4e	Three-Phase	Electronic	9
2019	Landis + Gyr	RXS4	Three-Phase	Electronic	14
2019	Landis + Gyr	SSM2	Three-Phase	Electronic	4
2019	Sangamo	J4EDS	Single-Phase	Electromechanical	2
2019	Sangamo	J4ES	Single-Phase	Electromechanical	4
2019	Sangamo	J4S	Single-Phase	Electromechanical	410
2019	Sangamo	J4SA	Single-Phase	Electromechanical	1
2019	Sangamo	J5DS	Single-Phase	Electromechanical	1
2019	Sangamo	J5S	Single-Phase	Electromechanical	1682
2019	Sangamo	P20S	Three-Phase	Electromechanical	1
2019	Sangamo	S12S	Three-Phase	Electromechanical	1
2019	Sangamo	S4DS	Three-Phase	Electromechanical	1
2019	Sangamo	SL12S	Three-Phase	Electromechanical	1
2019	Siemens	AX	Single-Phase	Electronic	14
2019	Siemens	AXR	Single-Phase	Electronic	5
2019	Westinghouse	D2A	Single-Phase	Electromechanical	1
2019	Westinghouse	D4A-3M	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S	Single-Phase	Electromechanical	738
2019	Westinghouse	D4S-2	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S-3M	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S-5	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S-7M	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S-8M	Three-Phase	Electromechanical	1
2019	Westinghouse	D4S-M	Single-Phase	Electromechanical	2
2019	Westinghouse	D5S	Single-Phase	Electromechanical	28
2019	Westinghouse	D5S-3M	Three-Phase	Electromechanical	1
2019	Westinghouse	D5S-8M	Three-Phase	Electromechanical	1

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC

Dated January 8, 2021

Case No. 2020-00349

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 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 resp

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC

Dated January 8, 2021

Case No. 2020-00349

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 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 commit to letting customers know 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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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
 - a. 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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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

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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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 timeline 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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

**Response to Joint Initial Data Requests of the Attorney General and KIUC
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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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 the response to Question No. 202.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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 (CVR) 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.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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 2-18.

KENTUCKY UTILITIES COMPANY

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Case No. 2020-00349

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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Case No. 2020-00349

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.
 - 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.

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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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A.P.C.D.
ADMINISTRATION

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 NO_x 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 reinstated as early as practicable after cessation of the event causing the delay.

2. Verification and Reporting

Within 30 days after the end of the calendar month, LG&E shall submit a monthly report to the District identifying daily plant-wide emissions of NO_x. 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: Keith Talley, Sr.
Keith Talley, Sr.
Executive Director

Date: 4/15/2020

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A.P.C.D.
ADMINISTRATION

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 County¹. 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.

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>

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC

Dated January 8, 2021

Case No. 2020-00349

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. In order to extend the life of Brown Unit 3 the below Capital investments would need to be made:
 - Turbine overhaul that included replacements of the HP-IP Seals, HP Inlet Bell Seals, and Turbine Blades.
 - Significant Boiler work including the replacements of the Economizer assemblies and headers, Lower Slope tubes, Upper Arch Water Wall tubes, Final Superheat Pendants, and Reheat Outlet Dissimilar Metal Weld joints.
 - Replacement of 2 feedwater heaters.
 - Mill work including a Gearbox overhaul and replacement of Dynamic Classifier Rotors.
 - SCR Catalyst layer replacements.

- PJFF (Pulse Jet Fabric Filter) Bags and Cages replacement.
 - FGD Expansion Joint Replacements.
 - FGD Recycle Pump overhauls.
- c. In order to extend the life of Brown Unit 3 the below operating and maintenance activities would need to occur:
- Brown 3 Major Outage including the below scope:
 - Boiler repairs.
 - Inspections and repairs to various Brown 3 equipment including but not limited to mills, pumps, valves, duct work, expansion joints, hoppers, spray nozzles, burners, injection lances, conveyors, belts, chutes, fans, motors, etc.
 - Testing of various Brown 3 equipment to ensure compliance, including PJFF bag testing, catalyst testing, breaker testing, battery load testing, motor testing.
 - Industrial cleaning
 - Brown 3 Boiler Assessment with scope of work that includes full boiler scaffolding and inspection of the entire boiler.
 - Brown 3 Turbine Overhaul including the below scope:
 - Disassemble, clean, blast, NDE, inspect and assemble both the High Pressure-Intermediate Pressure and Low-Pressure sections of the turbine.
 - Full rewind of the Generator Field

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 KU information.

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	163376	BR 3-1 & 3-2 BFP Recirc Valves	\$0.18
Generation Reliability	159301	BR CCRT Gyp Tank Agitator Grbx	\$0.02
Generation Reliability	162279	BR Demin Controls Upgr	\$0.06
Generation Reliability	160687	BR FGD 0-2 Recycle Pump Rbld	\$0.15
Generation Reliability	159639	BR Field Devices to U3 DCS	\$0.32
Generation Reliability	159633	BR Gyp Hydrocyclone Encl Vent	\$0.50
Generation Reliability	160011	BR Limestone Belt Repl	\$0.05
Generation Reliability	157463	BR Limestone Slurry Pump Repl	\$0.04
Generation Reliability	157464	BR Limestone Slurry Pump Spare	\$0.03
Generation Reliability	160371	BR Recyc Pump Valve Seal 2022	\$0.62
Generation Reliability	159634	BR Recycle Pump Valve Seal Rep	\$0.58
Generation Reliability	147904	BR1 Main Xfmr Bushing Repl	\$0.03
Generation Reliability	159653	BR3 A Heater Drain Pump Repl	\$0.09
Generation Reliability	160685	BR3 Air Preheating Coil Pump	\$0.03
Generation Reliability	159641	BR3 Baghouse Elec Disconnects	\$0.04
Generation Reliability	160345	BR3 BCWP Ovhl 2021	\$0.09
Generation Reliability	158723	BR3 HWRP Spare Rebuild	\$0.27
Generation Reliability	155082	BR3 Oper WorkStation (WP) Upgr	\$0.01
Generation Reliability	159636	BR3 Roof Replacement	\$0.50
Generation Reliability	159638	BR3 RTU Upgrade	\$0.06
Generation Reliability	162247	BR3 Stand Pipe Refurbishment	\$0.19
Generation Reliability	159154	BR3-1 CWP Motor Recondition	\$0.13
Generation Reliability	159642	BR3-1 HWR Cyclone Separator	\$0.08
Generation Reliability	158721	BR3-1 HWRP Rebuild	\$0.28
Generation Reliability	142770	BR3-2 BFPT Blade Repl	\$0.00
Generation Reliability	162618	BR3-2 Control AC Dryer Drum	\$0.02
Generation Reliability	159618	BR3-2 CWP Motor Recondition	\$0.06
Generation Reliability	159643	BR3-2 HWR Cyclone Separator	\$0.08
Generation Reliability	157252	BR3-2 ID Fan Motor Rewind	\$0.46
Generation Reliability	162300	BRCT Ammonia Comp Cntrl Board	\$0.07
Generation Reliability	162664	BRCT BOP Fire Sys Jockey Pump	\$0.01
Generation Reliability	155145	BRCT DCS HMI Software Upgr	\$0.31
Generation Reliability	157267	BRCT Gas Compressor Ovhl	\$0.27
Generation Reliability	157274	BRCT Gas Line Controls Upgr	\$0.19
Generation Reliability	144541	BRCT Gas Pipeline Relocation	\$2.19
Generation Reliability	156176	BRCT TN Gas PL Overpres Prot	\$0.06
Generation Reliability	159657	BRCT5 DC Battery Repl	\$0.03
Generation Reliability	160820	BRCT6 & CT7 Flux Probe Install	\$0.03
Generation Reliability	159659	BRCT6 DC Battery Repl	\$0.04
Generation Reliability	159662	BRCT7 DC Battery Repl	\$0.04
Generation Reliability	155158	BRCT7 Quench Cooler Nozzles	\$0.09
Generation Reliability	157305	BRCY D9 Dozer Recert - RJS1579	\$0.66
Generation Reliability	162282	CR7 Auto Shutdown	\$0.17
Generation Reliability	159032	CR7 Cir Wtr Pmp Mtr	(\$0.00)
Generation Reliability	163553	CR7 Cooling Tower Motors	\$0.02
Generation Reliability	152776	CR7 DCS Hardware Refresh	\$0.14
Generation Reliability	154833	CR7 EQ OVERHAUL	\$1.48
Generation Reliability	161058	CR7 Evap Cooling Pipe Repl	\$0.15
Generation Reliability	162462	CR7 HRH1 Vlv Act Replace	\$0.01
Generation Reliability	162211	CR7 R1 Static Seal	\$0.21
Generation Reliability	161106	CR7 Raw Water Pump A 2019	\$0.14
Generation Reliability	162810	CR7 Sludge Pump	\$0.02
Generation Reliability	163315	CR7 Spare Cooling Twr Fan	\$0.04
Generation Reliability	162287	CR7 ST SEE Replace	\$0.58

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	162610	CR7 ST Turning Gear Motor	\$0.03
Generation Reliability	152055	CR7 T3K Hardware Refresh	\$0.46
Generation Reliability	157389	DX Crest Gate Walkway Repl	\$0.04
Generation Reliability	159668	DX RTU Upgrade	\$0.02
Generation Reliability	155108	DX Runner & Shaft Repl	\$0.86
Generation Reliability	161443	DX Station Batteries	\$0.03
Generation Reliability	162308	DX3 Runner & Shaft Repl	\$1.22
Generation Reliability	160661	GH 1&2 M Conveyor LED Lighting	\$0.00
Generation Reliability	131173	GH 10K Silo Feed Gates Repl	\$1.09
Generation Reliability	152794	GH 1-1 BCWP Major Ovrhl 21	\$0.09
Generation Reliability	152812	GH 1-1 SBAC Major Overhaul	\$0.35
Generation Reliability	154865	GH 1-1A SO3 Air Comp	\$0.08
Generation Reliability	161999	GH 1-2 Condensate Pmp Ovrhl21	\$0.09
Generation Reliability	155172	GH 1-2 LPSW Pump Major Ovrhl21	\$0.21
Generation Reliability	152800	GH 1-4 BCWP Major Ovrhl 20	\$0.08
Generation Reliability	161719	GH 1-4 Control Air CompOvrhl20	\$0.18
Generation Reliability	133794	GH 1-4 Pulv Gearbox	\$0.73
Generation Reliability	162879	GH 1-5 FGD Agitator Gearbx Rpl	\$0.06
Generation Reliability	161142	GH 1A Conveyor Belt Repl	\$0.02
Generation Reliability	163404	GH 1E CONVEYOR BELT REPL	\$0.02
Generation Reliability	160771	GH 1H Conveyor Belt Repl 19	\$0.06
Generation Reliability	163147	GH 2-1 Circ Wtr Pump Motor Rwd	\$0.16
Generation Reliability	152827	GH 2-1 LPSW Pump Mjr Overhaul	\$0.21
Generation Reliability	160916	GH 2-1 Station Air Compressor	\$0.05
Generation Reliability	152802	GH 2-2 BCWP Major Ovrhl 20	\$0.08
Generation Reliability	152945	GH 2-3 BCWP Major Ovrhl 21	\$0.09
Generation Reliability	160788	GH 2-B Wet Ash Crusher Repl19	\$0.00
Generation Reliability	160780	GH 2M1 Coal Belt Scale	\$0.05
Generation Reliability	161457	GH 2M1 Conveyor Belt Repl	\$0.01
Generation Reliability	160783	GH 2M2 Coal Belt Scale	\$0.05
Generation Reliability	26GH	GH 3&4 Station Air Comp Repl	\$0.20
Generation Reliability	159605	GH 3-1 Ash Sluice Pump Ovrhl20	\$0.18
Generation Reliability	159604	GH 3-1 Aux Cond Vac Pump20	\$0.19
Generation Reliability	162878	GH 3-1 Condensate Motor Rwnd	\$0.05
Generation Reliability	154885	GH 3-1 LPSW Strainer Repl	\$0.25
Generation Reliability	160789	GH 3-1 Main Cond Vac Pmp 19	\$0.08
Generation Reliability	156532	GH 3-1 Sand Filter Rebuild	(\$0.00)
Generation Reliability	159727	GH 3-1 Wet Ash ClnkrCrshr Rbld	\$0.10
Generation Reliability	159611	GH 3-1A RO Booster Pump Repl20	\$0.04
Generation Reliability	154895	GH 3-1A SO3 Air Comp	\$0.06
Generation Reliability	156534	GH 3-2 Sand Filter Rebuild	\$0.00
Generation Reliability	39GH	GH 3-2 Well Wtr Pump Rebuild21	\$0.05
Generation Reliability	159728	GH 3-2 Wet Ash ClnkrCrshr Rbld	\$0.10
Generation Reliability	160600	GH 3-2 Wet Ash Crusher Repl19	\$0.00
Generation Reliability	159610	GH 3-2A RO Booster Pump Repl20	\$0.04
Generation Reliability	159603	GH 3-3 Aux Cond Vac Pump21	\$0.17
Generation Reliability	156535	GH 3-3 Sand Filter Rebuild	(\$0.00)
Generation Reliability	160985	GH 3-4 Mill Motor Rotor Rewind	\$0.06
Generation Reliability	160770	GH 3G Conveyor Belt Repl 2019	\$0.01
Generation Reliability	160784	GH 3N4 Coal Belt Scale	\$0.05
Generation Reliability	159174	GH 4-1 Mill Motor Rotor Rbld19	(\$0.00)
Generation Reliability	154904	GH 4-1A SO3 Air Comp	\$0.06
Generation Reliability	154905	GH 4-1B SO3 Air Comp	\$0.06
Generation Reliability	159612	GH 4-2 LPSW Strainer Repl20	\$0.25

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	159730	GH 4-2 Wet Ash ClnkrCrshr Rbld	\$0.10
Generation Reliability	162737	GH 4-4 Pulverizer Gearbox Repl	\$0.44
Generation Reliability	151355	GH 4-6 Pulv Gearbox	\$0.01
Generation Reliability	161607	GH 4H Conveyor Belt Repl20	\$0.04
Generation Reliability	161456	GH 4M Conveyor Belt Repl	\$0.02
Generation Reliability	160768	GH 4N3 Conveyor Belt Repl 2019	\$0.01
Generation Reliability	160785	GH 4N4 Coal Belt Scale	\$0.06
Generation Reliability	160769	GH 5G Conveyor Repl 19	\$0.01
Generation Reliability	156570	GH 657E Scraper Recert 2019	\$1.20
Generation Reliability	161606	GH 6G Conveyor Belt Repl	\$0.01
Generation Reliability	154911	GH 7&8 G Conveyor LED Lighting	\$0.00
Generation Reliability	47GH	GH Air Flow and Dew Pt Monitor	\$0.07
Generation Reliability	161131	GH BAND SAW - SMM SHOP	\$0.03
Generation Reliability	48GH	GH Barge Unloader DC Drive Rpl	\$0.02
Generation Reliability	140170	GH BU Bucket and Chain 2020	\$0.31
Generation Reliability	160562	GH CBU Bucket ElevatorSpareMtr	(\$0.00)
Generation Reliability	161754	GH CCR 0-1 Cake Wash Htr Rpl20	\$0.07
Generation Reliability	160809	GH CCR Bottom Ash Rd Concrete	(\$0.02)
Generation Reliability	156592	GH CCR Gypsum Blding Sump Pump	\$0.11
Generation Reliability	161218	GH CCR Rep	(\$0.00)
Generation Reliability	159624	GH CEM Calibration Equip20	\$0.01
Generation Reliability	57GH	GH Coal Handling Air Dryer Rpl	\$0.04
Generation Reliability	140184	GH Conveyor Belt Repl 20	\$0.05
Generation Reliability	140185	GH Conveyor Belt Repl 21	\$0.85
Generation Reliability	154912	GH CY 10k Silo LED Lighting	\$0.01
Generation Reliability	162812	GH CY CBU Bucket Elev Mtr Rpl	\$0.07
Generation Reliability	162736	GH CY Portable Air Comp Repl	\$0.02
Generation Reliability	158956	GH DCS Simulator	\$1.08
Generation Reliability	161051	GH Diesel Gen Test Load Bank	\$0.03
Generation Reliability	154974	GH DTLs Dust Collector	\$1.20
Generation Reliability	75GH	GH Gyp Farm Redundant Elec Sys	\$0.01
Generation Reliability	158369	GH Gyp Process B Breaker Repl	\$0.05
Generation Reliability	162351	GH Helium Analyzer 20	\$0.02
Generation Reliability	144348	GH Instrument Truck	\$0.05
Generation Reliability	154923	GH Interior Stack Lighting	\$0.16
Generation Reliability	163405	GH Knock Out Box Permanent Pwr	\$0.05
Generation Reliability	85GH	GH LS Mill Feed Chute20	\$0.04
Generation Reliability	86GH	GH LS Mill Feed Chute21	\$0.07
Generation Reliability	92GH	GH LSP 0-1 Instr Air Comp	\$0.08
Generation Reliability	93GH	GH LSP 0-1 Service Air Comp	\$0.08
Generation Reliability	144182	GH Main Entrance Guard House	\$0.83
Generation Reliability	140190	Gh Misc Motors 21	\$0.11
Generation Reliability	158729	GH Misc Plant Equip Repl	\$0.13
Generation Reliability	152904	GH Misc Safety/ERT	\$0.03
Generation Reliability	160737	GH Pipe Conveyor Spare Gearbox	\$0.06
Generation Reliability	95GH	GH PLC software Upgrade	\$0.10
Generation Reliability	163643	GH Potable Water Upgrade	\$0.22
Generation Reliability	161732	GH PWS Forklift	\$0.07
Generation Reliability	101GH	GH Recycle Pmp ImpellerRefrb20	\$0.06
Generation Reliability	102GH	GH Recycle Pmp ImpellerRefrb21	\$0.25
Generation Reliability	159168	GH Security Card Readers19	\$0.01
Generation Reliability	160729	GH Spare CCR Gyp Dewater Belt	\$0.22
Generation Reliability	162738	GH Spare Main Cond Vac Pump	\$0.05
Generation Reliability	144242	GH Spare SICK SAM Monitor	\$0.16

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	140202	GH Stacker Reclaimer Recert	\$0.31
Generation Reliability	154925	GH Transfer Hse 4 LED Lighting	\$0.01
Generation Reliability	161737	GH Whse Forklift Repl 21	\$0.05
Generation Reliability	161103	GH Wireless Vib Mon Equip	\$0.05
Generation Reliability	158732	GH1 Air Preheating Coils Rpl20	\$0.20
Generation Reliability	139GH	GH1 DCS Ignitor & Air Controls	\$0.03
Generation Reliability	142GH	GH1 F&G Feedwater HtrDCS Cntrl	\$0.08
Generation Reliability	162220	GH1 FGD ELEC RM HVAC REPL	\$0.16
Generation Reliability	161476	GH1 Gen Field Grnd Detect	\$0.09
Generation Reliability	154914	GH1 K Conveyor LED Lighting	\$0.00
Generation Reliability	162740	GH1 PJFF Hoist Upgrade	\$0.18
Generation Reliability	160539	GH1 PJFF LED Lighting	\$0.01
Generation Reliability	156GH	GH1 Res Aux Xfmr 4kV TransDuct	\$0.07
Generation Reliability	160980	GH1 Spare Ash Sluice Pmp Rbld	\$0.04
Generation Reliability	159741	GH1 Wet Ash Crusher Repl20	\$0.02
Generation Reliability	156593	GH1&2 Control Room Chiller Rpl	\$0.69
Generation Reliability	154915	GH1&2 J Conveyor LED Lighting	\$0.02
Generation Reliability	161870	GH2 Air Dryer Replacement	\$0.08
Generation Reliability	154916	GH2 CoalConveyorRoom LED Light	\$0.00
Generation Reliability	159105	GH2 CT Cell Rebuilds 2019	\$0.02
Generation Reliability	172GH	GH2 CT Gearbox Repl21	\$0.08
Generation Reliability	155549	GH2 CWP Discharge Valve Rpl	\$0.01
Generation Reliability	185GH	GH2 DCS Ignitor & Air Controls	\$0.03
Generation Reliability	160543	GH2 FGD Mnt Shp & Elec Rm LED	\$0.00
Generation Reliability	161749	GH2 GSU Bushing Repl 20	\$0.28
Generation Reliability	159164	GH2 HP-IP Outer CasingStud Rpl	\$0.16
Generation Reliability	160988	GH2 ID Fan Expansion Jt Repl	\$0.05
Generation Reliability	159163	GH2 LPA Bucket Repl 2019	\$0.15
Generation Reliability	189GH	GH2 PA FlowMonitor on MillsRpl	\$0.13
Generation Reliability	160540	GH2 PJFF LED Lighting	\$0.00
Generation Reliability	159097	GH2 Seal Skirt & DripScreenRpl	\$0.00
Generation Reliability	159745	GH2 Wet Ash Crusher Repl22	\$0.10
Generation Reliability	161097	GH2-1 PA FAN FOUND/SHAFT UPG	\$0.13
Generation Reliability	161098	GH2-2 PA FAN FOUND/SHAFT UPG	\$0.13
Generation Reliability	144423	GH3 3-3 Pulv Gearbox	\$0.06
Generation Reliability	133515	GH3 Boiler Burner Repl	(\$0.00)
Generation Reliability	193GH	GH3 Boiler Flame Cameras	\$0.05
Generation Reliability	196GH	GH3 DCS TDBFP SealWtr Inj Ctrl	\$0.05
Generation Reliability	161472	GH3 Exciter Cooler Replacement	\$0.08
Generation Reliability	154893	GH3 FGD Amiad Strainer	\$0.02
Generation Reliability	160514	GH3 FGD Amiad Strainer19	\$0.00
Generation Reliability	201GH	GH3 FGD Building Sump Repl	\$0.13
Generation Reliability	73GH	GH3 FGD Recycle Pump Gearbox19	\$0.00
Generation Reliability	163642	GH3 HPSW Piping Repl	\$0.21
Generation Reliability	160982	GH3 PA Fan Silencers Rpl	\$0.18
Generation Reliability	162727	GH3 PJFF Hoist Upgrade	\$0.04
Generation Reliability	160541	GH3 PJFF LED Lighting	\$0.01
Generation Reliability	154969	GH3 Pyrite Piping Repl21	\$0.16
Generation Reliability	154934	GH3 Station Batteries Repl	\$0.05
Generation Reliability	160984	GH3 Wet Ash Hopper Repl20	\$0.23
Generation Reliability	162GH	GH3-1 LPSW TWS REBUILD19	\$0.00
Generation Reliability	161034	GH3-3 Recycle Pump Impell Repl	\$0.05
Generation Reliability	219GH	GH4 Boiler Flame Cameras	\$0.05
Generation Reliability	161452	GH4 CT Blowdown Line Repl20	\$0.15

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	162464	GH4 CT Bypass Valve Repl	\$0.09
Generation Reliability	224GH	GH4 DCS TDBFP SealWtr Inj Ctrl	\$0.05
Generation Reliability	161249	GH4 Elctrmtc Relief Valves Rep	\$0.18
Generation Reliability	154894	GH4 FGD Amiad Strainer	\$0.05
Generation Reliability	229GH	GH4 FGD Building Sump Repl	\$0.05
Generation Reliability	162739	GH4 GSU Bushing Repl 20	\$0.45
Generation Reliability	159750	GH4 Main Condenser Exp JtRpl20	\$0.08
Generation Reliability	160983	GH4 PA Fan Silencers Rpl	\$0.17
Generation Reliability	160542	GH4 PJFF LED Lighting	\$0.00
Generation Reliability	154971	GH4 Pyrite Piping Repl21	\$0.16
Generation Reliability	159621	GH4 Stack Exp Joint Repl20	\$0.04
Generation Reliability	161302	GH4 Turb Snout Ring Repl 20	\$0.30
Generation Reliability	151380	GH4 Turbine Bldg LED Light	\$0.01
Generation Reliability	162410	GH4 Turbine-LPB Buckets Repl20	\$0.53
Generation Reliability	159405	GH4 Wet Ash Hopper Repl20	\$0.21
Generation Reliability	161733	Personnel Carrier Repl 2021	\$0.06
Generation Reliability	157167	PR13 Battery Replacement	\$0.02
Generation Reliability	152056	PR13 T3K Hardware Refresh	\$0.12
Generation Reliability	163632LGE	TC "C" COAL CONVEYOR BELT RE	\$0.06
Generation Reliability	163555LGE	TC "E" CONVEYOR BELT REPLACI	\$0.11
Generation Reliability	162760LGE	TC A TRAVELING WTR SCREEN	\$0.30
Generation Reliability	162425LGE	TC AGITATOR BLADE REPLACE	\$0.14
Generation Reliability	157302LGE	TC AMMONIA TANK WATER CUR	\$0.25
Generation Reliability	147470LGE	TC C COAL CONVEYOR SPARE MI	\$0.07
Generation Reliability	156635LGE	TC CBU BUCKETS & CHAINS 2018	\$0.00
Generation Reliability	162429LGE	TC CHUTE REPLACEMENT	\$0.12
Generation Reliability	162427LGE	TC CLEAN VAC PIPING	\$0.07
Generation Reliability	161486LGE	TC COAL CONVEYOR BELTS 2020	\$0.15
Generation Reliability	154729LGE	TC COAL CONVEYOR VFD UPGD	\$0.00
Generation Reliability	157150LGE	TC COAL HAND BUILD ROOF REPI	\$0.02
Generation Reliability	162791LGE	TC COAL YARD BUILDING SIDING	\$0.10
Generation Reliability	159520LGE	TC CONVEYOR BELT REPL 2019	\$0.11
Generation Reliability	140619LGE	TC CONVEYOR BELT REPLACE	\$0.14
Generation Reliability	157115LGE	TC CRITICAL HEAT UPGD	\$0.04
Generation Reliability	160326LGE	TC CRITICAL HEAT UPGD 2019	\$0.07
Generation Reliability	152009LGE	TC CT BULK CO STORAGE	(\$0.01)
Generation Reliability	153025LGE	TC CT CEM ANALYZER CHANGEO	\$0.14
Generation Reliability	156885LGE	TC CT CEMs SHELTERS 5-6	\$0.60
Generation Reliability	156863LGE	TC CT EMERSON PWCS	\$0.11
Generation Reliability	152001LGE	TC CT EX2000 DIGITAL FE CT10	\$0.11
Generation Reliability	152006LGE	TC CT EX2000 DIGITAL FE CT9	\$0.12
Generation Reliability	139795LGE	TC CT FAST START CT6	\$0.33
Generation Reliability	162712LGE	TC CT GAS HEATER PLC UPGD	\$0.12
Generation Reliability	153095LGE	TC CT GFI UPGRADE	\$0.06
Generation Reliability	159876LGE	TC CT GFI UPGRADE	\$0.03
Generation Reliability	152032LGE	TC CT HMI UPGRADE	\$0.22
Generation Reliability	159873LGE	TC CT HYDRAULIC PUMP UPG	\$0.14
Generation Reliability	152007LGE	TC CT LUBE OIL PUMPS	\$0.03
Generation Reliability	152015LGE	TC CT MARK VI UPGD CT9	\$0.10
Generation Reliability	156875LGE	TC CT MKVIe PHASE 2-3 CT10	\$0.27
Generation Reliability	156865LGE	TC CT MKVIe PHASE 2-3 CT5	\$0.27
Generation Reliability	156867LGE	TC CT MKVIe PHASE 2-3 CT6	\$0.27
Generation Reliability	156869LGE	TC CT MKVIe PHASE 2-3 CT7	\$0.27
Generation Reliability	156871LGE	TC CT MKVIe PHASE 2-3 CT8	\$0.27

Category	Project No.	Project Description	\$M Arbourh
Generation Reliability	156873LGE	TC CT MKVIe PHASE 2-3 CT9	\$0.27
Generation Reliability	158328LGE	TC CT MULTILIN UPG 2018	\$0.00
Generation Reliability	153070LGE	TC CT PEEC BATTERIES	\$0.18
Generation Reliability	163273LGE	TC CT PLATFORM INSTALL	\$0.05
Generation Reliability	156879LGE	TC CT PURGE CREDIT AIR CT10	\$0.06
Generation Reliability	156877LGE	TC CT PURGE CREDIT AIR CT8	\$0.06
Generation Reliability	153102LGE	TC CT REBUILD EXHAUST EXP JN	\$0.47
Generation Reliability	160803LGE	TC CT REBUILD EXHST DUCT 5of6	\$0.00
Generation Reliability	160887LGE	TC CT SITE HVAC REPLACEMENT	\$0.06
Generation Reliability	162714LGE	TC CT SWITCHYARD RTU UPGD	\$0.12
Generation Reliability	157299LGE	TC CT TURNING GEAR REFURB	\$0.04
Generation Reliability	160814LGE	TC CT TURNING GEAR REFURB 20	\$0.00
Generation Reliability	154792LGE	TC CT WAREHOUSE	\$0.31
Generation Reliability	160679LGE	TC DCS METERING SYST UPGD	\$0.09
Generation Reliability	156846LGE	TC DCS METERING UPGD	\$0.04
Generation Reliability	156836LGE	TC DCS SIMULATOR	\$0.57
Generation Reliability	161650LGE	TC ELECTROMECH RELAYS 2020	\$0.23
Generation Reliability	155443LGE	TC F COAL CONV GALLERY REBL	\$2.10
Generation Reliability	156994LGE	TC F COAL CONV SPARE MOTOR	\$0.05
Generation Reliability	156996LGE	TC FIRE SYSTEM UPG	\$0.00
Generation Reliability	153028LGE	TC FUEL BLEND FEEDER REPL	\$0.04
Generation Reliability	159690LGE	TC GAS LINE COMPNT UPG	\$0.03
Generation Reliability	159254LGE	TC HVAC UPGD 2019	\$0.03
Generation Reliability	162677LGE	TC HYDROCLONE UPGD	\$0.24
Generation Reliability	162467LGE	TC HYDROCYCLONE UPGD	\$0.11
Generation Reliability	160318LGE	TC IMPOUND IMPROVE 2019	\$0.00
Generation Reliability	161496LGE	TC IMPOUND IMPROVE 2020	\$0.18
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	\$0.11
Generation Reliability	133627LGE	TC LAB EQUIP PURCHASES	\$0.03
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	\$0.14
Generation Reliability	159937LGE	TC LIFT STATION REPL	\$0.06
Generation Reliability	154803LGE	TC LIMESTONE FEEDER UPG	\$0.11
Generation Reliability	162725LGE	TC LIMESTONE LBU UPGD	\$0.26
Generation Reliability	162438LGE	TC LIMESTONE RECLAIM UPGD	\$0.23
Generation Reliability	163420LGE	TC LIMESTONE SCALE UPGD	\$0.01
Generation Reliability	162431LGE	TC MAGNETIC SEPARATOR	\$0.19
Generation Reliability	161507LGE	TC MAT HANDLING STRUCT UPGI	\$0.13
Generation Reliability	160337LGE	TC MATERIAL HAND STRUCT UPC	\$0.03
Generation Reliability	156830LGE	TC MATERIAL HDLG STRUCT UPG	\$0.10
Generation Reliability	156825LGE	TC MOORING CELL REFURB	\$0.16
Generation Reliability	161494LGE	TC MOORING CELL UPGD 2020	\$0.28
Generation Reliability	152693LGE	TC OFFICE UPGRADES	\$0.19
Generation Reliability	152079LGE	TC OVATION SECUTY CENTER	\$0.09
Generation Reliability	156838LGE	TC PLC CONVERSION	\$0.19
Generation Reliability	133615LGE	TC PLT ENG/MTR RWNDS	\$0.21
Generation Reliability	161489LGE	TC PREDICTIVE EQUIP 2020	\$0.04
Generation Reliability	139682LGE	TC PREDICTIVE MAINT DEVICES	\$0.04
Generation Reliability	162815LGE	TC PWS EQUIP MODIFICATION	\$0.02
Generation Reliability	152097LGE	TC RAT RELAYS	\$0.01

Category	Project No.	Project Description	\$M Arbourgh
Generation Reliability	139769LGE	TC REPL FIRE SYSTEM CRUSHER 1	\$0.13
Generation Reliability	150049LGE	TC REPL LST TANK FLOORS	\$0.19
Generation Reliability	150077LGE	TC REPL SEWAGE TREAT PLANT	\$0.24
Generation Reliability	152070LGE	TC SHUTTLE BARGE WINCH UPGI	\$0.13
Generation Reliability	157122LGE	TC STACK ELEVATOR REFURB	\$0.24
Generation Reliability	156850LGE	TC STACKER RECLAIM OH	\$0.07
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 UPC	\$0.00
Generation Reliability	150059LGE	TC UPG COAL HAND SAMPLER	\$0.21
Generation Reliability	162440LGE	TC UPGD LIMESTONE SCALE	\$0.04
Generation Reliability	161915LGE	TC UPGD SW PUMP TRAIN - C	\$0.14
Generation Reliability	161013LGE	TC WIRELESS SENSOR INSTALL	\$0.04
Generation Reliability	153022LGE	TC2 A CEM ANALYZER CHANGE0	\$0.45
Generation Reliability	157248LGE	TC2 ABB MAINS BREAKER UPGD	(\$0.04)
Generation Reliability	159910LGE	TC2 AMMONIA TANK UPGD	\$0.07
Generation Reliability	159928LGE	TC2 CCW PUMP SPARE	\$0.13
Generation Reliability	160573LGE	TC2 CONDENSATE POLISH SUMP	\$0.00
Generation Reliability	154744LGE	TC2 COOLING TOWER PUMP OH	\$0.24
Generation Reliability	162359LGE	TC2 DYNAMIC CLASSIFIERS	\$0.29
Generation Reliability	162355LGE	TC2 ECONOMIZER DRAIN UPG	\$0.13
Generation Reliability	159887LGE	TC2 FGD SULFITE PROBE	\$0.10
Generation Reliability	153055LGE	TC2 MDBFP START UPG	\$0.23
Generation Reliability	159934LGE	TC2 MDBFP/ID FAN RELAY UPG	\$0.05
Generation Reliability	162423LGE	TC2 PYRITE HOPPER	\$0.21
Generation Reliability	162456LGE	TC2 RECYCLE PUMP PIPING	\$0.23
Generation Reliability	163429LGE	TC2 SUBMERG SCRAPER DOOR	\$0.05
Generation Reliability	160571LGE	TC2 TCS L&S CTRL UPG	\$0.06
Generation Reliability Total			\$53.69
Other	159499KU	159499KU-prox probe cal equipment	\$0.02
Other	GSCACONTL	ACCESS CONTROL OT	\$0.02
Other	GSCASMGTL	ASSET MANGMT OT LGE	\$0.46
Other	147993	BR 0-1 Gyp Dewat Vac Pump Rbld	\$0.05
Other	155102	BR 0-1 SFC Overhaul	\$0.30
Other	155103	BR 0-2 SFC Overhaul	\$0.30
Other	147894	BR All Terrain Forklift	\$0.03
Other	157379	BR Annhydrous Ammonia Fog Sys	\$0.17
Other	162217	BR Aux Power Meters	\$0.07
Other	160808	BR Bleach Storage Tank Repl	\$0.02
Other	162257	BR CCRT Filter Sep Platforms	\$0.07
Other	148002	BR CCRT LP Bot Ash Pump Rbld	\$0.12
Other	162256	BR CCRT Paddle Mixer Platforms	\$0.14
Other	162258	BR CCRT SFC Access Platforms	\$0.07
Other	144456	BR Crusher House Vac System	\$0.03
Other	147992	BR Gyp Dewatering Belt Repl	\$0.04
Other	162526	BR Land Purchase (Clay)	\$0.52
Other	157259	BR Landfill Capping (LTP)	\$0.10
Other	162262	BR Locker Room HVAC Repl	\$0.07
Other	BRMISCCAP	BR Miscellaneous Cap	\$0.77
Other	163378	BR MMHY Vehicle 2020	\$0.04
Other	157375	BR Regravel Main Ash Pond Dam	\$0.04
Other	162260	BR RO Chemical Berm Refurb	\$0.43
Other	160975	BR Roadway Lighting	\$0.04
Other	147896	BR Skid Loader	\$0.08

Category	Project No.	Project Description	\$M Arbourgh
Other	159813	BR Solar Share Vehicle	\$0.04
Other	163594	BR Stm Land Purchase	\$0.33
Other	162818	BR Training Building HVAC Repl	\$0.01
Other	163384	BR UNIT 3 ESP DEMO	\$3.50
Other	160339	BR Vehicle Repl 2021	\$0.04
Other	162259	BR Village Demolition	\$0.56
Other	162250	BR Warehouse Forklift	\$0.03
Other	159046	BR1 & BR2 Retirements	\$0.05
Other	157306	BR3 Auxiliary Boiler	\$0.02
Other	161776	BR3 Clark 3000 Forklift Retire	\$0.00
Other	162254	BR3 Conveyor Room Platform	\$0.04
Other	160648	BR3 CT Escape Ladders	(\$0.01)
Other	162255	BR3 Economizer Access Platform	\$0.06
Other	GSEBRDGAK	BR3 GSU DGA Installation KU	\$0.09
Other	159665	BRCT 11N2 Crane Cntrl & Motor	\$0.25
Other	160913	BRCT 6&7 HVAC Repl	\$0.02
Other	158941	BRCT GT24 Crane Controls Upgr	\$0.01
Other	159667	BRCT Storage Shed	\$0.30
Other	GSCCONFGL	CONFIGURATION OT LGE	\$0.02
Other	163313	CR7 Air Compressor 2020	\$0.03
Other	161900	CR7 Aux Stm Heater	\$0.02
Other	159625	CR7 Clarifier Inlet Valve	\$0.02
Other	162345	CR7 Condensor Clean	\$0.09
Other	161877	CR7 Cool Towr Wall	\$0.03
Other	160811	CR7 Emerson Start	\$0.38
Other	161153	CR7 Emerson TREX Commun	\$0.01
Other	159139	CR7 EQ BLDG SECUR	(\$0.00)
Other	161003	CR7 ICM Expansion 2019	\$0.05
Other	160716	CR7 ISS Housing	\$0.44
Other	162688	CR7 ISS Housing Rebuild	\$0.21
Other	158876	CR7 Ket Boil Upgrade	\$1.81
Other	159431	CR7 Lightning Arrestors	\$0.01
Other	144531	CR7 Misc Project (multi-year)	\$0.70
Other	160795	CR7 PLANT VEHICLE KU	\$0.04
Other	162859	CR7 Spare CEM Analyzer	\$0.02
Other	163508	CR7 Sump Pumps 2020	\$0.07
Other	160765	CR7 Training Modules	\$0.06
Other	160688	CR7 Training Simulation Bldg	\$0.02
Other	154831	CR7 UV LIGHTING	\$0.16
Other	161303	CR7 WARTY SHORTAGE LGE	\$0.21
Other	158878	CR7 Waterbox Lining	\$0.17
Other	160559	CR7 Wtrtrmt Catwalk	\$0.03
Other	GSCDRBCL	DISASTER RECOVER OT LGE	\$0.01
Other	151917	DX Access Bridge Refurb	\$0.00
Other	161271	DX Crane Walkway Repl	\$0.01
Other	146434	DX Dam Parapet Wall	\$6.09
Other	162309	DX DECS 250 Retrofit	\$0.06
Other	163408	DX Herrington Lake Buoys Repl	\$0.15
Other	160516	DX Spillway Swinging Bridge	\$0.00
Other	133638	EFFLUENT WATER STUDY-BR	\$0.10
Other	133641	EFFLUENT WATER STUDY-GH	(\$0.47)
Other	133679	EFFLUENT WATER STUDY-TC LGE	(\$1.88)
Other	161080	GH 1/2 ELECTRIC SHOP HVAC DEM	\$0.02
Other	156571	GH 10K Silo Dust Collector	\$0.06

Category	Project No.	Project Description	\$M Arbourgh
Other	157390	GH 1-2 Transport Blower Repl21	\$0.05
Other	154940	GH 2&3 Stack Elevator	\$0.14
Other	160767	GH 2-2 ME Chevron Replacment	\$0.12
Other	161070	GH 2-3 Stack Merc Trap Replace	\$0.06
Other	160730	GH 3&4 Coal Room Vacuum System	\$0.19
Other	161092	GH 3-1 Water Well Pump Rebuild	\$0.03
Other	154922	GH 4 AH and Fan Area LED Light	\$0.04
Other	157703	GH Ammonia Storage Deluge Sys	\$0.50
Other	161132	GH BAND SAW - SMM SHOP	\$0.01
Other	160981	GH Boiler Access Equipment	\$0.14
Other	163323	GH CCR Area Drainage Imp	\$0.75
Other	155030	GH CCR Bottom Ash Sump Submer	\$0.13
Other	144365	GH CCR Pipe Conveyor Belt	\$0.68
Other	161096	GH CCR Skid Steer 2019	\$0.08
Other	155038	GH CCR Valve Replacement U4 19	(\$0.00)
Other	161071	GH Coal Feeder Rad Source Ret	\$0.15
Other	161072	GH Coal Handling Rad Retire	\$0.06
Other	161267	GH Coal Sample Building	\$0.02
Other	161093	GH Contractor Transportation	\$0.08
Other	161762	GH CY Equipment Storage Bldg	\$0.34
Other	156604	GH CYReclmHprs1&2 & 1GCnvyrLED	\$0.00
Other	163403	GH DTLs Carryback Conveyor	\$0.14
Other	163324	GH DTLs Dust Collector	\$0.11
Other	163401	GH DTLs Fire Detection System	\$0.10
Other	163402	GH DTLs Pipe Convey Access Imp	\$0.06
Other	161052	GH Front Loader	\$0.44
Other	161127	GH Gener Flux Probe Monitor	\$0.02
Other	154851	GH Miscellaneous Shop Tools21	\$0.03
Other	154852	GH Miscellaneous Shop Tools22	\$0.03
Other	156597	GH Old Admin Building AHU Repl	\$0.46
Other	156598	GH Old LSPrepBldg LED LghtUpgd	\$0.05
Other	159681	GH Property Acquisition 19	\$0.00
Other	161684	GH Property Acquisition 20	\$0.01
Other	159419	GH SFCC Platforms	\$0.21
Other	156599	GH SmpleHse H1&2 Cnvyr LEDUpgd	\$0.10
Other	161134	GH TRENCH & SHORE BOXES	\$0.04
Other	156601	GH TrnsfrHse2 & G3&4 Cnvyr LED	\$0.09
Other	156603	GH TrsferHse4 & H3&4Cnvyr LED	\$0.02
Other	161120	GH Utility Crew Cab Vehicles	\$0.22
Other	161088	GH VACUUM/HYDRO TRUCK	\$0.45
Other	160772	GH Video Equipment Repl19	\$0.01
Other	161281	GH Warehouse Truck Repl	\$0.03
Other	161095	GH Water Truck CCR 2019	\$0.12
Other	160058	GH Weir Sampling Box	\$0.38
Other	161275	GH Welding Machines	\$0.03
Other	161663	GH1 Boiler Part Asbestos Abate	\$0.29
Other	161215	GH1 DRAIN TANK ASBESTOS REM	\$0.05
Other	160733	GH1 East Coal Room Vacuum Sys	\$0.12
Other	159577	GH1 PJFF Hoist Replacement20	\$0.08
Other	160734	GH1 West Coal Room Vacuum Sys	\$0.13
Other	161135	GH1/2 F ASH AIR COMPRESS ENCL	\$0.07
Other	160735	GH2 Coal Room Vacuum Sys	\$0.15
Other	161867	GH2 FGD HVAC Fluid Coolers Rpl	\$0.18
Other	161942	GH2 FGD LPSW Strainer Repl 21	\$0.34

Category	Project No.	Project Description	\$M Arbourgh
Other	161126	GH2 HY-PRO ES CONTAM REM SK	\$0.04
Other	135279	GH2 PJFF BC 21	\$1.88
Other	159578	GH2 PJFF Hoist Replacement20	\$0.08
Other	161099	GH2-1 FGD Inlet Insul Repl	\$0.11
Other	154918	GH3 AH and Fan Area LED Light	\$0.03
Other	161015	GH3 FGD INLET DUCT INSUL REPL	\$0.10
Other	161115	GH3 HY-PRO ES CONTAM REM SK	\$0.04
Other	159579	GH3 PJFF Hoist Replacement20	\$0.08
Other	160976	GH3 Precip LED Lighting	\$0.11
Other	161094	GH3-2 FGD Agitator Shaft Repl	\$0.03
Other	161078	GH3-4 FGD Agitator Shaft Repl	\$0.02
Other	156596	GH4 Exterior LED Light Upgrade	\$0.19
Other	159580	GH4 PJFF Hoist Replacement20	\$0.08
Other	160978	GH4 Precip LED Lighting	\$0.11
Other	159450	GH4 Stack Compliance Mon21	\$0.05
Other	161665	GH4 Turbine Bldg 2nd Flr LED	\$0.07
Other	157612	GHEM DUST CONTROL NON-ECR	\$0.01
Other	157591	GHEM ENV IMP NON ECR	\$7.88
Other	144514	GS CDM CIP Ver 8.0 LGE	\$0.09
Other	148155	GS CDM CIP Ver 9.0	\$0.10
Other	GSCIPV8L	GS CDM CIP Version 8 LGE	\$0.06
Other	144503	GS CDM GMD Protection	\$0.01
Other	161315LGE	GS CDM KIP Printer LGE	\$0.02
Other	132931	GS CDM Lrg Format	\$0.05
Other	GSCINV20L	GS CDM OT Inv Mgmt- 2020	\$0.21
Other	161236	GS CDM TCA Switch	\$0.01
Other	157804	GS CR7 Bus Tie	\$0.01
Other	148135	GS GE CV GIS	\$0.14
Other	148132	GS GE CV Landfill Instrum	\$0.07
Other	133076	GS GE Dam Impnd	\$0.12
Other	132756	GS GE Lab Equip	\$0.08
Other	GSSLLABEL	GS GE Lab Equip 2020	\$0.09
Other	GSMPHTK	GS GE M Prtble Hrdness Tstr-KU	\$0.01
Other	161121	GS GE M Spark OES	\$0.04
Other	161111	GS GE M Viscometer	\$0.03
Other	GSMMACK	GS GE Motion Amp Camera	\$0.02
Other	144494	GS GE PDM Equip Upgrade	\$0.02
Other	136480	GS GE Test Equipment Pool LGE	\$0.23
Other	GSMVMEL	GS GE Vibration Monitor Equip	\$0.11
Other	155124	GS GenEng MHM Software	\$0.01
Other	155127	GS GenEng Transformer Protection	\$0.21
Other	155126	GS GenEng Vibration Monitor	\$0.12
Other	160847	GS GL Coal Mstr Ash Anlzl	\$0.07
Other	GSSLMICRK	GS SL Asbestos Microscope - KU	\$0.04
Other	GSSLATCLK	GS SL Autoclave - KU	\$0.01
Other	GSSLBTUCL	GS SL BTU Calorimeter - LGE	\$0.05
Other	160744	GS SL Discrete Analyzer	\$0.05
Other	GSSLDISHK	GS SL Dishwasher - KU	\$0.02
Other	GSSLRENOL	GS SL Lab Renovation 2021 LGE	\$0.07
Other	160760	GS SL Mercury 1631	\$0.02
Other	160758	GS SL Office HVAC	\$0.06
Other	GSSLOPCTL	GS SL Oil Particle Counter-LGE	\$0.03
Other	GSSLALRML	GS SL Smart Alarms LGE	\$0.02
Other	GSSLRBATK	GS SL UPS Battery Replace KU	\$0.01

Category	Project No.	Project Description	SM Arbourgh
Other	158929	GS Transformer prot CR7	\$0.12
Other	160652KU	GS Transformer Prot GH	\$0.16
Other	162782	KU SOLAR SHARE ARRAY 3	\$0.14
Other	140342LGE	MISC TOOLS	\$0.01
Other	GSCOTNWKL	NETWORK MONITORING OT LGE	\$0.15
Other	GSCOTSEGL	NETWORK SEGMENTATION OT LC	\$0.24
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	163269	SOLAR SHARE ARRAY 3	\$0.40
Other	163275	SOLAR SHARE ARRAY 4 LGE	\$0.47
Other	GSESPICTL	SPIR CT TRIMBLE COUNTY LGE	\$0.00
Other	GSESPIRTL	SPIR TRIMBLE COUNTY LGE	\$0.00
Other	GSSLABTCL	SYSTEM LAB TRIMBLE COUNTY-	\$0.59
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	\$0.16
Other	162218LGE	TC CT INSTALL LED LIGHTING	\$0.14
Other	153072LGE	TC FUEL HANDLING DOZER	\$0.20
Other	161104LGE	TC GYPSUM LOADOUT TRANSFOF	\$0.02
Other	160741LGE	TC HAUL ROAD PAVING 2019	\$0.25
Other	153056LGE	TC IMPOUNDMENT IMPROVEMEN	\$0.04
Other	159056LGE	TC LAB EQUIPMENT 2019	\$0.03
Other	161463LGE	TC LAB EQUIPMENT 2020	\$0.04
Other	161466LGE	TC LAB MONITORS 2020	\$0.00
Other	159058LGE	TC LAB MONITORS-2019	\$0.01
Other	159048LGE	TC LED LIGHTING 2019	\$0.05
Other	161482LGE	TC LED LIGHTING 2020	\$0.20
Other	160677LGE	TC MATERIAL HAND OFFICE UPGI	\$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	\$0.04
Other	159864LGE	TC PWS EQUIP/MONITORS	\$0.02
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	159060LGE	TC WASTE SLUDGE PUMPS	\$0.06
Other	160776LGE	TC WET PIT LIFT STATION UPGD	\$0.09
Other	GSCVULMGL	VULNERABILITY MANGMT OT LG	\$0.03
Other	GSC3DPRTK	Z18 3D printer	\$0.01
Other Total			\$43.32
Outage for Coal Fired Units	155085	BR 3-1 Contr Air Compress Ovhl	\$0.08
Outage for Coal Fired Units	159656	BR 3-1/3-5 Pulv Dyn Classifier	\$0.12
Outage for Coal Fired Units	157462	BR Abs to FGD Exp Joints Repl	\$0.26
Outage for Coal Fired Units	157467	BR CY Conveyor Belt Repl	\$0.06
Outage for Coal Fired Units	160686	BR FGD 0-6 Recycle Pump Rbld	\$0.15
Outage for Coal Fired Units	161091	BR FGD Absorber Tile Repl	\$0.32
Outage for Coal Fired Units	151997	BR FGD Agitator Blade Repl	\$0.65
Outage for Coal Fired Units	135116	BR FGD Recycle Pump Rbld	\$0.15
Outage for Coal Fired Units	155091	BR FGD Umbilical Repl	\$0.04
Outage for Coal Fired Units	155088	BR Stack PM Analyzer Repl	\$0.01
Outage for Coal Fired Units	155090	BR Stack Umbilical Repl	\$0.05

Category	Project No.	Project Description	\$M Arbourgh
Outage for Coal Fired Units	137190	BR SW Lines Coating	\$0.27
Outage for Coal Fired Units	157377	BR2/3 Bypass Stack Cap	\$0.10
Outage for Coal Fired Units	157942	BR3 AB Heater Repl	\$0.67
Outage for Coal Fired Units	161445	BR3 Air Heater Basket Repl	\$1.55
Outage for Coal Fired Units	148006	BR3 BFPT Electronic Ovspd Cntr	\$0.34
Outage for Coal Fired Units	160889	BR3 BFPT Seals Repl	\$0.02
Outage for Coal Fired Units	133964	BR3 BMS Repl-Upgrade	\$0.16
Outage for Coal Fired Units	135113	BR3 Coal Fdr Transition Chutes	\$0.03
Outage for Coal Fired Units	157253	BR3 Coal Feeder Motor Repl	\$0.00
Outage for Coal Fired Units	155070	BR3 Eng Work Station (AW) Upgr	\$0.08
Outage for Coal Fired Units	137165	BR3 Field Ground Detector	\$0.09
Outage for Coal Fired Units	157251	BR3 Generator Rotor Rewind	\$0.77
Outage for Coal Fired Units	144727	BR3 HP Inlet Bell Seals	\$0.15
Outage for Coal Fired Units	144722	BR3 HP-IP Blading	\$0.35
Outage for Coal Fired Units	144725	BR3 HP-IP Seals	\$0.17
Outage for Coal Fired Units	147918	BR3 Hyd Gas Dryer Refurb	\$0.00
Outage for Coal Fired Units	155094	BR3 Ignitor Upgrade	\$0.08
Outage for Coal Fired Units	160612	BR3 IP Turb Inlet Ring Seals	\$0.21
Outage for Coal Fired Units	147930	BR3 Pulv Dynmc Classifier Repl	\$0.01
Outage for Coal Fired Units	151993	BR3 SCR Catalyst - Bottom	\$0.59
Outage for Coal Fired Units	151998	BR3 Steam Seperator Repl	\$0.05
Outage for Coal Fired Units	159617	BR3 TV Gasket Modification	\$0.15
Outage for Coal Fired Units	144717	BR3-1 BFPT Blading	\$0.09
Outage for Coal Fired Units	153458	BR3-1 Condensate Pump Overhaul	\$0.09
Outage for Coal Fired Units	155086	BR3-2 Station AirCompress Ovhl	\$0.06
Outage for Coal Fired Units	157255	BR3-4 SB Air Compressor	\$0.25
Outage for Coal Fired Units	135117	BR3-5 Pulverizer Gearbox Ovhl	\$0.04
Outage for Coal Fired Units	161447	CR7 CCI Valves 2020	\$0.31
Outage for Coal Fired Units	148096	CR7 NGCC STG	\$0.80
Outage for Coal Fired Units	162222	CR7 ST Bearings	\$0.14
Outage for Coal Fired Units	152783	GH 1-2 BFP Major Ovrhl 21	\$0.25
Outage for Coal Fired Units	161931	GH 1-6 Burner Modification	\$0.08
Outage for Coal Fired Units	152770	GH 2-1 BFP Major Ovrhl 19	\$0.15
Outage for Coal Fired Units	163618	GH 2-2 BFP Overhaul	\$0.08
Outage for Coal Fired Units	160599	GH 2-2B FGD AgitatorGrbx Ovrhl	\$0.05
Outage for Coal Fired Units	151399	GH 2-3 FGD Header Repl	\$0.69
Outage for Coal Fired Units	152779	GH 3-2 BFP Major Ovrhl 19	\$0.07
Outage for Coal Fired Units	161903	GH 3-2 Stator Cooler Repl22	\$0.10
Outage for Coal Fired Units	162357	GH 4-1 FGD Agitator Shaft Repl	\$0.03
Outage for Coal Fired Units	152782	GH 4-2 BFP Major Ovrhl 21	\$0.24
Outage for Coal Fired Units	162358	GH 4-2 FGD Agitator Shaft Repl	\$0.02
Outage for Coal Fired Units	161706	GH 4-2 Stator Cooler Repl	\$0.07
Outage for Coal Fired Units	161479	GH 4-5 FGD Agitator Shaft Repl	\$0.02
Outage for Coal Fired Units	161480	GH 4-7 FGD Agitator Shaft Repl	\$0.08
Outage for Coal Fired Units	144378	GH 480v USS TRansformer	\$0.30
Outage for Coal Fired Units	152862	GH CY Transfer Point Upgrade	\$0.00
Outage for Coal Fired Units	160986	GH Spare FGD Agitator Shafts	\$0.14
Outage for Coal Fired Units	162631	GH Spare Stator Bars	\$3.88
Outage for Coal Fired Units	151390	GH Stn Srvce Water Piping Repl	\$0.20
Outage for Coal Fired Units	161660	GH1 Boiler Partial Reinsulate	\$0.08
Outage for Coal Fired Units	163322	GH1 Boiler Safety Repl21	\$0.75
Outage for Coal Fired Units	140222	GH1 Burner Corner Tubing	\$3.02
Outage for Coal Fired Units	161760	GH1 Burner Replacement 2020	\$0.11
Outage for Coal Fired Units	162368	GH1 Burner Replacement 2021	\$0.13

Category	Project No.	Project Description	\$M Arbourgh
Outage for Coal Fired Units	137100	GH1 Controls Syst Upgrade	\$0.00
Outage for Coal Fired Units	121GH	GH1 Cooling Tower ComplRebuild	\$11.55
Outage for Coal Fired Units	144391	GH1 CW Piping Rehab	\$1.13
Outage for Coal Fired Units	147343	GH1 Econ Inlet Header Repl	\$1.23
Outage for Coal Fired Units	149GH	GH1 FGD Inlet Block Repl21	\$0.35
Outage for Coal Fired Units	154982	GH1 Final SH Inlet Leg DMW Rpl	\$1.25
Outage for Coal Fired Units	131978	GH1 Reheat Pend Assy Repl	\$12.16
Outage for Coal Fired Units	144327	GH1 SCR Catalyst L1 New	\$2.14
Outage for Coal Fired Units	144312	GH1 SH Pendant Platens	\$4.78
Outage for Coal Fired Units	147399	GH1 SH Steam Cooled Spacer	\$0.99
Outage for Coal Fired Units	148101	GH1 Turbine	\$1.98
Outage for Coal Fired Units	161604	GH1 Turbine Crossover Exp Jt20	\$0.17
Outage for Coal Fired Units	154989	GH1 Waterwall panel repl 2020	\$1.08
Outage for Coal Fired Units	144302	GH2 4kv Switchgear	\$1.76
Outage for Coal Fired Units	140216	GH2 7 & 8 Stage Bucket Repl	\$0.37
Outage for Coal Fired Units	152005	GH2 Burner Replacement 19	\$0.02
Outage for Coal Fired Units	162394	GH2 Burner Replacement 2021	\$0.13
Outage for Coal Fired Units	159165	GH2 Crossover Bellows Repl	\$0.05
Outage for Coal Fired Units	159820	GH2 CW Piping Repl 21	\$0.80
Outage for Coal Fired Units	137477	GH2 FGD In & Out Exp Jt	\$0.37
Outage for Coal Fired Units	154991	GH2 Final SH Inlet Leg DMW Rpl	\$0.11
Outage for Coal Fired Units	151404	GH2 Furnace Wall Metal Overlay	\$1.89
Outage for Coal Fired Units	140218	GH2 HP Turb Seal Ring Repl	\$0.13
Outage for Coal Fired Units	188GH	GH2 PA Duct Mtl Exp Joint Rpl	\$0.00
Outage for Coal Fired Units	155002	GH2 Steam Cooled Spacer Repl	\$0.64
Outage for Coal Fired Units	137417	GH2 T & B AH Basket Repl	\$0.60
Outage for Coal Fired Units	140217	GH2 Turb Packing Repl	\$0.49
Outage for Coal Fired Units	158949	GH3 #3 Boiler DivisionWall Rpl	\$0.42
Outage for Coal Fired Units	159841	GH3 AH Duct Insulation	\$1.41
Outage for Coal Fired Units	162774	GH3 AH Hot End Bskt Rpl 2020	\$0.63
Outage for Coal Fired Units	137104	GH3 Coal Hand Relay Repl	\$0.10
Outage for Coal Fired Units	159822	GH3 CW Piping Repl 21	\$1.00
Outage for Coal Fired Units	161750	GH3 Electromatic Valve Repl20	\$0.18
Outage for Coal Fired Units	197GH	GH3 FGD Agitator Shaft Repl21	\$0.14
Outage for Coal Fired Units	140196	GH3 Furnace Wall Metal Overlay	\$0.15
Outage for Coal Fired Units	151366	GH3 Furnace Wall Metal Ovrly19	\$1.71
Outage for Coal Fired Units	137084	GH3 ME Spray Pipe Repl	(\$0.00)
Outage for Coal Fired Units	154942	GH3 Precip Rebuild Phase 3	\$0.43
Outage for Coal Fired Units	154943	GH3 Precip Rebuild Phase 4	\$0.45
Outage for Coal Fired Units	151403	GH3 RH Otlt Terminal Tube Repl	\$0.24
Outage for Coal Fired Units	209GH	GH3 SCR Exp Joint Repl	\$0.31
Outage for Coal Fired Units	157415	GH3 SCR Outlet Exp Joint Repl	\$0.30
Outage for Coal Fired Units	155008	GH3 Vertical RH Partial Repl18	(\$0.00)
Outage for Coal Fired Units	144309	GH4 480v MCC Replacement	\$0.19
Outage for Coal Fired Units	161743	GH4 7,8,9 Stg Diaphragm BldRpl	\$0.24
Outage for Coal Fired Units	156629	GH4 AH Basket Repl 2020	\$2.39
Outage for Coal Fired Units	159843	GH4 AH Duct Insulation	\$0.70
Outage for Coal Fired Units	161933	GH4 Coal Nozzle Repl21	\$0.64
Outage for Coal Fired Units	161932	GH4 Coal Nozzle Repl22	\$0.08
Outage for Coal Fired Units	220GH	GH4 Cooling Tower ComplRebuild	\$10.86
Outage for Coal Fired Units	159827	GH4 CW Piping Repl 21	\$1.00
Outage for Coal Fired Units	126302	GH4 Econ Outlet Duct Exp Jt	\$0.09
Outage for Coal Fired Units	140199	GH4 Furnace Wall Metal Overlay	\$1.34
Outage for Coal Fired Units	151367	GH4 Furnace Wall Overlay 2024	\$0.15

Category	Project No.	Project Description	\$M Arbourgh
Outage for Coal Fired Units	162409	GH4 Generator Stator Rewind20	\$4.13
Outage for Coal Fired Units	160894	GH4 HP-IP Blade Repl 20	\$0.53
Outage for Coal Fired Units	137070	GH4 ME Spray Piping Repl	\$0.49
Outage for Coal Fired Units	147347	GH4 Mill BSO Repl	\$0.46
Outage for Coal Fired Units	151437	GH4 PA Duct Replacement	\$0.45
Outage for Coal Fired Units	161813	GH4 PA Fan Protect Relay Upgrd	\$0.02
Outage for Coal Fired Units	154951	GH4 Precip Rebuild Phase 4	\$0.83
Outage for Coal Fired Units	137474	GH4 Primary SH Repl	\$1.99
Outage for Coal Fired Units	151439	GH4 Pulv Cold Air Dampers Repl	\$0.20
Outage for Coal Fired Units	155014	GH4 RH Outlet Terminal TubeRpl	\$2.05
Outage for Coal Fired Units	157416	GH4 SCR Outlet Exp Joint Repl	\$0.33
Outage for Coal Fired Units	161451	GH4 Turb Packing Repl	\$1.62
Outage for Coal Fired Units	137244	Gh4 Upper Econ Repl	\$1.79
Outage for Coal Fired Units	162533	GH4 Upper SH Attemperator Repl	\$0.13
Outage for Coal Fired Units	155017	GH4 Vertical RH Repl	\$2.62
Outage for Coal Fired Units	156027	ST L-O BLADES LGE	(\$0.02)
Outage for Coal Fired Units	152683LGE	TC2 B BFP OVERHAUL	\$0.14
Outage for Coal Fired Units	152665LGE	TC2 B FD FAN OVERHAUL	\$0.42
Outage for Coal Fired Units	160911LGE	TC2 BOILER WATER WALL PANEL	\$1.10
Outage for Coal Fired Units	150015LGE	TC2 BURNER REPL (B,E ROWS)	\$0.00
Outage for Coal Fired Units	137585LGE	TC2 DCS UPDRADE	\$0.04
Outage for Coal Fired Units	155651LGE	TC2 EXPANSION JOINTS	\$0.64
Outage for Coal Fired Units	161146LGE	TC2 FINAL RH LEAD INLET LEG	\$0.45
Outage for Coal Fired Units	159920LGE	TC2 FINAL SH INLET LEG	\$0.49
Outage for Coal Fired Units	159922LGE	TC2 FINAL SH INLET LEG-2	\$0.17
Outage for Coal Fired Units	153047LGE	TC2 FINAL SH REPL	\$0.30
Outage for Coal Fired Units	156853LGE	TC2 ID FAN SEALING AIR FLOW	\$0.06
Outage for Coal Fired Units	152104LGE	TC2 LAST STAGE BUCKETS	\$5.49
Outage for Coal Fired Units	157777LGE	TC2 LOWER SLOPE REPLACE	\$0.04
Outage for Coal Fired Units	157191LGE	TC2 LOWER SLOPE WW REPL	\$0.83
Outage for Coal Fired Units	161273LGE	TC2 MDBFP VOITH OH	\$0.31
Outage for Coal Fired Units	152695LGE	TC2 MS TURBINE BYPASS VALVE	\$0.17
Outage for Coal Fired Units	153060LGE	TC2 REPL AH CE BASKETS	\$0.24
Outage for Coal Fired Units	160564LGE	TC2 RH ATTEMPERATORS-SPARE	\$0.25
Outage for Coal Fired Units	159915LGE	TC2 SB CONTROL SYST UPG	\$0.15
Outage for Coal Fired Units	153080LGE	TC2 SCR CATALYST L1	\$1.17
Outage for Coal Fired Units	153081LGE	TC2 SCR CATALYST L2 NEW	\$0.56
Outage for Coal Fired Units	162645LGE	TC2 SPARE ID FAN BLADES	\$0.18
Outage for Coal Fired Units	152040LGE	TC2 SSC REPLACE CHAIN	\$0.10
Outage for Coal Fired Units	150064LGE	TC2 SSC TILE	\$0.20
Outage for Coal Fired Units	161276LGE	TC2 TD BFP RECIRC VALVES	\$0.21
Outage for Coal Fired Units Total			\$122.64
Outage for Combustion Turbines	157261	BRCT 6&7 SFC Controls Upgr	\$0.32
Outage for Combustion Turbines	157263	BRCT6 AVR Upgrade	\$0.14
Outage for Combustion Turbines	123906	BRCT6 C Inspection	\$0.00
Outage for Combustion Turbines	155110	BRCT6 Gen Protect Relay Upgr	\$0.08
Outage for Combustion Turbines	157265	BRCT7 AVR Upgrade	\$0.14
Outage for Combustion Turbines	131972	BRCT7 C Inspection	\$13.24
Outage for Combustion Turbines	155144	BRCT7 Gen Protect Relay Upgr	(\$0.04)
Outage for Combustion Turbines	155150	BRCT7 GT Thermal Insulation	\$0.59
Outage for Combustion Turbines	147950	BRCT8 C Insp & Parts Recond	\$6.63
Outage for Combustion Turbines	155147	BRCT8 Cooling Water Pump Upgr	\$0.03
Outage for Combustion Turbines	144542	CR7 NGCC HGP	\$17.50
Outage for Combustion Turbines	132002	TC CT HGP Insp Unit 7	\$0.02

Category	Project No.	Project Description	Arbough
Outage for Combustion Turbines	132004	TC CT HGP Insp Unit 8	\$2.06
Outage for Combustion Turbines	132003	TC CT HGP Insp Unit 9	\$3.02
Outage for Combustion Turbines	153083LGE	TC CT MAJOR INSPECTION #1	\$10.17
Outage for Combustion Turbines Total			\$53.89
Power Plant Demolition	153263	GREEN RIVER DEMO	\$1.56
Power Plant Demolition	144659	Pineville Demo	\$0.35
Power Plant Demolition	144660	Tyrone Demo	\$1.50
Power Plant Demolition Total			\$3.40
Grand Total			\$276.95

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 2-30 for further information about the Southeast Energy Exchange Market.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 247

Responding Witness: N/A

Q-247. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-247. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

Question No. 248

Responding Witness: N/A

Q-248. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO
MAINTAIN NUMBERING WITH CASE NO. 2020-00350]

A-248. N/A

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY**Response to Joint Initial Data Requests of the Attorney General and KIUC
Dated January 8, 2021****Case No. 2020-00349****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.

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
<i>Construction Subtotal:</i>	\$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
<i>DMS/DSCADA Subtotal:</i>	\$2,443	\$3,369	\$4,430	\$1,924	\$12,166
<i>Project Total:</i>	\$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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITES COMPANY**2- WAY FLOW CIRCUITS**

FEEDER_ID	0073	0148	0440	0607	0903	2123	2457
0001	0074	0149	0441	0608	0913	2124	2458
0003	0076	0154	0451	0626	0920	2126	2469
0004	0077	0159	0452	0627	0924	2129	2472
0007	0078	0160	0454	0628	0935	2136	2500
0011	0080	0163	0459	0631	0936	2138	2503
0016	0081	0167	0460	0639	0939	2140	2504
0023	0082	0168	0461	0641	0940	2150	2505
0024	0086	0178	0470	0642	0950	2151	2509
0025	0091	0187	0471	0643	0966	2166	2510
0026	0096	0189	0475	0645	1071	2170	2513
0027	0097	0194	0476	0650	1325	2176	2515
0030	0098	0199	0481	0688	1327	2224	2516
0031	0100	0204	0500	0701	1328	2226	2518
0032	0101	0205	0501	0707	1404	2228	2519
0033	0105	0219	0503	0746	1443	2232	2522
0036	0106	0226	0504	0752	1468	2304	2527
0037	0109	0280	0505	0768	1492	2310	2528
0041	0110	0286	0507	0769	1498	2321	2529
0043	0111	0293	0509	0777	1520	2326	2532
0044	0112	0301	0512	0780	1602	2329	2533
0045	0116	0331	0513	0801	1606	2332	2534
0046	0118	0334	0515	0805	1607	2334	2541
0047	0126	0337	0516	0806	1609	2335	2542
0048	0127	0402	0547	0816	1612	2407	4451
0049	0128	0405	0580	0825	1638	2408	4511
0050	0130	0406	0581	0847	1728	2411	4614
0051	0132	0410	0585	0853	1759	2413	4618
0053	0134	0411	0586	0855	2100	2414	4641
0055	0135	0421	0594	0864	2101	2427	4645
0063	0137	0425	0599	0865	2103	2436	4700
0064	0143	0426	0600	0868	2106	2442	4702
0068	0145	0427	0601	0874	2109	2443	4703
0069	0146	0430	0603	0878	2113	2444	4704
0071	0147	0431	0604	0881	2114	2455	4720

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 1-374 in Case No. 2017-00370: https://psc.ky.gov/pscecf/2016-00370/derek.rahn%40ge-ku.com/01252017012210/11-2016_AG_DR1_KU_%28VOL_09_-_Q265-Q374%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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

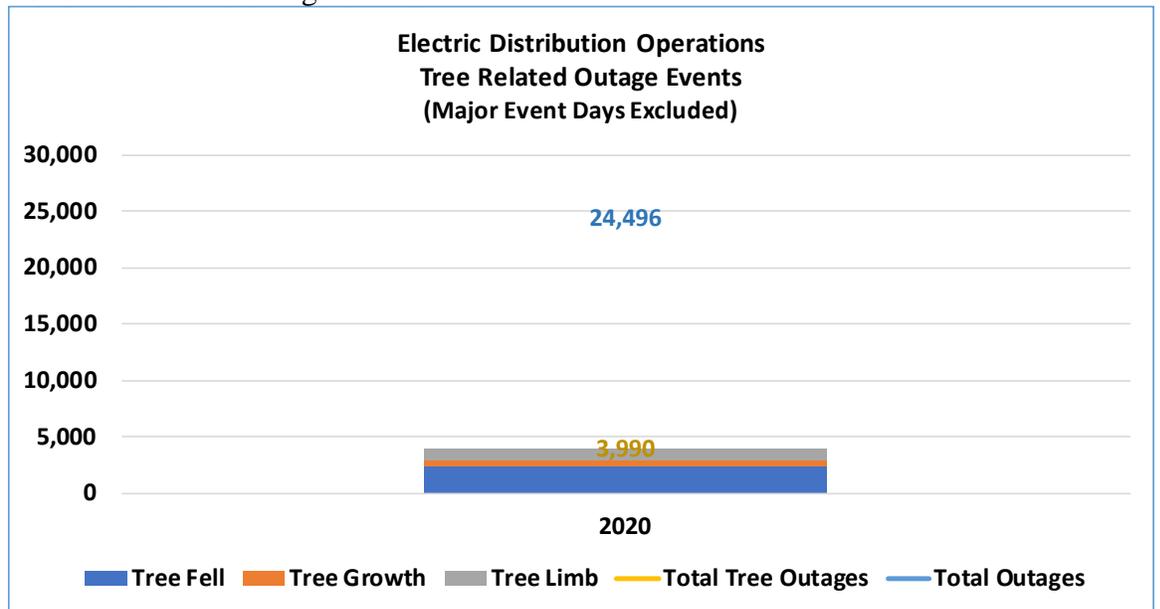
Question No. 255

Responding Witness: John K. Wolfe

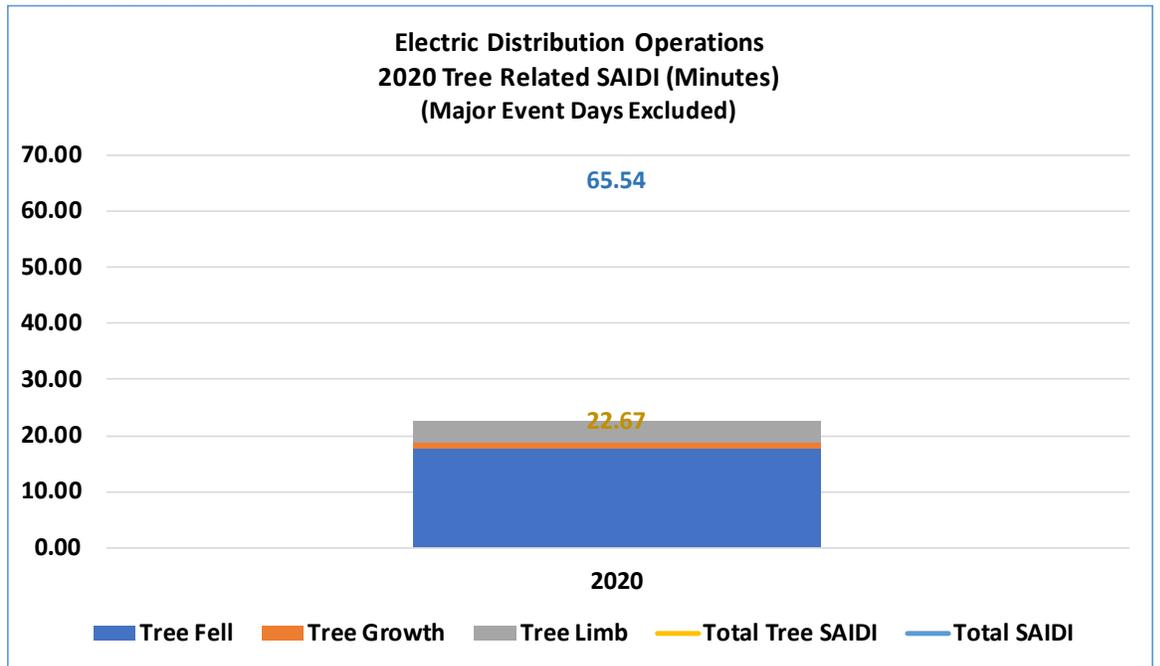
Q-255. Reference the Wolfe testimony, Exhibit JKW-1, Figures 11, 12 and 13 at pp. 29-30. In the same format as depicted in each of those Figures, provide the tree-related outages for calendar year 2020 to date.

A-255.

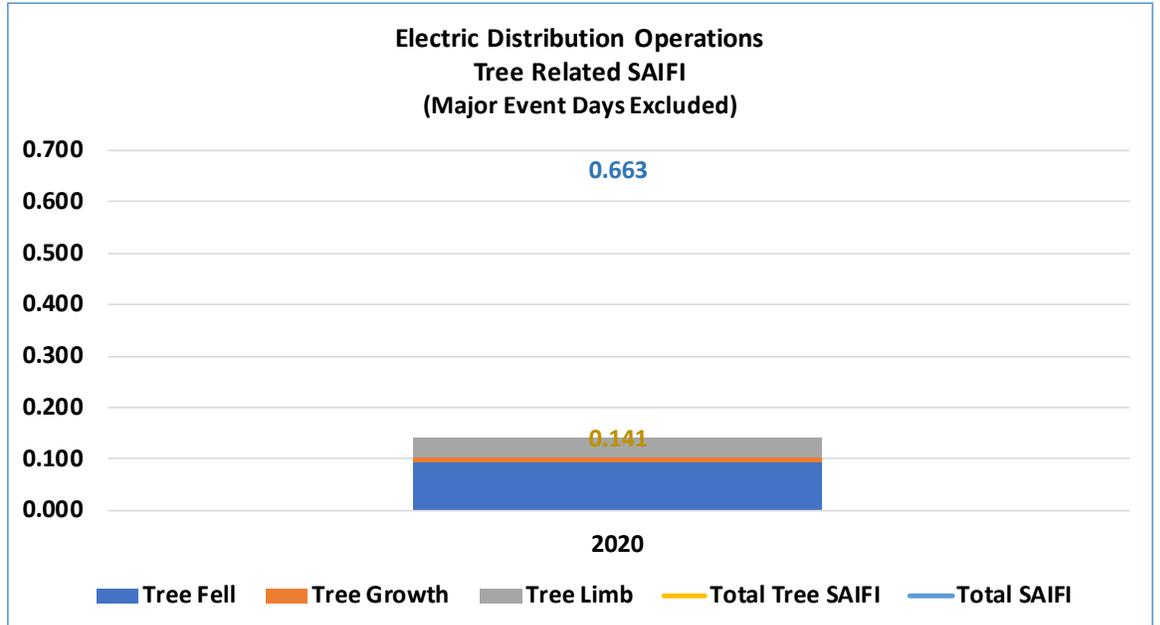
a. 2020 Tree related outage events



b. 2020 Tree related SAIDI



c. 2020 Tree related SAIFI



KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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	2,643,597	1,843,686	3,686,000	3,796,000	3,906,985	4,022,427	4,141,000
Routine	15,145,988	15,246,522	14,789,881	15,224,429	15,670,417	16,132,561	16,608,434
Total	17,789,585	17,090,208	18,475,881	19,020,429	19,577,402	20,154,989	20,749,434

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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
NIDT	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
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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	16399	
2019	2019	Funded	0	SHI 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	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	0	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	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	11306	9091	0	0	20391	Enhance	System Enhancements	KU	2020	Discretionary	310		
2019	2019	Funded	4	DSP White Sulphur 138- 12KV substation	3325	3347	0	0	0	9431	0	12789	9469	0	31244162	31338393	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	3888429	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	86928	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	876	10000	11248	3111	2666	0	0	27022	Enhance	System Enhancements	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	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	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	0	50000	Maintain	Repair/Replace Defective Equipment/CH	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	Irving/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 Asim - Circuit 4618 to Fariston Industrial Park	400	0	0	0	0	108	0	0	0	0	0	0	28454	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 0608 Switchgear	150	0	0	0	0	7	0	0	532	505	0	0	1031	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	732	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	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	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	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	291	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	0	Enhance	Reliability Underground	KU	2019	Discretionary	70
2020	2020	Funded	1	DSP Tuckert 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 Tuckert Station Substation (2020_2021)	0	3900	1800	0	0	63950	0	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	27249	0	3503043	9618	25864	0	0	3538523	Enhance	System Enhancements	KU	2020	Discretionary	130	
2020	2020	Funded	6	DSP Hoover 2 Distribution	0	800	800	0	0	1404	0	0	21309	10452	0	0	31762	Enhance	System Enhancements	KU	2020	Discretionary	160	
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	2			

	BP Year	2020
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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	3595364	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	800	
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	292197	0	100000000	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	292197	0	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	1260	33	0	0	0	237812	0	100000000	100000000	100000000	100000000	0	400000000	Enhance	System Enhancements	KU	2020	Non-Discr	1393	
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	8134	0	0	12231	18506	0	21411697	21442434	21442434	Enhance	System Enhancements	KU	2020	Non-Discr	1096	
2020	2020	Funded	0	DSP White Sulphur 138_ 12KV substation	4176	0	0	0	8134	0	0	12231	18506	0	21411697	21442434	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	237850	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	223420	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	67798	67798	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	6486
2020	2020	Funded	0	NIDT Projects Funding by YEAR	12000	12000	11000	10000	10000	0	0	0	0	0	0	0	0	Enhance	System Enhancements	KU	2020	Non-Discr	5300	
2020	2020	Funded	0	Pole Inspection and Treatment KU STR	7588	7816	8050	8292	8507	172	0	449119	251958	604116	0	1305194	1305194	Maintain	Pole Inspection	LGE	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	853591	853591	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	26783390	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	6682698	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	1442702	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	815789	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	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	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	58	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	42111	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	11204	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	148842	148842	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	883	
2020	2020	Funded	0	SCM LGE SIO BREAKERS	650	750	500	625	0	234	0	0	427459	1082896	0	1510355	1510355	Maintain	Aging Infrastructure	LGE	2020	Non-Discr	3525	
2020	2020	Funded	0	SCM LGE SIO RELAYS	2500	2500	2500	2500	0	0	0	0	74	1	0	74	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 & 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 KU AND LGE REPLACE SUBSTATION BATTERIES	281	288	295	303	310	2333	0	113038	542584	0	0	655622	655622	Maintain	Aging Infrastructure	KU	2020	Non-Discr	1477	
2020	2020	Funded	0	SCM RAP KU LEGACY ARRESTER REPLACE	87	69	70	71	74	3978	5000	0	172050	89466	0	0	266516	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	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	1349502	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	51226	129860	0	181085	181085	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	70594	42357	0	112951	112951	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	78993	189583	0	268576	268576	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	Maint						

	BP Year	2020
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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	48588	118852	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	85610	215063	0	0	304672	Maintain	Aging Infrastructure	KU	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	0	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 Reconnector	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	108821	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	148891	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 Reconnector	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	8169	0	0	26036	55655	0	0	83127	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 LCN Manchester 254 Greasy Reconnector	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	0	0	0	0	0	0	0	0	0	0	0	0	0	
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	0	0	0	0	0	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	0	0	0	0	0	300	
2022	2022	Funded	1	DSP Ashbottom Substation	0	3200	1900	0	0	5638	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	11960190	Enhance	System Enhancements	KU	2022	Discretionary	2000	
2022	2022	Funded	4	SCM KU SIO TXFMR UPGRADES	0	0	1500	1500	1500	417	0	0	18007	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	
2022	2022	Funded	26	DSP Carlisle circuit 879 Upgrade	0	0	0	1500	0	24	0	0	6261	30333	0	0	36593	Enhance	System Enhancements	KU	2022	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	2425	2594	247165	0	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	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	2033	0	0	6359	3288	0	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	0	0	0	0	0	0	0	0	0	0	0	0	0	
2023	2023	Funded	10	SIO Small Wire Removal KU	0	0	0	1800	750	297	0	0	0	0	0	0	0	0	0	0	0	0	0	
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	0	0	0	0	0	380	
2024	2024	Funded	0	DSP Nicholasville Rd Substation Property	0	0	0	0	1000	0	0	0	0	0	0	0	0	0	0	0	0	0	1000	
2024	2024	Funded	1	DSP Elizabethtown Industrial Substation Project	0	0	0	2185	183066	0	0	0	0	0	0	0	0	0	0	0	0	0	2185	
2024	2024	Funded	1	DSP Horse Cave Industrial Distribution Exit Circuits Project	0	0	0	0	432	247165	0	0	0	0	0	0	0	0	0	0	0	0	432	
2024	2024	Funded	2	DSP Fariston Distribution Circuit 0217 Reconnector Project	0	0	0	1900	216895	0	100000000	100000000	100000000	100000000	100000000	100000000	400000000	Enhance	System Enhancements	KU	2024	Discretionary	1900	
2024	2024	Funded	2	DSP Old Henry Substation (2024_2025)	0	0	0	2500	10846	0	0	0	0	0	0	27115493	27115493	Enhance	System Enhancements	LGE	2024	Discretionary	2500	
2024	2024	Funded																						

	BP Year	2021
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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	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	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	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	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	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	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	10000000	10000000	10000000	10000000	0	0	40000000	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	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	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	0	Enhance	System Enhancements	LGE	2021	Non-Discr	1000
2021	2021	Funded	0	LED Downtown Manhole Structural Repairs RAP	434	444	455	466	478	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	2277
2021	2021	Funded	0	LED Downtown Network Vault Structural Repairs RAP - 2021	1750	1794	1500	1538	1576	0	0	0	0	0	0	0	0	0	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	8158
2021	2021	Funded	0	LED Downtown Network Vent Type Protector Repl RAP - 2021	853	874	896	919	942	0	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	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	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	MIOT Projects Funding by Year	1200	1100	1000	1000	1000	0	0	0	0	0	0	0	0	0	Enhance	System Enhancements	LGE	2021	Non-Discr	3390
2021	2021	Funded	0	Pole Inspection and Treatment KU STR	7816	8050	8292	8507	8720	167	0	449119	251958	604116	0	0	1305191	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	430292	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	1510352	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	1895	
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	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	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	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	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	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	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	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP EARL SUBSTN BUILDINGS & GRNDS - 2021	51	53	54	55	57	0	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	271515	Maintain	Aging Infrastructure	KU	2021	Non-Discr	2025	
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	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	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	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	112953	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	268575	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	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	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	0	Maintain	Substation Maintenance	KU	2021	Non-Discr	163
2021	2021	Funded	0	SCM RAP LEX SUBSTATION BUILDINGS & GRNDS - 2021	51	53	54	55	57	0	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	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	0	Maintain	Substation Maintenance	LGE	2021	Non-Discr	615
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	314	
2021	2021	Funded	0	SCM RAP LGE STR REPL LEGACY BREAKERS - 2021	964	988	1013	1038	1064	93	0	0	26446	63471	0	0	89911	Maintain	Aging Infrastructure	LGE	2021	Non-Discr	5097	
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 & GRNDS - 2021	51	53	54	55	57	0	0	0	0	0	0	0	0	0	Maintain	Substation Maintenance	LGE	2021	Non-Discr	

	BP Year	2021
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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	400	
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	3205	
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	4	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	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	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	5651580	Enhance	Reliability Overhead	KU	2021	Discretionary	4308
2021	2021	Funded	8	LEO Substation Ext Cable Replacement LGE STR RAP	1660	1720	1500	1538	1576	5586	0	6488198	479972	2304037	0	0	9272206	9272206	Maintain	Aging Infrastructure	LGE	2021	Discretionary	7994
2021	2021	Funded	9	LEO Umb Cable Replacement Program LGE STR	1700	1700	1030	1061	1093	4917	0	4925887	1330168	2102279	0	0	8358333	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	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	1550164	Enhance	System Enhancements	KU	2021	Discretionary	3000
2021	2021	Funded	13	LON Manchester 254 Greasy Reconnector	95	0	0	0	0	757	0	4401	34275	33264	0	0	71940	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	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	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	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	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	67683	81219	0	0	148901	148901	Maintain	Aging Infrastructure	LGE	2021	Discretionary	1347
2021	2021	Funded	19	KU Direct Burial Replacement	1000	1000	1000	1000	1000	502	0	340255	94212	107670	0	0	502137	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	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	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	85676	50862	0	0	85676	85676	Enhance	System Enhancements	KU	2021	Discretionary	215
2021	2021	Funded	23	RIC REL 2304 Reconnector	250	0	0	0	0	356	0	0	34947	54065	0	0	89012	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	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	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	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	339080	339080	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	873116	873116	Maintain	Aging Infrastructure	KU	2021	Discretionary	1880
2021	2021	Funded	29	PIN Meldrum 0208 Hutch Re-route	250	0	0	0	0	242	0	41092	9366	9958	0	0	60416	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	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	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	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	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	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	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	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	16746	16746	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	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	0	Enhance	System Enhancements	KU	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	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	260168	Enhance	System Enhancements	LGE	2022	Discretionary	300
2022	2022	Funded	5	SCM KU SIO TXFMR UPGRADES	0	1000	1000	0	0	626	0	184107	441856	4201	0	0	625963	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	11204	Enhance	System Enhancements	KU	2022	Discretionary	6000
2023	2023	Funded	0	DSP Clinton St. Substation Property	0	200	0	0	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	300	4300	7000	3592	1000000	0	48558	29135	0	0	107769	107769	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															

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

Response to Joint Initial Data Requests of the Attorney General and KIUC

Dated January 8, 2021

Case No. 2020-00349

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.

Case No. 2020-00349
Attachment to Response to AG-KIUC-1 Question No. 260
Page 1 of 2
Saunders

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;00039FAC L;158693KU;158693LGE;159676KU;159676LGE;16011 8KU;160118LGE;160432KU;160432LGE;160880LGE;1 60880OKU;161005KU;161005LGE;162849KU;162849LG E	\$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;0064FACI K;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
Somerset 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

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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 for each utility 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.

KENTUCKY UTILITIES COMPANY

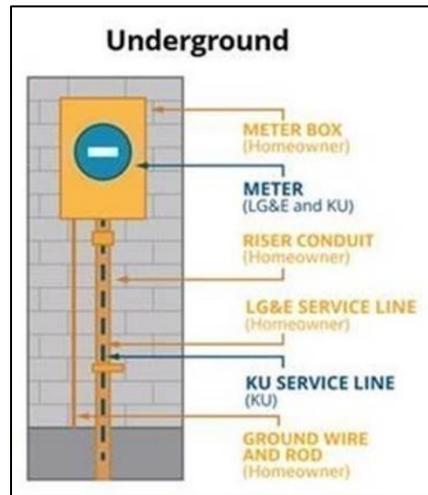
Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021

Case No. 2020-00349

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 KU, the service line is included in the rates and is not the customer's responsibility. Therefore, the warranty would cover the riser conduit, ground wire/rod and the meter box.



KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.¹² This expansion of the economy and the additional revenue benefits all customers.

¹² Just the Facts: Economic Impact of 100 Jobs, Think Kentucky, July 2018, <https://ced.ky.gov/kyedc/pdfs/100jobs.pdf>

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.

KENTUCKY UTILITIES COMPANY

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

Case No. 2020-00349

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.