COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES	**)))**	**CASE NO. 2018-00294**
	)	
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
KENT W. BLAKE
CHIEF FINANCIAL OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

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Q. Please state your name, position, and business address.

A. My name is Kent W. Blake. I am the Chief Financial Officer of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut intervenor testimony on the issues of: (1) the use of Allowance for Funds Used During Construction ("AFUDC") in lieu of Construction Work in Progress ("CWIP"); (2) slippage adjustments to the Companies' forecasted capitalization; and (3) economic development adjustments to the Companies' operating income.

Q. Before addressing these points, do you have any general observations concerning the claims and arguments presented in the testimony of the intervenors?

A. Yes. A number of the adjustments raised in the testimony of the intervenors simply defer recovery of incurred costs, in some cases to an indefinite period in the future. Under this approach, customers in effect receive a one-time benefit, with the costs to be borne later by other customers. This is not sound ratemaking practice. Other proposed "normalization" adjustments are simply based on the selective use of historical averages in a results-oriented fashion and are contrary to Commission precedent with respect to the appropriate use of normalization and the basic tenets of a forward-looking test period. Finally, some of the adjustments are the product of numeric calculations without any consideration or understanding of the activities already undertaken or necessary to be undertaken in the forecast test period in order to provide safe and reliable service to the Companies' customers based on the judgment of an experienced management team.

<u>KIUC's Argument to Capitalize Construction Financing Costs in the Form of AFUDC</u>

Q. How do the Companies currently recover construction financing costs?

A. The Companies use the Construction Work In Progress ("CWIP") methodology, which allows the carrying costs on capital investments in projects under construction to be recovered through current rates.

Q. Are there benefits to including CWIP in capitalization and rate base compared to the Allowance for Funds Used During Construction Methodology for construction financing costs?

A. Yes, there are many benefits, including lower capitalized costs, stable cash flows, and improved quality of cash earnings. The *Accounting for Public Utilities* treatise identifies the following benefits:

- Because CWIP has the lower capitalized costs, the inclusion of CWIP in rate base actually reduces the total cost to the utility and its customers over the life of the plant.[1]

- Inclusion of CWIP in rate base also causes increased cash flows and allows the utilities to avoid a certain amount of outside financing, which is advantageous whenever incremental borrowing costs exceed embedded costs.[2]

- Increased cash flows and less outside financing lead to an improved quality of actual cash earnings. Because securities analysts and bond rating agencies focus on cash flow and cost deferrals, the improved

[1] Accounting for Public Utilities, § 4.04[4], pg. 4-15.
[2] *Id.*

quality of cash earnings may allow required financings at relatively lower costs.[3]

- The greater risk associated with higher levels of non-cash earnings, such as AFUDC, would ultimately be reflected in higher rates of return required by investors.[4]

- Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.[5]

Q. How long have the Companies been including CWIP in capitalization and rate base?

A. The Commission has authorized the use of CWIP for ratemaking since at least the 1970s to address the impact of construction costs on utilities' financial integrity.[6] Like the long-standing use of capitalization as the valuation policy for the Companies' property for ratemaking discussed in Mr. Garrett's testimony, both CWIP and capitalization are long-standing policies of this Commission for the Companies.

Indeed, in LG&E's 1983 rate case, the Commission noted in its final order, "LG&E had never accrued AFUDC."[7] The Commission further observed, "[t]his means that the present ratepayers are paying less because of financing costs paid by prior ratepayers."[8] In rejecting the argument by intervenors to adopt the AFUDC approach, the Commission further remarked that it was "painfully aware that a switch

[3] *Id.*
[4] *Id.*
[5] *Id.*
[6] *The Treatment of CWIP, Eugene F. Brigham, Public Utility Research Center Working Paper* 5-81 (October 1981) (https://bear.warrington.ufl.edu/centers/purc/docs//papers/8111_Brigham_The_Treatment_of.pdf).
[7] Case No. 8924, Order at 28-29 (May 16, 1984).
[8] Case No. 8924, Order at 28-29 (May 16, 1984).

to the accrual of AFUDC could lead to grave difficulties later" and expressly held that the historical treatment of CWIP should continue.[9]

In the course of denying the Attorney General and other intervenors' petitions for rehearing on the CWIP issue, the Commission stated:

> LG&E's electric rates are lower now, due to the current CWIP policy, than if AFUDC had been accrued on prior construction projects. These lower rates result from a lower rate base, lower return requirement and lower depreciation expense. A cash return on CWIP also benefits ratepayers through lower financing costs due to improved financial ratios and reduction in risk as perceived by the investment community."[10]

In addition, the Kentucky courts have also upheld the Commission's decision to allow CWIP accounting for LG&E.[11]

Because the Commission has never directed the Companies to change their CWIP methodology, the Companies' rate bases are much lower than they otherwise would be and their embedded cost of debt is relatively low. These two factors have helped the Companies over time to have some of the lowest rates in the nation.

Q. Is KIUC witness Kollen's assertion that the Virginia Commission excludes CWIP from rate base for KU correct?

A. No. Under Virginia Commission regulation, KU has not accrued AFUDC for decades. The Virginia Commission has recognized KU's construction costs as CWIP

[9] Case No. 8924, Order at 36 (May 16, 1984).
[10] Case No. 8924, Order at 2 (June 25, 1984).
[11] *Jefferson County Fiscal Court v. Kentucky Public Service Commission*, Opinion and Order, 29 PUR 4th, pp. 143-144 (Franklin Circuit Court March 15, 1977) ("The commission was on sound ground when it allowed LG&E to include CWIP in the rate base. The evidence is uncontradicted that, for many years, LG&E (with commission approval) has included CWIP in its rate base, but it has not increased its earnings by an allowance for funds used during construction (AFUDC). Therefore, LG&E's rate base is smaller, and its revenue requirements are less than they would have been had its rate base included an AFUDC component. There is respectable authority for the proposition that the policy of including CWIP in the rate base, and of paying for construction costs currently, instead of mortgaging the future, is the sounder approach, because it costs consumers less in the long run.").

and thus as part of rate base in KU rate cases in Virginia since Old Dominion Power was legally merged into KU and KU was reincorporated as a Virginia corporation. KU has included CWIP in rate base in five base rate cases filed with the Virginia Commission following the expiration of the legislative rate cap in 2008.

Q. Have other regulators recognized the potential benefits associated with including CWIP in rate base?

A. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. Studies prepared by Pacific Economics Group Research LLC and Edison Electric Institute show that more than 21 states have recent electric utility precedents for CWIP in rate base.[12]

Q. KIUC Witness Kollen suggests that the AFUDC approach "provides the Companies dollar for dollar recovery of its actual construction financing costs, no more and no less." Do you agree with this statement?

A. No. Mr. Kollen appropriately notes that the methodology of the Federal Energy Regulatory Commission (FERC) requires the Companies to first assign its short-term debt balance to CWIP and applies the weighted average of long-term debt and common equity only to any residual amount of financing costs. Yet Mr. Kollen ignores this nuance in his testimony and calculation of the revenue requirement effect of removing CWIP from capitalization in these proceedings. Rebuttal Exhibit KWB-1 shows that the weighted average cost of capital that the Companies would use to accrue AFUDC under this methodology for the forecasted test period would be 6.04%

[12] Pacific Economics Group Research LLC, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* (January 2013); Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

for KU and 3.36% for LG&E, or 154 and 428 basis points lower than the actual weighted average cost of capital for KU and LG&E. The larger reduction in the AFUDC rate for LG&E is due to the fact that its thirteen-month average short-term debt balance is greater than its thirteen-month average CWIP balance in the forecasted test period, meaning that all of LG&E's CWIP is assumed to be funded by short-term debt under the FERC methodology. The FERC methodology also contains rules as to the timing of these calculations which were not used in Rebuttal Exhibit KWB-1 in order to simplify the calculations and limit them to data already contained in the record of these proceedings. Interestingly, despite Mr. Kollen's understanding the FERC methodology, he calculated the revenue requirement impact of removing CWIP from the Companies' revenue requirement using their weighted average cost of capital, rather than removing it from short-term debt first and then allocating any remaining balance on a pro rata basis between long-term debt and equity. This difference between the Companies actual weighted average cost of capital and the FERC AFUDC methodology would not provide the Companies a full recovery of its actual construction financing costs.

Q. KIUC Witness Kollen also asserts that AFUDC is consistent with generally accepted accounting principles ("GAAP"). Is this a credible argument for the use of AFUDC?

A. No. As noted earlier, the Companies have decades of history of including CWIP in capitalization and rate base and not recording AFUDC for its Kentucky and Virginia retail jurisdictions. That treatment has been reflected in their published financial statements filed with the Securities and Exchange Commission. Those financial statements have always been prepared in accordance with GAAP as evidenced by the unqualified audit opinions received and included with those financial statements. To put a finer point on this, in accordance with ASC 980-835-25-1 and 30-1, AFUDC should be capitalized only during periods of construction and only if it is probable that the regulated utility will receive subsequent recovery through the ratemaking process. Any amounts that are not probable of recovery should not be capitalized. Furthermore, pursuant to ASC 980-835-25-2, if AFUDC is not capitalized because future recovery through rates is not probable, the regulated utility should not alternatively capitalize interest cost under ASC 835-20, Interest – Capitalization of Interest.

Q. KIUC Witness Kollen also makes multiple contentions in support of AFUDC that it depreciates the construction financing costs over the useful life of the asset, somehow avoiding intergenerational inequities. Do you agree?

A. No. The trade-off is that AFUDC involves the compounding effect of those construction financing costs, meaning those financing costs increase the amount capitalized and increases the cost of capital recovered by the Companies over the life of the assets. More importantly, this traditional AFUDC vs. CWIP argument is significantly mitigated in the case of the Companies. As shown in Rebuttal Exhibit KWB-2, nearly half (46%) of the thirteen-month average CWIP balance of the Companies for the forecasted test period represents projects in service by the end of the forecasted test period. Of those projects not yet in service by the end of the forecasted test period, Rebuttal Exhibit KWB-2 also shows that the weighted average time period before going into service is only about eight months beyond the end of the forecasted test period.

Q. What methodologies does KIUC witness Kollen suggest the Companies use to recover construction financing costs?

A. Mr. Kollen recommends the Commission exclude CWIP from capitalization and order the Companies to accrue AFUDC starting with the effective date when base rates are reset in this case. He recommends the Commission use the Duke/Columbia Gas methodology or, in the alternative, the Kentucky Power methodology.

The Kentucky Power methodology in effect since 1984 includes CWIP in rate base, but offsets the inclusion of CWIP in rate base by including AFUDC in operating income, called the "AFUDC offset." When the operating income deficiency or surplus is grossed up to the revenue requirement, the effect of the "AFUDC offset" is a reduction in the revenue requirement equivalent to the grossed-up return times the CWIP balance. Kentucky Power has been utilizing the "AFUDC offset" since 1984.

Unlike the Kentucky Power methodology, the Duke/Columbia Gas methodology eliminates the steps of including CWIP in rate base and including the "AFUDC offset" in operating income, reasoning that these two steps result in zero recovery of a return on CWIP. Instead, CWIP is not included in rate base at all. This is a 100% AFUDC approach and Duke has used this methodology since 1992.

Q. If the Commission were to consider the KIUC's recommendation to require the Companies to switch from CWIP in capitalization and rate base to AFUDC, do Mr. Kollen's calculations produce an accurate revenue requirement impact of this?

A. No. As noted above, the revenue requirement impact of removing CWIP from capitalization would have to employ the same FERC weighted average cost of capital methodology used to accrue AFUDC in order to provide the Companies an opportunity to recover their construction financing costs. In addition, Mr. Kollen removed the Companies' entire CWIP balance, failing to recognize that a portion of the total CWIP balance represented construction payables which were not in the Companies' thirteen-month average capitalization for the forecasted test period and, as a result, did not need to be removed from capitalization. Rebuttal Exhibit KWB-3 includes a revised calculation of the revenue requirement impact of this change in methodology with these two adjustments. As shown in that exhibit, these two adjustments reduce Mr. Kollen's proposed KU revenue requirement reduction from $12.7 million to $6.7 million and LG&E's electric revenue requirement reduction from $7.7 million to $1.1 million.

Q. Do you agree with Mr. Kollen's recommendations?

A. No. For the reasons noted above the Commission should not deviate from its long-established support for including CWIP in the Companies' capitalization and rate base.

In addition to the reasons noted above, the Companies would have to leave behind decades of CWIP accounting and create completely new accounting protocols to conform to AFUDC accounting. Even more important than the administrative burden, if the Commission were to direct the Companies to accrue AFUDC instead of allowing CWIP, the cash flow and quality of earnings impacts would negatively affect the Companies.

Attached as Rebuttal Exhibit KWB-4 is the most recently released report by Moody's affirming the current stable ratings of the Companies. But the report cautions that "[t]he stable outlook for KU and LG&E reflects Moody's expectation that the regulatory environments will remain credit supportive" and "incorporates Moody's view that KU and LG&E will continue to generate stable cash flow and adequate financial metrics…."[13] An Order directing the Companies to switch from a ratemaking methodology in place for decades to one that adversely impacts funds from operations ("FFO") and calls into question the quality of earnings would not be viewed favorably by credit rating agencies. The elimination of cash recovery of construction financing costs replaced by non-cash AFUDC earnings for the forecasted test period, as recommended by the KIUC, would adversely impact the Companies' FFO/Debt metrics.

Slippage Adjustments to the Companies' Forecasted Test Period

Q. What is a slippage adjustment?

A. This is a claim that asserts the reasonableness of budgeted capital expenditures should be adjusted based on historic comparisons of actual to budgeted capital expenditures, with the adjusted amount expressed as a percentage of the budgeted amounts as the so-called "slippage factor." The slippage factor claim is normally based on an average of the variances over the past ten years. As is the case with using averages,

[13] *Moody's Affirms the Ratings of Kentucky Utilities Co., Louisville Gas & Electric Company, and LG&E and KU Energy LLC; Rating Outlooks Stable*, Moody's Investor Service, at 3 (Jan. 15, 2019).

there are multiple ways to calculate the slippage factor,[14] but the Commission has requested the mathematical average for both Companies in this rate case.[15]

Q. Do the Companies believe that a "slippage factor" should be applied to their forward-looking test period capital projects as suggested by KIUC witness Kollen or Attorney General witness Mullinax?

A. No. The Companies have addressed this same intervenor recommendation in multiple recent rate cases. In none of those cases did the Commission impose such a slippage adjustment on the Companies. Ms. Mullinax suggests such an adjustment was made in the Companies' last base rate cases. In those cases, the parties agreed to an adjustment for slippage,[16] but this was part of a settlement and thus was not imposed on the Companies by the Commission. In fact, the *Stipulation and Recommendation Agreement* explicitly states that it "shall not have any precedential value in this or any other jurisdiction."[17] As the Companies have explained in their discovery responses, the calculated capital construction slippage factors demonstrate their accuracy in estimating their budgets for utility plant. This accuracy has been achieved through the very robust process for forecasting capital expenditures and managing to that forecast described in detail in the testimony of Mr. Arbough.

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[14] KIUC witness Kollen recommends the weighted average slippage factor of 95.373% (sum of 2008-2017 base rate capital actual cost divided by sum of 2008-2017 base rate capital budget cost). AG witness Mullinax recommends the mathematical average slippage factor of 96.027% (sum of mathematic average of the 2008-2017 yearly slippage factors divided by 10 years).

[15] *See* Case Nos. 2018-00294 and 2018-00295, Data Request PSC 1-13 and PSC 2-65.

[16] Case No. 2016-00370, Order at 8 (June 22, 2017) and Case No. 2016-00371, Order at 10 (June 22, 2017).

[17] *See* Case No. 2016-00370, Section 6.12 to Stipulation and Recommendation Agreement, Order (June 22, 2017); *See* Case No. 2016-00371, Section 6.12 to Stipulation and Recommendation Agreement, Order (June 22, 2017).

Given the high degrees of accuracy demonstrated with years of being both over and under budget, the need to apply a slippage factor does not exist and the Commission should decline to do so.[18] Going forward, a purely numeric slippage factor calculation may provide a perverse disincentive for utilities to continue their efforts to reduce capital costs after having established their annual budgets.

Q. Are the Companies aware of instances in which the Commission has not applied a "slippage factor" to projected capital construction in a forward-looking test period rate case?

A. Yes. Contrary to the contention in KIUC Witness Kollen and AG Witness Mullinax's testimony, Commission precedent does not support "slippage factor adjustments" to projected capital expenditure in all forward-looking test period rate cases. With the exception of rate proceedings involving Kentucky-American Water Company ("KAWC"),[19] the Commission appears to have applied a slippage adjustment in only one other proceeding.[20] Since that decision, which was entered more than thirteen years ago, the Commission has not applied a slippage adjustment factor in any non-

[18] The Companies believe a slippage factor should not be applied at all. In the alternative, if the Commission does apply a slippage factor, the Companies request the Commission use the mathematical average pursuant to Commission precedent.

[19] The Commission's treatment of KAWC appears to be based upon historic concerns regarding that utility's budgeting process. See, e.g., Case No. 95-554, *Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Nov. 19, 1993) at 3 ("Based on the historical relationship demonstrated by the slippage factor, the Commission concluded Kentucky-American's 'very best estimate(s)' of construction spending was inaccurate and showed a pervasive pattern of over budgeting for construction. To eliminate Kentucky-American's historical overestimation, the Commission reduced the forecasted recurring and specific budget projects by their respective slippage factors.")

[20] Case No. 2005-00042, *An Adjustment of the Gas Rates of Union Heat, Light and Power Company* (Ky. PSC Dec. 22, 2005).

KAWC forward-looking test period proceeding. This included a proceeding where the subject utility had a calculated slippage factor of 81.396.[21]

Given KU and LG&E's greater accuracy and the Commission's decision not to apply a slippage factor in recent cases, it is clear that Commission precedent does not support the application of a slippage factor adjustment in the current proceedings.

Q. If the Commission were inclined to make a revenue requirement adjustment for slippage, do you agree with the calculations of the KIUC witness Kollen and AG witness Mullinax?

A. No. First, KIUC Witness Kollen used the weighted average slippage factor calculation rather than the mathematical average noted by the Commission in its Order in Case No. 2005-00042, the Order quoted by Mr. Kollen on page 22 of his testimony. Relative to the Companies' original quantification of the revenue requirement effect of applying the mathematical average slippage factor, two adjustments are appropriate. First, in order to be consistent with this calculation from prior proceedings, the factor should not be applied to FERC Account No. 108, Retirement Work In Progress. Secondly, using the Commission quote from page 22 of Mr. Kollen's testimony, the calculation should use the "most recent ten year period." As the Companies are filing this rebuttal testimony on February 21, 2019, the most recent 10 year period would include 2018. An updated slippage calculation and revenue requirement impact is shown in Rebuttal Exhibit KWB-5. That exhibit reduces the previously calculated revenue requirement of the slippage adjustment for

[21] Case No. 2010-00167, *Application of East Kentucky Power Cooperative, Inc. for General Adjustment of Electric Rates* (Ky. PSC Jan. 14, 2011).

KU, LG&E electric operations and LG&E gas operations from $2,685,522, $1,304,937 and $432,475 to $1,296,112, $1,277,010 and $425,829.

Economic Development Adjustments to the Companies' Operating Income

Q. Do the Companies agree with AG witness Mullinax's recommendation that economic development costs should be excluded from base rates?

A. No. 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. 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.[22] A recent publication by the Kentucky Cabinet for Economic Development noted that the creation of 100 new jobs can result in an additional 320 jobs in other sectors, resulting in a total impact of 420 jobs.[23] The total value added of these 420 new jobs is $69,159,000 and $9,442,600 in total state and local taxes.[24]

Moreover, as noted in the PPL acquisition commitment number 38 approved by the Commission, the Companies committed to maintaining its pro-active stance on developing economic opportunities in Kentucky and supporting economic development activities throughout the Companies' service territories.

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[22] Just the Facts: Economic Impact of 100 Jobs, Think Kentucky, July 2018, http://thinkkentucky.com/kyedc/pdfs/100jobs.pdf.
[23] *Id.*
[24] *Id.*

Q. What costs are included in the economic development expenses the Companies are seeking to recover?

A. The economic development costs that the Companies are requesting to recover are reasonable and total $654,809.[25] In general these expenses are largely associated with four Economic Development Project Manager positions that are responsible for marketing and promoting the service territory to new and expanding businesses and providing direct company support for economic development projects and some minor associated expenses.

Q. How do you respond to Ms. Mullinax's contention that the Companies should provide a "record of incremental revenues generated through economic development" and "forecasts of future revenue growth expected"?

A. The Companies would point to its retail load forecast filed in these proceedings. In addition, the Companies employ a variety of tactics focused on economic development project leadership, leading and partnering on marketing opportunities of expansion and investment opportunities in Kentucky, providing leadership to communities and local economic development organizations, and providing guidance and input into the development of infrastructure to support a community's growth prospects. This activity contributed to 156 announced new and expanding companies in the LG&E and KU service territories as noted by the Kentucky Cabinet for Economic Development. The investment totaled $4 billion and resulted in 7,580

[25] KU February 15, 2019 Corrected Response to Attorney General's Supplemental Data Requests for Information No.49 Dated December 13, 2018; LG&E February 15, 2019 Corrected Response to Attorney General's Supplemental Data Requests for Information No, 49 Dated December 13, 2018; LG&E and KU's Economic Development Rider ("EDR"), which is designed to promote economic development efforts and encourage brownfield development, assists companies in demand reduction credits on their electric utility bills. The 2019 forecast EDR credit totals $1,029,068 ($904,886 for KU and $124,183 for LG&E).

jobs. The Companies have been recognized as a "Top Ten Utility" for their economic development efforts six times in the past seven years by *Site Selection* magazine.

Q. What is your response to AG Witness Mullinax's claims that "economic development by definition is neither a reasonable nor necessary cost of providing safe and reliable electricity and natural gas service to customers" and "the day-to-day activities of economic development risk can distract the Companies from their stated mission to provide safe and reliable service to its customers"?

A. The Companies were very surprised by these statements being included in testimony sponsored by the Kentucky Attorney General, as well as Louisville/Jefferson County Metro Government and Lexington-Fayette Urban County Government, the two largest metropolitan areas in the state. The Companies believe that assisting existing customers as they look to expand business as well as working with prospective customers, alongside state and local economic development and other officials, is a core component of customer service. The current administration enthusiastically supports economic development because of the widespread benefits for the state. Near the beginning of his term, Governor Bevin stated "When it comes to economic development, we have our foot on the gas."[26] As of October 2018, the Bevin administration had announced and reported 1,101 new expanded facilities, over $18 billion in new investment, more than 50,000 new jobs, and $86.6 billion in exports.[27] A key factor in economic development, especially in the manufacturing sector, is low

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[26] Susan Gosselin, *Business-Savvy Approach Scores $8 Billion in Economic Development Deals*, THE LANE REPORT, 30 (Dec. 2017).
[27] Think Kentucky, Cabinet for Economic Development, http://thinkkentucky.com.

electricity rates.[28] Economic development officials expect the Companies to work with them to help existing businesses expand and to bring new businesses to the state.

Q. In the event the Commission accepts any of the revenue requirement modifications proposed by intervening parties, would it be appropriate to simply accumulate the impacts for those adjustments?

A. No. The proposed modifications of various intervenors are not independent of one another. For example, many of the proposed adjustments that impact net operating income would also impact capitalization. Likewise, the proposed adjustments that impact capitalization would impact the revenue requirement effect of a change in the weighted average cost of capital, including the authorized return on equity. Some of these interdependencies are even more nuanced. For example, as noted in the testimony of Mr. Garrett, any of the proposed reductions in depreciation rates would also have partially offsetting revenue requirement effects by increasing the Companies' capitalization and thus cost of capital, as well as by reducing the rate of amortization for excess accumulated deferred income taxes.

Q. Does this conclude your testimony?

A. Yes.

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[28] Mr. Baron agrees with Mr. Conroy and Mr. Seelye in their belief that economic development impacts are important considerations when assessing rate increases. Direct Testimony of Stephen J. Baron at page 20. Mr. Baron also points out that the Kentucky Cabinet for Economic Development lists the low cost of electricity as number 5 of the top 10 reasons companies locate and expand in Kentucky. Direct Testimony of Stephen J. Baron at page 21. Mr. Baron further notes that Kentucky's economy is more sensitive to energy prices compared to most competitor states, partly because of Kentucky's larger than average manufacturing sector. Direct Testimony of Stephen J. Baron at page 23-24.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

K W Blake
Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Tammy J. Elzy
Notary Public

My Commission Expires:

November 9, 2022

KENTUCKY UTILITIES COMPANY

	WACC AS FILED (1)			**AFUDC FERC**		
	PERCENT OF TOTAL	COST RATE	13 MONTH AVERAGE WEIGHTED COST	PERCENT OF TOTAL	COST RATE	AVERAGE WEIGHTED COST
SHORT-TERM DEBT	0.84%	3.37%	0.03%	37.11%	3.37%	1.25%
LONG-TERM DEBT	46.10%	4.38%	2.02%	29.24%	4.38%	1.28%
COMMON EQUITY	53.06%	10.42%	5.53%	33.65%	10.42%	3.51%
TOTAL CAPITAL	**100.00%**		**7.58%**	**100.00%**		**6.04%**

LOUISVILLE GAS AND ELECTRIC COMPANY (ELECTRIC)

	WACC AS FILED (1)			**AFUDC FERC** (2)		
	PERCENT OF TOTAL	COST RATE	13 MONTH AVERAGE WEIGHTED COST	PERCENT OF TOTAL	COST RATE	AVERAGE WEIGHTED COST
SHORT-TERM DEBT	1.40%	3.36%	0.05%	100.00%	3.36%	3.36%
LONG-TERM DEBT	45.50%	4.53%	2.06%	0.00%	0.00%	0.00%
COMMON EQUITY	53.10%	10.42%	5.53%	0.00%	0.00%	0.00%
TOTAL CAPITAL	**100.00%**		**7.64%**	**100.00%**		**3.36%**

1. KU Supplemental Response to PSC 1-53 – Schedule J (Ky. PSC Feb. 15, 2019); LG&E Supplemental Response to PSC 1-53 – Schedule J (Ky. PSC Feb. 15, 2019).

2. While acknowledging the FERC rate formula allows for negative long term debt and equity rates, if short term debt is greater than the 13 month average CWIP we have applied 100% to short term debt and 0% to long term and equity.

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	00093FACK	101,365.00	-	-	-	-	-	-	-	-	-	-	-	-	7,797.31	5/31/2019	(11)	0.0028%	(0.00)
0110	100GH	153,669.22	153,669.22	153,669.22	153,669.22	153,669.22	153,669.22	153,669.22	-	-	-	-	-	-	82,744.96	11/30/2019	(5)	0.0299%	(0.00)
0110	120756	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	12/1/2020	8	0.0230%	0.00
0110	123906	11,156,555.61	-	-	-	-	-	-	-	-	-	-	-	-	858,196.59	5/31/2019	(11)	0.3104%	(0.03)
0110	124930	(6,325.74)	(7,693.51)	(8,326.40)	(9,474.99)	(10,923.77)	(12,321.98)	(15,352.26)	(16,912.24)	-	-	-	-	-	(6,717.76)	12/31/2019	(4)	-0.0024%	0.00
0110	131562	196,746.20	255,237.60	300,993.00	366,077.40	-	-	-	-	-	-	-	-	-	86,081.09	8/31/2019	(8)	0.0311%	(0.00)
0110	133615KU	88,584.00	88,584.00	88,584.00	88,584.00	220,678.34	220,678.34	220,678.34	220,678.34	-	-	-	-	-	95,157.64	12/1/2019	(4)	0.0344%	(0.00)
0110	133794	325,075.46	-	-	-	-	-	-	-	-	-	-	-	-	25,005.80	5/30/2019	(11)	0.0090%	(0.00)
0110	133964	89,357.88	89,357.88	89,357.88	89,357.88	177,562.67	190,939.61	838,038.86	1,403,984.83	-	-	-	-	-	228,304.42	12/31/2019	(4)	0.0826%	(0.00)
0110	133KU16	77,453.94	78,453.94	79,453.94	80,453.94	81,453.94	82,453.94	83,453.94	84,453.94	84,453.94	84,453.94	91,266.44	98,078.94	111,703.94	85,968.36	12/31/2020	8	0.0311%	0.00
0110	134256	24,930.80	31,163.50	37,396.20	43,628.90	49,861.60	56,094.30	62,327.00	68,559.70	74,792.40	301,301.68	527,810.96	803,635.24	-	160,115.56	4/30/2020	-	0.0579%	-
0110	136480KU	98,880.63	98,880.63	127,489.89	127,489.89	127,489.89	156,099.15	-	-	-	-	-	-	-	56,640.78	10/31/2019	(6)	0.0205%	(0.00)
0110	137084	50,000.00	50,000.00	50,000.00	50,000.00	50,000.00	50,000.00	314,714.00	-	-	-	-	-	-	47,285.69	11/30/2019	(5)	0.0171%	(0.00)
0110	137100	206,000.00	206,000.00	206,000.00	948,013.97	-	-	-	-	-	-	-	-	-	120,462.61	8/31/2019	(8)	0.0436%	(0.00)
0110	137244	174,489.03	175,423.78	175,423.78	175,705.17	175,787.48	370,040.23	370,513.86	647,564.21	660,493.16	661,520.67	869,774.41	915,753.08	1,178,219.68	503,900.66	5/31/2020	1	0.1823%	0.00
0110	137417	500,000.00	500,000.00	500,000.00	1,000,000.00	1,000,000.00	1,000,000.00	1,000,000.00	-	-	-	-	-	-	423,076.92	11/30/2019	(5)	0.1530%	(0.01)
0110	137474	341,883.02	342,262.78	342,262.78	342,680.81	342,785.97	681,065.49	681,253.83	1,224,775.18	1,278,781.79	1,279,809.29	1,635,497.47	1,978,674.97	2,478,182.30	996,147.36	5/31/2020	1	0.3603%	0.00
0110	137539	60,220.98	95,252.33	125,089.91	132,393.14	132,393.14	132,393.14	132,393.14	132,393.14	-	-	-	-	-	72,502.22	12/31/2019	(4)	0.0262%	(0.00)
0110	137585KU	1,548,471.25	-	-	-	-	-	-	-	-	-	-	-	-	119,113.17	5/31/2019	(11)	0.0431%	(0.00)
0110	138168	4,533,346.07	4,965,384.00	5,372,394.34	5,564,573.91	5,569,730.61	5,576,606.21	5,582,536.41	5,587,693.11	-	-	-	-	-	3,288,635.74	12/31/2019	(4)	1.1896%	(0.05)
0110	138842	640,817.25	747,712.56	-	-	-	-	-	-	-	-	-	-	-	106,809.99	6/30/2019	(10)	0.0386%	(0.00)
0110	139696	5,719,050.79	6,214,068.74	6,709,086.69	7,204,104.64	7,699,122.59	8,082,880.54	8,466,638.49	8,854,597.42	-	-	-	-	-	4,534,580.76	12/31/2019	(4)	1.6403%	(0.07)
0110	140183	253,462.20	337,949.60	422,437.00	506,924.40	591,411.80	675,899.20	760,386.60	-	-	-	-	-	-	272,959.29	11/30/2019	(5)	0.0987%	(0.00)
0110	140202	4,191,973.27	4,726,973.27	-	-	-	-	-	-	-	-	-	-	-	686,072.81	6/30/2019	(10)	0.2482%	(0.02)
0110	140282	30,340.64	37,925.80	45,510.96	53,096.12	60,681.28	68,266.44	75,851.60	83,436.76	-	-	-	-	-	35,008.43	12/31/2019	(4)	0.0127%	(0.00)
0110	144065	2,049,518.92	2,650,508.16	3,251,497.40	-	-	-	-	-	-	-	-	-	-	611,655.73	7/31/2019	(9)	0.2213%	(0.02)
0110	144108	434,442.80	621,598.44	775,743.96	-	-	-	-	-	-	-	-	-	-	140,906.55	7/31/2019	(9)	0.0510%	(0.00)
0110	144116	778,618.74	802,254.89	957,177.84	1,573,595.42	2,190,013.00	2,806,430.58	3,131,503.31	3,667,337.44	3,918,294.88	4,135,609.82	4,409,689.10	4,627,003.98	4,844,318.86	2,910,911.37	6/30/2020	2	1.0530%	0.02
0110	144302	5,011,959.31	5,011,959.31	5,011,959.31	5,378,783.25	5,378,783.25	5,378,783.25	5,834,503.25	-	-	-	-	-	-	2,846,671.61	11/30/2019	(5)	1.0297%	(0.05)
0110	144365	320,025.80	320,025.80	568,595.82	2,068,595.83	2,318,595.83	2,968,595.83	-	-	-	-	-	-	-	683,420.05	11/30/2019	(5)	0.2472%	(0.01)
0110	144541	10,525,711.78	12,864,406.78	15,359,856.78	19,094,856.78	19,216,356.78	-	-	-	-	-	-	-	-	5,927,783.76	9/30/2019	(7)	2.1442%	(0.15)
0110	144717	161,378.30	161,378.30	161,378.30	161,378.30	161,378.30	161,378.30	417,756.50	674,134.70	-	-	-	-	-	158,473.92	12/31/2019	(4)	0.0573%	(0.00)
0110	144722	673,653.90	673,653.90	673,653.90	673,653.90	673,653.90	673,653.90	1,874,229.45	3,074,805.00	-	-	-	-	-	691,612.14	12/31/2019	(4)	0.2502%	(0.01)
0110	145028	83,323.59	130,965.14	132,708.37	177,308.97	221,346.76	246,688.01	-	-	-	-	-	-	-	76,333.91	10/31/2019	(6)	0.0276%	(0.00)
0110	145088	14,000.00	14,000.00	42,000.00	42,000.00	42,000.00	84,000.00	84,000.00	84,000.00	-	-	-	-	-	31,230.77	12/31/2019	(4)	0.0113%	(0.00)
0110	147488	244,953.86	351,021.73	-	-	-	-	-	-	-	-	-	-	-	45,844.28	6/30/2019	(10)	0.0166%	(0.00)
0110	147494	195,782.42	269,471.41	-	-	-	-	-	-	-	-	-	-	-	35,788.76	6/30/2019	(10)	0.0129%	(0.00)
0110	147496	195,782.41	269,471.39	-	-	-	-	-	-	-	-	-	-	-	35,788.75	6/30/2019	(10)	0.0129%	(0.00)
0110	147503	195,782.41	269,471.39	-	-	-	-	-	-	-	-	-	-	-	35,788.75	6/30/2019	(10)	0.0129%	(0.00)
0110	148716	20,626.82	25,783.52	30,940.22	36,096.92	1,175,423.62	1,865,459.22	2,554,549.42	3,242,866.12	4,818,215.39	5,245,190.39	6,657,201.48	7,120,323.13	7,624,172.44	3,108,988.36	11/30/2020	7	1.1246%	0.08
0110	148823	5,041,466.24	5,692,301.49	6,343,136.74	7,536,794.52	8,187,629.77	8,838,465.02	9,489,300.27	10,140,135.52	10,790,970.77	11,789,885.05	12,680,207.31	13,570,529.57	14,460,851.83	9,581,667.24	12/31/2020	8	3.4660%	0.28
0110	148851	3,448,469.24	3,596,537.86	4,085,819.48	4,085,819.48	4,085,819.48	4,085,819.48	4,085,819.48	4,085,819.48	4,085,819.48	4,254,000.57	4,422,181.66	4,590,362.75	-	3,762,483.73	4/30/2020	-	1.3610%	-
0110	149049	40,062.08	52,362.67	60,094.27	72,394.86	84,695.45	90,553.04	92,836.96	-	-	-	-	-	-	37,923.03	11/30/2019	(5)	0.0137%	(0.00)
0110	149496	101,365.00	101,365.00	202,730.00	202,730.00	202,730.00	304,095.00	304,095.00	304,095.00	-	-	-	-	-	132,554.23	12/31/2019	(4)	0.0479%	(0.00)
0110	149992	3,598,552.38	4,028,137.25	4,307,904.65	-	-	-	-	-	-	-	-	-	-	918,045.71	7/31/2019	(9)	0.3321%	(0.03)
0110	150015KU	197,645.35	-	-	-	-	-	-	-	-	-	-	-	-	15,203.49	5/31/2019	(11)	0.0055%	(0.00)
0110	150017KU	107,806.45	107,806.45	107,806.45	107,806.45	107,806.45	107,806.45	107,806.45	107,806.45	-	-	-	-	-	66,342.43	12/1/2019	(4)	0.0240%	(0.00)
0110	150221	594.33	594.33	-	-	-	-	-	-	-	-	-	-	-	91.44	6/30/2019	(10)	0.0000%	(0.00)
0110	151366	200,000.00	200,000.00	200,000.00	200,000.00	200,000.00	200,000.00	779,482.84	-	-	-	-	-	-	152,267.91	11/30/2019	(5)	0.0551%	(0.00)
0110	151370	109,752.94	109,752.94	109,752.94	109,752.94	109,752.94	336,689.00	336,689.00	-	-	-	-	-	-	94,010.98	11/30/2019	(5)	0.0340%	(0.00)
0110	151380	172,187.64	-	-	-	-	-	-	-	-	-	-	-	-	13,245.20	5/31/2019	(11)	0.0048%	(0.00)
0110	151465	179.98	179.98	179.98	179.98	179.98	179.98	179.98	179.98	-	-	-	-	-	110.76	12/31/2019	(4)	0.0000%	(0.00)
0110	151487	16,875.70	16,875.70	23,547.57	31,330.66	31,330.66	31,330.66	31,330.66	31,330.66	-	-	-	-	-	16,457.87	12/31/2019	(4)	0.0060%	(0.00)
0110	151491	15,492.12	29,666.72	37,567.52	66,707.53	83,682.43	107,298.82	127,515.23	127,515.23	-	-	-	-	-	45,803.51	12/31/2019	(4)	0.0166%	(0.00)
0110	151492	58,444.00	58,444.00	60,489.96	60,489.96	63,558.33	63,558.33	63,558.33	63,558.33	-	-	-	-	-	37,853.94	12/31/2019	(4)	0.0137%	(0.00)
0110	151493	98,064.30	124,052.31	125,340.91	172,340.19	183,197.61	183,197.61	184,486.21	195,178.42	-	-	-	-	-	97,373.66	12/31/2019	(4)	0.0352%	(0.00)
0110	151494	40,914.58	375,206.00	375,206.00	375,206.00	375,206.00	395,663.29	416,120.58	436,577.87	-	-	-	-	-	214,623.10	12/31/2019	(4)	0.0776%	(0.00)
0110	151504	56,114.40	97,938.00	97,938.00	104,074.73	104,074.73	104,074.73	104,074.73	104,074.73	-	-	-	-	-	59,412.62	12/31/2019	(4)	0.0215%	(0.00)
0110	151508	14,181.04	18,628.20	23,075.36	23,075.36	27,522.52	27,522.52	27,522.52	27,522.52	-	-	-	-	-	14,542.31	12/31/2019	(4)	0.0053%	(0.00)
0110	151512	35,656.42	107,594.39	107,594.39	192,524.04	192,524.04	192,524.04	213,221.39	213,221.39	-	-	-	-	-	96,527.70	12/31/2019	(4)	0.0349%	(0.00)
0110	151513	104,642.40	151,549.80	203,250.60	203,250.60	203,250.60	203,250.60	203,250.60	203,250.60	-	-	-	-	-	113,515.06	12/31/2019	(4)	0.0411%	(0.00)
0110	151514	52,012.87	52,012.87	52,012.87	52,012.87	52,012.87	52,012.87	52,012.87	52,012.87	-	-	-	-	-	32,007.92	12/31/2019	(4)	0.0116%	(0.00)
0110	151517	54,735.91	66,204.81	66,204.81	66,204.81	85,311.01	85,311.01	85,311.01	85,311.01	-	-	-	-	-	45,738.03	12/31/2019	(4)	0.0165%	(0.00)
0110	151522	63,746.89	77,847.60	85,279.20	102,713.33	124,465.49	138,566.20	145,997.80	156,006.60	-	-	-	-	-	68,817.16	12/31/2019	(4)	0.0249%	(0.00)
0110	151523	48,620.11	49,758.71	77,590.24	77,590.24	99,285.04	120,979.84	154,204.81	154,204.81	-	-	-	-	-	60,171.83	12/31/2019	(4)	0.0218%	(0.00)
0110	151524	69,067.87	89,416.93	102,848.89	123,306.18	123,306.18	123,306.18	123,306.18	127,398.09	-	-	-	-	-	67,842.81	12/31/2019	(4)	0.0245%	(0.00)
0110	151525	28,206.56	58,459.07	58,459.07	60,505.03	60,505.03	84,359.98	84,359.98	97,328.31	-	-	-	-	-	40,937.16	12/31/2019	(4)	0.0148%	(0.00)
0110	151526	27,217.96	29,263.92	55,235.22	55,235.22	59,327.13	75,628.93	79,720.84	79,720.84	-	-	-	-	-	35,488.47	12/31/2019	(4)	0.0128%	(0.00)
0110	151775	386,747.78	398,303.51	453,300.24	520,922.97	588,545.70	656,168.43	729,354.16	802,539.89	901,851.62	1,020,588.91	1,148,645.70	1,276,702.49	1,405,409.28	791,467.74	12/31/2020	8	0.2863%	0.02
0110	152005	112,866.49	112,866.49	112,866.49	112,866.49	112,866.49	221,152.70	221,152.70	-	-	-	-	-	-	77,433.68	11/30/2019	(5)	0.0280%	(0.00)
0110	152070KU	49,619.52	49,619.52	49,619.52	49,619.52	49,619.52	49,619.52	-	-	-	-	-	-	-	22,901.32	10/31/2019	(6)	0.0083%	(0.00)
0110	152119	365,628.59	552,430.44	733,587.12	777,928.17	777,928.17	777,928.17	777,928.17	777,928.17	-	-	-	-	-	426,252.85	12/31/2019	(4)	0.1542%	(0.01)
0110	152229	9,691.56	9,691.56	20,000.36	20,000.36	20,000.36	20,000.36	20,000.36	20,000.36	-	-	-	-	-	10,721.94	12/31/2019	(4)	0.0039%	(0.00)
0110	152638	197,848.79	321,708.57	-	-	-	-	-	-	-	-	-	-	-	39,965.95	6/30/2019	(10)	0.0145%	(0.00)
0110	152652KU	1,141,704.25	-	-	-	-	-	-	-	-	-	-	-	-	87,823.40	5/31/2019	(11)	0.0318%	(0.00)
0110	152683KU	131,986.13	131,986.13	131,986.13	131,986.13	131,986.13	131,986.13	131,986.13	-	-	-	-	-	-	71,069.45	11/30/2019	(5)	0.0257%	(0.00)
0110	152693KU	71,867.52	71,867.52	71,867.52	71,867.52	196,830.38	196,830.38	196,830.38	196,830.38	-	-	-	-	-	82,676.28	12/1/2019	(4)	0.0299%	(0.00)
0110	152770	5,208.80	5,208.80	5,208.80	5,208.80	5,208.80	5,208.80	214,276.23	-	-	-	-	-	-	18,886.85	11/30/2019	(5)	0.0068%	(0.00)
0110	152771	26,354.90	26,354.90	52,709.80	52,709.80	52,709.80	79,064.70	79,064.70	79,064.70	-	-	-	-	-	34,464.10	12/31/2019	(4)	0.0125%	(0.00)
0110	152801	25,341.25	50,682.50	50,682.50	50,682.50	98,729.51	98,729.51	98,729.51	-	-	-	-	-	-	36,429.02	11/30/2019	(5)	0.0132%	(0.00)
0110	152813	209,748.46	234,323.18	234,323.18	234,323.18	234,323.18	234,323.18	235,474.25	235,474.25	235,474.25	264,230.49	264,230.49	264,230.49	264,230.49	241,900.70	11/30/2020	7	0.0875%	0.01
0110	152820	1,560,323.35	1,716,045.75	1,865,325.15	1,871,768.15	-	-	-	-	-	-	-	-	-	539,497.11	8/31/2019	(8)	0.1952%	(0.02)
0110	153069	729,158.72	772,075.38	814,992.04	857,908.70	900,825.36	943,742.02	986,658.68	1,029,575.34	-	-	-	-	-	541,148.94	12/31/2019	(4)	0.1957%	(0.01)
0110	153080	36,624.22	-	-	-	-	-	-	-	-	-	-	-	-	2,817.25	5/31/2019	(11)	0.0010%	(0.00)
0110	153562	6,461,490.45	7,466,984.78	-	-	-	-	-	-	-	-	-	-	-	1,071,421.17	6/30/2019	(10)	0.3876%	(0.04)
0110	154077	1,617,337.61	1,623,181.44	1,629,025.27	1,847,598.22	2,066,171.17	2,284,744.12	2,503,317.07	2,721,890.02	-	-	-	-	-	1,253,328.07	12/31/2019	(4)	0.4534%	(0.02)
0110	154096	4,130,238.05	4,236,843.06	-	-	-	-	-	-	-	-	-	-	-	643,621.62	6/30/2019	(10)	0.2328%	(0.02)
0110	154118	2,315,842.62	2,315,842.62	2,315,842.62	2,315,842.62	2,315,842.62	2,315,842.62	2,315,842.62	2,315,842.62	-	-	-	-	-	1,425,133.92	12/31/2019	(4)	0.5155%	(0.02)
0110	154216	167,436.46	179,930.11	192,423.76	204,917.41	217,411.06	229,904.71	242,398.36	254,892.01	-	-	-	-	-	129,947.22	12/31/2019	(4)	0.0470%	(0.00)
0110	154585	1,637,306.22	2,219,450.50	2,801,594.78	3,383,739.06	4,448,986.62	5,388,736.05	6,384,114.71	7,124,615.99	7,775,563.27	7,913,279.96	8,050,996.65	8,188,713.34	8,326,430.03	5,664,886.71	12/31/2020	8	2.0491%	0.16
0110	154729KU	43,133.72	43,133.72	85,551.39	85,551.39	85,551.39	85,551.39	85,551.39	85,551.39	-	-	-	-	-	46,121.21	12/1/2019	(4)	0.0167%	(0.00)
0110	154920	37,322.12	37,322.12	37,322.12	37,322.12	37,322.12	37,322.12	37,322.12	-	-	-	-	-	-	20,096.53	11/30/2019	(5)	0.0073%	(0.00)
0110	155031	172,935.37	-	-	-	-	-	-	-	-	-	-	-	-	13,302.72	5/31/2019	(11)	0.0048%	(0.00)
0110	155070	248,000.00	248,000.00	248,000.00	248,000.00	248,000.00	248,000.00	441,437.37	634,874.74	-	-	-	-	-	197,254.78	12/31/2019	(4)	0.0714%	(0.00)
0110	155082	135,285.21	135,285.21	135,285.21	135,285.21	135,285.21	135,285.21	244,785.55	354,285.89	-	-	-	-	-	108,521.75	12/31/2019	(4)	0.0393%	(0.00)
0110	155127KU	91,549.62	91,549.62	91,549.62	91,549.62	137,324.43	183,099.24	-	-	-	-	-	-	-	52,817.09	10/31/2019	(6)	0.0191%	(0.00)
0110	155280	29,155.20	41,389.27	49,509.47	63,658.56	70,490.16	79,605.68	86,437.28	93,268.88	100,100.48	106,932.08	115,598.11	122,429.71	129,261.31	83,679.71	12/31/2020	8	0.0303%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	155530	675,416.63	738,034.91	754,562.58	771,091.27	787,619.96	804,147.63	820,676.32	837,205.01	-	-	-	-	-	476,058.02	12/31/2019	(4)	0.1722%	(0.01)
0110	156370	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	12/31/2018	(16)	0.0000%	0.00
0110	156381	856,066.74	926,659.94	998,391.74	1,070,123.54	1,141,855.34	1,213,587.14	-	-	-	-	-	-	-	477,437.26	10/31/2019	(6)	0.1727%	(0.01)
0110	156598	29,212.20	-	-	-	-	-	-	-	-	-	-	-	-	2,247.09	5/31/2019	(11)	0.0008%	(0.00)
0110	156687	2,719,115.32	-	-	-	-	-	-	-	-	-	-	-	-	209,162.72	5/31/2019	(11)	0.0757%	(0.01)
0110	156689	3,248,776.73	3,382,449.89	3,811,546.78	3,811,546.78	3,811,546.78	3,811,546.78	3,811,546.78	3,811,546.78	3,811,546.78	4,262,441.78	-	-	-	2,890,345.84	2/28/2020	(2)	1.0455%	(0.02)
0110	156853KU	88,968.14	-	-	-	-	-	-	-	-	-	-	-	-	6,843.70	5/31/2019	(11)	0.0025%	(0.00)
0110	156855KU	34,861.89	-	-	-	-	-	-	-	-	-	-	-	-	2,681.68	5/31/2019	(11)	0.0010%	(0.00)
0110	156859KU	48,806.64	-	-	-	-	-	-	-	-	-	-	-	-	3,754.36	5/31/2019	(11)	0.0014%	(0.00)
0110	156909 KU	178,533.71	178,533.71	178,533.71	178,533.71	178,533.71	178,533.71	178,533.71	-	-	-	-	-	-	96,133.54	11/30/2019	(5)	0.0348%	(0.00)
0110	156967KU	69,723.79	-	-	-	-	-	-	-	-	-	-	-	-	5,363.37	5/31/2019	(11)	0.0019%	(0.00)
0110	157066	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	12/31/2020	8	0.0718%	0.01
0110	157109KU	234,127.50	234,127.50	234,127.50	234,127.50	234,127.50	234,127.50	234,127.50	234,127.50	-	-	-	-	-	144,078.46	12/31/2019	(4)	0.0521%	(0.00)
0110	157208	2,500.01	-	-	-	-	-	-	-	-	-	-	-	-	192.31	5/31/2019	(11)	0.0001%	(0.00)
0110	157251	258,435.00	258,435.00	258,435.00	258,435.00	258,435.00	258,435.00	957,754.05	1,657,073.10	-	-	-	-	-	320,418.24	12/31/2019	(4)	0.1159%	(0.00)
0110	157260	1,176,030.00	1,176,030.00	1,176,030.00	1,830,904.00	2,494,006.80	-	-	-	-	-	-	-	-	604,076.98	9/30/2019	(7)	0.2185%	(0.02)
0110	157299KU	42,121.17	42,121.17	42,121.17	42,121.17	42,121.17	42,121.17	42,121.17	42,121.17	-	-	-	-	-	25,920.72	12/1/2019	(4)	0.0094%	(0.00)
0110	157591	4,875,000.00	5,375,000.00	-	-	-	-	-	-	-	-	-	-	-	788,461.54	6/30/2019	(10)	0.2852%	(0.03)
0110	157599	645,454.18	645,454.18	787,779.18	939,135.10	960,548.08	974,477.42	974,477.42	974,477.42	-	-	-	-	-	530,907.92	12/31/2019	(4)	0.1920%	(0.01)
0110	157601	322,150.00	322,150.00	407,545.00	492,940.00	549,999.80	549,999.80	549,999.80	549,999.80	-	-	-	-	-	288,060.32	12/31/2019	(4)	0.1042%	(0.00)
0110	157605	20,626.82	25,783.52	30,940.22	690,791.92	1,065,993.62	1,442,914.22	1,818,889.42	2,954,171.52	3,324,216.52	3,688,240.82	5,154,922.80	5,546,992.01	5,918,697.96	2,437,167.80	11/30/2020	7	0.8816%	0.06
0110	157617	872,655.51	954,518.76	1,034,615.01	1,114,711.26	1,194,807.51	1,274,903.76	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,443,921.59	1,232,317.96	10/31/2020	6	0.4458%	0.03
0110	157703	154,290.00	211,720.00	429,440.00	-	-	-	-	-	-	-	-	-	-	61,188.46	7/31/2019	(9)	0.0221%	(0.00)
0110	157710	166,600.27	333,200.55	-	-	-	-	-	-	-	-	-	-	-	38,446.22	6/30/2019	(10)	0.0139%	(0.00)
0110	157777KU	697,774.50	-	-	-	-	-	-	-	-	-	-	-	-	53,674.96	5/31/2019	(11)	0.0194%	(0.00)
0110	157846	183,329.64	366,659.28	549,988.92	733,318.56	916,648.20	1,099,977.84	1,283,318.61	1,466,659.38	-	-	-	-	-	507,684.65	12/31/2019	(4)	0.1836%	(0.01)
0110	157893	18,666.72	23,333.38	28,000.04	32,666.70	37,333.36	42,000.02	46,666.68	51,333.34	56,000.00	60,666.74	65,333.40	70,000.06	74,666.72	46,666.70	12/31/2020	8	0.0169%	0.00
0110	157896	18,666.72	23,333.38	28,000.04	32,666.70	37,333.36	42,000.02	46,666.68	51,333.34	-	-	-	-	-	21,538.48	12/31/2019	(4)	0.0078%	(0.00)
0110	158019	1,536,099.42	1,536,099.42	1,571,217.34	-	-	-	-	-	-	-	-	-	-	357,185.86	7/31/2019	(9)	0.1292%	(0.01)
0110	158113	14,944.44	14,944.44	14,944.44	14,944.44	14,944.44	14,944.44	14,944.44	14,944.44	-	-	-	-	-	9,196.58	12/31/2019	(4)	0.0033%	(0.00)
0110	158169	230,000.00	230,000.00	-	-	-	-	-	-	-	-	-	-	-	35,384.62	6/30/2019	(10)	0.0128%	(0.00)
0110	158170	210,000.00	210,000.00	-	-	-	-	-	-	-	-	-	-	-	32,307.69	6/30/2019	(10)	0.0117%	(0.00)
0110	158181	20,000.54	20,000.54	20,000.54	20,000.54	20,000.54	20,000.54	20,000.54	20,000.54	-	-	-	-	-	12,308.02	12/31/2019	(4)	0.0045%	(0.00)
0110	161004KU	535,453.16	-	-	-	-	-	-	-	-	-	-	-	-	41,188.70	5/31/2019	(11)	0.0149%	(0.00)
0110	162170	20,457.30	64,500.10	64,500.10	64,500.10	64,500.10	64,500.10	64,500.10	64,500.10	-	-	-	-	-	36,304.46	12/31/2019	(4)	0.0131%	(0.00)
0110	163000	3,415.80	4,554.40	5,693.00	6,831.60	7,970.20	-	-	-	-	-	-	-	-	2,189.62	9/30/2019	(7)	0.0008%	(0.00)
0110	163020	25,588.63	30,593.03	35,597.43	40,308.55	-	-	-	-	-	-	-	-	-	10,160.59	8/31/2019	(8)	0.0037%	(0.00)
0110	163021	51,148.08	65,718.00	78,004.00	92,573.92	107,143.84	121,713.76	127,863.48	-	-	-	-	-	-	49,551.16	11/30/2019	(5)	0.0179%	(0.00)
0110	163022	28,598.86	60,567.87	-	-	-	-	-	-	-	-	-	-	-	6,858.98	6/30/2019	(10)	0.0025%	(0.00)
0110	163023	69,917.97	139,835.94	-	-	-	-	-	-	-	-	-	-	-	16,134.92	6/30/2019	(10)	0.0058%	(0.00)
0110	163025	42,187.96	52,496.76	80,976.46	92,573.86	104,993.52	-	-	-	-	-	-	-	-	28,709.89	9/30/2019	(7)	0.0104%	(0.00)
0110	163029	60,564.20	126,603.00	-	-	-	-	-	-	-	-	-	-	-	14,397.48	6/30/2019	(10)	0.0052%	(0.00)
0110	163030	169,426.80	233,188.40	-	-	-	-	-	-	-	-	-	-	-	30,970.40	6/30/2019	(10)	0.0112%	(0.00)
0110	163049	362,580.00	453,225.00	543,870.00	641,420.29	729,488.09	813,690.09	886,206.09	898,342.09	-	-	-	-	-	409,909.36	12/31/2019	(4)	0.1483%	(0.01)
0110	IT0101K	2,864,699.04	3,198,447.66	3,532,196.28	3,865,944.90	4,213,248.40	4,560,551.90	4,907,855.40	5,255,158.90	5,602,462.40	5,779,940.96	6,255,028.72	-	-	3,848,887.27	3/31/2020	(1)	1.3922%	(0.01)
0110	IT0225K	219,788.16	-	-	-	-	-	-	-	-	-	-	-	-	16,906.78	5/31/2019	(11)	0.0061%	(0.00)
0110	IT0235K	108,000.00	138,000.00	-	-	-	-	-	-	-	-	-	-	-	18,923.08	6/30/2019	(10)	0.0068%	(0.00)
0110	IT0242K	544,847.73	568,847.73	576,047.73	583,247.73	588,047.73	590,447.73	590,447.73	-	-	-	-	-	-	310,918.01	11/30/2019	(5)	0.1125%	(0.01)
0110	IT0246K	139,320.76	195,049.06	250,777.36	306,505.66	362,233.96	417,962.26	473,690.56	501,554.72	529,418.88	585,040.93	640,662.98	696,285.03	751,907.08	450,031.48	6/30/2020	2	0.1628%	0.00
0110	IT0301K	356,446.56	365,247.71	374,048.86	382,850.01	391,651.16	400,452.31	409,253.46	415,854.32	-	-	-	-	-	238,138.80	12/31/2019	(4)	0.0861%	(0.00)
0110	IT0305K	196,800.00	201,600.00	206,400.00	211,200.00	216,000.00	220,800.00	225,600.00	-	-	-	-	-	-	113,723.08	11/30/2019	(5)	0.0411%	(0.00)
0110	IT0329K	1,438,557.80	1,524,242.03	-	-	-	-	-	-	-	-	-	-	-	227,907.68	6/30/2019	(10)	0.0824%	(0.01)
0110	IT0333K	175,251.39	197,651.38	220,051.37	242,451.36	264,851.35	287,251.34	-	-	-	-	-	-	-	106,731.40	10/31/2019	(6)	0.0386%	(0.00)
0110	IT0350K	19,600.00	33,600.00	47,600.00	61,600.00	-	-	-	-	-	-	-	-	-	12,492.31	8/31/2019	(8)	0.0045%	(0.00)
0110	IT0404K	24,000.00	40,800.00	64,800.00	88,800.00	112,800.00	136,800.00	153,600.00	-	-	-	-	-	-	47,815.38	11/30/2019	(5)	0.0173%	(0.00)
0110	IT0408K	19,200.00	28,800.00	40,320.00	51,840.00	63,360.00	74,880.00	86,400.00	-	-	-	-	-	-	28,061.54	11/30/2019	(5)	0.0102%	(0.00)
0110	IT0412K	42,240.00	52,800.00	63,360.00	73,920.00	84,480.00	95,040.00	105,600.00	116,160.00	-	-	-	-	-	48,738.46	12/31/2019	(4)	0.0176%	(0.00)
0110	IT0413K	78,346.76	98,411.17	118,475.58	138,539.99	158,604.40	178,668.81	198,733.22	218,797.63	-	-	-	-	-	91,429.04	12/31/2019	(4)	0.0331%	(0.00)
0110	IT0432K	7,998.72	9,998.40	11,998.08	13,997.76	15,997.44	17,997.12	19,996.80	21,996.48	-	-	-	-	-	9,229.29	12/31/2019	(4)	0.0033%	(0.00)
0110	IT0433K	25,599.36	31,999.20	38,399.04	44,798.88	51,198.72	57,598.56	63,998.40	70,398.24	-	-	-	-	-	29,537.72	12/31/2019	(4)	0.0107%	(0.00)
0110	IT0434K	2,800.00	5,600.00	16,800.00	28,000.00	39,200.00	50,400.00	61,600.00	72,800.00	-	-	-	-	-	21,323.08	12/31/2019	(4)	0.0077%	(0.00)
0110	IT0440K	24,000.00	24,000.00	24,000.00	24,000.00	24,000.00	24,000.00	24,000.00	24,000.00	-	-	-	-	-	14,769.23	12/31/2019	(4)	0.0053%	(0.00)
0110	IT0441K	6,720.00	6,720.00	12,480.00	12,480.00	31,200.00	31,200.00	-	-	-	-	-	-	-	7,753.85	10/31/2019	(6)	0.0028%	(0.00)
0110	IT0443K	26,400.00	38,400.00	50,400.00	62,400.00	72,000.00	81,600.00	88,800.00	-	-	-	-	-	-	32,307.69	11/30/2019	(5)	0.0117%	(0.00)
0110	IT0444K	13,440.00	13,440.00	19,200.00	29,760.00	32,640.00	41,280.00	42,720.00	-	-	-	-	-	-	14,806.15	11/30/2019	(5)	0.0054%	(0.00)
0110	IT0446K	4,800.00	9,600.00	9,600.00	9,600.00	14,400.00	14,400.00	-	-	-	-	-	-	-	4,800.00	10/31/2019	(6)	0.0017%	(0.00)
0110	IT0448K	12,240.00	19,440.00	28,800.00	38,400.00	45,600.00	54,960.00	65,760.00	-	-	-	-	-	-	20,400.00	11/30/2019	(5)	0.0074%	(0.00)
0110	IT0451K	17,280.00	26,880.00	34,080.00	41,280.00	48,480.00	55,680.00	58,560.00	-	-	-	-	-	-	21,710.77	11/30/2019	(5)	0.0079%	(0.00)
0110	IT0453K	14,847.81	29,695.66	524,624.14	722,595.53	920,566.92	1,118,538.31	1,316,509.70	1,366,002.56	1,385,799.70	1,385,799.70	1,405,443.87	1,425,088.04	1,434,910.10	1,003,878.62	11/30/2020	7	0.3631%	0.03
0110	IT0454K	31,200.00	48,000.00	64,800.00	84,000.00	103,200.00	120,000.00	134,400.00	-	-	-	-	-	-	45,046.15	11/30/2019	(5)	0.0163%	(0.00)
0110	IT0459K	85,000.00	135,000.00	185,000.00	210,000.00	235,000.00	-	-	-	-	-	-	-	-	65,384.62	9/30/2019	(7)	0.0237%	(0.00)
0110	IT0467K	10,584.48	10,584.48	20,184.48	20,184.48	20,184.48	29,784.48	-	-	-	-	-	-	-	8,577.45	10/31/2019	(6)	0.0031%	(0.00)
0110	IT0473K	3,360.00	4,320.00	10,080.00	12,480.00	17,280.00	19,200.00	-	-	-	-	-	-	-	5,132.31	10/31/2019	(6)	0.0019%	(0.00)
0110	IT0477K	449,138.40	561,423.00	673,707.60	785,992.20	898,276.80	1,010,561.40	1,122,846.00	-	-	-	-	-	-	423,226.57	11/30/2019	(5)	0.1531%	(0.01)
0110	IT0479K	8,160.00	12,960.00	19,200.00	22,560.00	27,360.00	36,000.00	43,200.00	-	-	-	-	-	-	13,033.85	11/30/2019	(5)	0.0047%	(0.00)
0110	IT0481K	2,800.00	5,600.00	8,400.00	22,400.00	33,600.00	42,000.00	-	-	-	-	-	-	-	8,830.77	10/31/2019	(6)	0.0032%	(0.00)
0110	IT0483K	15,120.00	22,680.00	30,240.00	37,800.00	45,360.00	52,920.00	60,480.00	68,040.00	-	-	-	-	-	25,587.69	12/31/2019	(4)	0.0093%	(0.00)
0110	IT0486K	26,439.02	29,629.94	32,820.86	36,011.78	56,524.81	59,723.24	62,914.16	65,649.23	-	-	-	-	-	28,439.46	12/31/2019	(4)	0.0103%	(0.00)
0110	IT0488K	31,977.64	39,972.05	47,966.46	55,960.87	63,955.28	71,949.69	79,944.10	87,938.51	-	-	-	-	-	36,897.28	12/31/2019	(4)	0.0133%	(0.00)
0110	IT0489K	48,000.00	48,000.00	48,000.00	48,000.00	-	-	-	-	-	-	-	-	-	14,769.23	8/31/2019	(8)	0.0053%	(0.00)
0110	IT0493K	348,000.00	360,000.00	372,000.00	-	-	-	-	-	-	-	-	-	-	83,076.92	7/31/2019	(9)	0.0301%	(0.00)
0110	IT0494K	19,200.00	28,800.00	38,400.00	48,000.00	57,600.00	67,200.00	76,800.00	86,400.00	-	-	-	-	-	32,492.31	12/31/2019	(4)	0.0118%	(0.00)
0110	IT0495K	14,000.00	28,000.00	42,000.00	56,000.00	70,000.00	84,000.00	98,000.00	-	-	-	-	-	-	30,153.85	11/30/2019	(5)	0.0109%	(0.00)
0110	IT0496K	24,000.00	48,000.00	72,000.00	96,000.00	120,000.00	144,000.00	168,000.00	-	-	-	-	-	-	51,692.31	11/30/2019	(5)	0.0187%	(0.00)
0110	IT0497K	39,894.04	49,867.54	59,841.04	69,814.54	79,788.04	89,761.54	99,735.04	109,708.54	-	-	-	-	-	46,031.56	12/31/2019	(4)	0.0167%	(0.00)
0110	IT0498K	24,000.00	30,000.00	36,000.00	42,000.00	48,000.00	54,000.00	60,000.00	66,000.00	-	-	-	-	-	27,692.31	12/31/2019	(4)	0.0100%	(0.00)
0110	IT0499K	63,123.06	94,684.59	126,246.13	157,807.67	-	-	-	-	-	-	-	-	-	33,989.34	8/31/2019	(8)	0.0123%	(0.00)
0110	IT0500K	11,520.00	15,360.00	19,200.00	23,040.00	26,880.00	30,720.00	34,560.00	-	-	-	-	-	-	12,406.15	11/30/2019	(5)	0.0045%	(0.00)
0110	IT0501K	13,744.80	18,326.40	22,908.00	27,489.60	32,071.20	36,652.80	41,234.40	45,816.00	-	-	-	-	-	18,326.40	12/31/2019	(4)	0.0066%	(0.00)
0110	IT0507K	22,536.50	28,170.63	33,804.76	39,438.87	45,073.00	50,707.13	56,341.26	61,975.37	-	-	-	-	-	26,003.66	12/31/2019	(4)	0.0094%	(0.00)
0110	IT0508K	9,600.00	19,200.00	28,800.00	38,400.00	48,000.00	57,600.00	-	-	-	-	-	-	-	15,507.69	10/31/2019	(6)	0.0056%	(0.00)
0110	IT0509K	19,200.00	28,800.00	38,400.00	48,000.00	57,600.00	67,200.00	76,800.00	86,400.00	-	-	-	-	-	32,492.31	12/31/2019	(4)	0.0118%	(0.00)
0110	IT0511K	55,730.20	83,595.30	111,460.40	139,325.50	167,190.60	195,055.70	222,920.80	250,785.90	278,651.00	306,555.08	334,459.16	362,363.24	390,267.32	222,950.78	10/31/2020	6	0.0806%	0.00
0110	IT0512K	1,920.00	3,120.00	4,320.00	52,320.00	57,120.00	58,320.00	59,520.00	-	-	-	-	-	-	18,203.08	11/30/2019	(5)	0.0066%	(0.00)
0110	IT0513K	38,400.00	57,600.00	76,800.00	99,840.00	122,880.00	145,920.00	165,120.00	184,320.00	-	-	-	-	-	68,529.23	12/31/2019	(4)	0.0248%	(0.00)
0110	IT0517K	36,000.00	48,000.00	60,000.00	-	-	-	-	-	-	-	-	-	-	11,076.92	7/31/2019	(9)	0.0040%	(0.00)
0110	IT0518K	50,400.00	67,200.00	84,000.00	100,800.00	117,600.00	134,400.00	151,200.00	-	-	-	-	-	-	54,276.92	11/30/2019	(5)	0.0196%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	IT0519K	25,200.00	33,600.00	-	-	-	-	-	-	-	-	-	-	-	4,523.08	6/30/2019	(10)	0.0016%	(0.00)
0110	IT0520K	98,000.00	126,000.00	154,000.00	182,000.00	210,000.00	238,000.00	266,000.00	-	-	-	-	-	-	98,000.00	11/30/2019	(5)	0.0354%	(0.00)
0110	IT0521K	19,200.00	28,800.00	38,400.00	48,000.00	57,600.00	67,200.00	81,600.00	-	-	-	-	-	-	26,215.38	11/30/2019	(5)	0.0095%	(0.00)
0110	IT0522K	112,000.00	126,000.00	-	-	-	-	-	-	-	-	-	-	-	18,307.69	6/30/2019	(10)	0.0066%	(0.00)
0110	IT0524K	33,600.00	44,800.00	56,000.00	61,600.00	67,200.00	72,800.00	78,400.00	-	-	-	-	-	-	31,876.92	11/30/2019	(5)	0.0115%	(0.00)
0110	IT0525K	117,600.00	-	-	-	-	-	-	-	-	-	-	-	-	9,046.15	5/31/2019	(11)	0.0033%	(0.00)
0110	IT0526K	14,400.00	43,200.00	72,000.00	100,800.00	129,600.00	158,400.00	187,200.00	216,000.00	-	-	-	-	-	70,892.31	12/31/2019	(4)	0.0256%	(0.00)
0110	IT0527K	20,000.00	25,000.00	-	-	-	-	-	-	-	-	-	-	-	3,461.54	6/30/2019	(10)	0.0013%	(0.00)
0110	IT0528K	12,500.00	25,000.00	37,500.00	50,000.00	62,500.00	-	-	-	-	-	-	-	-	14,423.08	9/30/2019	(7)	0.0052%	(0.00)
0110	IT0529K	24,000.00	43,200.00	48,000.00	52,800.00	57,600.00	-	-	-	-	-	-	-	-	17,353.85	9/30/2019	(7)	0.0063%	(0.00)
0110	IT0532K	9,600.00	14,400.00	19,200.00	24,000.00	28,800.00	33,600.00	38,400.00	43,200.00	-	-	-	-	-	16,246.15	12/31/2019	(4)	0.0059%	(0.00)
0110	IT0534K	44,800.00	-	-	-	-	-	-	-	-	-	-	-	-	3,446.15	5/31/2019	(11)	0.0012%	(0.00)
0110	IT0535K	70,000.00	-	-	-	-	-	-	-	-	-	-	-	-	5,384.62	5/31/2019	(11)	0.0019%	(0.00)
0110	IT0536K	112,000.00	140,000.00	168,000.00	196,000.00	-	-	-	-	-	-	-	-	-	47,384.62	8/31/2019	(8)	0.0171%	(0.00)
0110	IT0538K	36,000.00	72,000.00	108,000.00	-	-	-	-	-	-	-	-	-	-	16,615.38	7/31/2019	(9)	0.0060%	(0.00)
0110	IT0540K	11,905.17	23,810.34	35,715.51	47,620.68	-	-	-	-	-	-	-	-	-	9,157.82	8/31/2019	(8)	0.0033%	(0.00)
0110	IT0542K	48,000.00	60,000.00	72,000.00	84,000.00	96,000.00	108,000.00	120,000.00	132,000.00	-	-	-	-	-	55,384.62	12/31/2019	(4)	0.0200%	(0.00)
0110	IT0543K	24,000.00	48,000.00	72,000.00	96,000.00	120,000.00	-	-	-	-	-	-	-	-	27,692.31	9/30/2019	(7)	0.0100%	(0.00)
0110	IT0548K	43,200.00	57,600.00	72,000.00	86,400.00	100,800.00	115,200.00	129,600.00	-	-	-	-	-	-	46,523.08	11/30/2019	(5)	0.0168%	(0.00)
0110	IT0550K	223,406.38	229,122.51	234,838.64	240,554.77	246,270.90	251,987.03	257,703.16	263,419.29	-	-	-	-	-	149,792.51	12/31/2019	(4)	0.0542%	(0.00)
0110	IT0551K	28,800.00	38,400.00	48,000.00	57,600.00	67,200.00	76,800.00	86,400.00	-	-	-	-	-	-	31,015.38	11/30/2019	(5)	0.0112%	(0.00)
0110	IT0553K	33,600.00	44,800.00	56,000.00	67,200.00	78,400.00	89,600.00	100,800.00	-	-	-	-	-	-	36,184.62	11/30/2019	(5)	0.0131%	(0.00)
0110	IT0554K	33,600.00	44,800.00	56,000.00	67,200.00	78,400.00	89,600.00	100,800.00	-	-	-	-	-	-	36,184.62	11/30/2019	(5)	0.0131%	(0.00)
0110	IT0555K	33,600.00	44,800.00	56,000.00	67,200.00	78,400.00	89,600.00	100,800.00	-	-	-	-	-	-	36,184.62	11/30/2019	(5)	0.0131%	(0.00)
0110	IT0556K	81,120.00	83,040.00	-	-	-	-	-	-	-	-	-	-	-	12,627.69	6/30/2019	(10)	0.0046%	(0.00)
0110	IT0557K	48,000.00	72,000.00	96,000.00	120,000.00	144,000.00	168,000.00	192,000.00	216,000.00	-	-	-	-	-	81,230.77	12/31/2019	(4)	0.0294%	(0.00)
0110	IT0560K	44,799.98	67,199.97	89,599.96	111,999.95	134,399.94	156,799.93	179,199.92	201,599.91	223,999.90	246,245.22	268,490.54	290,735.86	312,981.18	179,080.94	10/31/2020	6	0.0648%	0.00
0110	IT0561K	11,200.00	16,800.00	22,400.00	28,000.00	33,600.00	39,200.00	44,800.00	50,400.00	56,000.00	64,400.00	72,800.00	81,200.00	89,600.00	46,953.85	10/31/2020	6	0.0170%	0.00
0110	IT0562K	126,000.00	154,000.00	182,000.00	210,000.00	238,000.00	266,000.00	294,000.00	322,000.00	336,000.00	378,000.00	434,000.00	490,000.00	-	263,846.15	4/30/2020	-	0.0954%	-
0110	IT0563K	28,000.00	39,200.00	50,400.00	61,600.00	72,800.00	84,000.00	95,200.00	103,600.00	112,000.00	126,000.00	140,000.00	154,000.00	-	82,061.54	4/30/2020	-	0.0297%	-
0110	IT0568K	79,200.00	118,800.00	158,400.00	198,000.00	237,600.00	277,200.00	316,800.00	356,400.00	-	-	-	-	-	134,030.77	12/31/2019	(4)	0.0485%	(0.00)
0110	IT0604K	66,643.70	99,965.55	133,287.40	166,609.25	199,931.10	233,252.95	266,574.80	355,433.14	388,754.99	422,093.67	455,432.35	488,771.03	522,109.71	292,219.97	11/30/2020	7	0.1057%	0.01
0110	IT0688K	38,400.00	57,600.00	76,800.00	96,000.00	115,200.00	124,800.00	134,400.00	-	-	-	-	-	-	49,476.92	11/30/2019	(5)	0.0179%	(0.00)
0110	IT0708K	13,846.97	27,693.94	55,387.91	96,928.86	138,469.77	180,010.70	221,551.63	249,245.60	276,939.57	318,631.47	360,323.37	402,015.27	443,707.17	214,211.71	10/31/2020	6	0.0775%	0.00
0110	IT1067K	1,920.00	3,120.00	4,320.00	52,320.00	57,120.00	58,320.00	59,520.00	-	-	-	-	-	-	18,203.08	11/30/2019	(5)	0.0066%	(0.00)
0110	IT1086K	57,047.40	85,571.11	114,094.82	142,618.53	185,404.08	242,451.49	289,991.00	337,530.51	-	-	-	-	-	111,900.69	12/31/2019	(4)	0.0405%	(0.00)
0110	LI-000024	5,219,990.96	5,405,123.12	5,590,255.28	5,775,387.44	5,960,519.60	6,145,651.76	6,330,783.92	6,515,916.08	-	-	-	-	-	3,611,048.32	12/31/2019	(4)	1.3062%	(0.05)
0110	LI-000028	83,335.68	1,075,497.36	1,333,055.18	1,590,613.00	1,712,889.68	1,835,166.36	1,957,443.04	2,324,647.42	-	-	-	-	-	916,357.52	12/31/2019	(4)	0.3315%	(0.01)
0110	LI-000030	2,112,707.22	-	-	-	-	-	-	-	-	-	-	-	-	162,515.94	5/31/2019	(11)	0.0588%	(0.01)
0110	LI-000055	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000058	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000060	7,614.24	9,517.80	11,421.36	13,324.92	15,228.48	17,132.04	19,035.60	20,939.16	-	-	-	-	-	8,785.66	12/31/2019	(4)	0.0032%	(0.00)
0110	LI-000061	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000063	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000064	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000066	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000067	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000068	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000069	30,457.24	38,071.55	45,685.86	53,300.17	60,914.48	68,528.79	76,143.10	83,757.41	-	-	-	-	-	35,142.97	12/31/2019	(4)	0.0127%	(0.00)
0110	LI-000083	609,377.69	746,025.23	882,672.77	1,019,320.31	1,155,967.85	1,292,615.39	-	-	-	-	-	-	-	438,921.48	10/31/2019	(6)	0.1588%	(0.01)
0110	LI-000085	436,055.62	523,143.71	610,231.80	697,319.89	784,407.98	871,496.07	958,584.16	1,045,672.25	-	-	-	-	-	455,916.27	12/31/2019	(4)	0.1649%	(0.01)
0110	LI-000086	722,415.37	890,561.39	1,058,707.41	1,226,853.43	-	-	-	-	-	-	-	-	-	299,887.51	8/31/2019	(8)	0.1085%	(0.01)
0110	LI-000092	1,386,771.41	1,499,865.85	1,611,241.39	1,722,616.93	1,833,992.47	1,943,649.11	2,053,305.75	-	-	-	-	-	-	927,034.07	11/30/2019	(5)	0.3353%	(0.02)
0110	SU-000002	214,000.00	267,500.00	321,000.00	374,500.00	428,000.00	481,500.00	535,000.00	588,500.00	642,000.00	700,333.37	758,666.70	817,000.03	875,333.36	538,717.96	12/31/2020	8	0.1949%	0.02
0110	SU-000004	1,614,181.98	1,690,551.01	-	-	-	-	-	-	-	-	-	-	-	254,210.23	6/30/2019	(10)	0.0920%	(0.01)
0110	SU-000010	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	5/31/2020	1	0.0041%	0.00
0110	SU-000040	575,651.53	596,313.26	596,313.26	604,907.76	604,907.76	604,907.76	604,907.76	604,907.76	-	-	-	-	-	368,678.22	12/31/2019	(4)	0.1334%	(0.01)
0110	SU-000079	43,333.32	54,166.65	64,999.98	75,833.31	86,666.64	97,499.97	108,333.30	119,166.63	-	-	-	-	-	49,999.98	12/31/2019	(4)	0.0181%	(0.00)
0110	SU-000081	57,333.32	71,666.65	85,999.98	100,333.31	114,666.64	128,999.97	143,333.30	157,666.63	-	-	-	-	-	66,153.83	12/31/2019	(4)	0.0239%	(0.00)
0110	SU-000082	216,333.32	270,416.65	324,499.98	378,583.31	432,666.64	486,749.97	540,833.30	594,916.63	-	-	-	-	-	249,615.37	12/31/2019	(4)	0.0903%	(0.00)
0110	SU-000084	67,000.00	83,750.00	100,500.00	117,250.00	134,000.00	150,750.00	167,500.00	184,250.00	-	-	-	-	-	77,307.69	12/31/2019	(4)	0.0280%	(0.00)
0110	SU-000086	57,333.32	71,666.65	85,999.98	100,333.31	114,666.64	128,999.97	143,333.30	157,666.63	-	-	-	-	-	66,153.83	12/31/2019	(4)	0.0239%	(0.00)
0110	SU-000096	107,333.32	134,166.65	160,999.98	187,833.31	214,666.64	241,499.97	268,333.30	295,166.63	-	-	-	-	-	123,846.14	12/31/2019	(4)	0.0448%	(0.00)
0110	SU-000097	21,624.60	27,030.75	32,436.90	37,843.05	43,249.20	48,655.35	54,061.50	59,467.65	-	-	-	-	-	24,951.46	12/31/2019	(4)	0.0090%	(0.00)
0110	SU-000116	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000117	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000118	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000119	54,419.32	62,922.32	71,425.32	79,928.32	88,431.32	100,335.53	112,239.74	124,143.95	-	-	-	-	-	53,372.76	12/31/2019	(4)	0.0193%	(0.00)
0110	SU-000120	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000122	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000123	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000124	16,666.68	20,833.35	25,000.02	29,166.69	33,333.36	37,500.03	41,666.70	45,833.37	-	-	-	-	-	19,230.78	12/31/2019	(4)	0.0070%	(0.00)
0110	SU-000130	66,730.23	88,973.64	111,217.05	133,460.46	177,947.27	222,434.08	266,920.89	311,407.70	355,894.51	400,145.87	488,648.59	577,151.31	621,402.67	294,025.71	6/30/2020	2	0.1064%	0.00
0110	SU-000144	92,070.80	105,675.63	119,280.46	132,885.29	146,490.12	165,536.86	184,583.60	203,630.34	-	-	-	-	-	88,473.32	12/31/2019	(4)	0.0320%	(0.00)
0110	SU-000146	92,070.80	105,675.63	119,280.46	132,885.29	146,490.12	165,536.86	184,583.60	203,630.34	-	-	-	-	-	88,473.32	12/31/2019	(4)	0.0320%	(0.00)
0110	SU-000165	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000166	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000167	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000168	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000169	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000170	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	SU-000179	883,069.40	1,248,002.20	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,172,462.68	2,266,888.56	2,361,314.44	2,455,740.32	1,994,902.71	12/31/2020	8	0.7216%	0.06
0110	SU-000195	1,522.88	1,903.60	2,284.32	2,665.04	3,045.76	3,426.48	3,807.20	4,187.92	-	-	-	-	-	1,757.17	12/31/2019	(4)	0.0006%	(0.00)
0110	SU-000196	8,897.37	17,794.74	23,355.58	28,916.42	36,701.60	-	-	-	-	-	-	-	-	8,897.36	9/30/2019	(7)	0.0032%	(0.00)
0110	SU-000199	1,522.88	1,903.60	2,284.32	2,665.04	3,045.76	3,426.48	3,807.20	4,187.92	-	-	-	-	-	1,757.17	12/31/2019	(4)	0.0006%	(0.00)
0110	SU-000200	32,284.68	40,355.85	48,427.02	56,498.19	64,569.36	72,640.53	80,711.70	88,782.87	-	-	-	-	-	37,251.55	12/31/2019	(4)	0.0135%	(0.00)
0110	SU-000208	139,494.00	174,367.50	209,241.00	244,114.50	278,988.00	313,861.50	348,735.00	383,608.50	-	-	-	-	-	160,954.62	12/31/2019	(4)	0.0582%	(0.00)
0110	SU-000209	33,502.92	41,878.65	50,254.38	58,630.11	67,005.84	75,381.57	83,757.30	92,133.03	-	-	-	-	-	38,657.22	12/31/2019	(4)	0.0140%	(0.00)
0110	SU-000210	36,853.24	46,066.55	55,279.86	64,493.17	73,706.48	82,919.79	92,133.10	101,346.41	-	-	-	-	-	42,522.97	12/31/2019	(4)	0.0154%	(0.00)
0110	SU-000213	32,284.68	40,355.85	48,427.02	56,498.19	64,569.36	72,640.53	80,711.70	88,782.87	-	-	-	-	-	37,251.55	12/31/2019	(4)	0.0135%	(0.00)
0110	SU-000217	1,522.88	1,903.60	2,284.32	2,665.04	3,045.76	3,426.48	3,807.20	4,187.92	-	-	-	-	-	1,757.17	12/31/2019	(4)	0.0006%	(0.00)
0110	SU-000218	36,853.24	46,066.55	55,279.86	64,493.17	73,706.48	82,919.79	92,133.10	101,346.41	-	-	-	-	-	42,522.97	12/31/2019	(4)	0.0154%	(0.00)
0110	SU-000219	32,589.24	40,736.55	48,883.86	57,031.17	65,178.48	73,325.79	81,473.10	89,620.41	-	-	-	-	-	37,602.97	12/31/2019	(4)	0.0136%	(0.00)
0110	SU-000244	90,939.57	90,939.57	90,939.57	90,939.57	90,939.57	90,939.57	-	-	-	-	-	-	-	41,972.11	10/31/2019	(6)	0.0152%	(0.00)
0110	SU-000247	1,373,172.78	1,382,374.68	1,391,576.58	1,400,778.48	1,409,980.38	1,419,182.28	1,428,384.18	1,437,586.08	-	-	-	-	-	864,848.88	12/31/2019	(4)	0.3128%	(0.01)
0110	SU-000248	(5,000.00)	(1,250.00)	2,500.00	6,250.00	10,000.00	13,750.00	17,500.00	21,250.00	-	-	-	-	-	5,000.00	12/31/2019	(4)	0.0018%	(0.00)
0110	SU-000250	33,320.00	41,650.00	49,980.00	58,310.00	66,640.00	74,970.00	83,300.00	91,630.00	-	-	-	-	-	38,446.15	12/31/2019	(4)	0.0139%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	SU-000251	33,320.00	41,650.00	49,980.00	58,310.00	66,640.00	74,970.00	83,300.00	91,630.00	-	-	-	-	-	38,446.15	12/31/2019	(4)	0.0139%	(0.00)
0110	SU-000252	62,281.57	106,768.38	133,460.48	146,806.53	155,703.90	-	-	-	-	-	-	-	-	46,540.07	9/30/2019	(7)	0.0168%	(0.00)
0110	SU-000253	123,908.36	142,331.54	160,754.72	179,177.90	197,601.08	223,393.55	249,186.02	274,978.49	-	-	-	-	-	119,333.20	12/31/2019	(4)	0.0432%	(0.00)
0110	SU-000254	(25,000.00)	(18,750.00)	(12,500.00)	(6,250.00)	-	6,250.00	12,500.00	18,750.00	-	-	-	-	-	(1,923.08)	12/31/2019	(4)	-0.0007%	0.00
0110	SU-000255	15,000.00	18,750.00	22,500.00	26,250.00	30,000.00	33,750.00	37,500.00	41,250.00	-	-	-	-	-	17,307.69	12/31/2019	(4)	0.0063%	(0.00)
0110	SU-000257	83,320.00	104,150.00	124,980.00	145,810.00	166,640.00	187,470.00	208,300.00	229,130.00	-	-	-	-	-	96,138.46	12/31/2019	(4)	0.0348%	(0.00)
0110	SU-000258	93,320.00	116,650.00	139,980.00	163,310.00	186,640.00	209,970.00	233,300.00	256,630.00	-	-	-	-	-	107,676.92	12/31/2019	(4)	0.0389%	(0.00)
0110	SU-000259	35,680.00	44,600.00	53,520.00	62,440.00	71,360.00	80,280.00	89,200.00	98,120.00	-	-	-	-	-	41,169.23	12/31/2019	(4)	0.0149%	(0.00)
0110	SU-000281	40,666.64	50,833.31	60,999.98	71,166.65	81,333.32	91,499.99	101,666.66	111,833.33	-	-	-	-	-	46,923.07	12/31/2019	(4)	0.0170%	(0.00)
0110	SU-000309	36,279.48	41,948.15	47,616.82	53,285.49	58,954.16	66,890.32	74,826.48	82,762.64	-	-	-	-	-	35,581.81	12/31/2019	(4)	0.0129%	(0.00)
0110	SU-000310	36,279.48	41,948.15	47,616.82	53,285.49	58,954.16	66,890.32	74,826.48	82,762.64	-	-	-	-	-	35,581.81	12/31/2019	(4)	0.0129%	(0.00)
0110	SU-000316	153,117.96	175,792.66	198,467.36	221,142.06	243,816.76	275,561.30	307,305.84	339,050.38	-	-	-	-	-	147,250.33	12/31/2019	(4)	0.0533%	(0.00)
0110	SU-000317	72,559.04	83,896.39	95,233.74	106,571.09	117,908.44	133,780.72	149,653.00	165,525.28	-	-	-	-	-	71,163.67	12/31/2019	(4)	0.0257%	(0.00)
0110	SU-000328	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	89,791.72	99,315.08	-	-	-	-	-	42,698.16	12/31/2019	(4)	0.0154%	(0.00)
0110	SU-000329	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	89,791.72	99,315.08	-	-	-	-	-	42,698.16	12/31/2019	(4)	0.0154%	(0.00)
0110	SU-000330	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	89,791.72	99,315.08	-	-	-	-	-	42,698.16	12/31/2019	(4)	0.0154%	(0.00)
0110	SU-000331	21,767.68	32,651.52	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	-	-	-	-	-	32,337.57	12/31/2019	(4)	0.0117%	(0.00)
0110	SU-000332	21,767.68	32,651.52	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	-	-	-	-	-	32,337.57	12/31/2019	(4)	0.0117%	(0.00)
0110	SU-000333	21,767.68	32,651.52	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	-	-	-	-	-	32,337.57	12/31/2019	(4)	0.0117%	(0.00)
0110	SU-000334	21,767.68	32,651.52	43,535.36	50,337.77	57,140.18	63,942.59	70,745.00	80,268.36	-	-	-	-	-	32,337.57	12/31/2019	(4)	0.0117%	(0.00)
0110	SU-000344	44,486.82	66,730.23	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	156,206.38	223,439.12	290,671.86	357,904.60	135,558.04	5/31/2020	1	0.0490%	0.00
0110	SU-000353	53,384.21	80,076.31	124,563.12	169,049.93	233,110.97	277,597.78	322,084.59	366,571.40	411,058.21	548,177.56	685,296.91	-	-	251,613.15	3/31/2020	(1)	0.0910%	(0.00)
0110	SU-000377	17,794.74	26,692.11	35,589.48	48,935.53	62,281.58	75,627.63	84,525.00	93,422.37	102,319.74	159,821.39	-	-	-	54,385.35	2/29/2020	(2)	0.0197%	(0.00)
0110	SU-000389	51,604.68	60,502.05	69,399.42	81,855.73	94,312.04	-	-	-	-	-	-	-	-	27,513.38	9/30/2019	(7)	0.0100%	(0.00)
0110	SU-000390	17,201.53	20,167.31	23,133.09	27,285.19	31,437.29	-	-	-	-	-	-	-	-	9,171.11	9/30/2019	(7)	0.0033%	(0.00)
0110	SU-000393	1,898.12	2,847.18	3,440.34	4,033.50	4,626.66	5,457.07	6,287.48	-	-	-	-	-	-	2,199.26	11/30/2019	(5)	0.0008%	(0.00)
0110	SU-000394	20,241.50	25,691.14	-	-	-	-	-	-	-	-	-	-	-	3,533.28	6/30/2019	(10)	0.0013%	(0.00)
0110	SU-000395	37,665.96	-	-	-	-	-	-	-	-	-	-	-	-	2,897.38	5/31/2019	(11)	0.0010%	(0.00)
0110	SU-000404	13,346.01	17,794.68	22,243.35	26,692.02	31,140.69	35,589.36	38,258.57	38,258.57	38,258.57	42,683.71	51,533.97	69,234.51	95,785.33	40,063.03	5/31/2020	1	0.0145%	0.00
0110	SU-000405	(1,918.68)	(9,444.43)	(16,970.18)	10,553.19	42,939.74	67,073.54	106,560.35	146,047.16	232,318.73	271,570.09	389,324.19	624,832.37	865,835.73	209,901.68	6/30/2020	2	0.0759%	0.00
0110	SU-000408	26,692.08	35,589.45	44,486.82	53,384.19	66,730.24	80,076.29	91,642.86	100,540.23	109,437.60	153,688.96	242,191.68	330,694.40	463,448.50	138,354.10	10/31/2020	6	0.0500%	0.00
0110	133683	1,644,165.17	1,648,125.17	1,652,085.17	1,663,965.17	1,675,845.17	1,687,725.17	1,699,605.17	1,711,485.17	1,723,365.17	1,748,565.17	1,773,765.17	1,798,965.17	1,824,165.17	1,711,679.02	11/30/2023	43	0.6192%	0.27
0110	SU-000098	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	12/31/2021	20	0.0019%	0.00
0110	146434	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	11/30/2021	19	0.0783%	0.01
0110	133641	58,380.07	69,380.07	80,380.07	113,380.07	146,380.07	179,380.07	212,380.07	245,380.07	278,380.07	348,379.98	418,379.91	488,379.85	558,379.76	245,918.47	11/30/2023	43	0.0890%	0.04
0110	00017FACK	135,600.81	140,048.09	144,495.37	275,648.90	280,096.18	284,543.46	440,536.48	444,983.76	449,431.04	449,431.04	449,431.04	453,860.81	584,996.83	348,700.29	12/31/2021	20	0.1261%	0.03
0110	00105FACK	113,347.36	116,905.78	120,464.20	124,022.62	127,581.04	131,139.46	344,624.80	344,624.80	344,624.80	459,624.80	574,624.80	937,589.21	1,063,663.61	369,449.02	12/31/2021	20	0.1336%	0.03
0110	139958	99,856.52	124,820.64	149,784.76	174,748.88	199,713.00	224,677.12	249,641.24	274,605.36	299,569.48	456,451.34	1,326,658.17	2,196,865.00	3,067,071.83	680,343.33	12/31/2021	20	0.2461%	0.05
0110	145403	10,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	19,230.77	12/31/2023	44	0.0070%	0.00
0110	145843	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	3,228.70	6,964.89	12,271.94	18,117.72	3,121.10	12/31/2023	44	0.0011%	0.00
0110	147830	1,808,333.32	1,989,166.65	2,169,999.98	2,350,833.31	2,531,666.64	2,712,499.97	2,893,333.30	3,074,166.63	3,255,000.00	3,435,833.33	3,616,666.66	3,797,499.99	3,978,333.32	2,893,333.32	12/31/2023	44	1.0466%	0.46
0110	148391	71,053.66	88,817.08	106,580.50	124,343.92	142,107.34	159,870.76	177,634.18	195,397.60	213,161.02	247,853.00	282,544.97	317,236.94	351,928.91	190,656.14	12/31/2025	68	0.0690%	0.05
0110	148846	129,760.41	154,725.55	179,690.69	204,655.83	229,620.97	254,586.11	279,551.25	304,516.39	329,481.53	523,449.97	1,314,529.64	2,105,609.31	2,896,688.98	685,143.59	12/31/2022	32	0.2478%	0.08
0110	149345	311,249.73	311,249.73	311,249.73	311,249.73	311,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	372,788.19	12/31/2023	44	0.1348%	0.06
0110	152641	212,924.79	336,784.58	428,001.14	453,823.28	453,823.28	453,823.28	453,823.28	453,823.28	495,196.20	495,196.20	495,196.20	495,196.20	495,196.20	440,215.99	12/31/2021	20	0.1592%	0.03
0110	152706	33,248.70	33,248.70	33,248.70	33,248.70	33,248.70	33,248.70	99,879.56	166,510.41	233,141.26	657,194.10	1,081,247.10	1,505,300.10	1,929,353.10	451,701.37	12/31/2022	32	0.1634%	0.05
0110	155100	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	6/30/2023	38	0.0369%	0.01
0110	155309	331,028.53	415,796.33	500,564.13	585,331.93	670,099.73	752,290.33	834,480.93	917,810.13	1,000,000.73	1,047,853.33	1,096,844.53	1,147,104.33	1,197,364.13	807,428.39	12/31/2023	44	0.2921%	0.13
0110	157614	32,751.06	46,925.66	62,388.86	78,335.29	93,798.49	109,261.69	122,147.69	135,000.19	135,000.19	135,000.19	143,880.39	154,917.21	168,237.51	109,049.57	11/30/2023	43	0.0394%	0.02
0110	163043	288,000.04	369,000.05	450,000.06	531,000.07	612,000.08	693,000.09	762,000.10	831,000.11	900,000.12	969,000.13	1,038,000.14	1,107,000.15	1,188,000.15	749,077.02	12/31/2022	32	0.2710%	0.09
0110	BRMISCCAP	115,874.49	115,874.49	115,874.49	115,874.49	115,874.49	115,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	385,105.26	12/31/2028	104	0.1393%	0.14
0110	IT0000K	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	12/31/2025	68	0.7670%	0.52
0110	SU-000001	48,935.52	62,281.57	80,076.30	97,871.03	115,665.76	133,460.49	151,255.22	164,601.27	177,947.32	206,239.63	234,531.98	302,075.69	369,619.40	164,966.24	12/31/2021	20	0.0597%	0.01
0110	SU-000229	41,166.20	51,457.75	73,749.30	96,040.85	118,332.40	140,623.95	162,915.50	185,207.05	223,498.60	355,008.79	486,518.90	618,029.01	749,539.12	254,006.72	12/31/2021	20	0.0919%	0.02
0110	00084FACK	-	1,778.71	358,334.92	562,843.63	767,352.34	1,123,908.55	1,143,324.77	-	-	-	-	-	-	304,426.38	11/30/2019	(5)	0.1101%	(0.01)
0110	00104FACK	-	50,682.50	101,365.00	197,357.66	248,040.16	-	-	-	-	-	-	-	-	45,957.33	9/30/2019	(7)	0.0166%	(0.00)
0110	147343	-	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	1,053,740.84	-	-	810,569.88	3/31/2020	(1)	0.2932%	(0.00)
0110	150065KU	-	31,012.20	31,012.20	31,012.20	31,012.20	31,012.20	31,012.20	31,012.20	-	-	-	-	-	16,698.88	12/31/2019	(4)	0.0060%	(0.00)
0110	151403	-	80,402.00	80,402.00	80,402.00	80,402.00	80,402.00	80,402.00	-	-	-	-	-	-	37,108.62	11/30/2019	(5)	0.0134%	(0.00)
0110	151502	-	19,232.36	21,370.39	23,604.37	26,883.38	26,883.38	26,883.38	26,883.38	-	-	-	-	-	13,210.82	12/31/2019	(4)	0.0048%	(0.00)
0110	151503	-	316,995.60	316,995.60	316,995.60	357,646.83	382,996.03	419,566.63	419,566.63	-	-	-	-	-	194,674.07	12/31/2019	(4)	0.0704%	(0.00)
0110	151506	-	23,194.80	48,621.46	55,293.33	55,293.33	55,293.33	55,293.33	59,740.49	-	-	-	-	-	27,133.08	12/31/2019	(4)	0.0098%	(0.00)
0110	151509	-	13,822.52	21,605.61	21,605.61	21,605.61	21,605.61	21,605.61	21,605.61	-	-	-	-	-	11,035.09	12/31/2019	(4)	0.0040%	(0.00)
0110	151510	-	45,101.00	71,551.55	71,551.55	71,551.55	71,551.55	71,551.55	71,551.55	-	-	-	-	-	36,493.10	12/31/2019	(4)	0.0132%	(0.00)
0110	151511	-	171,699.88	171,699.88	171,699.88	182,324.76	231,667.83	231,667.83	231,667.83	-	-	-	-	-	107,109.84	12/31/2019	(4)	0.0387%	(0.00)
0110	151519	-	71,650.20	79,832.89	161,349.25	161,349.25	240,510.61	240,510.61	240,510.61	-	-	-	-	-	91,977.96	12/31/2019	(4)	0.0333%	(0.00)
0110	151527	-	8,182.69	31,642.26	35,734.17	35,734.17	35,734.17	35,734.17	35,734.17	-	-	-	-	-	16,807.37	12/31/2019	(4)	0.0061%	(0.00)
0110	151539	-	64,740.61	64,740.61	64,740.61	64,740.61	77,565.21	98,816.69	98,816.69	-	-	-	-	-	41,089.31	12/31/2019	(4)	0.0149%	(0.00)
0110	151540	-	32,662.40	65,129.21	94,823.22	102,611.03	111,687.44	121,633.69	121,633.69	-	-	-	-	-	50,013.90	12/31/2019	(4)	0.0181%	(0.00)
0110	151541	-	12,886.00	29,637.80	29,637.80	29,637.80	44,498.40	59,932.98	59,932.98	-	-	-	-	-	20,474.14	12/31/2019	(4)	0.0074%	(0.00)
0110	151542	-	36,346.25	36,346.25	36,346.25	36,346.25	50,347.56	50,347.56	54,719.57	-	-	-	-	-	23,138.44	12/31/2019	(4)	0.0084%	(0.00)
0110	151543	-	10,606.20	17,737.80	28,344.00	34,337.00	35,933.32	35,933.32	35,933.32	-	-	-	-	-	15,294.23	12/31/2019	(4)	0.0055%	(0.00)
0110	151547	-	7,731.60	14,174.60	14,174.60	22,000.27	22,000.27	22,000.27	22,000.27	-	-	-	-	-	9,544.76	12/31/2019	(4)	0.0035%	(0.00)
0110	151550	-	1,288.60	12,423.39	15,000.59	15,000.59	15,000.59	15,000.59	15,000.59	-	-	-	-	-	6,824.23	12/31/2019	(4)	0.0025%	(0.00)
0110	152810	-	101,365.00	101,365.00	101,365.00	101,365.00	169,279.55	169,279.55	169,279.55	-	-	-	-	-	70,253.74	12/31/2019	(4)	0.0254%	(0.00)
0110	152860	-	106,251.20	216,218.20	334,066.80	440,318.00	563,321.00	670,710.80	792,425.20	-	-	-	-	-	240,254.71	12/31/2019	(4)	0.0869%	(0.00)
0110	155285	-	159,786.40	220,132.20	280,478.00	340,823.80	-	-	-	-	-	-	-	-	77,016.95	9/30/2019	(7)	0.0279%	(0.00)
0110	155549	-	725.30	725.30	725.30	86,666.45	86,666.45	104,478.23	-	-	-	-	-	-	21,537.46	11/30/2019	(5)	0.0078%	(0.00)
0110	156830KU	-	92,155.50	92,155.50	92,155.50	92,155.50	92,155.50	92,155.50	92,155.50	-	-	-	-	-	49,622.19	12/1/2019	(4)	0.0179%	(0.00)
0110	156848KU	-	30,886.65	30,886.65	30,886.65	30,886.65	30,886.65	30,886.65	30,886.65	-	-	-	-	-	16,631.27	12/1/2019	(4)	0.0060%	(0.00)
0110	157150KU	-	22,217.76	22,217.76	22,217.76	22,217.76	22,217.76	22,217.76	22,217.76	-	-	-	-	-	11,963.41	12/1/2019	(4)	0.0043%	(0.00)
0110	157616	-	106,251.20	217,356.80	333,916.80	440,168.00	560,743.80	670,560.80	792,275.20	-	-	-	-	-	240,097.89	12/31/2019	(4)	0.0869%	(0.00)
0110	163031	-	19,329.00	46,655.40	-	-	-	-	-	-	-	-	-	-	5,075.72	7/31/2019	(9)	0.0018%	(0.00)
0110	163045	-	40,707.56	75,860.65	-	-	-	-	-	-	-	-	-	-	8,966.79	7/31/2019	(9)	0.0032%	(0.00)
0110	244GH	-	723.41	31,760.88	-	-	-	-	-	-	-	-	-	-	2,498.79	7/31/2019	(9)	0.0009%	(0.00)
0110	IT0425K	-	22,400.00	44,800.00	50,400.00	56,000.00	-	-	-	-	-	-	-	-	13,353.85	9/30/2019	(7)	0.0048%	(0.00)
0110	IT0449K	-	12,000.00	12,000.00	12,000.00	-	-	-	-	-	-	-	-	-	2,769.23	8/31/2019	(8)	0.0010%	(0.00)
0110	IT0456K	-	24,758.57	49,517.14	-	-	-	-	-	-	-	-	-	-	5,713.52	7/31/2019	(9)	0.0021%	(0.00)
0110	IT0460K	-	5,000.00	15,000.00	25,000.00	35,000.00	45,000.00	55,000.00	65,000.00	75,000.00	100,000.00	-	-	-	32,307.69	2/28/2020	(2)	0.0117%	(0.00)
0110	IT0466K	-	24,000.00	24,000.00	24,000.00	24,000.00	-	-	-	-	-	-	-	-	7,384.62	9/30/2019	(7)	0.0027%	(0.00)
0110	IT0475K	-	28,000.00	56,000.00	84,000.00	-	-	-	-	-	-	-	-	-	12,923.08	8/31/2019	(8)	0.0047%	(0.00)
0110	IT0552K	-	28,000.00	56,000.00	84,000.00	112,000.00	140,000.00	168,000.00	196,000.00	-	-	-	-	-	60,307.69	12/31/2019	(4)	0.0218%	(0.00)
0110	IT0558K	-	14,000.00	28,000.00	42,000.00	56,000.00	70,000.00	84,000.00	98,000.00	112,000.00	126,000.00	140,000.00	154,000.00	-	71,076.92	4/30/2020	-	0.0257%	-
0110	LI-000033	-	89,835.94	809,216.73	988,888.62	1,168,560.51	1,348,232.32	1,438,068.26	1,707,904.20	-	-	-	-	-	580,823.58	12/31/2019	(4)	0.2101%	(0.01)
0110	LI-000046	-	159,180.63	-	-	-	-	-	-	-	-	-	-	-	12,244.66	6/30/2019	(10)	0.0044%	(0.00)
0110	LI-000051	-	114,214.54	-	-	-	-	-	-	-	-	-	-	-	8,785.73	6/30/2019	(10)	0.0032%	(0.00)
0110	141391	-	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	30,000.00	12/31/2023	44	0.0109%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	152874	-	4,220.58	9,729.76	39,439.82	43,660.40	74,509.06	106,533.61	138,053.39	138,053.39	138,053.39	138,053.39	138,053.39	138,053.39	85,108.74	12/31/2023	44	0.0308%	0.01
0110	137101	-	-	742,013.96	-	-	-	-	-	-	-	-	-	-	57,078.00	7/31/2019	(9)	0.0206%	(0.00)
0110	139682KU	-	-	20,674.80	20,674.80	20,674.80	20,674.80	20,674.80	20,674.80	-	-	-	-	-	9,542.22	12/1/2019	(4)	0.0035%	(0.00)
0110	144426	-	-	36,755.20	36,755.20	36,755.20	36,755.20	36,755.20	36,755.20	-	-	-	-	-	16,963.94	12/31/2019	(4)	0.0061%	(0.00)
0110	144510KU	-	-	59,357.82	118,715.64	-	-	-	-	-	-	-	-	-	13,697.96	8/31/2019	(8)	0.0050%	(0.00)
0110	150031KU	-	-	54,581.47	54,581.47	54,581.47	54,581.47	54,581.47	54,581.47	-	-	-	-	-	25,191.45	12/1/2019	(4)	0.0091%	(0.00)
0110	150053KU	-	-	78,564.24	78,564.24	78,564.24	78,564.24	78,564.24	78,564.24	-	-	-	-	-	36,260.42	12/1/2019	(4)	0.0131%	(0.00)
0110	151375	-	-	98,385.59	220,178.58	-	-	-	-	-	-	-	-	-	24,504.94	8/31/2019	(8)	0.0089%	(0.00)
0110	151488	-	-	139,168.80	174,749.47	208,106.56	208,106.56	208,106.56	208,106.56	-	-	-	-	-	88,180.35	12/31/2019	(4)	0.0319%	(0.00)
0110	151528	-	-	32,918.31	61,744.71	90,571.11	119,438.50	119,438.50	119,438.50	-	-	-	-	-	41,811.51	12/31/2019	(4)	0.0151%	(0.00)
0110	151545	-	-	644,572.00	644,572.00	644,572.00	644,572.00	644,572.00	644,572.00	-	-	-	-	-	297,494.77	12/31/2019	(4)	0.1076%	(0.00)
0110	151548	-	-	15,463.20	15,463.20	15,463.20	15,463.20	15,463.20	23,000.22	-	-	-	-	-	7,716.63	12/31/2019	(4)	0.0028%	(0.00)
0110	152803	-	-	(7,000.00)	(7,000.00)	(7,000.00)	-	-	-	-	-	-	-	-	(1,615.38)	9/30/2019	(7)	-0.0006%	0.00
0110	153056KU	-	-	74,059.20	74,059.20	74,059.20	74,059.20	74,059.20	74,059.20	-	-	-	-	-	34,181.17	12/1/2019	(4)	0.0124%	(0.00)
0110	153081	-	-	37,634.30	-	-	-	-	-	-	-	-	-	-	2,894.95	7/31/2019	(9)	0.0010%	(0.00)
0110	154759KU	-	-	63,885.13	63,885.13	63,885.13	63,885.13	63,885.13	63,885.13	-	-	-	-	-	29,485.44	12/1/2019	(4)	0.0107%	(0.00)
0110	155077KU	-	-	10,337.40	10,337.40	10,337.40	10,337.40	10,337.40	10,337.40	-	-	-	-	-	4,771.11	12/1/2019	(4)	0.0017%	(0.00)
0110	155124KU	-	-	63,000.00	63,000.00	63,000.00	63,000.00	63,000.00	63,000.00	-	-	-	-	-	29,076.92	12/31/2019	(4)	0.0105%	(0.00)
0110	155287	-	-	68,438.80	-	-	-	-	-	-	-	-	-	-	5,264.52	7/31/2019	(9)	0.0019%	(0.00)
0110	156825KU	-	-	147,448.80	147,448.80	147,448.80	147,448.80	147,448.80	147,448.80	-	-	-	-	-	68,053.29	12/1/2019	(4)	0.0246%	(0.00)
0110	156846KU	-	-	36,862.20	36,862.20	36,862.20	36,862.20	36,862.20	36,862.20	-	-	-	-	-	17,013.32	12/1/2019	(4)	0.0062%	(0.00)
0110	157118KU	-	-	27,376.65	27,376.65	27,376.65	27,376.65	27,376.65	27,376.65	-	-	-	-	-	12,635.38	12/1/2019	(4)	0.0046%	(0.00)
0110	162172	-	-	650,000.55	650,000.55	650,000.55	650,000.55	650,000.55	650,000.55	-	-	-	-	-	300,000.25	12/31/2019	(4)	0.1085%	(0.00)
0110	163034	-	-	50,159.80	-	-	-	-	-	-	-	-	-	-	3,858.45	7/31/2019	(9)	0.0014%	(0.00)
0110	163035	-	-	68,438.80	-	-	-	-	-	-	-	-	-	-	5,264.52	7/31/2019	(9)	0.0019%	(0.00)
0110	IT0403K	-	-	135,979.58	135,979.58	135,979.58	-	-	-	-	-	-	-	-	31,379.90	9/30/2019	(7)	0.0114%	(0.00)
0110	IT0445K	-	-	14,000.00	-	-	-	-	-	-	-	-	-	-	1,076.92	7/31/2019	(9)	0.0004%	(0.00)
0110	IT0533K	-	-	8,400.00	25,200.00	42,000.00	-	-	-	-	-	-	-	-	5,815.38	9/30/2019	(7)	0.0021%	(0.00)
0110	SU-000351	-	-	22,243.41	44,486.82	66,730.23	102,319.70	137,909.17	173,498.64	219,764.93	281,689.80	343,614.67	432,078.77	564,774.91	183,777.77	8/31/2020	4	0.0665%	0.00
0110	SU-000371	-	-	7,893.60	15,787.20	23,680.80	35,521.49	47,011.84	56,665.57	71,665.57	84,935.09	98,204.61	115,897.28	133,589.95	53,142.54	5/31/2020	1	0.0192%	0.00
0110	SU-000372	-	-	22,243.41	44,486.82	93,422.33	142,357.84	172,942.52	203,527.20	224,880.88	255,843.31	300,075.34	388,539.44	454,887.51	177,169.74	5/31/2020	1	0.0641%	0.00
0110	SU-000373	-	-	35,589.47	97,871.03	177,947.32	258,023.61	302,510.42	338,099.89	368,350.94	430,275.81	518,739.91	651,436.05	727,515.19	300,489.20	5/31/2020	1	0.1087%	0.00
0110	SU-000374	-	-	44,486.81	88,973.62	186,844.64	284,715.66	346,997.22	378,137.99	409,278.76	471,203.63	559,667.73	736,595.93	842,752.86	334,588.83	5/31/2020	1	0.1210%	0.00
0110	SU-000375	-	-	8,897.37	17,794.74	26,692.11	40,038.16	52,494.47	61,391.84	61,391.84	74,661.46	87,931.08	105,623.89	123,316.70	50,787.20	5/31/2020	1	0.0184%	0.00
0110	SU-000396	-	-	4,448.67	8,897.34	13,346.01	17,794.68	22,243.35	22,243.35	22,243.35	48,794.17	75,344.99	128,446.62	181,548.25	41,950.06	5/31/2020	1	0.0152%	0.00
0110	SU-000397	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,413.93	20,379.17	28,344.41	36,309.65	9,617.62	5/31/2020	1	0.0035%	0.00
0110	SU-000398	-	-	2,669.21	5,338.42	8,007.63	8,007.63	8,007.63	8,007.63	8,007.63	16,857.89	25,708.15	47,833.83	92,085.19	17,733.14	5/31/2020	1	0.0064%	0.00
0110	SU-000399	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,045.74	26,644.46	40,693.45	54,742.44	14,047.14	12/31/2020	8	0.0051%	0.00
0110	SU-000400	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,413.93	20,379.17	28,344.41	36,309.65	9,617.62	5/31/2020	1	0.0035%	0.00
0110	SU-000401	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,045.74	26,644.46	40,693.45	54,742.44	14,047.14	12/31/2020	8	0.0051%	0.00
0110	140342KU	-	-	35,176.46	35,176.46	35,176.46	35,176.46	35,176.46	35,176.46	48,903.86	48,903.86	48,903.86	48,903.86	48,903.86	35,044.47	12/31/2023	44	0.0127%	0.01
0110	115GH	-	-	-	15,519.49	15,519.49	15,519.49	15,519.49	15,519.49	-	-	-	-	-	5,969.03	12/31/2019	(4)	0.0022%	(0.00)
0110	134864	-	-	-	2,302.14	13,348.29	39,676.76	56,340.73	56,340.73	-	-	-	-	-	12,923.74	12/31/2019	(4)	0.0047%	(0.00)
0110	144083	-	-	-	5,006.70	10,013.40	15,020.10	20,026.80	25,033.50	30,040.20	69,934.99	109,829.78	-	-	21,915.81	3/31/2020	(1)	0.0079%	(0.00)
0110	144913	-	-	-	445,725.00	730,375.00	1,015,025.00	1,442,000.00	1,868,975.00	2,700,000.42	3,206,057.42	3,728,312.08	4,253,127.30	4,766,865.95	1,858,189.47	12/31/2020	8	0.6722%	0.05
0110	147250	-	-	-	68,150.00	124,709.34	158,087.34	201,479.60	-	-	-	-	-	-	42,494.33	11/30/2019	(5)	0.0154%	(0.00)
0110	147489	-	-	-	211,034.25	282,993.10	-	-	-	-	-	-	-	-	38,002.10	9/30/2019	(7)	0.0137%	(0.00)
0110	147498	-	-	-	199,461.41	276,873.89	-	-	-	-	-	-	-	-	36,641.18	9/30/2019	(7)	0.0133%	(0.00)
0110	147499	-	-	-	154,387.29	308,774.57	-	-	-	-	-	-	-	-	35,627.84	9/30/2019	(7)	0.0129%	(0.00)
0110	151507	-	-	-	71,688.79	71,688.79	71,688.79	71,688.79	71,688.79	-	-	-	-	-	27,572.61	12/31/2019	(4)	0.0100%	(0.00)
0110	152808	-	-	-	22,300.30	22,300.30	22,300.30	-	-	-	-	-	-	-	5,146.22	10/31/2019	(6)	0.0019%	(0.00)
0110	154849	-	-	-	26,047.71	26,047.71	26,047.71	26,047.71	26,047.71	-	-	-	-	-	10,018.35	12/31/2019	(4)	0.0036%	(0.00)
0110	155018	-	-	-	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	102,446.14	7/31/2020	3	0.0371%	0.00
0110	156629	-	-	-	496,495.24	496,495.24	496,495.24	996,495.25	996,495.25	1,496,495.25	1,496,495.25	1,894,002.16	1,894,002.16	1,894,002.16	935,190.25	5/31/2020	1	0.3383%	0.00
0110	156692	-	-	-	208,580.20	-	-	-	-	-	-	-	-	-	16,044.63	8/31/2019	(8)	0.0058%	(0.00)
0110	156980KU	-	-	-	18,514.80	18,514.80	18,514.80	18,514.80	18,514.80	-	-	-	-	-	7,121.08	12/1/2019	(4)	0.0026%	(0.00)
0110	157647	-	-	-	210,505.00	324,365.00	486,139.57	599,999.57	599,999.57	-	-	-	-	-	170,846.82	12/31/2019	(4)	0.0618%	(0.00)
0110	157813KU	-	-	-	542,713.50	542,713.50	-	-	-	-	-	-	-	-	83,494.38	9/30/2019	(7)	0.0302%	(0.00)
0110	163048	-	-	-	104,455.57	207,760.07	312,215.64	398,331.18	429,542.50	-	-	-	-	-	111,715.77	12/31/2019	(4)	0.0404%	(0.00)
0110	IT0294K	-	-	-	22,641.20	45,282.40	-	-	-	-	-	-	-	-	5,224.89	9/30/2019	(7)	0.0019%	(0.00)
0110	IT0428K	-	-	-	14,000.00	28,000.00	42,000.00	-	-	-	-	-	-	-	6,461.54	10/31/2019	(6)	0.0023%	(0.00)
0110	IT0458K	-	-	-	47,613.14	190,452.57	309,485.41	428,518.25	547,551.09	595,164.23	642,917.37	786,176.83	929,436.29	1,096,572.32	428,760.58	6/30/2020	2	0.1551%	0.00
0110	IT0506K	-	-	-	5,600.00	16,800.00	-	-	-	-	-	-	-	-	1,723.08	9/30/2019	(7)	0.0006%	(0.00)
0110	IT0523K	-	-	-	28,000.00	56,000.00	84,000.00	112,000.00	126,000.00	-	-	-	-	-	31,230.77	12/31/2019	(4)	0.0113%	(0.00)
0110	IT0559K	-	-	-	14,000.00	28,000.00	42,000.00	56,000.00	70,000.00	84,000.00	98,000.00	112,000.00	126,000.00	140,000.00	59,230.77	6/30/2020	2	0.0214%	0.00
0110	LI-000034	-	-	-	404,435.03	808,870.06	-	-	-	-	-	-	-	-	93,331.16	9/30/2019	(7)	0.0338%	(0.00)
0110	LI-000047	-	-	-	147,805.09	-	-	-	-	-	-	-	-	-	11,369.62	8/31/2019	(8)	0.0041%	(0.00)
0110	LI-000048	-	-	-	114,214.54	-	-	-	-	-	-	-	-	-	8,785.73	8/31/2019	(8)	0.0032%	(0.00)
0110	LI-000049	-	-	-	114,214.54	-	-	-	-	-	-	-	-	-	8,785.73	8/31/2019	(8)	0.0032%	(0.00)
0110	LI-000050	-	-	-	147,805.16	-	-	-	-	-	-	-	-	-	11,369.63	8/31/2019	(8)	0.0041%	(0.00)
0110	LI-000099	-	-	-	240,190.94	315,062.17	389,933.40	464,804.68	584,179.91	-	-	-	-	-	153,397.78	12/31/2019	(4)	0.0555%	(0.00)
0110	SU-000099	-	-	-	155,331.50	310,663.00	465,994.50	621,326.00	776,657.50	-	-	-	-	-	179,228.65	12/31/2019	(4)	0.0648%	(0.00)
0110	SU-000256	-	-	-	50,000.00	100,000.00	150,000.00	200,000.00	250,000.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0110	IT0480K	-	-	-	58,580.35	117,160.70	175,741.05	234,321.40	292,901.75	351,482.10	413,922.53	476,362.96	538,478.01	600,918.44	250,759.18	6/30/2021	14	0.0907%	0.01
0110	SU-000203	-	-	-	149,956.04	299,912.10	449,868.16	599,824.22	749,780.28	999,736.34	1,222,573.29	1,445,410.33	1,668,247.37	1,891,084.41	728,953.27	6/30/2022	26	0.2637%	0.07
0110	133622KU	-	-	-	-	45,599.42	45,599.42	45,599.42	45,599.42	-	-	-	-	-	14,030.59	12/1/2019	(4)	0.0051%	(0.00)
0110	133627KU	-	-	-	-	28,117.73	28,117.73	28,117.73	28,117.73	-	-	-	-	-	8,651.61	12/1/2019	(4)	0.0031%	(0.00)
0110	140032KU	-	-	-	-	92,462.30	92,462.30	92,462.30	92,462.30	-	-	-	-	-	28,449.94	12/31/2019	(4)	0.0103%	(0.00)
0110	140654KU	-	-	-	-	206,748.00	206,748.00	206,748.00	206,748.00	-	-	-	-	-	63,614.77	12/1/2019	(4)	0.0230%	(0.00)
0110	147764	-	-	-	-	69,941.85	-	-	-	-	-	-	-	-	5,380.14	9/30/2019	(7)	0.0019%	(0.00)
0110	150052KU	-	-	-	-	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	742,275.50	169,171.79	5/31/2020	1	0.0612%	0.00
0110	151489	-	-	-	-	31,675.45	31,675.45	31,675.45	31,675.45	-	-	-	-	-	9,746.29	12/31/2019	(4)	0.0035%	(0.00)
0110	151754	-	-	-	-	31,127.14	62,254.28	95,160.11	95,160.11	-	-	-	-	-	21,823.20	12/31/2019	(4)	0.0079%	(0.00)
0110	151766	-	-	-	-	3,569.37	172,060.91	272,149.43	357,399.62	-	-	-	-	-	61,936.87	12/31/2019	(4)	0.0224%	(0.00)
0110	152032KU	-	-	-	-	252,727.02	252,727.02	252,727.02	252,727.02	-	-	-	-	-	77,762.16	12/31/2019	(4)	0.0281%	(0.00)
0110	152118	-	-	-	-	7,584.94	365,628.59	578,317.93	759,474.61	-	-	-	-	-	131,615.85	12/31/2019	(4)	0.0476%	(0.00)
0110	152120	-	-	-	-	7,584.94	339,741.10	552,430.44	733,587.12	-	-	-	-	-	125,641.82	12/31/2019	(4)	0.0454%	(0.00)
0110	153072KU	-	-	-	-	578,894.40	-	-	-	-	-	-	-	-	44,530.34	9/30/2019	(7)	0.0161%	(0.00)
0110	153097	-	-	-	-	40,000.00	-	-	-	-	-	-	-	-	3,076.92	9/30/2019	(7)	0.0011%	(0.00)
0110	153425	-	-	-	-	1,770.20	84,657.54	133,911.11	175,844.90	-	-	-	-	-	30,475.67	12/31/2019	(4)	0.0110%	(0.00)
0110	153426	-	-	-	-	1,770.20	84,657.54	133,911.11	175,844.90	-	-	-	-	-	30,475.67	12/31/2019	(4)	0.0110%	(0.00)
0110	154792KU	-	-	-	-	434,894.42	434,894.42	434,894.42	434,894.42	434,894.42	434,894.42	-	-	-	200,720.50	2/28/2020	(2)	0.0726%	(0.00)
0110	155017	-	-	-	-	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	4,560,239.71	4,560,239.71	922,228.57	5/31/2020	1	0.3336%	0.00
0110	156697	-	-	-	-	457,997.41	915,994.82	-	-	-	-	-	-	-	105,691.71	10/31/2019	(6)	0.0382%	(0.00)
0110	157711	-	-	-	-	108,286.78	216,573.55	-	-	-	-	-	-	-	24,989.26	10/31/2019	(6)	0.0090%	(0.00)
0110	157779KU	-	-	-	-	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	759,046.95	759,046.95	267,066.35	5/31/2020	1	0.0966%	0.00
0110	220GH	-	-	-	-	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	2,448,056.14	4,472,668.40	7,509,586.80	1,772,677.80	5/31/2020	1	0.6412%	0.01

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	48GH	-	-	-	-	82,222.59	128,057.68	-	-	-	-	-	-	-	16,175.41	10/31/2019	(6)	0.0059%	(0.00)
0110	IT0417K	-	-	-	-	36,000.00	36,000.00	-	-	-	-	-	-	-	5,538.46	10/31/2019	(6)	0.0020%	(0.00)
0110	IT0438K	-	-	-	-	33,600.00	-	-	-	-	-	-	-	-	2,584.62	9/30/2019	(7)	0.0009%	(0.00)
0110	LI-000065	-	-	-	-	137,057.54	274,115.08	-	-	-	-	-	-	-	31,628.66	10/31/2019	(6)	0.0114%	(0.00)
0110	SU-000052	-	-	-	-	8,897.37	17,794.74	26,692.11	35,589.48	40,038.15	62,163.83	106,415.19	172,792.23	327,671.98	61,388.85	5/31/2020	1	0.0222%	0.00
0110	SU-000055	-	-	-	-	33,703.32	67,406.64	101,109.96	134,813.28	186,516.60	304,270.70	422,024.80	657,532.98	893,041.16	215,416.88	7/31/2020	3	0.0779%	0.00
0110	SU-000070	-	-	-	-	22,243.41	66,730.22	111,217.03	155,703.84	177,947.25	200,072.93	244,324.29	332,827.01	421,329.73	133,261.21	12/31/2020	8	0.0482%	0.00
0110	SU-000378	-	-	-	-	8,897.37	17,794.74	26,692.11	33,810.01	33,810.01	42,656.42	51,502.83	64,772.45	82,465.26	27,877.02	7/31/2020	3	0.0101%	0.00
0110	147818	-	-	-	-	178,181.38	362,370.88	546,560.38	730,749.88	914,939.38	914,939.38	914,939.38	914,939.38	914,939.38	491,735.34	12/31/2030	128	0.1779%	0.23
0110	00034FACK	-	-	-	-	-	131,749.93	292,692.98	453,636.03	-	-	-	-	-	67,544.53	12/31/2019	(4)	0.0244%	(0.00)
0110	133653KU	-	-	-	-	-	28,942.42	28,942.42	28,942.42	-	-	-	-	-	6,679.02	12/1/2019	(4)	0.0024%	(0.00)
0110	140619KU	-	-	-	-	-	65,608.03	65,608.03	65,608.03	-	-	-	-	-	15,140.31	12/1/2019	(4)	0.0055%	(0.00)
0110	144456	-	-	-	-	-	104,788.46	159,407.12	-	-	-	-	-	-	20,322.74	11/30/2019	(5)	0.0074%	(0.00)
0110	147228	-	-	-	-	-	29,615.22	59,230.44	88,845.66	133,460.88	284,496.69	435,532.50	586,568.31	-	124,442.28	4/30/2020	-	0.0450%	-
0110	147734	-	-	-	-	-	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	43,041.14	7/31/2020	3	0.0156%	0.00
0110	151006KU	-	-	-	-	-	414,916.67	-	-	-	-	-	-	-	31,916.67	10/31/2019	(6)	0.0115%	(0.00)
0110	151515	-	-	-	-	-	17,079.00	30,612.40	41,998.40	-	-	-	-	-	6,899.22	12/31/2019	(4)	0.0025%	(0.00)
0110	152007KU	-	-	-	-	-	72,361.80	72,361.80	72,361.80	-	-	-	-	-	16,698.88	12/31/2019	(4)	0.0060%	(0.00)
0110	152016KU	-	-	-	-	-	165,708.52	165,708.52	165,708.52	-	-	-	-	-	38,240.43	12/31/2019	(4)	0.0138%	(0.00)
0110	152097KU	-	-	-	-	-	60,822.63	60,822.63	60,822.63	-	-	-	-	-	14,035.99	12/31/2019	(4)	0.0051%	(0.00)
0110	152704	-	-	-	-	-	49,973.26	99,946.52	149,919.78	199,893.04	450,976.26	702,059.49	953,142.72	1,204,225.95	293,087.46	12/31/2020	8	0.1060%	0.01
0110	153047KU	-	-	-	-	-	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	486,040.88	93,746.47	5/31/2020	1	0.0339%	0.00
0110	153070KU	-	-	-	-	-	130,251.24	130,251.24	130,251.24	-	-	-	-	-	30,057.98	12/1/2019	(4)	0.0109%	(0.00)
0110	155443KU	-	-	-	-	-	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	482,407.98	7/31/2020	3	0.1745%	0.01
0110	156698	-	-	-	-	-	1,427,226.45	1,849,529.59	2,271,832.73	-	-	-	-	-	426,814.52	12/31/2019	(4)	0.1544%	(0.01)
0110	157115KU	-	-	-	-	-	74,059.20	74,059.20	74,059.20	-	-	-	-	-	17,090.58	12/1/2019	(4)	0.0062%	(0.00)
0110	157253	-	-	-	-	-	53,984.20	80,899.20	91,185.20	-	-	-	-	-	17,389.89	12/31/2019	(4)	0.0063%	(0.00)
0110	157297KU	-	-	-	-	-	144,723.60	144,723.60	144,723.60	-	-	-	-	-	33,397.75	12/1/2019	(4)	0.0121%	(0.00)
0110	IT0419K	-	-	-	-	-	4,800.00	12,000.00	19,200.00	24,000.00	28,800.00	33,600.00	38,400.00	43,200.00	15,692.31	10/31/2020	6	0.0057%	0.00
0110	IT0463K	-	-	-	-	-	27,696.75	55,393.50	83,090.25	-	-	-	-	-	12,783.12	12/31/2019	(4)	0.0046%	(0.00)
0110	LI-000036	-	-	-	-	-	1,157,305.11	2,314,610.30	3,471,915.49	-	-	-	-	-	534,140.84	12/31/2019	(4)	0.1932%	(0.01)
0110	LI-000072	-	-	-	-	-	63,197.98	126,395.96	189,593.94	-	-	-	-	-	29,168.30	12/31/2019	(4)	0.0106%	(0.00)
0110	SU-000343	-	-	-	-	-	6,673.02	13,346.04	20,019.06	26,692.08	77,293.55	127,895.02	178,496.49	229,097.96	52,270.25	5/31/2020	1	0.0189%	0.00
0110	SU-000349	-	-	-	-	-	48,713.08	97,426.16	146,139.24	194,852.32	243,507.58	292,162.84	358,510.91	424,858.98	138,936.24	11/30/2020	7	0.0503%	0.00
0110	127111	-	-	-	-	-	74,961.43	149,922.86	224,884.29	299,845.72	465,703.39	631,561.15	797,418.91	963,276.67	277,505.72	12/31/2021	20	0.1004%	0.02
0110	148854	-	-	-	-	-	49,983.61	99,967.24	149,950.87	199,934.50	299,683.50	399,432.50	499,181.50	598,930.50	176,697.25	12/31/2021	20	0.0639%	0.01
0110	157443	-	-	-	-	-	24,862.32	49,724.64	74,586.96	99,449.28	124,097.85	148,746.42	173,394.99	198,043.56	68,685.08	12/31/2022	32	0.0248%	0.01
0110	158028	-	-	-	-	-	5,000.00	20,000.00	40,000.00	50,000.00	100,000.00	150,000.00	250,000.00	350,000.00	74,230.77	12/31/2022	32	0.0269%	0.01
0110	158030	-	-	-	-	-	5,000.00	20,000.00	40,000.00	50,000.00	100,000.00	150,000.00	200,000.00	250,000.00	62,692.31	12/31/2022	32	0.0227%	0.01
0110	00066FACK	-	-	-	-	-	-	228,071.25	430,801.25	-	-	-	-	-	50,682.50	12/31/2019	(4)	0.0183%	(0.00)
0110	135113	-	-	-	-	-	-	81,996.40	163,992.80	-	-	-	-	-	18,922.25	12/31/2019	(4)	0.0068%	(0.00)
0110	135117	-	-	-	-	-	-	340,859.31	681,718.62	-	-	-	-	-	78,659.84	12/31/2019	(4)	0.0285%	(0.00)
0110	137104	-	-	-	-	-	-	156,528.51	-	-	-	-	-	-	12,040.65	11/30/2019	(5)	0.0044%	(0.00)
0110	137165	-	-	-	-	-	-	46,616.94	93,233.88	-	-	-	-	-	10,757.76	12/31/2019	(4)	0.0039%	(0.00)
0110	137190	-	-	-	-	-	-	837,553.75	1,675,107.50	-	-	-	-	-	193,281.63	12/31/2019	(4)	0.0699%	(0.00)
0110	140216	-	-	-	-	-	-	696,082.44	-	-	-	-	-	-	53,544.80	11/30/2019	(5)	0.0194%	(0.00)
0110	140217	-	-	-	-	-	-	648,974.47	-	-	-	-	-	-	49,921.11	11/30/2019	(5)	0.0181%	(0.00)
0110	140218	-	-	-	-	-	-	226,097.65	-	-	-	-	-	-	17,392.13	11/30/2019	(5)	0.0063%	(0.00)
0110	144325	-	-	-	-	-	-	798,130.78	798,130.78	798,130.78	798,130.78	798,130.78	1,377,563.21	2,138,029.24	577,403.57	5/31/2020	1	0.2089%	0.00
0110	144327	-	-	-	-	-	-	798,130.80	798,130.80	798,130.80	798,130.80	798,130.80	-	-	306,973.38	3/31/2020	(1)	0.1110%	(0.00)
0110	144725	-	-	-	-	-	-	141,843.70	283,687.40	-	-	-	-	-	32,733.16	12/31/2019	(4)	0.0118%	(0.00)
0110	144727	-	-	-	-	-	-	154,649.80	309,299.60	-	-	-	-	-	35,688.42	12/31/2019	(4)	0.0129%	(0.00)
0110	144728	-	-	-	-	-	-	186,296.20	372,592.40	-	-	-	-	-	42,991.43	12/31/2019	(4)	0.0156%	(0.00)
0110	145803	-	-	-	-	-	-	33,292.57	66,585.13	99,877.69	708,087.34	1,316,296.94	1,924,506.54	2,532,716.14	513,950.95	6/30/2020	2	0.1859%	0.00
0110	147500	-	-	-	-	-	-	195,782.41	269,471.39	-	-	-	-	-	35,788.75	12/31/2019	(4)	0.0129%	(0.00)
0110	147501	-	-	-	-	-	-	195,782.41	269,471.39	-	-	-	-	-	35,788.75	12/31/2019	(4)	0.0129%	(0.00)
0110	147531	-	-	-	-	-	-	215,613.89	326,873.89	-	-	-	-	-	41,729.83	12/31/2019	(4)	0.0151%	(0.00)
0110	147918	-	-	-	-	-	-	30,945.83	61,891.66	-	-	-	-	-	7,141.35	12/31/2019	(4)	0.0026%	(0.00)
0110	147930	-	-	-	-	-	-	84,550.75	169,101.50	-	-	-	-	-	19,511.71	12/31/2019	(4)	0.0071%	(0.00)
0110	147993	-	-	-	-	-	-	51,912.13	103,824.26	-	-	-	-	-	11,979.72	12/31/2019	(4)	0.0043%	(0.00)
0110	148006	-	-	-	-	-	-	41,375.38	82,750.76	-	-	-	-	-	9,548.16	12/31/2019	(4)	0.0035%	(0.00)
0110	151608	-	-	-	-	-	-	24,992.72	49,985.43	74,978.14	274,266.19	473,554.24	672,842.29	-	120,816.85	4/30/2020	-	0.0437%	-
0110	151998	-	-	-	-	-	-	227,148.60	454,297.20	-	-	-	-	-	52,418.91	12/31/2019	(4)	0.0190%	(0.00)
0110	152015KU	-	-	-	-	-	-	166,070.33	166,070.33	-	-	-	-	-	25,549.28	12/31/2019	(4)	0.0092%	(0.00)
0110	152055 KU	-	-	-	-	-	-	238,098.40	238,098.40	238,098.40	238,098.40	238,098.40	238,098.40	-	109,891.57	4/30/2020	-	0.0398%	-
0110	152772 KU	-	-	-	-	-	-	294,221.60	294,221.60	294,221.60	294,221.60	294,221.60	294,221.60	-	135,794.58	4/30/2020	-	0.0491%	-
0110	152981	-	-	-	-	-	-	80,521.31	80,521.31	-	-	-	-	-	12,387.89	12/31/2019	(4)	0.0045%	(0.00)
0110	153080KU	-	-	-	-	-	-	629,199.63	629,199.63	629,199.63	629,199.63	629,199.63	1,137,069.63	2,145,350.71	494,493.73	5/30/2020	1	0.1789%	0.00
0110	153458	-	-	-	-	-	-	49,246.33	98,492.66	-	-	-	-	-	11,364.54	12/31/2019	(4)	0.0041%	(0.00)
0110	154917	-	-	-	-	-	-	26,658.65	26,658.65	26,658.65	26,658.65	26,658.65	26,658.65	-	12,303.99	4/30/2020	-	0.0045%	-
0110	154989	-	-	-	-	-	-	128,057.67	128,057.67	128,057.67	128,057.67	128,057.67	-	-	49,252.95	3/31/2020	(1)	0.0178%	(0.00)
0110	155002	-	-	-	-	-	-	837,880.00	-	-	-	-	-	-	64,452.31	11/30/2019	(5)	0.0233%	(0.00)
0110	155014	-	-	-	-	-	-	86,145.00	86,145.00	86,145.00	86,145.00	131,289.00	707,305.00	707,305.00	145,421.46	5/31/2020	1	0.0526%	0.00
0110	155085	-	-	-	-	-	-	31,835.10	63,670.20	-	-	-	-	-	7,346.56	12/31/2019	(4)	0.0027%	(0.00)
0110	155086	-	-	-	-	-	-	21,214.83	42,429.66	-	-	-	-	-	4,895.73	12/31/2019	(4)	0.0018%	(0.00)
0110	155087	-	-	-	-	-	-	33,120.85	66,241.70	-	-	-	-	-	7,643.27	12/31/2019	(4)	0.0028%	(0.00)
0110	155088	-	-	-	-	-	-	69,250.35	138,500.70	-	-	-	-	-	15,980.85	12/31/2019	(4)	0.0058%	(0.00)
0110	155089	-	-	-	-	-	-	110,428.55	220,857.10	-	-	-	-	-	25,483.51	12/31/2019	(4)	0.0092%	(0.00)
0110	155090	-	-	-	-	-	-	23,818.48	47,636.96	-	-	-	-	-	5,496.57	12/31/2019	(4)	0.0020%	(0.00)
0110	155091	-	-	-	-	-	-	16,395.43	32,790.86	-	-	-	-	-	3,783.56	12/31/2019	(4)	0.0014%	(0.00)
0110	155092	-	-	-	-	-	-	32,658.00	65,316.00	-	-	-	-	-	7,536.46	12/31/2019	(4)	0.0027%	(0.00)
0110	155093	-	-	-	-	-	-	23,726.33	47,452.66	-	-	-	-	-	5,475.31	12/31/2019	(4)	0.0020%	(0.00)
0110	155094	-	-	-	-	-	-	268,969.70	537,939.40	-	-	-	-	-	62,069.93	12/31/2019	(4)	0.0225%	(0.00)
0110	156694	-	-	-	-	-	-	574,472.64	1,049,783.89	-	-	-	-	-	124,942.81	12/31/2019	(4)	0.0452%	(0.00)
0110	157202	-	-	-	-	-	-	14,755.70	30,178.96	50,035.00	142,577.35	335,960.88	529,344.41	610,893.94	131,826.63	8/31/2020	4	0.0477%	0.00
0110	157203	-	-	-	-	-	-	16,678.33	33,356.67	50,035.01	399,566.00	488,151.01	576,736.02	665,321.03	171,526.47	8/31/2020	4	0.0620%	0.00
0110	157204	-	-	-	-	-	-	4,293.20	13,547.16	25,017.50	115,270.15	214,057.95	312,845.75	411,633.55	84,358.87	5/31/2020	1	0.0305%	0.00
0110	157205	-	-	-	-	-	-	30,401.46	60,802.92	100,069.99	740,075.25	858,188.58	976,301.91	1,094,415.24	296,942.72	12/31/2020	8	0.1074%	0.01
0110	157206	-	-	-	-	-	-	7,600.37	15,200.74	25,017.49	243,207.64	318,498.79	393,789.94	-	77,178.07	4/30/2020	-	0.0279%	-
0110	157210	-	-	-	-	-	-	22,801.10	45,602.20	75,052.47	581,928.05	684,958.69	787,989.33	891,019.97	237,642.45	9/30/2020	5	0.0860%	0.00
0110	157215	-	-	-	-	-	-	16,678.33	33,356.67	50,035.01	175,898.00	376,317.01	576,736.02	665,321.03	145,718.62	8/31/2020	4	0.0527%	0.00
0110	157252	-	-	-	-	-	-	374,307.20	748,614.40	-	-	-	-	-	86,378.58	12/31/2019	(4)	0.0312%	(0.00)
0110	157309	-	-	-	-	-	-	25,000.31	50,000.63	75,000.95	187,360.09	299,719.31	412,078.53	524,437.75	121,045.97	6/30/2020	2	0.0438%	0.00
0110	157373	-	-	-	-	-	-	10,053.27	20,106.54	-	-	-	-	-	2,319.99	12/31/2019	(4)	0.0008%	(0.00)
0110	157402	-	-	-	-	-	-	60,970.20	121,940.40	-	-	-	-	-	14,070.05	12/31/2019	(4)	0.0051%	(0.00)
0110	157404	-	-	-	-	-	-	69,910.40	139,820.80	-	-	-	-	-	16,133.17	12/31/2019	(4)	0.0058%	(0.00)
0110	157462	-	-	-	-	-	-	120,346.00	240,692.00	-	-	-	-	-	27,772.15	12/31/2019	(4)	0.0100%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	157635	-	-	-	-	-	-	265,836.22	531,672.45	797,508.68	1,418,731.42	2,039,954.14	2,661,176.86	3,282,399.58	845,944.57	6/30/2020	2	0.3060%	0.01
0110	157636	-	-	-	-	-	-	203,348.04	406,696.08	610,044.12	819,947.20	1,029,850.24	1,239,753.28	1,894,696.30	477,256.56	8/31/2020	4	0.1726%	0.01
0110	157639	-	-	-	-	-	-	151,250.06	302,500.11	453,750.16	923,283.62	1,392,817.08	1,862,350.54	2,331,884.00	570,602.74	10/31/2020	6	0.2064%	0.01
0110	157641	-	-	-	-	-	-	130,009.92	260,019.84	390,029.76	704,059.10	1,018,088.49	1,332,117.88	1,646,147.27	421,574.79	8/31/2020	4	0.1525%	0.01
0110	157660	-	-	-	-	-	-	16,667.15	33,334.31	50,001.47	321,777.78	593,554.09	865,330.40	-	144,666.55	4/30/2020	-	0.0523%	-
0110	188GH	-	-	-	-	-	-	256,115.36	-	-	-	-	-	-	19,701.18	11/30/2019	(5)	0.0071%	(0.00)
0110	209GH	-	-	-	-	-	-	51,265.13	-	-	-	-	-	-	3,943.47	11/30/2019	(5)	0.0014%	(0.00)
0110	LI-000094	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	189,825.80	329,719.79	469,613.78	609,507.77	130,656.21	5/31/2020	1	0.0473%	0.00
0110	LI-000095	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	159,847.04	269,762.27	379,677.50	489,592.73	107,595.63	5/31/2020	1	0.0389%	0.00
0110	LI-000096	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	189,825.80	329,719.79	469,613.78	609,507.77	130,656.21	5/31/2020	1	0.0473%	0.00
0110	LI-000098	-	-	-	-	-	-	7,600.37	15,200.74	25,017.49	243,207.64	318,498.79	393,789.94	-	77,178.07	4/30/2020	-	0.0279%	-
0110	SU-000053	-	-	-	-	-	-	8,897.37	17,794.74	26,692.11	39,967.51	62,093.19	106,344.55	222,283.12	37,236.35	5/31/2020	1	0.0135%	0.00
0110	157209	-	-	-	-	-	-	7,600.37	15,200.74	25,017.49	50,178.56	75,339.63	100,500.70	125,661.77	30,730.71	3/31/2021	11	0.0111%	0.00
0110	157211	-	-	-	-	-	-	45,602.20	91,204.40	150,104.97	323,626.51	354,249.15	384,871.79	415,494.43	135,781.03	12/31/2022	32	0.0491%	0.02
0110	140199	-	-	-	-	-	-	-	205,720.00	205,720.00	205,720.00	705,720.01	868,579.57	1,130,324.47	255,521.85	5/31/2020	1	0.0924%	0.00
0110	151363	-	-	-	-	-	-	-	459,440.00	459,440.00	459,440.00	459,440.00	-	-	141,366.15	3/31/2020	(1)	0.0511%	(0.00)
0110	152387	-	-	-	-	-	-	-	250,371.55	500,033.55	500,033.55	500,033.55	902,756.70	1,358,899.20	308,625.24	12/31/2020	8	0.1116%	0.01
0110	156850KU	-	-	-	-	-	-	-	95,841.72	-	-	-	-	-	7,372.44	12/31/2019	(4)	0.0027%	(0.00)
0110	157315	-	-	-	-	-	-	-	75,000.97	75,000.97	177,243.46	279,486.01	381,728.56	483,971.11	113,263.93	6/30/2020	2	0.0410%	0.00
0110	157942	-	-	-	-	-	-	-	180,330.20	180,330.20	180,330.20	180,330.20	338,120.20	-	81,495.46	4/30/2020	-	0.0295%	-
0110	131978	-	-	-	-	-	-	-	459,440.00	459,440.00	459,440.00	877,022.00	1,294,604.00	1,712,186.00	404,779.38	5/31/2021	13	0.1464%	0.02
0110	144312	-	-	-	-	-	-	-	287,150.00	287,150.00	287,150.00	287,150.00	287,150.00	287,150.00	132,530.77	4/30/2021	12	0.0479%	0.01
0110	140283	-	-	-	-	-	-	-	-	-	7,660.99	15,321.97	22,982.96	30,643.95	5,893.07	12/31/2020	8	0.0021%	0.00
0110	144309	-	-	-	-	-	-	-	-	-	1,000.00	2,000.00	103,523.07	176,062.45	21,737.35	5/31/2020	1	0.0079%	0.00
0110	149093	-	-	-	-	-	-	-	-	-	36,206.60	73,681.80	116,231.40	151,299.40	29,032.25	8/31/2020	4	0.0105%	0.00
0110	151764	-	-	-	-	-	-	-	-	-	19,916.09	39,832.18	59,748.27	-	9,192.04	4/30/2020	-	0.0033%	-
0110	152613	-	-	-	-	-	-	-	-	-	(530.87)	(1,061.70)	(1,592.53)	-	(245.01)	4/30/2020	-	-0.0001%	-
0110	152950	-	-	-	-	-	-	-	-	-	71,495.56	132,675.50	191,195.44	198,562.58	45,686.85	12/31/2020	8	0.0165%	0.00
0110	154950	-	-	-	-	-	-	-	-	-	44,251.60	44,251.60	44,251.60	44,251.60	13,615.88	5/31/2020	1	0.0049%	0.00
0110	154951	-	-	-	-	-	-	-	-	-	90,938.60	90,938.60	90,938.60	90,938.60	27,981.11	5/31/2020	1	0.0101%	0.00
0110	157022	-	-	-	-	-	-	-	-	-	22,874.94	28,957.94	43,686.66	51,038.26	11,273.68	12/31/2020	8	0.0041%	0.00
0110	157023	-	-	-	-	-	-	-	-	-	4,073.11	54,817.11	68,239.66	68,239.66	15,028.43	12/31/2020	8	0.0054%	0.00
0110	157025	-	-	-	-	-	-	-	-	-	2,036.55	26,888.55	26,888.55	26,888.55	6,361.71	12/31/2020	8	0.0023%	0.00
0110	157029	-	-	-	-	-	-	-	-	-	24,379.79	31,075.22	98,413.85	115,437.92	20,715.91	12/31/2020	8	0.0075%	0.00
0110	157055	-	-	-	-	-	-	-	-	-	20,363.26	38,476.36	69,021.25	69,021.25	15,144.78	12/31/2020	8	0.0055%	0.00
0110	157063	-	-	-	-	-	-	-	-	-	4,430.63	4,430.63	8,020.77	19,988.74	2,836.21	12/31/2020	8	0.0010%	0.00
0110	157261	-	-	-	-	-	-	-	-	-	134,348.54	329,281.62	389,866.16	-	65,653.56	4/30/2020	-	0.0237%	-
0110	157898	-	-	-	-	-	-	-	-	-	4,666.74	9,333.40	14,000.06	18,666.72	3,589.76	12/31/2020	8	0.0013%	0.00
0110	163047	-	-	-	-	-	-	-	-	-	28,465.00	110,767.00	-	-	10,710.15	3/31/2020	(1)	0.0039%	(0.00)
0110	IT0302K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	148,800.00	292,800.00	34,523.08	11/30/2020	7	0.0125%	0.00
0110	IT0306K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	196,800.00	388,800.00	45,600.00	12/31/2020	8	0.0165%	0.00
0110	IT0612K	-	-	-	-	-	-	-	-	-	10,560.00	21,120.00	31,680.00	42,240.00	8,123.08	12/31/2020	8	0.0029%	0.00
0110	IT0615K	-	-	-	-	-	-	-	-	-	18,145.21	38,200.43	58,255.65	78,310.87	14,839.40	12/31/2020	8	0.0054%	0.00
0110	IT0627K	-	-	-	-	-	-	-	-	-	2,990.58	5,981.16	8,971.74	11,962.32	2,300.45	12/31/2020	8	0.0008%	0.00
0110	IT0636K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	14,400.00	26,400.00	3,692.31	11/30/2020	7	0.0013%	0.00
0110	IT0652K	-	-	-	-	-	-	-	-	-	5,000.00	10,000.00	35,000.00	85,000.00	10,384.62	9/30/2020	5	0.0038%	0.00
0110	IT0671K	-	-	-	-	-	-	-	-	-	124,824.98	249,649.96	374,474.94	499,299.92	96,019.22	11/30/2020	7	0.0347%	0.00
0110	IT0693K	-	-	-	-	-	-	-	-	-	6,000.00	12,000.00	18,000.00	24,000.00	4,615.38	12/31/2020	8	0.0017%	0.00
0110	IT0705K	-	-	-	-	-	-	-	-	-	5,990.08	11,980.16	17,970.24	23,960.32	4,607.75	12/31/2020	8	0.0017%	0.00
0110	IT0904K	-	-	-	-	-	-	-	-	-	11,892.11	23,784.45	35,676.79	-	5,488.72	4/30/2020	-	0.0020%	-
0110	SU-000088	-	-	-	-	-	-	-	-	-	19,583.33	39,166.66	58,749.99	78,333.32	15,064.10	12/31/2020	8	0.0054%	0.00
0110	SU-000089	-	-	-	-	-	-	-	-	-	12,916.67	25,833.34	38,750.01	51,666.68	9,935.90	12/31/2020	8	0.0036%	0.00
0110	SU-000191	-	-	-	-	-	-	-	-	-	6,195.19	12,390.38	16,262.38	20,134.38	4,229.41	6/30/2020	2	0.0015%	0.00
0110	SU-000220	-	-	-	-	-	-	-	-	-	7,384.78	14,769.56	22,154.34	29,539.12	5,680.60	12/31/2020	8	0.0021%	0.00
0110	SU-000221	-	-	-	-	-	-	-	-	-	9,211.94	18,423.88	27,635.82	36,847.76	7,086.11	12/31/2020	8	0.0026%	0.00
0110	SU-000222	-	-	-	-	-	-	-	-	-	7,384.78	14,769.56	22,154.34	29,539.12	5,680.60	12/31/2020	8	0.0021%	0.00
0110	SU-000223	-	-	-	-	-	-	-	-	-	8,069.98	16,139.96	24,209.94	32,279.92	6,207.68	12/31/2020	8	0.0022%	0.00
0110	SU-000224	-	-	-	-	-	-	-	-	-	8,069.98	16,139.96	24,209.94	32,279.92	6,207.68	12/31/2020	8	0.0022%	0.00
0110	SU-000241	-	-	-	-	-	-	-	-	-	8,450.61	16,901.22	25,351.83	33,802.44	6,500.47	12/31/2020	8	0.0024%	0.00
0110	SU-000320	-	-	-	-	-	-	-	-	-	5,410.15	10,820.30	16,230.45	21,640.60	4,161.65	12/31/2020	8	0.0015%	0.00
0110	SU-000321	-	-	-	-	-	-	-	-	-	5,410.15	10,820.30	16,230.45	21,640.60	4,161.65	12/31/2020	8	0.0015%	0.00
0110	SU-000326	-	-	-	-	-	-	-	-	-	13,525.38	27,050.76	40,576.14	54,101.52	10,404.14	12/31/2020	8	0.0038%	0.00
0110	137807	-	-	-	-	-	-	-	-	-	6,254.47	12,508.88	18,763.29	25,017.70	4,811.10	12/31/2021	20	0.0017%	0.00
0110	151763	-	-	-	-	-	-	-	-	-	22,011.00	44,022.00	66,033.00	88,044.00	16,931.54	12/31/2021	20	0.0061%	0.00
0110	157216	-	-	-	-	-	-	-	-	-	12,813.67	25,627.29	38,440.91	51,254.53	9,856.65	12/31/2030	128	0.0036%	0.00
0110	IT0609K	-	-	-	-	-	-	-	-	-	13,960.10	41,880.33	125,640.96	167,521.28	26,846.36	7/31/2021	15	0.0097%	0.00
0110	SU-000322	-	-	-	-	-	-	-	-	-	79,101.49	133,202.98	187,304.47	241,405.96	49,308.84	12/31/2021	20	0.0178%	0.00
0110	140184	-	-	-	-	-	-	-	-	-	-	62,799.52	114,951.85	177,751.37	27,346.36	11/30/2020	7	0.0099%	0.00
0110	142GH	-	-	-	-	-	-	-	-	-	-	15,430.71	-	-	1,186.98	3/31/2020	(1)	0.0004%	(0.00)
0110	144975	-	-	-	-	-	-	-	-	-	-	153,295.34	306,590.69	459,886.04	70,751.70	6/30/2020	2	0.0256%	0.00
0110	147347	-	-	-	-	-	-	-	-	-	-	102,376.63	255,941.58	320,229.08	52,195.95	5/31/2020	1	0.0189%	0.00
0110	149166	-	-	-	-	-	-	-	-	-	-	34,000.07	83,204.89	98,713.74	16,609.13	12/31/2020	8	0.0060%	0.00
0110	151437	-	-	-	-	-	-	-	-	-	-	106,471.70	106,471.70	106,471.70	24,570.39	5/31/2020	1	0.0089%	0.00
0110	153025	-	-	-	-	-	-	-	-	-	-	41,559.65	83,119.30	124,678.95	19,181.38	12/31/2020	8	0.0069%	0.00
0110	154961	-	-	-	-	-	-	-	-	-	-	97,750.53	97,750.53	97,750.53	22,557.81	5/31/2020	1	0.0082%	0.00
0110	156838KU	-	-	-	-	-	-	-	-	-	-	184,311.00	184,311.00	184,311.00	42,533.31	12/1/2020	8	0.0154%	0.00
0110	157010	-	-	-	-	-	-	-	-	-	-	9,680.84	14,755.24	17,926.74	3,258.68	12/31/2020	8	0.0012%	0.00
0110	157013	-	-	-	-	-	-	-	-	-	-	2,215.31	11,138.45	13,415.65	2,059.19	12/31/2020	8	0.0007%	0.00
0110	157016	-	-	-	-	-	-	-	-	-	-	30,875.39	35,110.18	35,110.18	7,776.60	12/31/2020	8	0.0028%	0.00
0110	157024	-	-	-	-	-	-	-	-	-	-	25,860.60	36,406.82	36,406.82	7,590.33	12/31/2020	8	0.0027%	0.00
0110	157028	-	-	-	-	-	-	-	-	-	-	54,377.48	54,377.48	60,486.00	13,018.54	12/31/2020	8	0.0047%	0.00
0110	157054	-	-	-	-	-	-	-	-	-	-	4,546.36	6,936.76	63,559.43	5,772.50	12/31/2020	8	0.0021%	0.00
0110	157058	-	-	-	-	-	-	-	-	-	-	22,673.40	26,746.51	26,746.51	5,858.96	12/31/2020	8	0.0021%	0.00
0110	157061	-	-	-	-	-	-	-	-	-	-	6,175.70	12,351.40	12,351.40	2,375.27	12/31/2020	8	0.0009%	0.00
0110	IT0514K	-	-	-	-	-	-	-	-	-	-	9,600.00	19,200.00	38,400.00	5,169.23	12/31/2020	8	0.0019%	0.00
0110	IT0606K	-	-	-	-	-	-	-	-	-	-	2,400.00	7,200.00	14,400.00	1,846.15	11/30/2020	7	0.0007%	0.00
0110	IT0613K	-	-	-	-	-	-	-	-	-	-	13,488.00	26,976.00	40,464.00	6,225.23	11/30/2020	7	0.0023%	0.00
0110	IT0614K	-	-	-	-	-	-	-	-	-	-	4,868.64	9,737.28	14,605.92	2,247.06	8/31/2020	4	0.0008%	0.00
0110	IT0618K	-	-	-	-	-	-	-	-	-	-	10,800.00	21,600.00	43,200.00	5,815.38	12/31/2020	8	0.0021%	0.00
0110	IT0644K	-	-	-	-	-	-	-	-	-	-	2,160.00	7,200.00	12,240.00	1,661.54	11/30/2020	7	0.0006%	0.00
0110	IT0647K	-	-	-	-	-	-	-	-	-	-	2,880.00	10,080.00	17,280.00	2,326.15	11/30/2020	7	0.0008%	0.00
0110	IT0649K	-	-	-	-	-	-	-	-	-	-	4,800.00	14,400.00	28,800.00	3,692.31	11/30/2020	7	0.0013%	0.00
0110	IT0651K	-	-	-	-	-	-	-	-	-	-	9,600.00	9,600.00	19,200.00	2,953.85	10/31/2020	6	0.0011%	0.00
0110	IT0672K	-	-	-	-	-	-	-	-	-	-	1,440.00	4,800.00	8,160.00	1,107.69	11/30/2020	7	0.0004%	0.00
0110	IT0675K	-	-	-	-	-	-	-	-	-	-	4,320.00	14,400.00	28,800.00	3,655.38	11/30/2020	7	0.0013%	0.00
0110	IT0680K	-	-	-	-	-	-	-	-	-	-	2,734.75	5,925.29	26,435.95	2,699.69	12/31/2020	8	0.0010%	0.00
0110	IT0689K	-	-	-	-	-	-	-	-	-	-	8,400.00	16,800.00	25,200.00	3,876.92	6/30/2020	2	0.0014%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	IT0690K	-	-	-	-	-	-	-	-	-	-	16,800.00	33,600.00	50,400.00	7,753.85	11/30/2020	7	0.0028%	0.00
0110	IT0695K	-	-	-	-	-	-	-	-	-	-	3,840.00	7,680.00	11,520.00	1,772.31	11/30/2020	7	0.0006%	0.00
0110	IT0701K	-	-	-	-	-	-	-	-	-	-	14,000.00	28,000.00	42,000.00	6,461.54	11/30/2020	7	0.0023%	0.00
0110	IT0711K	-	-	-	-	-	-	-	-	-	-	12,000.00	24,000.00	36,000.00	5,538.46	11/30/2020	7	0.0020%	0.00
0110	IT0712K	-	-	-	-	-	-	-	-	-	-	5,600.00	11,200.00	16,800.00	2,584.62	11/30/2020	7	0.0009%	0.00
0110	IT0722K	-	-	-	-	-	-	-	-	-	-	9,600.00	19,200.00	28,800.00	4,430.77	11/30/2020	7	0.0016%	0.00
0110	IT1087K	-	-	-	-	-	-	-	-	-	-	23,737.91	47,475.82	71,213.73	10,955.96	12/31/2020	8	0.0040%	0.00
0110	138485	-	-	-	-	-	-	-	-	-	-	5,121.09	12,802.74	20,484.39	2,954.48	12/31/2021	20	0.0011%	0.00
0110	00051FACK	-	-	-	-	-	-	-	-	-	-	-	25,341.25	25,341.25	3,898.65	9/30/2020	5	0.0014%	0.00
0110	00100FACK	-	-	-	-	-	-	-	-	-	-	-	8,535.15	17,070.30	1,969.65	8/31/2020	4	0.0007%	0.00
0110	101GH	-	-	-	-	-	-	-	-	-	-	-	75,922.97	151,845.94	17,520.69	10/31/2020	6	0.0063%	0.00
0110	126072	-	-	-	-	-	-	-	-	-	-	-	17,257.60	-	1,327.51	4/30/2020	-	0.0005%	-
0110	135116	-	-	-	-	-	-	-	-	-	-	-	106,868.85	-	8,220.68	4/30/2020	-	0.0030%	-
0110	137485	-	-	-	-	-	-	-	-	-	-	-	10,286.00	10,286.00	1,582.46	5/31/2020	1	0.0006%	0.00
0110	144374	-	-	-	-	-	-	-	-	-	-	-	178,779.95	178,779.95	27,504.61	5/31/2020	1	0.0099%	0.00
0110	144542 KU	-	-	-	-	-	-	-	-	-	-	-	11,354,355.14	-	873,411.93	4/30/2020	-	0.3159%	-
0110	148096 KU	-	-	-	-	-	-	-	-	-	-	-	621,210.17	-	47,785.40	4/30/2020	-	0.0173%	-
0110	148104 KU	-	-	-	-	-	-	-	-	-	-	-	461,978.24	-	35,536.79	4/30/2020	-	0.0129%	-
0110	149487	-	-	-	-	-	-	-	-	-	-	-	14,000.00	14,000.00	2,153.85	12/31/2020	8	0.0008%	0.00
0110	151997	-	-	-	-	-	-	-	-	-	-	-	116,196.54	-	8,938.20	4/30/2020	-	0.0032%	-
0110	153022	-	-	-	-	-	-	-	-	-	-	-	27,368.55	27,368.55	4,210.55	12/31/2020	8	0.0015%	0.00
0110	153465	-	-	-	-	-	-	-	-	-	-	-	52,783.58	-	4,060.28	4/30/2020	-	0.0015%	-
0110	155102	-	-	-	-	-	-	-	-	-	-	-	295,647.05	-	22,742.08	4/30/2020	-	0.0082%	-
0110	155103	-	-	-	-	-	-	-	-	-	-	-	295,647.05	-	22,742.08	4/30/2020	-	0.0082%	-
0110	157017	-	-	-	-	-	-	-	-	-	-	-	40,823.80	50,967.19	7,060.85	12/31/2020	8	0.0026%	0.00
0110	157034	-	-	-	-	-	-	-	-	-	-	-	43,751.00	55,341.83	7,622.53	12/31/2020	8	0.0028%	0.00
0110	157056	-	-	-	-	-	-	-	-	-	-	-	54,037.11	54,037.11	8,313.40	12/31/2020	8	0.0030%	0.00
0110	157062	-	-	-	-	-	-	-	-	-	-	-	4,787.70	16,793.73	1,660.11	12/31/2020	8	0.0006%	0.00
0110	157075KU	-	-	-	-	-	-	-	-	-	-	-	85,349.96	85,349.96	13,130.76	12/1/2020	8	0.0047%	0.00
0110	157254	-	-	-	-	-	-	-	-	-	-	-	51,394.25	-	3,953.40	4/30/2020	-	0.0014%	-
0110	157642	-	-	-	-	-	-	-	-	-	-	-	306,347.31	612,694.62	70,695.53	12/31/2020	8	0.0256%	0.00
0110	157645	-	-	-	-	-	-	-	-	-	-	-	117,494.23	234,988.45	27,114.05	9/30/2020	5	0.0098%	0.00
0110	163028	-	-	-	-	-	-	-	-	-	-	-	31,522.20	65,451.60	7,459.52	10/31/2020	6	0.0027%	0.00
0110	IT0407K	-	-	-	-	-	-	-	-	-	-	-	14,000.00	42,000.00	4,307.69	7/31/2020	3	0.0016%	0.00
0110	IT0452K	-	-	-	-	-	-	-	-	-	-	-	28,000.00	56,000.00	6,461.54	10/31/2020	6	0.0023%	0.00
0110	IT0634K	-	-	-	-	-	-	-	-	-	-	-	5,760.00	5,760.00	886.15	10/31/2020	6	0.0003%	0.00
0110	IT0637K	-	-	-	-	-	-	-	-	-	-	-	8,160.00	8,160.00	1,255.38	11/30/2020	7	0.0005%	0.00
0110	IT0661K	-	-	-	-	-	-	-	-	-	-	-	9,600.00	10,584.48	1,552.65	10/31/2020	6	0.0006%	0.00
0110	IT0668K	-	-	-	-	-	-	-	-	-	-	-	960.00	3,360.00	332.31	10/31/2020	6	0.0001%	0.00
0110	IT0673K	-	-	-	-	-	-	-	-	-	-	-	2,800.00	5,600.00	646.15	11/30/2020	7	0.0002%	0.00
0110	IT0674K	-	-	-	-	-	-	-	-	-	-	-	7,560.00	15,120.00	1,744.62	12/31/2020	8	0.0006%	0.00
0110	IT0681K	-	-	-	-	-	-	-	-	-	-	-	48,000.00	48,000.00	7,384.62	8/31/2020	4	0.0027%	0.00
0110	IT0682K	-	-	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	553.85	12/31/2020	8	0.0002%	0.00
0110	IT0694K	-	-	-	-	-	-	-	-	-	-	-	31,557.96	63,115.92	7,282.61	8/31/2020	4	0.0026%	0.00
0110	IT0713K	-	-	-	-	-	-	-	-	-	-	-	5,600.00	11,200.00	1,292.31	11/30/2020	7	0.0005%	0.00
0110	IT0715K	-	-	-	-	-	-	-	-	-	-	-	14,000.00	28,000.00	3,230.77	8/31/2020	4	0.0012%	0.00
0110	IT0716K	-	-	-	-	-	-	-	-	-	-	-	4,800.00	9,600.00	1,107.69	12/31/2020	8	0.0004%	0.00
0110	IT0718K	-	-	-	-	-	-	-	-	-	-	-	112,000.00	140,000.00	19,384.62	5/31/2020	1	0.0070%	0.00
0110	IT0720K	-	-	-	-	-	-	-	-	-	-	-	116,900.23	122,579.59	18,421.52	12/31/2020	8	0.0067%	0.00
0110	IT0723K	-	-	-	-	-	-	-	-	-	-	-	24,000.00	48,000.00	5,538.46	12/31/2020	8	0.0020%	0.00
0110	IT0726K	-	-	-	-	-	-	-	-	-	-	-	33,600.00	67,200.00	7,753.85	12/31/2020	8	0.0028%	0.00
0110	LI-000059	-	-	-	-	-	-	-	-	-	-	-	45,419.53	-	3,493.81	4/30/2020	-	0.0013%	-
0110	152992	-	-	-	-	-	-	-	-	-	-	-	(1,184.76)	(4,151.26)	(410.46)	12/31/2021	20	-0.0001%	(0.00)
0110	IT0569K	-	-	-	-	-	-	-	-	-	-	-	498,412.56	1,096,471.53	122,683.39	12/31/2021	20	0.0444%	0.01
0110	126302	-	-	-	-	-	-	-	-	-	-	-	-	456,753.23	35,134.86	5/31/2020	1	0.0127%	0.00
0110	140170	-	-	-	-	-	-	-	-	-	-	-	-	170,000.00	13,076.92	9/30/2020	5	0.0047%	0.00
0110	144362	-	-	-	-	-	-	-	-	-	-	-	-	100,000.00	7,692.31	6/30/2020	2	0.0028%	0.00
0110	147506	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	15,873.26	6/30/2020	2	0.0057%	0.00
0110	147507	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	15,873.26	6/30/2020	2	0.0057%	0.00
0110	147513	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	15,873.26	6/30/2020	2	0.0057%	0.00
0110	148111	-	-	-	-	-	-	-	-	-	-	-	-	2,920,303.33	224,638.72	5/31/2020	1	0.0813%	0.00
0110	149021KU	-	-	-	-	-	-	-	-	-	-	-	-	137,124.90	10,548.07	5/31/2020	1	0.0038%	0.00
0110	150064KU	-	-	-	-	-	-	-	-	-	-	-	-	320,537.25	24,656.71	5/30/2020	1	0.0089%	0.00
0110	151439	-	-	-	-	-	-	-	-	-	-	-	-	157,901.70	12,146.28	5/31/2020	1	0.0044%	0.00
0110	152659KU	-	-	-	-	-	-	-	-	-	-	-	-	658,798.27	50,676.79	5/31/2020	1	0.0183%	0.00
0110	152685KU	-	-	-	-	-	-	-	-	-	-	-	-	140,661.05	10,820.08	12/31/2020	8	0.0039%	0.00
0110	154744KU	-	-	-	-	-	-	-	-	-	-	-	-	78,108.80	6,008.37	12/1/2020	8	0.0022%	0.00
0110	155558KU	-	-	-	-	-	-	-	-	-	-	-	-	1,365,438.99	105,033.77	5/31/2020	1	0.0380%	0.00
0110	155651KU	-	-	-	-	-	-	-	-	-	-	-	-	475,194.10	36,553.39	5/30/2020	1	0.0132%	0.00
0110	155659KU	-	-	-	-	-	-	-	-	-	-	-	-	199,205.42	15,323.49	5/30/2020	1	0.0055%	0.00
0110	156834KU	-	-	-	-	-	-	-	-	-	-	-	-	126,718.43	9,747.57	12/31/2020	8	0.0035%	0.00
0110	157708	-	-	-	-	-	-	-	-	-	-	-	-	108,287.94	8,329.84	6/30/2020	2	0.0030%	0.00
0110	IT0628K	-	-	-	-	-	-	-	-	-	-	-	-	12,000.00	923.08	10/31/2020	6	0.0003%	0.00
0110	IT0633K	-	-	-	-	-	-	-	-	-	-	-	-	24,000.00	1,846.15	12/31/2020	8	0.0007%	0.00
0110	IT0656K	-	-	-	-	-	-	-	-	-	-	-	-	96,000.00	7,384.62	10/31/2020	6	0.0027%	0.00
0110	IT0710K	-	-	-	-	-	-	-	-	-	-	-	-	9,600.00	738.46	10/31/2020	6	0.0003%	0.00
0110	SU-000364	-	-	-	-	-	-	-	-	-	-	-	-	57,678.59	4,436.81	6/30/2020	2	0.0016%	0.00
0110	121GH	-	-	-	-	-	-	-	-	-	-	-	-	1,000,000.00	76,923.08	5/31/2021	13	0.0278%	0.00
0110	156577	-	-	-	-	-	-	-	-	-	-	-	-	169,290.00	13,022.31	5/31/2021	13	0.0047%	0.00
0110	IT0724K	-	-	-	-	-	-	-	-	-	-	-	-	4,872.96	374.84	2/28/2021	10	0.0001%	0.00
0100	00029FACL	705,518.23	723,008.28	921,523.05	939,013.10	956,503.15	1,208,179.54	1,335,672.14	1,344,266.64	1,352,861.14	1,632,527.83	1,658,782.02	1,685,036.21	1,711,290.40	1,244,167.83	10/31/2020	6	0.4500%	0.03
0100	00065FACL	2,655,982.80	-	-	-	-	-	-	-	-	-	-	-	-	204,306.37	5/31/2019	(11)	0.0739%	(0.01)
0100	00076FACL	145,256.05	246,621.05	246,621.05	-	-	-	-	-	-	-	-	-	-	49,115.24	7/31/2019	(9)	0.0178%	(0.00)
0100	123906LGE	6,794,164.24	-	-	-	-	-	-	-	-	-	-	-	-	522,628.02	5/31/2019	(11)	0.1890%	(0.02)
0100	124518	381,046.44	381,046.44	745,131.41	745,131.41	745,131.41	745,131.41	745,131.41	745,131.41	-	-	-	-	-	402,529.33	12/1/2019	(4)	0.1456%	(0.01)
0100	124526	57,441.16	57,441.16	57,441.16	57,441.16	57,441.16	57,441.16	57,441.16	57,441.16	-	-	-	-	-	35,348.41	12/1/2019	(4)	0.0128%	(0.00)
0100	131715	223,116.98	446,233.96	675,010.14	895,759.22	1,116,508.30	1,337,257.38	1,560,487.24	1,780,052.37	1,779,052.37	1,904,639.92	2,029,053.52	2,153,467.12	2,277,880.72	1,398,347.63	12/31/2020	8	0.5058%	0.04
0100	132960	600,000.00	-	-	-	-	-	-	-	-	-	-	-	-	46,153.85	5/31/2019	(11)	0.0167%	(0.00)
0100	133615LGE	95,966.00	95,966.00	95,966.00	95,966.00	238,488.85	238,488.85	238,488.85	238,488.85	-	-	-	-	-	102,909.18	12/1/2019	(4)	0.0372%	(0.00)
0100	134198	2,770,647.79	3,015,504.20	3,260,360.61	3,505,217.02	3,750,073.43	3,994,929.84	4,239,786.25	4,484,642.66	4,729,499.07	4,729,499.07	5,348,260.07	5,348,260.07	5,348,260.07	4,194,226.17	5/31/2020	1	1.5172%	0.02
0100	134898	189,724.85	189,724.85	289,724.85	289,724.85	289,724.85	289,724.85	289,724.85	289,724.85	389,724.85	389,724.85	389,724.85	389,724.85	389,724.85	312,801.77	12/31/2020	8	0.1131%	0.01
0100	136480	56,530.89	56,530.89	73,333.15	73,333.15	73,333.15	90,135.41	-	-	-	-	-	-	-	32,553.59	10/31/2019	(6)	0.0118%	(0.00)
0100	136636	476,166.34	872,971.65	1,269,776.96	1,269,776.96	1,269,776.96	1,453,276.23	1,606,894.49	-	-	-	-	-	-	632,203.05	11/30/2019	(5)	0.2287%	(0.01)
0100	137585LGE	368,382.19	-	-	-	-	-	-	-	-	-	-	-	-	28,337.09	5/31/2019	(11)	0.0103%	(0.00)
0100	139721	1,096,742.57	1,096,742.57	1,096,742.57	1,096,742.57	1,096,742.57	1,096,742.57	1,468,399.67	1,468,399.67	-	-	-	-	-	732,096.52	12/31/2019	(4)	0.2648%	(0.01)
0100	139873	3,874,026.74	-	-	-	-	-	-	-	-	-	-	-	-	298,002.06	5/31/2019	(11)	0.1078%	(0.01)
0100	139880	1,290,880.30	-	-	-	-	-	-	-	-	-	-	-	-	99,298.48	5/31/2019	(11)	0.0359%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	139892	253,880.06	253,880.06	253,880.06	263,800.19	328,281.06	472,030.23	670,340.12	-	-	-	-	-	-	192,007.06	11/30/2019	(5)	0.0695%	(0.00)
0100	140440	2,029,978.68	-	-	-	-	-	-	-	-	-	-	-	-	156,152.21	5/31/2019	(11)	0.0565%	(0.01)
0100	141004	1,109,527.86	1,164,174.27	1,452,321.65	1,734,145.33	2,026,508.51	2,322,770.56	2,607,337.06	2,778,076.96	-	-	-	-	-	1,168,835.55	12/31/2019	(4)	0.4228%	(0.02)
0100	143600	88,225.17	-	-	-	-	-	-	-	-	-	-	-	-	6,786.55	5/31/2019	(11)	0.0025%	(0.00)
0100	143605	198,402.64	198,402.64	396,805.28	396,805.28	396,805.28	396,805.28	595,207.92	1,170,223.10	-	-	-	-	-	288,419.80	12/31/2019	(4)	0.1043%	(0.00)
0100	143637	803,000.00	803,000.00	803,000.00	803,000.00	1,593,000.00	1,593,000.00	1,913,000.00	2,443,000.00	-	-	-	-	-	827,230.77	12/31/2019	(4)	0.2992%	(0.01)
0100	144782	(931.44)	(1,113.52)	(1,184.69)	(1,296.21)	(1,557.56)	(1,751.87)	(2,067.91)	(2,310.49)	(2,545.37)	(2,775.38)	(2,941.21)	(3,145.35)	(3,323.29)	(2,072.64)	5/31/2020	1	-0.0007%	(0.00)
0100	144869	1,107,753.04	1,352,216.48	1,757,650.07	2,043,540.89	2,511,050.98	2,978,561.07	3,461,320.66	-	-	-	-	-	-	1,170,161.01	11/30/2019	(5)	0.4233%	(0.02)
0100	145027	94,169.27	98,528.36	123,160.45	127,519.54	160,189.87	-	-	-	-	-	-	-	-	46,428.27	9/30/2019	(7)	0.0168%	(0.00)
0100	145087	11,000.00	11,000.00	33,000.00	33,000.00	33,000.00	66,000.00	66,000.00	66,000.00	-	-	-	-	-	24,538.46	12/31/2019	(4)	0.0089%	(0.00)
0100	147048	158,722.11	158,722.11	158,722.11	654,728.73	1,150,735.35	1,150,735.35	1,150,735.35	-	-	-	-	-	-	352,546.24	11/30/2019	(5)	0.1275%	(0.01)
0100	147054	937,938.02	-	-	-	-	-	-	-	-	-	-	-	-	72,149.08	5/31/2019	(11)	0.0261%	(0.00)
0100	147078	991,424.18	-	-	-	-	-	-	-	-	-	-	-	-	76,263.40	5/31/2019	(11)	0.0276%	(0.00)
0100	148469	(817,022.12)	(817,022.12)	(817,022.12)	(817,022.12)	(817,022.12)	-	-	-	-	-	-	-	-	(314,239.28)	9/30/2019	(7)	-0.1137%	0.01
0100	148484	2,542,818.68	2,662,468.91	2,779,661.24	2,895,759.62	3,012,595.29	3,128,603.67	3,244,612.05	3,361,167.41	-	-	-	-	-	1,817,514.37	12/31/2019	(4)	0.6574%	(0.03)
0100	148490	5,140,910.14	5,446,903.09	5,745,774.43	-	-	-	-	-	-	-	-	-	-	1,256,429.82	7/31/2019	(9)	0.4545%	(0.04)
0100	148727	1,298,821.77	1,440,105.29	1,546,867.49	1,683,960.49	1,805,473.48	1,922,785.62	2,006,333.86	2,094,746.81	2,135,187.88	2,185,326.77	2,347,660.66	2,499,965.89	2,652,271.12	1,970,731.32	12/31/2020	8	0.7129%	0.06
0100	148821	733,079.14	862,327.06	991,574.98	-	-	-	-	-	-	-	-	-	-	198,998.55	7/31/2019	(9)	0.0720%	(0.01)
0100	148884	299,596.71	456,563.05	598,169.79	768,138.09	919,315.78	1,074,588.99	1,230,956.15	1,365,819.89	1,499,089.68	1,499,089.68	1,499,089.68	1,592,962.58	1,682,773.04	1,114,319.47	12/31/2020	8	0.4031%	0.03
0100	148885	20,626.82	25,783.52	30,940.22	364,281.92	861,716.12	1,415,566.72	1,968,471.92	2,520,603.62	2,999,216.59	4,289,910.34	4,993,629.09	5,697,347.84	6,277,803.01	2,420,453.67	6/30/2020	2	0.8755%	0.02
0100	149400	85,367.48	88,367.48	91,367.48	122,407.23	245,861.48	373,235.48	500,609.48	595,464.98	-	-	-	-	-	161,744.70	12/31/2019	(4)	0.0585%	(0.00)
0100	150015LGE	46,173.25	-	-	-	-	-	-	-	-	-	-	-	-	3,551.79	5/31/2019	(11)	0.0013%	(0.00)
0100	150017LGE	25,185.20	25,185.20	25,185.20	25,185.20	25,185.20	25,185.20	25,185.20	25,185.20	-	-	-	-	-	15,498.58	12/1/2019	(4)	0.0056%	(0.00)
0100	150035	134,793.00	134,793.00	134,793.00	134,793.00	134,793.00	134,793.00	134,793.00	-	-	-	-	-	-	72,580.85	11/30/2019	(5)	0.0263%	(0.00)
0100	150220	6,870.42	6,870.42	-	-	-	-	-	-	-	-	-	-	-	1,056.99	6/30/2019	(10)	0.0004%	(0.00)
0100	150222	0.03	0.03	-	-	-	-	-	-	-	-	-	-	-	0.00	6/30/2019	(10)	0.0000%	(0.00)
0100	151481	55,583.20	71,743.40	79,711.46	93,823.35	105,886.93	117,950.51	134,110.71	142,078.77	-	-	-	-	-	61,606.79	12/31/2019	(4)	0.0223%	(0.00)
0100	151482	185,770.08	232,257.60	278,655.12	325,142.64	371,540.16	419,121.63	465,519.15	513,100.62	-	-	-	-	-	214,700.54	12/31/2019	(4)	0.0777%	(0.00)
0100	151483	99,722.49	123,275.85	147,923.16	173,172.27	197,237.43	221,884.74	248,669.26	272,734.42	-	-	-	-	-	114,201.51	12/31/2019	(4)	0.0413%	(0.00)
0100	151484	471,055.18	589,843.13	708,631.08	827,419.03	946,206.98	1,064,994.93	1,189,926.71	1,306,666.35	-	-	-	-	-	546,518.72	12/31/2019	(4)	0.1977%	(0.01)
0100	151485	563,724.92	702,778.93	843,016.89	984,209.21	1,128,543.79	1,268,781.75	1,413,979.59	1,555,171.91	-	-	-	-	-	650,785.15	12/31/2019	(4)	0.2354%	(0.01)
0100	151486	3,750,869.52	4,688,758.02	5,625,462.57	6,563,351.07	7,499,503.51	8,440,545.58	9,388,924.27	10,317,293.59	-	-	-	-	-	4,328,823.70	12/31/2019	(4)	1.5659%	(0.06)
0100	151495	148,876.12	148,876.12	148,876.12	148,876.12	148,876.12	148,876.12	148,876.12	148,876.12	-	-	-	-	-	91,616.07	12/31/2019	(4)	0.0331%	(0.00)
0100	151497	11,839.50	35,102.44	57,181.43	57,181.43	74,179.16	79,890.88	79,890.88	79,890.88	-	-	-	-	-	36,550.51	12/31/2019	(4)	0.0132%	(0.00)
0100	151529	26,193.31	26,193.31	30,929.11	34,973.22	44,937.08	44,937.08	58,938.07	58,938.07	-	-	-	-	-	25,079.94	12/31/2019	(4)	0.0091%	(0.00)
0100	151534	21,632.76	36,394.11	36,394.11	36,394.11	36,394.11	36,394.11	55,891.26	74,958.64	-	-	-	-	-	25,727.17	12/31/2019	(4)	0.0093%	(0.00)
0100	151546	114,843.15	264,020.85	282,964.05	301,907.25	320,850.45	339,793.65	358,736.85	427,405.95	-	-	-	-	-	185,424.78	12/31/2019	(4)	0.0671%	(0.00)
0100	151553	564,838.20	706,047.75	847,257.30	992,562.37	1,133,771.92	1,274,981.47	1,418,239.33	1,559,448.88	-	-	-	-	-	653,626.71	12/31/2019	(4)	0.2364%	(0.01)
0100	151577	243,988.89	-	-	-	-	-	-	-	-	-	-	-	-	18,768.38	5/31/2019	(11)	0.0068%	(0.00)
0100	152070LGE	53,536.86	53,536.86	53,536.86	53,536.86	53,536.86	53,536.86	-	-	-	-	-	-	-	24,709.32	10/31/2019	(6)	0.0089%	(0.00)
0100	152224	605,643.71	893,241.15	1,093,248.23	-	-	-	-	-	-	-	-	-	-	199,394.85	7/31/2019	(9)	0.0721%	(0.01)
0100	152425	12,217.99	298,324.61	578,360.62	773,487.68	-	-	-	-	-	-	-	-	-	127,876.22	8/31/2019	(8)	0.0463%	(0.00)
0100	152433	32,802.96	78,560.96	147,197.96	215,834.96	337,169.46	458,503.96	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	372,392.53	10/31/2020	6	0.1347%	0.01
0100	152455	3,490.58	3,490.58	82,986.83	-	-	-	-	-	-	-	-	-	-	6,920.61	7/31/2019	(9)	0.0025%	(0.00)
0100	152507	45,758.00	45,758.00	45,758.00	45,758.00	-	-	-	-	-	-	-	-	-	14,079.38	8/31/2019	(8)	0.0051%	(0.00)
0100	152531	272,487.50	430,580.00	-	-	-	-	-	-	-	-	-	-	-	54,082.12	6/30/2019	(10)	0.0196%	(0.00)
0100	152532	24,388.01	52,717.29	125,004.57	185,079.72	274,421.52	358,043.57	438,598.83	491,296.33	-	-	-	-	-	149,965.37	12/31/2019	(4)	0.0542%	(0.00)
0100	152535	58,829.35	58,829.35	137,875.60	160,008.55	160,008.55	160,008.55	160,008.55	160,008.55	-	-	-	-	-	81,198.23	12/31/2019	(4)	0.0294%	(0.00)
0100	152553	22,879.00	45,758.00	45,758.00	45,758.00	45,758.00	-	-	-	-	-	-	-	-	15,839.31	9/30/2019	(7)	0.0057%	(0.00)
0100	152569	34,714.21	34,714.21	34,714.21	34,714.21	34,714.21	34,714.21	34,714.21	34,714.21	-	-	-	-	-	21,362.59	12/31/2019	(4)	0.0077%	(0.00)
0100	152573	138,931.65	173,938.05	210,992.76	246,953.52	281,959.92	316,966.32	354,021.03	389,027.43	-	-	-	-	-	162,522.36	12/31/2019	(4)	0.0588%	(0.00)
0100	152639	114,707.66	181,377.61	-	-	-	-	-	-	-	-	-	-	-	22,775.79	6/30/2019	(10)	0.0082%	(0.00)
0100	152642	106,001.10	172,671.04	-	-	-	-	-	-	-	-	-	-	-	21,436.32	6/30/2019	(10)	0.0078%	(0.00)
0100	152652LGE	247,468.25	-	-	-	-	-	-	-	-	-	-	-	-	19,036.02	5/31/2019	(11)	0.0069%	(0.00)
0100	152683LGE	30,960.15	30,960.15	30,960.15	30,960.15	30,960.15	30,960.15	30,960.15	-	-	-	-	-	-	16,670.85	11/30/2019	(5)	0.0060%	(0.00)
0100	152693LGE	93,456.48	93,456.48	93,456.48	93,456.48	244,698.11	244,698.11	244,698.11	244,698.11	-	-	-	-	-	104,047.57	12/1/2019	(4)	0.0376%	(0.00)
0100	152769	26,354.90	26,354.90	52,709.80	52,709.80	52,709.80	79,064.70	79,064.70	79,064.70	-	-	-	-	-	34,464.10	12/31/2019	(4)	0.0125%	(0.00)
0100	152778	20,273.00	30,409.50	40,546.00	50,682.50	60,819.00	70,955.50	81,092.00	91,228.50	-	-	-	-	-	34,308.15	12/31/2019	(4)	0.0124%	(0.00)
0100	152799	25,341.25	50,682.50	50,682.50	50,682.50	100,756.81	100,756.81	100,756.81	-	-	-	-	-	-	36,896.86	11/30/2019	(5)	0.0133%	(0.00)
0100	153065	749,539.72	783,206.38	816,873.04	850,539.70	884,206.36	917,873.02	951,539.68	985,206.34	-	-	-	-	-	533,768.02	12/31/2019	(4)	0.1931%	(0.01)
0100	153077	226,593.15	226,593.15	226,593.15	226,593.15	226,593.15	226,593.15	1,528,935.08	-	-	-	-	-	-	222,191.84	11/30/2019	(5)	0.0804%	(0.00)
0100	153561	4,680,538.42	5,408,655.02	-	-	-	-	-	-	-	-	-	-	-	776,091.80	6/30/2019	(10)	0.2807%	(0.03)
0100	153662	14,916,005.28	17,068,670.82	19,225,117.96	21,382,434.48	23,542,259.56	25,694,983.45	27,215,612.60	27,255,339.18	27,292,173.58	27,898,106.83	29,055,650.27	30,146,718.82	31,556,274.28	24,788,411.32	12/31/2020	8	8.9667%	0.72
0100	154095	2,989,093.85	3,066,289.88	3,143,485.91	3,316,722.24	3,393,918.27	3,471,114.30	-	-	-	-	-	-	-	1,490,817.27	10/31/2019	(6)	0.5393%	(0.03)
0100	154338	49,600.66	49,600.66	128,961.73	128,961.73	128,961.73	128,961.73	233,025.72	-	-	-	-	-	-	65,236.46	11/30/2019	(5)	0.0236%	(0.00)
0100	154341	49,600.66	49,600.66	128,961.73	128,961.73	128,961.73	-	-	-	-	-	-	-	-	37,391.27	9/30/2019	(7)	0.0135%	(0.00)
0100	154402	349,108.54	-	-	-	-	-	-	-	-	-	-	-	-	26,854.50	5/31/2019	(11)	0.0097%	(0.00)
0100	154415	941,531.31	991,085.58	-	-	-	-	-	-	-	-	-	-	-	148,662.84	6/30/2019	(10)	0.0538%	(0.01)
0100	154542	450,000.00	450,000.00	450,000.00	450,000.00	450,000.00	450,000.00	450,000.00	-	-	-	-	-	-	242,307.69	11/30/2019	(5)	0.0876%	(0.00)
0100	154555	546,879.97	-	-	-	-	-	-	-	-	-	-	-	-	42,067.69	5/31/2019	(11)	0.0152%	(0.00)
0100	154556	1,685,736.96	-	-	-	-	-	-	-	-	-	-	-	-	129,672.07	5/31/2019	(11)	0.0469%	(0.01)
0100	154678	188,468.59	-	-	-	-	-	-	-	-	-	-	-	-	14,497.58	5/31/2019	(11)	0.0052%	(0.00)
0100	154729LGE	46,728.20	46,728.20	92,680.67	92,680.67	92,680.67	92,680.67	92,680.67	92,680.67	-	-	-	-	-	49,964.65	12/1/2019	(4)	0.0181%	(0.00)
0100	154743	95,995.31	95,995.31	95,995.31	95,995.31	95,995.31	95,995.31	95,995.31	95,995.31	-	-	-	-	-	59,074.04	12/1/2019	(4)	0.0214%	(0.00)
0100	154753	73,989.60	73,989.60	73,989.60	73,989.60	73,989.60	73,989.60	73,989.60	179,233.00	-	-	-	-	-	53,627.71	12/1/2019	(4)	0.0194%	(0.00)
0100	154759LGE	(0.20)	(0.20)	68,928.51	68,928.51	68,928.51	68,928.51	68,928.51	68,928.51	-	-	-	-	-	31,813.13	12/1/2019	(4)	0.0115%	(0.00)
0100	155077LGE	(0.14)	(0.14)	11,153.37	11,153.37	11,153.37	11,153.37	11,153.37	11,153.37	-	-	-	-	-	5,147.69	12/1/2019	(4)	0.0019%	(0.00)
0100	155127	53,767.24	53,767.24	53,767.24	53,767.24	80,650.86	107,534.48	-	-	-	-	-	-	-	31,019.56	10/31/2019	(6)	0.0112%	(0.00)
0100	155386	1,019,353.32	1,024,510.02	1,576,641.72	2,128,773.42	2,680,905.12	3,234,755.72	3,787,660.92	4,339,792.62	4,883,943.04	5,239,476.79	5,595,010.54	5,950,544.29	6,306,078.04	3,674,418.89	5/31/2020	1	1.3291%	0.01
0100	155396	1,003,729.24	-	-	-	-	-	-	-	-	-	-	-	-	77,209.94	5/31/2019	(11)	0.0279%	(0.00)
0100	155529	528,736.65	589,098.70	596,956.89	604,815.08	612,673.27	620,531.46	628,389.65	636,247.84	-	-	-	-	-	370,573.04	12/31/2019	(4)	0.1340%	(0.01)
0100	156464	25,007.61	1,011,390.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	1,793,218.67	6/30/2020	2	0.6487%	0.01
0100	156518	613,313.25	630,149.73	646,986.21	663,822.69	1,084,608.42	1,585,667.90	2,151,774.88	2,498,520.36	-	-	-	-	-	759,603.34	12/31/2019	(4)	0.2748%	(0.01)
0100	156527	401,150.96	642,646.53	885,326.05	1,134,704.47	1,211,256.00	1,211,256.00	1,211,256.00	1,211,256.00	-	-	-	-	-	608,373.23	12/31/2019	(4)	0.2201%	(0.01)
0100	156753	900,000.00	900,000.00	900,000.00	900,000.00	900,000.00	900,000.00	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	1,643,954.87	11/30/2020	7	0.5947%	0.04
0100	156786	218,224.35	-	-	-	-	-	-	-	-	-	-	-	-	16,786.49	5/31/2019	(11)	0.0061%	(0.00)
0100	156787	792,868.48	-	-	-	-	-	-	-	-	-	-	-	-	60,989.88	5/31/2019	(11)	0.0221%	(0.00)
0100	156853LGE	20,869.06	-	-	-	-	-	-	-	-	-	-	-	-	1,605.31	5/31/2019	(11)	0.0006%	(0.00)
0100	156855LGE	8,177.48	-	-	-	-	-	-	-	-	-	-	-	-	629.04	5/31/2019	(11)	0.0002%	(0.00)
0100	156859LGE	11,448.47	-	-	-	-	-	-	-	-	-	-	-	-	880.65	5/31/2019	(11)	0.0003%	(0.00)
0100	156909	201,325.25	201,325.25	201,325.25	201,325.25	201,325.25	201,325.25	201,325.25	-	-	-	-	-	-	108,405.90	11/30/2019	(5)	0.0392%	(0.00)
0100	156967LGE	16,354.97	-	-	-	-	-	-	-	-	-	-	-	-	1,258.07	5/31/2019	(11)	0.0005%	(0.00)
0100	156999	75,077.19	75,077.19	75,077.19	75,077.19	75,077.19	75,077.19	75,077.19	-	-	-	-	-	-	40,426.18	11/30/2019	(5)	0.0146%	(0.00)
0100	157109LGE	54,918.79	54,918.79	54,918.79	54,918.79	54,918.79	54,918.79	54,918.79	54,918.79	-	-	-	-	-	33,796.18	12/31/2019	(4)	0.0122%	(0.00)
0100	157239	125,000.00	125,000.00	275,000.00	450,000.00	-	-	-	-	-	-	-	-	-	75,000.00	8/31/2019	(8)	0.0271%	(0.00)
0100	157299LGE	24,626.00	24,626.00	24,626.00	24,626.00	24,626.00	24,626.00	24,626.00	24,626.00	-	-	-	-	-	15,154.46	12/1/2019	(4)	0.0055%	(0.00)
0100	157552	224,780.54	286,646.44	340,629.49	401,311.44	465,534.94	522,671.57	584,527.17	638,510.22	-	-	-	-	-	266,508.60	12/31/2019	(4)	0.0964%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	157567	20,127.15	20,127.15	20,127.15	20,127.15	20,127.15	20,127.15	20,127.15	20,127.15	-	-	-	-	-	12,385.94	12/31/2019	(4)	0.0045%	(0.00)
0100	157602	157,246.92	235,870.38	315,438.22	397,214.17	475,837.63	554,461.09	633,084.55	711,708.01	790,331.47	790,331.47	790,331.47	832,260.21	874,188.95	581,408.04	12/31/2020	8	0.2103%	0.02
0100	157649	1,236,316.22	1,360,078.18	1,482,010.12	1,607,826.59	1,735,920.96	1,858,813.46	1,986,907.83	2,106,561.87	-	-	-	-	-	1,028,802.71	12/31/2019	(4)	0.3721%	(0.01)
0100	157696	54,763.63	68,454.53	82,145.44	95,836.35	109,527.25	123,218.16	136,909.07	150,599.97	-	-	-	-	-	63,188.80	12/31/2019	(4)	0.0229%	(0.00)
0100	157697	428,058.63	535,073.31	642,087.98	749,102.65	856,117.33	963,132.00	1,070,146.67	1,177,161.35	-	-	-	-	-	493,913.84	12/31/2019	(4)	0.1787%	(0.01)
0100	157746	560,000.00	-	-	-	-	-	-	-	-	-	-	-	-	43,076.92	5/31/2019	(11)	0.0156%	(0.00)
0100	157777LGE	163,012.88	-	-	-	-	-	-	-	-	-	-	-	-	12,539.45	5/31/2019	(11)	0.0045%	(0.00)
0100	157845	94,444.48	188,888.92	283,333.36	377,777.80	472,222.24	566,666.68	661,111.12	755,555.56	-	-	-	-	-	261,538.47	12/31/2019	(4)	0.0946%	(0.00)
0100	157892	14,666.80	18,333.45	22,000.10	25,666.75	29,333.40	33,000.05	36,666.70	40,333.35	44,000.00	47,666.85	51,333.50	55,000.15	58,666.80	36,666.76	12/31/2020	8	0.0133%	0.00
0100	157894	14,666.80	18,333.45	22,000.10	25,666.75	29,333.40	33,000.05	36,666.70	40,333.35	-	-	-	-	-	16,923.12	12/31/2019	(4)	0.0061%	(0.00)
0100	158018	815,398.22	815,398.22	814,804.98	-	-	-	-	-	-	-	-	-	-	188,123.19	7/31/2019	(9)	0.0680%	(0.01)
0100	158112	13,148.27	13,148.27	13,148.27	13,148.27	13,148.27	13,148.27	13,148.27	13,148.27	-	-	-	-	-	8,091.24	12/31/2019	(4)	0.0029%	(0.00)
0100	158158	1,480,783.72	-	-	-	-	-	-	-	-	-	-	-	-	113,906.44	5/31/2019	(11)	0.0412%	(0.00)
0100	161004LGE	126,457.83	-	-	-	-	-	-	-	-	-	-	-	-	9,727.53	5/31/2019	(11)	0.0035%	(0.00)
0100	406000004	582,559.88	728,199.85	905,458.32	1,082,716.79	1,259,975.26	1,417,208.68	1,562,848.65	1,708,488.62	-	-	-	-	-	711,342.77	12/31/2019	(4)	0.2573%	(0.01)
0100	406000021	1,036,738.87	1,321,762.49	1,618,323.14	1,909,309.89	2,197,024.32	2,480,941.82	2,787,694.19	3,064,229.59	-	-	-	-	-	1,262,771.10	12/31/2019	(4)	0.4568%	(0.02)
0100	406000030	1,046,366.53	1,189,549.78	1,359,081.78	1,554,962.53	1,750,843.28	1,946,724.03	2,128,305.05	2,274,650.15	-	-	-	-	-	1,019,267.93	12/31/2019	(4)	0.3687%	(0.01)
0100	406000048	300,506.00	397,161.50	493,817.00	603,905.10	713,993.20	818,985.40	923,977.60	-	-	-	-	-	-	327,103.52	11/30/2019	(5)	0.1183%	(0.01)
0100	419000005	58,000.18	58,000.18	116,000.36	116,000.36	116,000.36	-	-	-	-	-	-	-	-	35,692.42	9/30/2019	(7)	0.0129%	(0.00)
0100	447000001	1,023,831.96	1,140,163.07	1,142,797.95	1,262,861.16	1,404,903.37	1,521,057.17	1,643,074.55	1,761,491.92	-	-	-	-	-	838,475.47	12/31/2019	(4)	0.3033%	(0.01)
0100	447000002	194,607.29	210,416.54	226,225.79	242,035.04	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	242,750.10	12/31/2020	8	0.0878%	0.01
0100	447000003	(0.05)	(0.05)	(0.05)	(0.05)	-	-	-	-	-	-	-	-	-	(0.02)	8/31/2019	(8)	0.0000%	0.00
0100	447000006	2,931.28	133,135.53	344,636.03	534,621.11	769,179.77	1,064,700.45	1,246,715.78	1,397,112.61	-	-	-	-	-	422,540.97	12/31/2019	(4)	0.1528%	(0.01)
0100	447500002	4,604.48	12,296.48	12,296.48	20,710.51	27,840.06	27,840.06	200,061.27	-	-	-	-	-	-	23,511.49	11/30/2019	(5)	0.0085%	(0.00)
0100	448000005	91,370.85	91,370.85	91,370.85	109,584.05	109,584.05	113,546.15	123,481.70	138,904.21	-	-	-	-	-	66,862.52	12/31/2019	(4)	0.0242%	(0.00)
0100	448000029	34,318.50	93,339.70	190,895.20	243,592.70	400,897.25	400,897.25	400,897.25	400,897.25	-	-	-	-	-	166,595.01	12/31/2019	(4)	0.0603%	(0.00)
0100	IT0101L	2,250,981.48	2,513,212.54	2,775,443.60	3,037,674.66	3,310,555.99	3,583,437.32	3,856,318.65	4,129,199.98	4,402,081.31	4,541,528.76	4,914,812.00	-	-	3,024,249.71	3/31/2020	(1)	1.0940%	(0.01)
0100	IT0113CG	10,000.00	60,000.00	110,000.00	160,000.00	170,000.00	180,000.00	190,000.00	200,000.00	200,000.00	200,000.00	200,000.00	210,000.00	225,000.00	162,692.31	11/30/2020	7	0.0589%	0.00
0100	IT0225L	238,103.84	-	-	-	-	-	-	-	-	-	-	-	-	18,315.68	5/31/2019	(11)	0.0066%	(0.00)
0100	IT0235L	117,000.00	149,500.00	-	-	-	-	-	-	-	-	-	-	-	20,500.00	6/30/2019	(10)	0.0074%	(0.00)
0100	IT0242L	397,097.78	423,097.78	430,897.78	438,697.78	443,897.78	446,497.78	446,497.78	-	-	-	-	-	-	232,821.88	11/30/2019	(5)	0.0842%	(0.00)
0100	IT0246L	109,466.29	153,252.81	197,039.33	240,825.85	284,612.37	328,398.89	372,185.41	394,078.66	415,971.91	459,674.92	503,377.93	547,080.94	590,783.95	353,596.10	6/30/2020	2	0.1279%	0.00
0100	IT0301L	418,437.24	428,769.03	439,100.82	449,432.61	459,764.40	470,096.19	480,427.98	488,176.82	-	-	-	-	-	279,554.24	12/31/2019	(4)	0.1011%	(0.00)
0100	IT0305L	213,200.00	218,400.00	223,600.00	228,800.00	234,000.00	239,200.00	244,400.00	-	-	-	-	-	-	123,200.00	11/30/2019	(5)	0.0446%	(0.00)
0100	IT0329L	1,130,245.40	1,197,568.72	-	-	-	-	-	-	-	-	-	-	-	179,062.62	6/30/2019	(10)	0.0648%	(0.01)
0100	IT0333L	137,697.63	155,297.65	172,897.67	190,497.69	208,097.71	225,697.73	-	-	-	-	-	-	-	83,860.47	10/31/2019	(6)	0.0303%	(0.00)
0100	IT0337CG	265,000.00	-	-	-	-	-	-	-	-	-	-	-	-	20,384.62	5/31/2019	(11)	0.0074%	(0.00)
0100	IT0350L	15,400.00	26,400.00	37,400.00	48,400.00	-	-	-	-	-	-	-	-	-	9,815.38	8/31/2019	(8)	0.0036%	(0.00)
0100	IT0404L	26,000.00	44,200.00	70,200.00	96,200.00	122,200.00	148,200.00	166,400.00	-	-	-	-	-	-	51,800.00	11/30/2019	(5)	0.0187%	(0.00)
0100	IT0408L	20,800.00	31,200.00	43,680.00	56,160.00	68,640.00	81,120.00	93,600.00	-	-	-	-	-	-	30,400.00	11/30/2019	(5)	0.0110%	(0.00)
0100	IT0412L	45,760.00	57,200.00	68,640.00	80,080.00	91,520.00	102,960.00	114,400.00	125,840.00	-	-	-	-	-	52,800.00	12/31/2019	(4)	0.0191%	(0.00)
0100	IT0413L	84,875.66	106,612.11	128,348.56	150,085.01	171,821.46	193,557.91	215,294.36	237,030.81	-	-	-	-	-	99,048.14	12/31/2019	(4)	0.0358%	(0.00)
0100	IT0432L	8,665.28	10,831.60	12,997.92	15,164.24	17,330.56	19,496.88	21,663.20	23,829.52	-	-	-	-	-	9,998.40	12/31/2019	(4)	0.0036%	(0.00)
0100	IT0433L	27,732.64	34,665.80	41,598.96	48,532.12	55,465.28	62,398.44	69,331.60	76,264.76	-	-	-	-	-	31,999.20	12/31/2019	(4)	0.0116%	(0.00)
0100	IT0434L	2,200.00	4,400.00	13,200.00	22,000.00	30,800.00	39,600.00	48,400.00	57,200.00	-	-	-	-	-	16,753.85	12/31/2019	(4)	0.0061%	(0.00)
0100	IT0440L	26,000.00	26,000.00	26,000.00	26,000.00	26,000.00	26,000.00	26,000.00	26,000.00	-	-	-	-	-	16,000.00	12/31/2019	(4)	0.0058%	(0.00)
0100	IT0441L	7,280.00	7,280.00	13,520.00	13,520.00	33,800.00	33,800.00	-	-	-	-	-	-	-	8,400.00	10/31/2019	(6)	0.0030%	(0.00)
0100	IT0443L	28,600.00	41,600.00	54,600.00	67,600.00	78,000.00	88,400.00	96,200.00	-	-	-	-	-	-	35,000.00	11/30/2019	(5)	0.0127%	(0.00)
0100	IT0444L	14,560.00	14,560.00	20,800.00	32,240.00	35,360.00	44,720.00	46,280.00	-	-	-	-	-	-	16,040.00	11/30/2019	(5)	0.0058%	(0.00)
0100	IT0446L	5,200.00	10,400.00	10,400.00	10,400.00	15,600.00	15,600.00	-	-	-	-	-	-	-	5,200.00	10/31/2019	(6)	0.0019%	(0.00)
0100	IT0448L	13,260.00	21,060.00	31,200.00	41,600.00	49,400.00	59,540.00	71,240.00	-	-	-	-	-	-	22,100.00	11/30/2019	(5)	0.0080%	(0.00)
0100	IT0451L	18,720.00	29,120.00	36,920.00	44,720.00	52,520.00	60,320.00	63,440.00	-	-	-	-	-	-	23,520.00	11/30/2019	(5)	0.0085%	(0.00)
0100	IT0454L	33,800.00	52,000.00	70,200.00	91,000.00	111,800.00	130,000.00	145,600.00	-	-	-	-	-	-	48,800.00	11/30/2019	(5)	0.0177%	(0.00)
0100	IT0467L	11,466.52	11,466.52	21,866.52	21,866.52	21,866.52	32,266.52	-	-	-	-	-	-	-	9,292.24	10/31/2019	(6)	0.0034%	(0.00)
0100	IT0473L	3,640.00	4,680.00	10,920.00	13,520.00	18,720.00	20,800.00	-	-	-	-	-	-	-	5,560.00	10/31/2019	(6)	0.0020%	(0.00)
0100	IT0477L	527,249.40	659,061.75	790,874.10	922,686.45	1,054,498.80	1,186,311.15	1,318,123.50	-	-	-	-	-	-	496,831.17	11/30/2019	(5)	0.1797%	(0.01)
0100	IT0479L	8,840.00	14,040.00	20,800.00	24,440.00	29,640.00	39,000.00	46,800.00	-	-	-	-	-	-	14,120.00	11/30/2019	(5)	0.0051%	(0.00)
0100	IT0481L	2,200.00	4,400.00	6,600.00	17,600.00	26,400.00	33,000.00	-	-	-	-	-	-	-	6,938.46	10/31/2019	(6)	0.0025%	(0.00)
0100	IT0483L	11,880.00	17,820.00	23,760.00	29,700.00	35,640.00	41,580.00	47,520.00	53,460.00	-	-	-	-	-	20,104.62	12/31/2019	(4)	0.0073%	(0.00)
0100	IT0486L	31,037.10	34,782.97	38,528.84	42,274.71	66,355.22	70,109.89	73,855.76	77,066.48	-	-	-	-	-	33,385.46	12/31/2019	(4)	0.0121%	(0.00)
0100	IT0488L	34,642.40	43,303.00	51,963.60	60,624.20	69,284.80	77,945.40	86,606.00	95,266.60	-	-	-	-	-	39,972.00	12/31/2019	(4)	0.0145%	(0.00)
0100	IT0489L	52,000.00	52,000.00	52,000.00	52,000.00	-	-	-	-	-	-	-	-	-	16,000.00	8/31/2019	(8)	0.0058%	(0.00)
0100	IT0493L	377,000.00	390,000.00	403,000.00	-	-	-	-	-	-	-	-	-	-	90,000.00	7/31/2019	(9)	0.0326%	(0.00)
0100	IT0494L	20,800.00	31,200.00	41,600.00	52,000.00	62,400.00	72,800.00	83,200.00	93,600.00	-	-	-	-	-	35,200.00	12/31/2019	(4)	0.0127%	(0.00)
0100	IT0495L	11,000.00	22,000.00	33,000.00	44,000.00	55,000.00	66,000.00	77,000.00	-	-	-	-	-	-	23,692.31	11/30/2019	(5)	0.0086%	(0.00)
0100	IT0496L	26,000.00	52,000.00	78,000.00	104,000.00	130,000.00	156,000.00	182,000.00	-	-	-	-	-	-	56,000.00	11/30/2019	(5)	0.0203%	(0.00)
0100	IT0497L	43,218.52	54,023.14	64,827.76	75,632.38	86,437.00	97,241.62	108,046.24	118,850.86	-	-	-	-	-	49,867.50	12/31/2019	(4)	0.0180%	(0.00)
0100	IT0498L	26,000.00	32,500.00	39,000.00	45,500.00	52,000.00	58,500.00	65,000.00	71,500.00	-	-	-	-	-	30,000.00	12/31/2019	(4)	0.0109%	(0.00)
0100	IT0499L	68,383.34	102,575.01	136,766.67	170,958.33	-	-	-	-	-	-	-	-	-	36,821.80	8/31/2019	(8)	0.0133%	(0.00)
0100	IT0500L	12,480.00	16,640.00	20,800.00	24,960.00	29,120.00	33,280.00	37,440.00	-	-	-	-	-	-	13,440.00	11/30/2019	(5)	0.0049%	(0.00)
0100	IT0501L	14,890.20	19,853.60	24,817.00	29,780.40	34,743.80	39,707.20	44,670.60	49,634.00	-	-	-	-	-	19,853.60	12/31/2019	(4)	0.0072%	(0.00)
0100	IT0507L	24,414.57	30,518.21	36,621.85	42,725.50	48,829.14	54,932.78	61,036.42	67,140.07	-	-	-	-	-	28,170.66	12/31/2019	(4)	0.0102%	(0.00)
0100	IT0508L	10,400.00	20,800.00	31,200.00	41,600.00	52,000.00	62,400.00	-	-	-	-	-	-	-	16,800.00	10/31/2019	(6)	0.0061%	(0.00)
0100	IT0509L	20,800.00	31,200.00	41,600.00	52,000.00	62,400.00	72,800.00	83,200.00	93,600.00	-	-	-	-	-	35,200.00	12/31/2019	(4)	0.0127%	(0.00)
0100	IT0511L	43,788.00	65,682.00	87,576.00	109,470.00	131,364.00	153,258.00	175,152.00	197,046.00	218,940.00	240,864.62	262,789.24	284,713.86	306,638.48	175,175.55	10/31/2020	6	0.0634%	0.00
0100	IT0512L	2,080.00	3,380.00	4,680.00	56,680.00	61,880.00	63,180.00	64,480.00	-	-	-	-	-	-	19,720.00	11/30/2019	(5)	0.0071%	(0.00)
0100	IT0513L	41,600.00	62,400.00	83,200.00	108,160.00	133,120.00	158,080.00	178,880.00	199,680.00	-	-	-	-	-	74,240.00	12/31/2019	(4)	0.0269%	(0.00)
0100	IT0517L	39,000.00	52,000.00	65,000.00	-	-	-	-	-	-	-	-	-	-	12,000.00	7/31/2019	(9)	0.0043%	(0.00)
0100	IT0518L	39,600.00	52,800.00	66,000.00	79,200.00	92,400.00	105,600.00	118,800.00	-	-	-	-	-	-	42,646.15	11/30/2019	(5)	0.0154%	(0.00)
0100	IT0519L	19,800.00	26,400.00	-	-	-	-	-	-	-	-	-	-	-	3,553.85	6/30/2019	(10)	0.0013%	(0.00)
0100	IT0520L	77,000.00	99,000.00	121,000.00	143,000.00	165,000.00	187,000.00	209,000.00	-	-	-	-	-	-	77,000.00	11/30/2019	(5)	0.0279%	(0.00)
0100	IT0521L	20,800.00	31,200.00	41,600.00	52,000.00	62,400.00	72,800.00	88,400.00	-	-	-	-	-	-	28,400.00	11/30/2019	(5)	0.0103%	(0.00)
0100	IT0522L	88,000.00	99,000.00	-	-	-	-	-	-	-	-	-	-	-	14,384.62	6/30/2019	(10)	0.0052%	(0.00)
0100	IT0524L	26,400.00	35,200.00	44,000.00	48,400.00	52,800.00	57,200.00	61,600.00	-	-	-	-	-	-	25,046.15	11/30/2019	(5)	0.0091%	(0.00)
0100	IT0525L	127,400.00	-	-	-	-	-	-	-	-	-	-	-	-	9,800.00	5/31/2019	(11)	0.0035%	(0.00)
0100	IT0526L	15,600.00	46,799.99	77,999.98	109,199.97	140,399.96	171,599.95	202,799.94	233,999.93	-	-	-	-	-	76,799.98	12/31/2019	(4)	0.0278%	(0.00)
0100	IT0527L	20,000.00	25,000.00	-	-	-	-	-	-	-	-	-	-	-	3,461.54	6/30/2019	(10)	0.0013%	(0.00)
0100	IT0528L	12,500.00	25,000.00	37,500.00	50,000.00	62,500.00	-	-	-	-	-	-	-	-	14,423.08	9/30/2019	(7)	0.0052%	(0.00)
0100	IT0529L	26,000.00	46,800.00	52,000.00	57,200.00	62,400.00	-	-	-	-	-	-	-	-	18,800.00	9/30/2019	(7)	0.0068%	(0.00)
0100	IT0532L	10,400.00	15,600.00	20,800.00	26,000.00	31,200.00	36,400.00	41,600.00	46,800.00	-	-	-	-	-	17,600.00	12/31/2019	(4)	0.0064%	(0.00)
0100	IT0534L	35,200.00	-	-	-	-	-	-	-	-	-	-	-	-	2,707.69	5/31/2019	(11)	0.0010%	(0.00)
0100	IT0535L	55,000.00	-	-	-	-	-	-	-	-	-	-	-	-	4,230.77	5/31/2019	(11)	0.0015%	(0.00)
0100	IT0536L	88,000.00	110,000.00	132,000.00	154,000.00	-	-	-	-	-	-	-	-	-	37,230.77	8/31/2019	(8)	0.0135%	(0.00)
0100	IT0537CG	450,000.00	575,000.00	700,000.00	-	-	-	-	-	-	-	-	-	-	132,692.31	7/31/2019	(9)	0.0480%	(0.00)
0100	IT0538L	39,000.00	78,000.00	117,000.00	-	-	-	-	-	-	-	-	-	-	18,000.00	7/31/2019	(9)	0.0065%	(0.00)
0100	IT0540L	12,897.26	25,794.52	38,691.78	51,589.04	-	-	-	-	-	-	-	-	-	9,920.97	8/31/2019	(8)	0.0036%	(0.00)
0100	IT0542L	52,000.00	65,000.00	78,000.00	91,000.00	104,000.00	117,000.00	130,000.00	143,000.00	-	-	-	-	-	60,000.00	12/31/2019	(4)	0.0217%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	IT0543L	26,000.00	52,000.00	78,000.00	104,000.00	130,000.00	-	-	-	-	-	-	-	-	30,000.00	9/30/2019	(7)	0.0109%	(0.00)
0100	IT0548L	46,800.00	62,400.00	78,000.00	93,600.00	109,200.00	124,800.00	140,400.00	-	-	-	-	-	-	50,400.00	11/30/2019	(5)	0.0182%	(0.00)
0100	IT0550L	242,023.61	248,216.14	254,408.67	260,601.20	266,793.73	272,986.26	279,178.79	285,371.32	-	-	-	-	-	162,275.36	12/31/2019	(4)	0.0587%	(0.00)
0100	IT0551L	31,200.00	41,600.00	52,000.00	62,400.00	72,800.00	83,200.00	93,600.00	-	-	-	-	-	-	33,600.00	11/30/2019	(5)	0.0122%	(0.00)
0100	IT0553L	26,400.00	35,200.00	44,000.00	52,800.00	61,600.00	70,400.00	79,200.00	-	-	-	-	-	-	28,430.77	11/30/2019	(5)	0.0103%	(0.00)
0100	IT0554L	26,400.00	35,200.00	44,000.00	52,800.00	61,600.00	70,400.00	79,200.00	-	-	-	-	-	-	28,430.77	11/30/2019	(5)	0.0103%	(0.00)
0100	IT0555L	26,400.00	35,200.00	44,000.00	52,800.00	61,600.00	70,400.00	79,200.00	-	-	-	-	-	-	28,430.77	11/30/2019	(5)	0.0103%	(0.00)
0100	IT0556L	87,880.00	89,960.00	-	-	-	-	-	-	-	-	-	-	-	13,680.00	6/30/2019	(10)	0.0049%	(0.00)
0100	IT0557L	52,000.00	78,000.00	104,000.00	130,000.00	156,000.00	182,000.00	208,000.00	234,000.00	-	-	-	-	-	88,000.00	12/31/2019	(4)	0.0318%	(0.00)
0100	IT0560L	35,200.02	52,800.03	70,400.04	88,000.05	105,600.06	123,200.07	140,800.08	158,400.09	176,000.10	193,754.78	211,509.46	229,264.14	247,018.82	140,919.06	10/31/2020	6	0.0510%	0.00
0100	IT0561L	8,800.00	13,200.00	17,600.00	22,000.00	26,400.00	30,800.00	35,200.00	39,600.00	44,000.00	50,600.00	57,200.00	63,800.00	70,400.00	36,892.31	10/31/2020	6	0.0133%	0.00
0100	IT0562L	99,000.00	121,000.00	143,000.00	165,000.00	187,000.00	209,000.00	231,000.00	253,000.00	264,000.00	297,000.00	341,000.00	385,000.00	-	207,307.69	4/30/2020	-	0.0750%	-
0100	IT0563L	22,000.00	30,800.00	39,600.00	48,400.00	57,200.00	66,000.00	74,800.00	81,400.00	88,000.00	99,000.00	110,000.00	121,000.00	-	64,476.92	4/30/2020	-	0.0233%	-
0100	IT0565CG	199,723.47	299,585.18	399,446.89	499,308.60	599,170.31	699,032.02	798,893.73	898,755.44	998,617.15	1,048,394.43	1,123,060.35	1,197,726.27	1,272,392.19	771,854.31	7/31/2020	3	0.2792%	0.01
0100	IT0568L	85,800.00	128,700.00	171,600.00	214,500.00	257,400.00	300,300.00	343,200.00	386,100.00	-	-	-	-	-	145,200.00	12/31/2019	(4)	0.0525%	(0.00)
0100	IT0604L	52,363.02	78,544.53	104,726.04	130,907.55	157,089.06	183,270.57	209,452.08	279,269.30	305,450.81	331,645.48	357,840.15	384,034.82	410,229.49	229,601.76	11/30/2020	7	0.0831%	0.01
0100	IT0688L	41,600.00	62,400.00	83,200.00	104,000.00	124,800.00	135,200.00	145,600.00	-	-	-	-	-	-	53,600.00	11/30/2019	(5)	0.0194%	(0.00)
0100	IT0708L	10,879.76	21,759.52	43,519.05	76,158.34	108,797.63	141,436.92	174,076.21	195,835.74	217,595.27	250,353.19	283,111.11	315,869.03	348,626.95	168,309.13	10/31/2020	6	0.0609%	0.00
0100	IT1067L	2,080.00	3,380.00	4,680.00	56,680.00	61,880.00	63,180.00	64,480.00	-	-	-	-	-	-	19,720.00	11/30/2019	(5)	0.0071%	(0.00)
0100	IT1086L	61,801.37	92,702.06	123,602.75	154,503.44	200,854.45	262,655.80	314,156.92	365,658.04	-	-	-	-	-	121,225.76	12/31/2019	(4)	0.0439%	(0.00)
0100	LI-000037	582,787.53	-	-	-	-	-	-	-	-	-	-	-	-	44,829.81	5/31/2019	(11)	0.0162%	(0.00)
0100	LI-000062	46,997.28	58,746.60	70,495.92	82,245.24	93,994.56	105,743.88	117,493.20	129,242.52	-	-	-	-	-	54,227.63	12/31/2019	(4)	0.0196%	(0.00)
0100	LI-000090	5,834.06	10,001.25	-	-	-	-	-	-	-	-	-	-	-	1,218.10	6/30/2019	(10)	0.0004%	(0.00)
0100	SU-000029	250,738.90	250,738.90	250,738.90	256,967.07	263,195.24	269,423.41	275,651.58	275,651.58	275,651.58	320,202.74	364,753.90	409,305.06	453,856.22	301,298.08	5/31/2020	1	0.1090%	0.00
0100	SU-000032	66,666.68	83,333.35	100,000.02	116,666.69	133,333.36	150,000.03	166,666.70	183,333.37	-	-	-	-	-	76,923.09	12/31/2019	(4)	0.0278%	(0.00)
0100	SU-000041	591,039.37	739,649.14	-	-	-	-	-	-	-	-	-	-	-	102,360.65	6/30/2019	(10)	0.0370%	(0.00)
0100	SU-000063	1,131,726.25	1,246,766.50	1,361,806.75	1,361,806.75	1,361,806.75	-	-	-	-	-	-	-	-	497,224.08	9/30/2019	(7)	0.1799%	(0.01)
0100	SU-000077	435,331.92	459,682.36	484,032.80	508,383.24	532,733.68	561,375.04	590,016.40	618,657.76	-	-	-	-	-	322,324.09	12/31/2019	(4)	0.1166%	(0.00)
0100	SU-000102	173,357.08	-	-	-	-	-	-	-	-	-	-	-	-	13,335.16	5/31/2019	(11)	0.0048%	(0.00)
0100	SU-000131	162,522.88	203,153.60	243,784.32	284,415.04	-	-	-	-	-	-	-	-	-	68,759.68	8/31/2019	(8)	0.0249%	(0.00)
0100	SU-000132	197,459.68	-	-	-	-	-	-	-	-	-	-	-	-	15,189.21	5/31/2019	(11)	0.0055%	(0.00)
0100	SU-000133	173,357.08	-	-	-	-	-	-	-	-	-	-	-	-	13,335.16	5/31/2019	(11)	0.0048%	(0.00)
0100	SU-000137	80,000.00	100,000.00	120,000.00	140,000.00	160,000.00	180,000.00	200,000.00	220,000.00	-	-	-	-	-	92,307.69	12/31/2019	(4)	0.0334%	(0.00)
0100	SU-000141	197,459.70	-	-	-	-	-	-	-	-	-	-	-	-	15,189.21	5/31/2019	(11)	0.0055%	(0.00)
0100	SU-000142	152,574.37	160,589.63	168,604.89	176,620.15	184,635.41	192,650.67	200,665.93	208,681.19	-	-	-	-	-	111,155.56	12/31/2019	(4)	0.0402%	(0.00)
0100	SU-000171	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0100	SU-000172	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0100	SU-000261	510,029.46	546,054.86	624,463.51	944,030.76	1,266,019.91	1,649,360.64	1,868,781.67	2,098,202.70	-	-	-	-	-	731,303.35	12/31/2019	(4)	0.2645%	(0.01)
0100	SU-000271	83,320.00	104,150.00	124,980.00	145,810.00	166,640.00	187,470.00	208,300.00	229,130.00	-	-	-	-	-	96,138.46	12/31/2019	(4)	0.0348%	(0.00)
0100	SU-000275	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0100	SU-000279	50,000.00	62,500.00	75,000.00	87,500.00	100,000.00	112,500.00	125,000.00	137,500.00	-	-	-	-	-	57,692.31	12/31/2019	(4)	0.0209%	(0.00)
0100	SU-000292	74,000.00	92,500.00	111,000.00	129,500.00	148,000.00	166,500.00	185,000.00	203,500.00	-	-	-	-	-	85,384.62	12/31/2019	(4)	0.0309%	(0.00)
0100	SU-000293	1,070,818.49	1,307,739.44	-	-	-	-	-	-	-	-	-	-	-	182,965.99	6/30/2019	(10)	0.0662%	(0.01)
0100	SU-000294	868,978.75	1,119,735.84	-	-	-	-	-	-	-	-	-	-	-	152,978.05	6/30/2019	(10)	0.0553%	(0.01)
0100	SU-000335	86,024.32	99,465.61	112,906.90	126,348.19	139,789.48	158,607.30	177,425.12	196,242.94	-	-	-	-	-	84,369.99	12/31/2019	(4)	0.0305%	(0.00)
0100	SU-000370	297,873.45	317,607.13	337,340.81	357,074.49	396,541.82	455,742.80	534,677.48	588,353.05	630,153.05	669,507.06	708,861.07	748,215.08	787,569.09	525,347.41	12/31/2020	8	0.1900%	0.02
0100	133679	1,772,834.10	1,777,124.10	1,781,414.10	1,794,284.10	1,807,154.10	1,820,024.10	1,832,894.10	1,845,764.10	1,858,634.10	1,885,934.10	1,913,234.10	1,940,534.10	1,967,834.10	1,845,974.10	11/30/2023	43	0.6677%	0.29
0100	120754	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	12/31/2025	68	0.0705%	0.05
0100	133671	4,490,985.43	4,501,985.43	4,512,985.43	4,545,985.43	4,578,985.43	4,611,985.43	4,644,985.43	4,677,985.43	4,710,985.43	4,826,985.37	4,942,985.31	5,058,985.27	5,174,985.22	4,713,908.46	11/30/2022	31	1.7052%	0.53
0100	00035FACL	771,924.55	800,947.80	1,336,901.46	1,366,030.12	1,749,936.28	1,779,064.94	2,314,913.19	2,343,936.44	2,701,179.56	3,051,944.05	3,403,032.99	3,754,121.93	4,105,210.87	2,267,626.48	12/31/2021	20	0.8203%	0.16
0100	00105FACL	74,512.92	75,846.70	77,180.48	78,514.26	80,292.97	81,626.75	154,929.68	154,929.68	154,929.68	210,029.60	265,129.52	497,618.19	552,718.11	189,096.81	12/31/2021	20	0.0684%	0.01
0100	122457	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	12/31/2025	68	0.0474%	0.03
0100	138032	135,315.20	537,698.57	546,082.29	554,466.01	562,849.73	571,233.45	579,617.17	588,000.89	596,384.61	605,281.87	614,162.79	623,066.34	631,957.54	549,701.27	6/30/2023	38	0.1988%	0.08
0100	139495	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	12/31/2025	68	0.0034%	0.00
0100	144857	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	11/30/2021	19	0.0584%	0.01
0100	145402	10,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	19,230.77	12/31/2023	44	0.0070%	0.00
0100	147831	1,808,333.32	1,989,166.65	2,169,999.98	2,350,833.31	2,531,666.64	2,712,499.97	2,893,333.30	3,074,166.63	3,255,000.00	3,435,833.33	3,616,666.66	3,797,499.99	3,978,333.32	2,893,333.32	12/31/2023	44	1.0466%	0.46
0100	148396	125,083.87	156,354.85	187,625.83	218,896.81	250,167.79	281,438.77	312,709.75	343,980.73	375,251.71	441,902.53	508,553.41	575,204.29	641,855.17	339,925.04	12/31/2025	68	0.1230%	0.08
0100	149344	173,387.20	173,387.20	173,387.20	173,387.20	173,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	234,925.66	12/31/2023	44	0.0850%	0.04
0100	151231	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	12/31/2025	68	0.0004%	0.00
0100	151249	188,380.48	188,380.48	188,380.48	188,380.48	188,380.48	188,380.48	317,295.82	376,760.96	376,760.96	376,760.96	376,760.96	376,760.96	376,760.96	285,241.88	11/30/2021	19	0.1032%	0.02
0100	152501	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	11/30/2021	19	0.0000%	(0.00)
0100	152517	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	10/31/2021	18	0.0811%	0.01
0100	152583	50,908.00	50,908.00	50,908.00	50,908.00	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	86,006.27	12/31/2028	104	0.0311%	0.03
0100	154327	94,153.14	94,153.14	94,153.14	94,153.14	94,153.14	94,153.14	158,573.71	188,306.28	188,306.28	188,306.28	188,306.28	376,612.54	376,612.54	171,534.06	3/31/2021	11	0.0620%	0.01
0100	157584	(160,505.40)	(201,655.63)	(242,805.86)	(283,956.09)	(325,106.32)	(366,256.55)	(407,406.78)	(445,555.44)	(486,705.67)	(569,249.59)	(651,793.51)	(734,337.43)	(816,881.35)	(437,862.74)	1/31/2021	9	-0.1584%	(0.01)
0100	157611	47,358.00	66,732.16	86,859.31	105,802.51	124,745.71	141,321.01	157,896.31	165,000.01	165,000.01	167,347.91	176,739.51	194,348.76	211,958.01	139,316.09	11/30/2023	43	0.0504%	0.02
0100	157615	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	67,295.15	90,187.18	50,182.57	12/31/2023	44	0.0182%	0.01
0100	158032	350,000.00	450,000.00	650,000.00	950,000.00	1,250,000.00	1,650,000.00	2,050,000.00	2,550,000.00	3,050,000.00	3,800,000.00	4,550,000.00	5,300,000.00	6,300,000.00	2,530,769.23	6/30/2021	14	0.9154%	0.13
0100	447000022	929,193.18	960,811.68	1,013,509.18	1,869,654.41	2,093,944.41	2,318,234.41	2,456,728.16	3,364,605.41	3,501,987.33	3,554,684.83	3,741,856.33	3,898,679.08	4,025,153.08	2,594,541.65	12/31/2021	20	0.9385%	0.19
0100	447000030	977.10	977.10	977.10	8,332.77	21,507.15	34,681.53	49,810.08	62,984.46	62,984.46	62,984.46	62,984.46	62,984.46	62,984.46	38,089.97	11/30/2021	19	0.0138%	0.00
0100	IT0000L	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	12/31/2025	68	0.8649%	0.59
0100	TMPWKB	79,046.25	158,092.50	284,566.50	442,659.00	611,291.00	790,462.50	969,634.00	1,000,198.55	1,000,198.55	3,345,395.95	5,694,152.97	5,775,593.07	9,017,501.92	2,243,753.29	5/31/2021	13	0.8116%	0.11
0100	141618	-	35,000.00	35,000.00	35,000.00	35,000.00	40,000.00	-	-	-	-	-	-	-	13,846.15	10/31/2019	(6)	0.0050%	(0.00)
0100	147058	-	347,204.64	347,204.64	347,204.64	347,204.64	446,313.20	872,693.37	1,170,019.05	-	-	-	-	-	298,295.71	12/31/2019	(4)	0.1079%	(0.00)
0100	150065LGE	-	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	-	-	-	-	-	18,017.21	12/31/2019	(4)	0.0065%	(0.00)
0100	151000	-	85,796.25	85,796.25	85,796.25	85,796.25	85,796.25	85,796.25	-	-	-	-	-	-	39,598.27	11/30/2019	(5)	0.0143%	(0.00)
0100	151496	-	69,123.74	74,835.46	80,547.18	86,258.90	92,922.04	92,922.04	92,922.04	-	-	-	-	-	45,348.57	12/31/2019	(4)	0.0164%	(0.00)
0100	151531	-	30,371.53	30,371.53	54,907.01	54,907.01	54,907.01	54,907.01	54,907.01	-	-	-	-	-	25,790.62	12/31/2019	(4)	0.0093%	(0.00)
0100	151538	-	19,947.15	39,894.30	52,100.78	62,756.33	72,227.93	82,999.51	82,999.51	-	-	-	-	-	31,763.50	12/31/2019	(4)	0.0115%	(0.00)
0100	152419	-	278,527.00	567,306.87	665,482.72	678,897.44	697,656.95	-	-	-	-	-	-	-	222,143.92	10/31/2019	(6)	0.0804%	(0.00)
0100	152423	-	223,917.66	449,901.11	550,098.57	561,983.83	-	-	-	-	-	-	-	-	137,377.01	9/30/2019	(7)	0.0497%	(0.00)
0100	152424	-	122,104.25	213,707.19	242,535.93	246,445.34	250,354.75	254,264.16	265,991.33	-	-	-	-	-	122,723.30	12/31/2019	(4)	0.0444%	(0.00)
0100	152446	-	14,619.49	-	-	-	-	-	-	-	-	-	-	-	1,124.58	6/30/2019	(10)	0.0004%	(0.00)
0100	152508	-	368,882.50	368,882.50	368,882.50	474,277.50	553,323.75	627,388.28	683,995.19	-	-	-	-	-	265,048.63	12/31/2019	(4)	0.0959%	(0.00)
0100	152528	-	51,477.75	57,801.45	63,071.20	69,394.90	69,394.90	69,394.90	69,394.90	-	-	-	-	-	34,610.00	12/31/2019	(4)	0.0125%	(0.00)
0100	152529	-	34,318.50	34,318.50	44,858.00	55,270.13	55,270.13	55,270.13	55,270.13	-	-	-	-	-	25,736.58	12/31/2019	(4)	0.0093%	(0.00)
0100	155313	-	7,103.70	7,103.70	7,103.70	14,999.46	14,999.46	14,999.46	14,999.46	-	-	-	-	-	6,254.53	12/31/2019	(4)	0.0023%	(0.00)
0100	156830LGE	-	99,835.13	99,835.13	99,835.13	99,835.13	99,835.13	99,835.13	99,835.13	-	-	-	-	-	53,757.38	12/1/2019	(4)	0.0194%	(0.00)
0100	156848LGE	-	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	33,460.54	-	-	-	-	-	18,017.21	12/1/2019	(4)	0.0065%	(0.00)
0100	157150LGE	-	23,960.43	23,960.43	23,960.43	23,960.43	23,960.43	23,960.43	23,960.43	-	-	-	-	-	12,901.77	12/1/2019	(4)	0.0047%	(0.00)
0100	448000015	-	11,916.08	23,106.94	34,769.32	45,595.12	49,758.13	49,758.13	49,758.13	-	-	-	-	-	20,358.60	12/31/2019	(4)	0.0074%	(0.00)
0100	450000017	-	73,776.50	88,260.19	-	-	-	-	-	-	-	-	-	-	12,464.36	7/31/2019	(9)	0.0045%	(0.00)
0100	IT0425L	-	17,600.00	35,200.00	39,600.00	44,000.00	-	-	-	-	-	-	-	-	10,492.31	9/30/2019	(7)	0.0038%	(0.00)
0100	IT0449L	-	13,000.00	13,000.00	13,000.00	-	-	-	-	-	-	-	-	-	3,000.00	8/31/2019	(8)	0.0011%	(0.00)
0100	IT0456L	-	24,758.57	49,517.14	-	-	-	-	-	-	-	-	-	-	5,713.52	7/31/2019	(9)	0.0021%	(0.00)
0100	IT0466L	-	26,000.00	26,000.00	26,000.00	26,000.00	-	-	-	-	-	-	-	-	8,000.00	9/30/2019	(7)	0.0029%	(0.00)

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	IT0475L	-	22,000.00	44,000.00	66,000.00	-	-	-	-	-	-	-	-	-	10,153.85	8/31/2019	(8)	0.0037%	(0.00)
0100	IT0552L	-	22,000.00	44,000.00	66,000.00	88,000.00	110,000.00	132,000.00	154,000.00	-	-	-	-	-	47,384.62	12/31/2019	(4)	0.0171%	(0.00)
0100	IT0558L	-	11,000.00	22,000.00	33,000.00	44,000.00	55,000.00	66,000.00	77,000.00	88,000.00	99,000.00	110,000.00	121,000.00	-	55,846.15	4/30/2020	-	0.0202%	-
0100	141390	-	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	16,153.85	12/31/2023	44	0.0058%	0.00
0100	00036FACL	-	-	50,682.50	-	-	-	-	-	-	-	-	-	-	3,898.65	7/31/2019	(9)	0.0014%	(0.00)
0100	139682LGE	-	-	22,307.03	22,307.03	22,307.03	22,307.03	22,307.03	22,307.03	-	-	-	-	-	10,295.55	12/1/2019	(4)	0.0037%	(0.00)
0100	139889	-	-	81,345.10	404,741.42	728,137.74	809,482.84	1,029,503.84	1,249,524.84	-	-	-	-	-	330,979.68	12/31/2019	(4)	0.1197%	(0.00)
0100	144510	-	-	34,860.94	69,721.88	-	-	-	-	-	-	-	-	-	8,044.83	8/31/2019	(8)	0.0029%	(0.00)
0100	150031LGE	-	-	58,890.55	58,890.55	58,890.55	58,890.55	58,890.55	58,890.55	-	-	-	-	-	27,180.25	12/1/2019	(4)	0.0098%	(0.00)
0100	150053LGE	-	-	84,766.70	84,766.70	84,766.70	84,766.70	84,766.70	84,766.70	-	-	-	-	-	39,123.09	12/1/2019	(4)	0.0142%	(0.00)
0100	151498	-	-	258,693.08	275,102.33	291,511.58	307,920.83	330,992.65	341,932.15	-	-	-	-	-	138,934.82	12/31/2019	(4)	0.0503%	(0.00)
0100	151499	-	-	221,990.63	254,809.13	287,627.63	320,446.13	353,264.63	385,999.99	-	-	-	-	-	140,318.32	12/31/2019	(4)	0.0508%	(0.00)
0100	151500	-	-	19,039.07	38,078.14	58,692.72	71,716.17	83,555.67	95,540.80	-	-	-	-	-	28,201.74	12/31/2019	(4)	0.0102%	(0.00)
0100	151530	-	-	62,749.35	62,749.35	62,749.35	62,749.35	62,749.35	62,749.35	-	-	-	-	-	28,961.24	12/31/2019	(4)	0.0105%	(0.00)
0100	151544	-	-	375,783.75	375,783.75	375,783.75	375,783.75	375,783.75	375,783.75	-	-	-	-	-	173,438.65	12/31/2019	(4)	0.0627%	(0.00)
0100	151549	-	-	16,575.30	16,575.30	16,575.30	16,575.30	16,575.30	16,575.30	-	-	-	-	-	7,650.14	12/31/2019	(4)	0.0028%	(0.00)
0100	152439	-	-	25,166.90	73,523.49	-	-	-	-	-	-	-	-	-	7,591.57	8/31/2019	(8)	0.0027%	(0.00)
0100	152505	-	-	221,329.50	257,746.01	257,746.01	257,746.01	314,352.92	-	-	-	-	-	-	100,686.19	11/30/2019	(5)	0.0364%	(0.00)
0100	152534	-	-	34,318.50	34,318.50	41,696.15	54,216.18	54,216.18	54,216.18	-	-	-	-	-	20,998.59	12/31/2019	(4)	0.0076%	(0.00)
0100	152775	-	-	51,696.15	51,696.15	51,696.15	103,392.30	103,392.30	103,392.30	-	-	-	-	-	35,789.64	12/31/2019	(4)	0.0129%	(0.00)
0100	153056LGE	-	-	79,868.10	79,868.10	79,868.10	79,868.10	79,868.10	79,868.10	-	-	-	-	-	36,862.20	12/1/2019	(4)	0.0133%	(0.00)
0100	154762LGE	-	-	26,511.04	26,511.04	26,511.04	26,511.04	26,511.04	26,511.04	-	-	-	-	-	12,235.86	12/1/2019	(4)	0.0044%	(0.00)
0100	155124	-	-	37,000.00	37,000.00	37,000.00	37,000.00	37,000.00	37,000.00	-	-	-	-	-	17,076.92	12/31/2019	(4)	0.0062%	(0.00)
0100	155340	-	-	29,598.75	29,598.75	29,598.75	29,598.75	29,598.75	29,598.75	-	-	-	-	-	13,660.96	12/31/2019	(4)	0.0049%	(0.00)
0100	156723	-	-	54,560.73	79,337.88	-	-	-	-	-	-	-	-	-	10,299.89	8/31/2019	(8)	0.0037%	(0.00)
0100	156825LGE	-	-	159,736.20	159,736.20	159,736.20	159,736.20	159,736.20	159,736.20	-	-	-	-	-	73,724.40	12/1/2019	(4)	0.0267%	(0.00)
0100	157118LGE	-	-	29,950.54	29,950.54	29,950.54	29,950.54	29,950.54	29,950.54	-	-	-	-	-	13,823.33	12/1/2019	(4)	0.0050%	(0.00)
0100	157369	-	-	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	17,159.15	6/30/2020	2	0.0062%	0.00
0100	162174	-	-	64,999.42	64,999.42	64,999.42	64,999.42	64,999.42	64,999.42	-	-	-	-	-	29,999.73	12/31/2019	(4)	0.0109%	(0.00)
0100	448000030	-	-	363,210.05	1,106,605.44	2,227,517.54	3,693,595.17	5,153,730.17	6,773,466.68	-	-	-	-	-	1,486,009.62	12/31/2019	(4)	0.5375%	(0.02)
0100	451000015	-	-	52,697.50	129,635.85	-	-	-	-	-	-	-	-	-	14,025.64	8/31/2019	(8)	0.0051%	(0.00)
0100	IT0403L	-	-	159,628.21	159,628.21	159,628.21	-	-	-	-	-	-	-	-	36,837.28	9/30/2019	(7)	0.0133%	(0.00)
0100	IT0445L	-	-	11,000.00	-	-	-	-	-	-	-	-	-	-	846.15	7/31/2019	(9)	0.0003%	(0.00)
0100	IT0490L	-	-	9,963.90	19,927.79	29,891.67	39,855.55	49,819.43	524,053.74	-	-	-	-	-	51,808.62	12/31/2019	(4)	0.0187%	(0.00)
0100	IT0533L	-	-	6,600.00	19,800.00	33,000.00	-	-	-	-	-	-	-	-	4,569.23	9/30/2019	(7)	0.0017%	(0.00)
0100	SU-000367	-	-	8,893.48	17,786.96	26,680.44	40,020.64	52,471.52	61,365.00	61,365.00	74,671.21	87,977.42	105,719.01	123,460.60	50,800.87	5/31/2020	1	0.0184%	0.00
0100	SU-000368	-	-	17,786.94	35,573.88	53,360.82	80,041.22	104,942.92	122,729.86	122,729.86	149,342.25	175,954.64	211,437.84	246,921.04	101,601.64	5/31/2020	1	0.0368%	0.00
0100	SU-000369	-	-	13,340.20	26,680.40	40,020.60	57,807.54	75,594.48	82,709.27	82,709.27	100,450.86	118,192.45	144,804.84	171,417.23	70,286.70	5/31/2020	1	0.0254%	0.00
0100	SU-000402	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,435.95	20,423.21	28,410.47	36,397.73	9,634.56	5/31/2020	1	0.0035%	0.00
0100	SU-000403	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,013.34	26,604.12	40,669.62	54,735.12	14,039.15	12/31/2020	8	0.0051%	0.00
0100	140342LGE	-	-	16,301.29	16,301.29	16,301.29	16,301.29	16,301.29	16,301.29	36,892.39	36,892.39	36,892.39	36,892.39	36,892.39	21,713.05	12/31/2023	44	0.0079%	0.00
0100	TMPMCR	-	-	57,197.50	162,592.50	267,987.50	283,796.75	283,796.75	283,796.75	283,796.75	326,587.91	326,587.91	2,624,889.91	2,653,085.96	581,085.86	9/30/2021	17	0.2102%	0.04
0100	151021	-	-	-	359,485.14	359,485.14	359,485.14	359,485.14	359,485.14	-	-	-	-	-	138,263.52	12/1/2019	(4)	0.0500%	(0.00)
0100	152442	-	-	-	160,064.59	162,036.68	164,008.77	-	-	-	-	-	-	-	37,393.08	10/31/2019	(6)	0.0135%	(0.00)
0100	152524	-	-	-	13,701.35	29,374.79	-	-	-	-	-	-	-	-	3,313.55	9/30/2019	(7)	0.0012%	(0.00)
0100	152536	-	-	-	85,796.25	178,880.15	199,959.15	199,959.15	199,959.15	-	-	-	-	-	66,504.14	12/31/2019	(4)	0.0241%	(0.00)
0100	152805	-	-	-	22,300.30	22,300.30	22,300.30	-	-	-	-	-	-	-	5,146.22	10/31/2019	(6)	0.0019%	(0.00)
0100	156980LGE	-	-	-	20,057.70	20,057.70	20,057.70	20,057.70	20,057.70	-	-	-	-	-	7,714.50	12/1/2019	(4)	0.0028%	(0.00)
0100	157285	-	-	-	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	58,497.12	7/31/2020	3	0.0212%	0.00
0100	157813LGE	-	-	-	317,446.13	317,446.13	-	-	-	-	-	-	-	-	48,837.87	9/30/2019	(7)	0.0177%	(0.00)
0100	406000045	-	-	-	26,719.46	-	-	-	-	-	-	-	-	-	2,055.34	8/31/2019	(8)	0.0007%	(0.00)
0100	406000046	-	-	-	17,159.25	17,159.25	84,703.91	-	-	-	-	-	-	-	9,155.57	10/31/2019	(6)	0.0033%	(0.00)
0100	406000047	-	-	-	11,439.50	-	-	-	-	-	-	-	-	-	879.96	8/31/2019	(8)	0.0003%	(0.00)
0100	IT0294L	-	-	-	26,578.78	53,157.56	-	-	-	-	-	-	-	-	6,133.56	9/30/2019	(7)	0.0022%	(0.00)
0100	IT0428L	-	-	-	11,000.00	22,000.00	33,000.00	-	-	-	-	-	-	-	5,076.92	10/31/2019	(6)	0.0018%	(0.00)
0100	IT0458L	-	-	-	51,580.89	206,323.61	335,275.88	464,228.15	593,180.42	644,761.31	696,493.89	851,691.59	1,006,889.29	1,187,953.31	464,490.64	6/30/2020	2	0.1680%	0.00
0100	IT0506L	-	-	-	4,400.00	13,200.00	-	-	-	-	-	-	-	-	1,353.85	9/30/2019	(7)	0.0005%	(0.00)
0100	IT0523L	-	-	-	22,000.00	44,000.00	66,000.00	88,000.00	99,000.00	-	-	-	-	-	24,538.46	12/31/2019	(4)	0.0089%	(0.00)
0100	IT0559L	-	-	-	11,000.00	22,000.00	33,000.00	44,000.00	55,000.00	66,000.00	77,000.00	88,000.00	99,000.00	110,000.00	46,538.46	6/30/2020	2	0.0168%	0.00
0100	SU-000280	-	-	-	46,224.57	92,449.14	138,673.71	184,898.28	231,122.85	-	-	-	-	-	53,336.04	12/31/2019	(4)	0.0193%	(0.00)
0100	SU-000346	-	-	-	22,233.68	44,467.36	66,701.04	111,168.37	133,402.05	133,402.05	177,756.06	222,110.07	310,818.09	532,588.16	134,972.84	6/30/2020	2	0.0488%	0.00
0100	152513	-	-	-	36,888.25	89,585.75	142,283.25	194,980.75	247,678.25	300,375.75	300,375.75	300,375.75	300,375.75	300,375.75	170,253.46	10/31/2022	30	0.0616%	0.02
0100	IT0480L	-	-	-	63,462.05	126,924.10	190,386.15	253,848.20	317,310.25	380,772.30	448,078.23	515,384.16	582,346.94	649,652.87	271,397.33	6/30/2021	14	0.0982%	0.01
0100	00085FACL	-	-	-	-	50,682.50	101,365.00	-	-	-	-	-	-	-	11,695.96	10/31/2019	(6)	0.0042%	(0.00)
0100	124090	-	-	-	-	64,480.87	-	-	-	-	-	-	-	-	4,960.07	9/30/2019	(7)	0.0018%	(0.00)
0100	133622LGE	-	-	-	-	49,189.85	49,189.85	49,189.85	49,189.85	-	-	-	-	-	15,135.34	12/1/2019	(4)	0.0055%	(0.00)
0100	133627LGE	-	-	-	-	30,337.55	30,337.55	30,337.55	30,337.55	-	-	-	-	-	9,334.63	12/1/2019	(4)	0.0034%	(0.00)
0100	140032LGE	-	-	-	-	98,379.70	98,379.70	98,379.70	98,379.70	-	-	-	-	-	30,270.68	12/31/2019	(4)	0.0109%	(0.00)
0100	140654LGE	-	-	-	-	223,070.25	223,070.25	223,070.25	223,070.25	-	-	-	-	-	68,637.00	12/1/2019	(4)	0.0248%	(0.00)
0100	147766	-	-	-	-	31,423.15	-	-	-	-	-	-	-	-	2,417.17	9/30/2019	(7)	0.0009%	(0.00)
0100	150052LGE	-	-	-	-	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	173,400.56	39,521.23	5/31/2020	1	0.0143%	0.00
0100	151532	-	-	-	-	36,702.45	66,148.14	111,000.09	111,000.09	-	-	-	-	-	24,988.52	12/31/2019	(4)	0.0090%	(0.00)
0100	152032LGE	-	-	-	-	147,755.99	147,755.99	147,755.99	147,755.99	-	-	-	-	-	45,463.38	12/31/2019	(4)	0.0164%	(0.00)
0100	153072LGE	-	-	-	-	624,596.70	-	-	-	-	-	-	-	-	48,045.90	9/30/2019	(7)	0.0174%	(0.00)
0100	154593	-	-	-	-	99,108.56	594,651.36	-	-	-	-	-	-	-	53,366.15	10/31/2019	(6)	0.0193%	(0.00)
0100	154761	-	-	-	-	53,022.08	53,022.08	53,022.08	53,022.08	-	-	-	-	-	16,314.49	12/1/2019	(4)	0.0059%	(0.00)
0100	154792LGE	-	-	-	-	254,380.16	254,380.16	254,380.16	254,380.16	254,380.16	254,380.16	-	-	-	117,406.23	2/28/2020	(2)	0.0425%	(0.00)
0100	156722	-	-	-	-	322,102.83	-	-	-	-	-	-	-	-	24,777.14	9/30/2019	(7)	0.0090%	(0.00)
0100	157246	-	-	-	-	107,245.31	107,245.31	107,245.31	107,245.31	-	-	-	-	-	32,998.56	12/31/2019	(4)	0.0119%	(0.00)
0100	157779LGE	-	-	-	-	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	177,319.16	177,319.16	62,390.34	5/31/2020	1	0.0226%	0.00
0100	IT0417L	-	-	-	-	39,000.00	39,000.00	-	-	-	-	-	-	-	6,000.00	10/31/2019	(6)	0.0022%	(0.00)
0100	IT0438L	-	-	-	-	26,400.00	-	-	-	-	-	-	-	-	2,030.77	9/30/2019	(7)	0.0007%	(0.00)
0100	IT0564CG	-	-	-	-	49,591.73	99,183.46	148,775.19	198,366.92	247,958.65	347,702.93	447,447.21	547,191.49	646,935.77	210,242.57	8/31/2020	4	0.0761%	0.00
0100	157283	-	-	-	-	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	140,393.08	8/31/2021	16	0.0508%	0.01
0100	00027FACL	-	-	-	-	-	50,682.50	198,675.40	-	-	-	-	-	-	19,181.38	11/30/2019	(5)	0.0069%	(0.00)
0100	00034FACL	-	-	-	-	-	221,762.05	443,524.10	665,286.15	-	-	-	-	-	102,351.72	12/31/2019	(4)	0.0370%	(0.00)
0100	00075FACL	-	-	-	-	-	152,047.50	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	193,724.11	8/31/2020	4	0.0701%	0.00
0100	133653LGE	-	-	-	-	-	31,226.40	31,226.40	31,226.40	-	-	-	-	-	7,206.09	12/1/2019	(4)	0.0026%	(0.00)
0100	137587	-	-	-	-	-	100,000.00	761,548.75	-	-	-	-	-	-	66,272.98	11/30/2019	(5)	0.0240%	(0.00)
0100	140619LGE	-	-	-	-	-	70,787.63	70,787.63	70,787.63	-	-	-	-	-	16,335.61	12/1/2019	(4)	0.0059%	(0.00)
0100	147735	-	-	-	-	-	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	19,337.32	7/31/2020	3	0.0070%	0.00
0100	151006	-	-	-	-	-	96,886.15	-	-	-	-	-	-	-	7,452.78	10/31/2019	(6)	0.0027%	(0.00)
0100	151010	-	-	-	-	-	128,694.38	128,694.38	-	-	-	-	-	-	19,799.14	11/30/2019	(5)	0.0072%	(0.00)
0100	152007LGE	-	-	-	-	-	42,326.15	42,326.15	42,326.15	-	-	-	-	-	9,767.57	12/31/2019	(4)	0.0035%	(0.00)
0100	152016LGE	-	-	-	-	-	96,926.88	96,926.88	96,926.88	-	-	-	-	-	22,367.74	12/31/2019	(4)	0.0081%	(0.00)
0100	152097LGE	-	-	-	-	-	65,891.18	65,891.18	65,891.18	-	-	-	-	-	15,205.66	12/31/2019	(4)	0.0055%	(0.00)
0100	153047LGE	-	-	-	-	-	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	114,549.66	21,977.94	5/31/2020	1	0.0080%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	153070LGE	-	-	-	-	-	76,187.07	76,187.07	76,187.07	-	-	-	-	-	17,581.63	12/1/2019	(4)	0.0064%	(0.00)
0100	154541	-	-	-	-	-	79,361.07	228,023.92	337,043.33	446,062.74	446,062.74	446,062.74	446,062.74	446,062.74	221,134.00	11/30/2020	7	0.0800%	0.01
0100	155443LGE	-	-	-	-	-	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	520,304.64	7/31/2020	3	0.1882%	0.01
0100	156931	-	-	-	-	-	51,477.75	51,477.75	-	-	-	-	-	-	7,919.65	11/30/2019	(5)	0.0029%	(0.00)
0100	156934	-	-	-	-	-	38,398.13	38,398.13	-	-	-	-	-	-	5,907.40	11/30/2019	(5)	0.0021%	(0.00)
0100	156965	-	-	-	-	-	43,470.10	43,470.10	43,470.10	-	-	-	-	-	10,031.56	12/31/2019	(4)	0.0036%	(0.00)
0100	157074	-	-	-	-	-	428,981.25	428,981.25	428,981.25	-	-	-	-	-	98,995.67	12/31/2019	(4)	0.0358%	(0.00)
0100	157115LGE	-	-	-	-	-	79,868.10	79,868.10	79,868.10	-	-	-	-	-	18,431.10	12/1/2019	(4)	0.0067%	(0.00)
0100	157297LGE	-	-	-	-	-	84,652.30	84,652.30	84,652.30	-	-	-	-	-	19,535.15	12/1/2019	(4)	0.0071%	(0.00)
0100	157566	-	-	-	-	-	44,990.10	44,990.10	44,990.10	-	-	-	-	-	10,382.33	12/31/2019	(4)	0.0038%	(0.00)
0100	158125	-	-	-	-	-	561,943.75	961,943.75	-	-	-	-	-	-	117,222.12	11/30/2019	(5)	0.0424%	(0.00)
0100	IT0419L	-	-	-	-	-	5,200.00	13,000.00	20,800.00	26,000.00	31,200.00	36,400.00	41,600.00	46,800.00	17,000.00	10/31/2020	6	0.0061%	0.00
0100	IT0463L	-	-	-	-	-	21,761.80	43,523.60	65,285.40	-	-	-	-	-	10,043.91	12/31/2019	(4)	0.0036%	(0.00)
0100	148822	-	-	-	-	-	47,901.30	95,802.59	146,159.45	206,338.60	594,282.12	982,225.56	1,370,169.00	1,758,112.44	400,076.24	12/31/2021	20	0.1447%	0.03
0100	152711	-	-	-	-	-	51,998.88	103,997.77	155,996.66	207,995.55	373,607.41	539,219.15	704,830.89	870,442.63	231,391.46	12/31/2021	20	0.0837%	0.02
0100	156932	-	-	-	-	-	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	47,259.23	11/30/2021	19	0.0171%	0.00
0100	00066FACL	-	-	-	-	-	-	299,026.75	598,053.50	-	-	-	-	-	69,006.17	12/31/2019	(4)	0.0250%	(0.00)
0100	134238	-	-	-	-	-	-	26,763.47	53,526.97	79,431.01	287,415.99	495,400.97	703,385.95	-	126,609.97	4/30/2020	-	0.0458%	-
0100	137039	-	-	-	-	-	-	448,182.17	-	-	-	-	-	-	34,475.55	11/30/2019	(5)	0.0125%	(0.00)
0100	138395	-	-	-	-	-	-	159,592.50	-	-	-	-	-	-	12,276.35	11/30/2019	(5)	0.0044%	(0.00)
0100	138400	-	-	-	-	-	-	257,388.75	-	-	-	-	-	-	19,799.13	11/30/2019	(5)	0.0072%	(0.00)
0100	139878	-	-	-	-	-	-	1,189,859.32	2,344,998.17	-	-	-	-	-	271,912.11	12/31/2019	(4)	0.0984%	(0.00)
0100	139991	-	-	-	-	-	-	25,999.50	51,998.98	77,998.46	330,521.25	583,044.13	835,567.01	1,088,089.89	230,247.63	12/31/2020	8	0.0833%	0.01
0100	142399	-	-	-	-	-	-	991,085.60	1,982,171.20	-	-	-	-	-	228,712.06	12/31/2019	(4)	0.0827%	(0.00)
0100	143603	-	-	-	-	-	-	644,205.64	-	-	-	-	-	-	49,554.28	11/30/2019	(5)	0.0179%	(0.00)
0100	143609	-	-	-	-	-	-	243,001.50	-	-	-	-	-	-	18,692.42	11/30/2019	(5)	0.0068%	(0.00)
0100	143611	-	-	-	-	-	-	33,728.46	-	-	-	-	-	-	2,594.50	11/30/2019	(5)	0.0009%	(0.00)
0100	143634	-	-	-	-	-	-	62,496.82	-	-	-	-	-	-	4,807.45	11/30/2019	(5)	0.0017%	(0.00)
0100	147056	-	-	-	-	-	-	869,995.63	869,995.63	869,995.63	869,995.63	869,995.63	869,995.63	2,570,269.91	599,249.51	5/31/2020	1	0.2168%	0.00
0100	151015	-	-	-	-	-	-	343,185.00	-	-	-	-	-	-	26,398.85	11/30/2019	(5)	0.0095%	(0.00)
0100	151255	-	-	-	-	-	-	371,657.10	371,657.10	-	-	-	-	-	57,178.02	12/31/2019	(4)	0.0207%	(0.00)
0100	151259	-	-	-	-	-	-	366,952.15	366,952.15	-	-	-	-	-	56,454.18	12/31/2019	(4)	0.0204%	(0.00)
0100	152015LGE	-	-	-	-	-	-	97,138.51	97,138.51	-	-	-	-	-	14,944.39	12/31/2019	(4)	0.0054%	(0.00)
0100	152055	-	-	-	-	-	-	67,155.95	67,155.95	67,155.95	67,155.95	67,155.95	67,155.95	-	30,995.05	4/30/2020	-	0.0112%	-
0100	152063	-	-	-	-	-	-	60,597.19	-	-	-	-	-	-	4,661.32	11/30/2019	(5)	0.0017%	(0.00)
0100	152081	-	-	-	-	-	-	354,767.49	-	-	-	-	-	-	27,289.81	11/30/2019	(5)	0.0099%	(0.00)
0100	152449	-	-	-	-	-	-	23,051.09	-	-	-	-	-	-	1,773.16	11/30/2019	(5)	0.0006%	(0.00)
0100	152667	-	-	-	-	-	-	121,877.58	121,877.58	-	-	-	-	-	18,750.40	12/1/2019	(4)	0.0068%	(0.00)
0100	152670	-	-	-	-	-	-	125,876.22	-	-	-	-	-	-	9,682.79	11/30/2019	(5)	0.0035%	(0.00)
0100	152772	-	-	-	-	-	-	82,985.58	82,985.58	82,985.58	82,985.58	82,985.58	82,985.58	-	38,301.04	4/30/2020	-	0.0139%	-
0100	153080LGE	-	-	-	-	-	-	146,993.00	146,993.00	146,993.00	146,993.00	146,993.00	220,597.11	557,782.11	116,411.09	5/30/2020	1	0.0421%	0.00
0100	154395	-	-	-	-	-	-	247,771.40	-	-	-	-	-	-	19,059.34	11/30/2019	(5)	0.0069%	(0.00)
0100	154408	-	-	-	-	-	-	733,588.88	1,461,216.39	-	-	-	-	-	168,831.17	12/31/2019	(4)	0.0611%	(0.00)
0100	154646	-	-	-	-	-	-	119,023.03	-	-	-	-	-	-	9,155.62	11/30/2019	(5)	0.0033%	(0.00)
0100	154648	-	-	-	-	-	-	119,023.03	-	-	-	-	-	-	9,155.62	11/30/2019	(5)	0.0033%	(0.00)
0100	154659	-	-	-	-	-	-	148,783.43	214,237.75	-	-	-	-	-	27,924.71	12/31/2019	(4)	0.0101%	(0.00)
0100	154708	-	-	-	-	-	-	1,276,740.00	-	-	-	-	-	-	98,210.77	11/30/2019	(5)	0.0355%	(0.00)
0100	155418	-	-	-	-	-	-	1,189,302.72	2,378,605.44	-	-	-	-	-	274,454.47	12/31/2019	(4)	0.0993%	(0.00)
0100	156664	-	-	-	-	-	-	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	21,346.46	11/30/2020	7	0.0077%	0.00
0100	156666	-	-	-	-	-	-	718,954.50	718,954.50	-	-	-	-	-	110,608.38	12/31/2019	(4)	0.0400%	(0.00)
0100	156739	-	-	-	-	-	-	396,434.24	792,868.48	-	-	-	-	-	91,484.82	12/31/2019	(4)	0.0331%	(0.00)
0100	156789	-	-	-	-	-	-	396,434.24	792,868.48	-	-	-	-	-	91,484.82	12/31/2019	(4)	0.0331%	(0.00)
0100	156930	-	-	-	-	-	-	319,185.00	-	-	-	-	-	-	24,552.69	11/30/2019	(5)	0.0089%	(0.00)
0100	157747	-	-	-	-	-	-	170,000.00	170,000.00	170,000.00	170,000.00	170,000.00	170,000.00	-	78,461.54	4/30/2020	-	0.0284%	-
0100	157785	-	-	-	-	-	-	343,185.00	-	-	-	-	-	-	26,398.85	11/30/2019	(5)	0.0095%	(0.00)
0100	165001	-	-	-	-	-	-	407,532.19	-	-	-	-	-	-	31,348.63	11/30/2019	(5)	0.0113%	(0.00)
0100	LI-000088	-	-	-	-	-	-	16,635.63	33,271.28	49,906.93	466,603.52	883,300.12	1,299,996.72	1,716,693.32	343,569.81	5/31/2020	1	0.1243%	0.00
0100	00053FACL	-	-	-	-	-	-	-	50,682.50	-	-	-	-	-	3,898.65	12/31/2019	(4)	0.0014%	(0.00)
0100	00054FACL	-	-	-	-	-	-	-	50,682.50	-	-	-	-	-	3,898.65	12/31/2019	(4)	0.0014%	(0.00)
0100	156850LGE	-	-	-	-	-	-	-	116,231.80	-	-	-	-	-	8,940.91	12/31/2019	(4)	0.0032%	(0.00)
0100	157313	-	-	-	-	-	-	-	1,796.15	36,499.84	63,412.10	86,691.51	109,970.92	133,250.33	33,201.60	6/30/2020	2	0.0120%	0.00
0100	152614	-	-	-	-	-	-	-	-	-	(983.25)	(1,966.50)	(2,949.75)	-	(453.81)	4/30/2020	-	-0.0002%	-
0100	154738	-	-	-	-	-	-	-	-	-	168,592.50	168,592.50	168,592.50	168,592.50	51,874.62	12/1/2020	8	0.0188%	0.00
0100	155292	-	-	-	-	-	-	-	-	-	23,692.95	48,751.12	73,809.29	100,041.41	18,945.75	12/31/2020	8	0.0069%	0.00
0100	155315	-	-	-	-	-	-	-	-	-	19,957.15	39,914.30	59,871.45	79,828.60	15,351.65	12/31/2020	8	0.0056%	0.00
0100	155352	-	-	-	-	-	-	-	-	-	38,131.02	74,231.37	110,331.72	148,462.74	28,550.53	12/31/2020	8	0.0103%	0.00
0100	155359	-	-	-	-	-	-	-	-	-	145,170.14	290,340.28	435,510.42	580,680.56	111,669.34	12/31/2020	8	0.0404%	0.00
0100	155361	-	-	-	-	-	-	-	-	-	120,968.32	239,904.87	360,873.19	479,809.74	92,427.39	12/31/2020	8	0.0334%	0.00
0100	155363	-	-	-	-	-	-	-	-	-	913,783.88	1,828,044.94	2,740,883.77	3,666,395.43	703,777.54	12/31/2020	8	0.2546%	0.02
0100	155365	-	-	-	-	-	-	-	-	-	140,105.60	280,211.20	420,316.80	560,422.40	107,773.54	12/31/2020	8	0.0390%	0.00
0100	157051	-	-	-	-	-	-	-	-	-	53,121.32	96,073.43	130,091.93	149,898.61	33,014.25	12/31/2020	8	0.0119%	0.00
0100	157261LGE	-	-	-	-	-	-	-	-	-	82,003.40	200,971.38	237,935.98	-	40,070.06	4/30/2020	-	0.0145%	-
0100	406000005	-	-	-	-	-	-	-	-	-	85,482.01	170,964.02	256,446.03	379,616.29	68,654.49	10/31/2020	6	0.0248%	0.00
0100	406000022	-	-	-	-	-	-	-	-	-	130,638.60	250,235.62	369,832.64	509,491.22	96,938.31	12/31/2020	8	0.0351%	0.00
0100	448000019	-	-	-	-	-	-	-	-	-	22,679.00	79,979.30	148,886.05	207,467.43	35,308.60	12/31/2020	8	0.0128%	0.00
0100	448000031	-	-	-	-	-	-	-	-	-	1,501.40	10,510.86	29,757.47	32,760.27	5,733.08	12/31/2020	8	0.0021%	0.00
0100	IT0302L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	161,200.00	317,200.00	37,400.00	11/30/2020	7	0.0135%	0.00
0100	IT0306L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	213,200.00	421,200.00	49,400.00	12/31/2020	8	0.0179%	0.00
0100	IT0612L	-	-	-	-	-	-	-	-	-	11,440.00	22,880.00	34,320.00	45,760.00	8,800.00	12/31/2020	8	0.0032%	0.00
0100	IT0615L	-	-	-	-	-	-	-	-	-	19,657.31	41,383.82	63,110.33	84,836.84	16,076.02	12/31/2020	8	0.0058%	0.00
0100	IT0627L	-	-	-	-	-	-	-	-	-	3,239.79	6,479.58	9,719.37	12,959.16	2,492.15	12/31/2020	8	0.0009%	0.00
0100	IT0636L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	15,600.00	28,600.00	4,000.00	11/30/2020	7	0.0014%	0.00
0100	IT0671L	-	-	-	-	-	-	-	-	-	146,533.65	293,067.30	439,600.95	586,134.60	112,718.19	11/30/2020	7	0.0408%	0.00
0100	IT0693L	-	-	-	-	-	-	-	-	-	6,500.00	13,000.00	19,500.00	26,000.00	5,000.00	12/31/2020	8	0.0018%	0.00
0100	IT0705L	-	-	-	-	-	-	-	-	-	6,489.23	12,978.46	19,467.69	25,956.92	4,991.72	12/31/2020	8	0.0018%	0.00
0100	IT0904L	-	-	-	-	-	-	-	-	-	13,107.97	26,215.94	39,323.91	-	6,049.83	4/30/2020	-	0.0022%	-
0100	SU-000299	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	15,833.85	12/31/2020	8	0.0057%	0.00
0100	SU-000301	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	15,833.85	12/31/2020	8	0.0057%	0.00
0100	SU-000336	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	15,833.85	12/31/2020	8	0.0057%	0.00
0100	SU-000337	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	15,833.85	12/31/2020	8	0.0057%	0.00
0100	SU-000338	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	15,833.85	12/31/2020	8	0.0057%	0.00
0100	SU-000356	-	-	-	-	-	-	-	-	-	54,555.44	109,110.88	163,666.32	218,221.76	41,965.72	12/31/2020	8	0.0152%	0.00
0100	SU-000357	-	-	-	-	-	-	-	-	-	60,321.44	120,642.88	180,964.32	241,285.76	46,401.11	12/31/2020	8	0.0168%	0.00
0100	SU-000358	-	-	-	-	-	-	-	-	-	82,912.44	165,824.88	248,737.32	300,557.60	61,387.10	9/30/2020	5	0.0222%	0.00
0100	SU-000359	-	-	-	-	-	-	-	-	-	70,522.89	141,045.78	211,568.67	282,091.56	54,248.38	12/31/2020	8	0.0196%	0.00
0100	147819	-	-	-	-	-	-	-	-	-	85,666.70	171,333.44	257,000.18	342,666.92	65,897.48	12/31/2030	128	0.0238%	0.03
0100	152632	-	-	-	-	-	-	-	-	-	10,623.63	21,247.30	31,870.97	42,494.64	8,172.04	12/31/2021	20	0.0030%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	IT0609L	-	-	-	-	-	-	-	-	-	10,968.66	32,905.96	98,717.89	131,623.85	21,093.57	7/31/2021	15	0.0076%	0.00
0100	SU-000362	-	-	-	-	-	-	-	-	-	26,624.19	53,248.38	186,369.39	319,490.40	45,056.34	6/30/2021	14	0.0163%	0.00
0100	TMPMAGRC	-	-	-	-	-	-	-	-	-	17,483.56	29,716.25	269,849.74	396,588.23	54,895.21	6/30/2022	26	0.0199%	0.01
0100	TMPWKA	-	-	-	-	-	-	-	-	-	61,210.32	193,476.65	433,740.84	671,776.55	104,631.10	11/30/2022	31	0.0378%	0.01
0100	149165	-	-	-	-	-	-	-	-	-	-	39,807.17	44,136.59	83,436.93	12,875.44	12/31/2020	8	0.0047%	0.00
0100	153021	-	-	-	-	-	-	-	-	-	-	8,109.20	17,232.05	27,368.55	4,054.60	12/31/2020	8	0.0015%	0.00
0100	153024	-	-	-	-	-	-	-	-	-	-	39,430.99	80,990.64	122,550.29	18,690.15	12/31/2020	8	0.0068%	0.00
0100	156838LGE	-	-	-	-	-	-	-	-	-	-	199,670.25	199,670.25	199,670.25	46,077.75	12/1/2020	8	0.0167%	0.00
0100	406000052	-	-	-	-	-	-	-	-	-	-	53,497.50	101,725.25	149,953.00	23,475.06	10/31/2020	6	0.0085%	0.00
0100	447500003	-	-	-	-	-	-	-	-	-	-	6,948.90	11,849.22	11,849.22	2,357.49	11/30/2020	7	0.0009%	0.00
0100	447500004	-	-	-	-	-	-	-	-	-	-	2,955.38	2,955.38	2,955.38	682.01	9/30/2020	5	0.0002%	0.00
0100	IT0514L	-	-	-	-	-	-	-	-	-	-	10,400.00	20,800.00	41,600.00	5,600.00	12/31/2020	8	0.0020%	0.00
0100	IT0606L	-	-	-	-	-	-	-	-	-	-	2,600.00	7,800.00	15,600.00	2,000.00	11/30/2020	7	0.0007%	0.00
0100	IT0613L	-	-	-	-	-	-	-	-	-	-	14,612.00	29,224.00	43,836.00	6,744.00	11/30/2020	7	0.0024%	0.00
0100	IT0614L	-	-	-	-	-	-	-	-	-	-	5,274.36	10,548.72	15,823.08	2,434.32	8/31/2020	4	0.0009%	0.00
0100	IT0618L	-	-	-	-	-	-	-	-	-	-	11,700.00	23,400.00	46,800.00	6,300.00	12/31/2020	8	0.0023%	0.00
0100	IT0644L	-	-	-	-	-	-	-	-	-	-	2,340.00	7,800.00	13,260.00	1,800.00	11/30/2020	7	0.0007%	0.00
0100	IT0647L	-	-	-	-	-	-	-	-	-	-	3,120.00	10,920.00	18,720.00	2,520.00	11/30/2020	7	0.0009%	0.00
0100	IT0649L	-	-	-	-	-	-	-	-	-	-	5,200.00	15,600.00	31,200.00	4,000.00	11/30/2020	7	0.0014%	0.00
0100	IT0651L	-	-	-	-	-	-	-	-	-	-	10,400.00	10,400.00	20,800.00	3,200.00	10/31/2020	6	0.0012%	0.00
0100	IT0672L	-	-	-	-	-	-	-	-	-	-	1,560.00	5,200.00	8,840.00	1,200.00	11/30/2020	7	0.0004%	0.00
0100	IT0675L	-	-	-	-	-	-	-	-	-	-	4,680.00	15,600.00	31,200.00	3,960.00	11/30/2020	7	0.0014%	0.00
0100	IT0680L	-	-	-	-	-	-	-	-	-	-	3,210.35	6,955.77	31,033.51	3,169.20	12/31/2020	8	0.0011%	0.00
0100	IT0689L	-	-	-	-	-	-	-	-	-	-	6,600.00	13,200.00	19,800.00	3,046.15	6/30/2020	2	0.0011%	0.00
0100	IT0690L	-	-	-	-	-	-	-	-	-	-	13,200.00	26,400.00	39,600.00	6,092.31	11/30/2020	7	0.0022%	0.00
0100	IT0695L	-	-	-	-	-	-	-	-	-	-	4,160.00	8,320.00	12,480.00	1,920.00	11/30/2020	7	0.0007%	0.00
0100	IT0701L	-	-	-	-	-	-	-	-	-	-	11,000.00	22,000.00	33,000.00	5,076.92	11/30/2020	7	0.0018%	0.00
0100	IT0711L	-	-	-	-	-	-	-	-	-	-	13,000.00	26,000.00	39,000.00	6,000.00	11/30/2020	7	0.0022%	0.00
0100	IT0712L	-	-	-	-	-	-	-	-	-	-	4,400.00	8,800.00	13,200.00	2,030.77	11/30/2020	7	0.0007%	0.00
0100	IT0722L	-	-	-	-	-	-	-	-	-	-	10,400.00	20,800.00	31,200.00	4,800.00	11/30/2020	7	0.0017%	0.00
0100	IT1087L	-	-	-	-	-	-	-	-	-	-	25,716.10	51,432.20	77,148.30	11,868.97	12/31/2020	8	0.0043%	0.00
0100	144530	-	-	-	-	-	-	-	-	-	-	-	80,263.49	80,263.49	12,348.23	12/31/2020	8	0.0045%	0.00
0100	144542	-	-	-	-	-	-	-	-	-	-	-	3,202,510.42	-	246,346.96	4/30/2020	-	0.0891%	-
0100	148096	-	-	-	-	-	-	-	-	-	-	-	175,213.12	-	13,477.93	4/30/2020	-	0.0049%	-
0100	148104	-	-	-	-	-	-	-	-	-	-	-	130,301.55	-	10,023.20	4/30/2020	-	0.0036%	-
0100	149481	-	-	-	-	-	-	-	-	-	-	-	11,000.00	11,000.00	1,692.31	12/31/2020	8	0.0006%	0.00
0100	153018	-	-	-	-	-	-	-	-	-	-	-	101,365.00	101,365.00	15,594.62	12/31/2020	8	0.0056%	0.00
0100	157031	-	-	-	-	-	-	-	-	-	-	-	11,739.50	11,739.50	1,806.08	12/31/2020	8	0.0007%	0.00
0100	157060	-	-	-	-	-	-	-	-	-	-	-	19,957.15	24,465.52	3,417.13	12/31/2020	8	0.0012%	0.00
0100	157075LGE	-	-	-	-	-	-	-	-	-	-	-	20,020.36	20,020.36	3,080.06	12/1/2020	8	0.0011%	0.00
0100	157153	-	-	-	-	-	-	-	-	-	-	-	26,875.17	-	2,067.32	4/30/2020	-	0.0007%	-
0100	IT0407L	-	-	-	-	-	-	-	-	-	-	-	11,000.00	33,000.00	3,384.62	7/31/2020	3	0.0012%	0.00
0100	IT0452L	-	-	-	-	-	-	-	-	-	-	-	22,000.00	44,000.00	5,076.92	10/31/2020	6	0.0018%	0.00
0100	IT0634L	-	-	-	-	-	-	-	-	-	-	-	6,240.00	6,240.00	960.00	10/31/2020	6	0.0003%	0.00
0100	IT0637L	-	-	-	-	-	-	-	-	-	-	-	8,840.00	8,840.00	1,360.00	11/30/2020	7	0.0005%	0.00
0100	IT0661L	-	-	-	-	-	-	-	-	-	-	-	10,400.00	11,466.52	1,682.04	10/31/2020	6	0.0006%	0.00
0100	IT0668L	-	-	-	-	-	-	-	-	-	-	-	1,040.00	3,640.00	360.00	10/31/2020	6	0.0001%	0.00
0100	IT0673L	-	-	-	-	-	-	-	-	-	-	-	2,200.00	4,400.00	507.69	11/30/2020	7	0.0002%	0.00
0100	IT0674L	-	-	-	-	-	-	-	-	-	-	-	5,940.00	11,880.00	1,370.77	12/31/2020	8	0.0005%	0.00
0100	IT0681L	-	-	-	-	-	-	-	-	-	-	-	52,000.00	52,000.00	8,000.00	8/31/2020	4	0.0029%	0.00
0100	IT0682L	-	-	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	600.00	12/31/2020	8	0.0002%	0.00
0100	IT0694L	-	-	-	-	-	-	-	-	-	-	-	34,187.80	68,375.60	7,889.49	8/31/2020	4	0.0029%	0.00
0100	IT0713L	-	-	-	-	-	-	-	-	-	-	-	4,400.00	8,800.00	1,015.38	11/30/2020	7	0.0004%	0.00
0100	IT0715L	-	-	-	-	-	-	-	-	-	-	-	11,000.00	22,000.00	2,538.46	8/31/2020	4	0.0009%	0.00
0100	IT0716L	-	-	-	-	-	-	-	-	-	-	-	5,200.00	10,400.00	1,200.00	12/31/2020	8	0.0004%	0.00
0100	IT0718L	-	-	-	-	-	-	-	-	-	-	-	88,000.00	110,000.00	15,230.77	5/31/2020	1	0.0055%	0.00
0100	IT0720L	-	-	-	-	-	-	-	-	-	-	-	126,641.90	132,794.56	19,956.65	12/31/2020	8	0.0072%	0.00
0100	IT0723L	-	-	-	-	-	-	-	-	-	-	-	26,000.00	52,000.00	6,000.00	12/31/2020	8	0.0022%	0.00
0100	IT0726L	-	-	-	-	-	-	-	-	-	-	-	36,400.00	72,800.00	8,400.00	12/31/2020	8	0.0030%	0.00
0100	148882	-	-	-	-	-	-	-	-	-	-	-	125,950.57	251,901.14	29,065.52	12/31/2021	20	0.0105%	0.00
0100	406000034	-	-	-	-	-	-	-	-	-	-	-	10,539.50	31,618.50	3,242.92	12/31/2021	20	0.0012%	0.00
0100	IT0569L	-	-	-	-	-	-	-	-	-	-	-	391,587.42	861,468.43	96,388.91	12/31/2021	20	0.0349%	0.01
0100	SU-000347	-	-	-	-	-	-	-	-	-	-	-	7,867.01	15,734.02	1,815.46	8/31/2021	16	0.0007%	0.00
0100	132989	-	-	-	-	-	-	-	-	-	-	-	-	595,044.70	45,772.67	5/31/2020	1	0.0166%	0.00
0100	143595	-	-	-	-	-	-	-	-	-	-	-	-	991,872.29	76,297.87	11/30/2020	7	0.0276%	0.00
0100	147042	-	-	-	-	-	-	-	-	-	-	-	-	88,245.95	6,788.15	5/31/2020	1	0.0025%	0.00
0100	149021LGE	-	-	-	-	-	-	-	-	-	-	-	-	32,032.58	2,464.04	5/31/2020	1	0.0009%	0.00
0100	150064LGE	-	-	-	-	-	-	-	-	-	-	-	-	74,856.44	5,758.19	5/30/2020	1	0.0021%	0.00
0100	151578	-	-	-	-	-	-	-	-	-	-	-	-	193,340.36	14,872.34	5/31/2020	1	0.0054%	0.00
0100	151757	-	-	-	-	-	-	-	-	-	-	-	-	334,351.79	25,719.37	7/30/2020	3	0.0093%	0.00
0100	152659LGE	-	-	-	-	-	-	-	-	-	-	-	-	154,085.25	11,852.71	5/31/2020	1	0.0043%	0.00
0100	152685LGE	-	-	-	-	-	-	-	-	-	-	-	-	32,845.24	2,526.56	12/31/2020	8	0.0009%	0.00
0100	154464	-	-	-	-	-	-	-	-	-	-	-	-	163,529.12	12,579.16	6/30/2020	2	0.0046%	0.00
0100	154633	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	1,905.93	8/31/2020	4	0.0007%	0.00
0100	154639	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	1,905.93	7/31/2020	3	0.0007%	0.00
0100	154640	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	1,905.93	7/31/2020	3	0.0007%	0.00
0100	154642	-	-	-	-	-	-	-	-	-	-	-	-	19,821.72	1,524.75	7/31/2020	3	0.0006%	0.00
0100	154644	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	1,905.93	7/31/2020	3	0.0007%	0.00
0100	154744LGE	-	-	-	-	-	-	-	-	-	-	-	-	18,239.62	1,403.05	12/1/2020	8	0.0005%	0.00
0100	155558LGE	-	-	-	-	-	-	-	-	-	-	-	-	320,288.16	24,637.55	5/31/2020	1	0.0089%	0.00
0100	155651LGE	-	-	-	-	-	-	-	-	-	-	-	-	111,465.29	8,574.25	5/30/2020	1	0.0031%	0.00
0100	155659LGE	-	-	-	-	-	-	-	-	-	-	-	-	46,727.20	3,594.40	5/30/2020	1	0.0013%	0.00
0100	156834LGE	-	-	-	-	-	-	-	-	-	-	-	-	29,724.08	2,286.47	12/31/2020	8	0.0008%	0.00
0100	157038	-	-	-	-	-	-	-	-	-	-	-	-	14,234.19	1,094.94	12/31/2020	8	0.0004%	0.00
0100	157148	-	-	-	-	-	-	-	-	-	-	-	-	8,919.77	686.14	12/31/2020	8	0.0002%	0.00
0100	406000053	-	-	-	-	-	-	-	-	-	-	-	-	56,697.50	4,361.35	11/30/2020	7	0.0016%	0.00
0100	447500007	-	-	-	-	-	-	-	-	-	-	-	-	12,060.62	927.74	12/31/2020	8	0.0003%	0.00
0100	448000018	-	-	-	-	-	-	-	-	-	-	-	-	52,735.65	4,056.59	12/31/2020	8	0.0015%	0.00
0100	448000022	-	-	-	-	-	-	-	-	-	-	-	-	34,086.58	2,622.04	12/31/2020	8	0.0009%	0.00
0100	IT0628L	-	-	-	-	-	-	-	-	-	-	-	-	13,000.00	1,000.00	10/31/2020	6	0.0004%	0.00
0100	IT0633L	-	-	-	-	-	-	-	-	-	-	-	-	26,000.00	2,000.00	12/31/2020	8	0.0007%	0.00

LG&E and KU - CWIP Projects included in Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	Average CWIP Balance	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	IT0656L	-	-	-	-	-	-	-	-	-	-	-	-	104,000.00	8,000.00	10/31/2020	6	0.0029%	0.00
0100	IT0710L	-	-	-	-	-	-	-	-	-	-	-	-	10,400.00	800.00	10/31/2020	6	0.0003%	0.00
0100	IT0724L	-	-	-	-	-	-	-	-	-	-	-	-	3,876.51	298.19	2/28/2021	10	0.0001%	0.00
0100	SU-000360	-	-	-	-	-	-	-	-	-	-	-	-	62,184.33	4,783.41	3/31/2021	11	0.0017%	0.00
0100	SU-000361	-	-	-	-	-	-	-	-	-	-	-	-	72,563.15	5,581.78	3/31/2021	11	0.0020%	0.00
		267,180,130.92	252,236,454.92	248,932,612.93	264,610,417.66	295,762,597.97	305,338,955.82	360,241,447.48	356,196,963.17	187,632,268.79	213,905,896.10	242,532,918.63	287,369,482.47	311,924,588.34	276,451,133.48				5.65

127,691,381.97 Average CWIP Balance of Projects in CWIP during the Test Year that are in service as of April 30, 2020

46.19% Percent of projects in service at the end of the Test Period included in the 13 Month Average CWIP

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	155309	331,028.53	415,796.33	500,564.13	585,331.93	670,099.73	752,290.33	834,480.93	917,810.13	1,000,000.73	1,047,853.33	1,096,844.53	1,147,104.33	1,197,364.13	12/31/2023	6	0.3839%	0.02
0110	157614	32,751.06	46,925.66	62,388.86	78,335.29	93,798.49	109,261.69	122,147.69	135,000.19	135,000.19	135,000.19	143,880.39	154,917.21	168,237.51	11/30/2023	6	0.0539%	0.00
0110	163043	288,000.04	369,000.05	450,000.06	531,000.07	612,000.08	693,000.09	762,000.10	831,000.11	900,000.12	969,000.13	1,038,000.14	1,107,000.15	1,188,000.15	12/31/2022	6	0.3809%	0.02
0110	152874	-	4,220.58	9,729.76	39,439.82	43,660.40	74,509.06	106,533.61	138,053.39	138,053.39	138,053.39	138,053.39	138,053.39	138,053.39	12/31/2023	6	0.0443%	0.00
0110	BRMISCCAP	115,874.49	115,874.49	115,874.49	115,874.49	115,874.49	115,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	615,874.49	12/31/2028	6	0.1974%	0.01
0110	140342KU	-	-	35,176.46	35,176.46	35,176.46	35,176.46	35,176.46	35,176.46	48,903.86	48,903.86	48,903.86	48,903.86	48,903.86	12/31/2023	6	0.0157%	0.00
0110	147818	-	-	-	-	178,181.38	362,370.88	546,560.38	730,749.88	914,939.38	914,939.38	914,939.38	914,939.38	914,939.38	12/31/2030	6	0.2933%	0.02
0110	157216	-	-	-	-	-	-	-	-	-	12,813.67	25,627.29	38,440.91	51,254.53	12/31/2030	6	0.0164%	0.00
0110	145843	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	(1.00)	3,228.70	6,964.89	12,271.94	18,117.72	12/31/2023	6	0.0058%	0.00
0110	IT0000K	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	2,120,249.84	12/31/2025	6	0.6797%	0.04
0110	141391	-	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	32,500.00	12/31/2023	6	0.0104%	0.00
0110	145403	10,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	12/31/2023	6	0.0064%	0.00
0110	149345	311,249.73	311,249.73	311,249.73	311,249.73	311,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	411,249.73	12/31/2023	6	0.1318%	0.01
0110	148391	71,053.66	88,817.08	106,580.50	124,343.92	142,107.34	159,870.76	177,634.18	195,397.60	213,161.02	247,853.00	282,544.97	317,236.94	351,928.91	12/31/2025	6	0.1128%	0.01
0110	147830	1,808,333.32	1,989,166.65	2,169,999.98	2,350,833.31	2,531,666.64	2,712,499.97	2,893,333.30	3,074,166.63	3,255,000.00	3,435,833.33	3,616,666.66	3,797,499.99	3,978,333.32	12/31/2023	6	1.2754%	0.08
0110	148716	20,626.82	25,783.52	30,940.22	36,096.92	1,175,423.62	1,865,459.22	2,554,549.42	3,242,866.12	4,818,215.39	5,245,190.39	6,657,201.48	7,120,323.13	7,624,172.44	11/30/2020	7	2.4442%	0.17
0110	157605	20,626.82	25,783.52	30,940.22	690,791.92	1,065,993.62	1,442,914.22	1,818,889.42	2,954,171.52	3,324,216.52	3,688,240.82	5,154,922.80	5,546,992.01	5,918,697.96	11/30/2020	7	1.8975%	0.13
0110	149093	-	-	-	-	-	-	-	-	-	36,206.60	73,681.80	116,231.40	151,299.40	8/31/2020	4	0.0485%	0.00
0110	157066	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	198,444.65	12/31/2020	8	0.0636%	0.01
0110	144913	-	-	-	445,725.00	730,375.00	1,015,025.00	1,442,000.00	1,868,975.00	2,700,000.42	3,206,057.42	3,728,312.08	4,253,127.30	4,766,865.95	12/31/2020	8	1.5282%	0.12
0110	157022	-	-	-	-	-	-	-	-	-	22,874.94	28,957.94	43,686.66	51,038.26	12/31/2020	8	0.0164%	0.00
0110	157023	-	-	-	-	-	-	-	-	-	4,073.11	54,817.11	68,239.66	68,239.66	12/31/2020	8	0.0219%	0.00
0110	157025	-	-	-	-	-	-	-	-	-	2,036.55	26,888.55	26,888.55	26,888.55	12/31/2020	8	0.0086%	0.00
0110	157029	-	-	-	-	-	-	-	-	-	24,379.79	31,075.22	98,413.85	115,437.92	12/31/2020	8	0.0370%	0.00
0110	157055	-	-	-	-	-	-	-	-	-	20,363.26	38,476.36	69,021.25	69,021.25	12/31/2020	8	0.0221%	0.00
0110	157063	-	-	-	-	-	-	-	-	-	4,430.63	4,430.63	8,020.77	19,988.74	12/31/2020	8	0.0064%	0.00
0110	157010	-	-	-	-	-	-	-	-	-	-	9,680.84	14,755.24	17,926.74	12/31/2020	8	0.0057%	0.00
0110	157013	-	-	-	-	-	-	-	-	-	-	2,215.31	11,138.45	13,415.65	12/31/2020	8	0.0043%	0.00
0110	157016	-	-	-	-	-	-	-	-	-	-	30,875.39	35,110.18	35,110.18	12/31/2020	8	0.0113%	0.00
0110	157024	-	-	-	-	-	-	-	-	-	-	25,860.60	36,406.82	36,406.82	12/31/2020	8	0.0117%	0.00
0110	157028	-	-	-	-	-	-	-	-	-	-	54,377.48	54,377.48	60,486.00	12/31/2020	8	0.0194%	0.00
0110	157054	-	-	-	-	-	-	-	-	-	-	4,546.36	6,936.76	63,559.43	12/31/2020	8	0.0204%	0.00
0110	157058	-	-	-	-	-	-	-	-	-	-	22,673.40	26,746.51	26,746.51	12/31/2020	8	0.0086%	0.00
0110	157061	-	-	-	-	-	-	-	-	-	-	6,175.70	12,351.40	12,351.40	12/31/2020	8	0.0040%	0.00
0110	138485	-	-	-	-	-	-	-	-	-	-	5,121.09	12,802.74	20,484.39	12/31/2021	20	0.0066%	0.00
0110	157017	-	-	-	-	-	-	-	-	-	-	-	40,823.80	50,967.19	12/31/2020	8	0.0163%	0.00
0110	157034	-	-	-	-	-	-	-	-	-	-	-	43,751.00	55,341.83	12/31/2020	8	0.0177%	0.00
0110	157056	-	-	-	-	-	-	-	-	-	-	-	54,037.11	54,037.11	12/31/2020	8	0.0173%	0.00
0110	157062	-	-	-	-	-	-	-	-	-	-	-	4,787.70	16,793.73	12/31/2020	8	0.0054%	0.00
0110	152813	209,748.46	234,323.18	234,323.18	234,323.18	234,323.18	234,323.18	235,474.25	235,474.25	235,474.25	264,230.49	264,230.49	264,230.49	264,230.49	11/30/2020	7	0.0847%	0.01
0110	155280	29,155.20	41,389.27	49,509.47	63,658.56	70,490.16	79,605.68	86,437.28	93,268.88	100,100.48	106,932.08	115,598.11	122,429.71	129,261.31	12/31/2020	8	0.0414%	0.00
0110	157617	872,655.51	954,518.76	1,034,615.01	1,114,711.26	1,194,807.51	1,274,903.76	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,355,000.01	1,443,921.59	10/31/2020	6	0.4629%	0.03
0110	152950	-	-	-	-	-	-	-	-	-	71,495.56	132,675.50	191,195.44	198,562.58	12/31/2020	8	0.0637%	0.01
0110	163028	-	-	-	-	-	-	-	-	-	-	-	31,522.20	65,451.60	10/31/2020	6	0.0210%	0.00
0110	150052KU	-	-	-	-	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	182,119.72	742,275.50	5/31/2020	1	0.2380%	0.00
0110	157779KU	-	-	-	-	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	279,109.80	759,046.95	759,046.95	5/31/2020	1	0.2433%	0.00
0110	153047KU	-	-	-	-	-	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	104,666.18	486,040.88	5/31/2020	1	0.1558%	0.00
0110	155443KU	-	-	-	-	-	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	783,912.96	7/31/2020	3	0.2513%	0.01
0110	153080KU	-	-	-	-	-	-	629,199.63	629,199.63	629,199.63	629,199.63	629,199.63	1,137,069.63	2,145,350.71	5/30/2020	1	0.6878%	0.01
0110	156838KU	-	-	-	-	-	-	-	-	-	-	184,311.00	184,311.00	184,311.00	12/1/2020	8	0.0591%	0.00
0110	157075KU	-	-	-	-	-	-	-	-	-	-	-	85,349.96	85,349.96	12/1/2020	8	0.0274%	0.00
0110	149021KU	-	-	-	-	-	-	-	-	-	-	-	-	137,124.90	5/31/2020	1	0.0440%	0.00
0110	150064KU	-	-	-	-	-	-	-	-	-	-	-	-	320,537.25	5/30/2020	1	0.1028%	0.00
0110	152659KU	-	-	-	-	-	-	-	-	-	-	-	-	658,798.27	5/31/2020	1	0.2112%	0.00
0110	152685KU	-	-	-	-	-	-	-	-	-	-	-	-	140,661.05	12/31/2020	8	0.0451%	0.00
0110	154744KU	-	-	-	-	-	-	-	-	-	-	-	-	78,108.80	12/1/2020	8	0.0250%	0.00
0110	155558KU	-	-	-	-	-	-	-	-	-	-	-	-	1,365,438.99	5/31/2020	1	0.4377%	0.00
0110	155651KU	-	-	-	-	-	-	-	-	-	-	-	-	475,194.10	5/30/2020	1	0.1523%	0.00
0110	155659KU	-	-	-	-	-	-	-	-	-	-	-	-	199,205.42	5/30/2020	1	0.0639%	0.00
0110	156834KU	-	-	-	-	-	-	-	-	-	-	-	-	126,718.43	12/31/2020	8	0.0406%	0.00
0110	140199	-	-	-	-	-	-	-	205,720.00	205,720.00	205,720.00	705,720.01	868,579.57	1,130,324.47	5/31/2020	1	0.3624%	0.00
0110	131978	-	-	-	-	-	-	-	459,440.00	459,440.00	459,440.00	877,022.00	1,294,604.00	1,712,186.00	5/31/2021	13	0.5489%	0.07
0110	144312	-	-	-	-	-	-	-	287,150.00	287,150.00	287,150.00	287,150.00	287,150.00	287,150.00	4/30/2021	12	0.0921%	0.01
0110	154951	-	-	-	-	-	-	-	-	-	90,938.60	90,938.60	90,938.60	90,938.60	5/31/2020	1	0.0292%	0.00
0110	137485	-	-	-	-	-	-	-	-	-	-	-	10,286.00	10,286.00	5/31/2020	1	0.0033%	0.00
0110	140170	-	-	-	-	-	-	-	-	-	-	-	-	170,000.00	9/30/2020	5	0.0545%	0.00
0110	146434	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	216,545.86	11/30/2021	19	0.0694%	0.01
0110	155100	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	101,961.69	6/30/2023	38	0.0327%	0.01
0110	137244	174,489.03	175,423.78	175,423.78	175,705.17	175,787.48	370,040.23	370,513.86	647,564.21	660,493.16	661,520.67	869,774.41	915,753.08	1,178,219.68	5/31/2020	1	0.3777%	0.00
0110	137474	341,883.02	342,262.78	342,262.78	342,680.81	342,785.97	681,065.49	681,253.83	1,224,775.18	1,278,781.79	1,279,809.29	1,635,497.47	1,978,674.97	2,478,182.30	5/31/2020	1	0.7945%	0.01
0110	155018	-	-	-	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	133,179.98	7/31/2020	3	0.0427%	0.00
0110	156629	-	-	-	496,495.24	496,495.24	496,495.24	996,495.25	996,495.25	1,496,495.25	1,496,495.25	1,894,002.16	1,894,002.16	1,894,002.16	5/31/2020	1	0.6072%	0.01
0110	155017	-	-	-	-	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	409,784.57	4,560,239.71	4,560,239.71	5/31/2020	1	1.4620%	0.01
0110	220GH	-	-	-	-	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	1,435,750.00	2,448,056.14	4,472,668.40	7,509,586.80	5/31/2020	1	2.4075%	0.02
0110	144325	-	-	-	-	-	-	798,130.78	798,130.78	798,130.78	798,130.78	798,130.78	1,377,563.21	2,138,029.24	5/31/2020	1	0.6854%	0.01
0110	155014	-	-	-	-	-	-	86,145.00	86,145.00	86,145.00	86,145.00	131,289.00	707,305.00	707,305.00	5/31/2020	1	0.2268%	0.00
0110	144309	-	-	-	-	-	-	-	-	-	1,000.00	2,000.00	103,523.07	176,062.45	5/31/2020	1	0.0564%	0.00
0110	154950	-	-	-	-	-	-	-	-	-	44,251.60	44,251.60	44,251.60	44,251.60	5/31/2020	1	0.0142%	0.00
0110	140184	-	-	-	-	-	-	-	-	-	-	62,799.52	114,951.85	177,751.37	11/30/2020	7	0.0570%	0.00
0110	147347	-	-	-	-	-	-	-	-	-	-	102,376.63	255,941.58	320,229.08	5/31/2020	1	0.1027%	0.00
0110	151437	-	-	-	-	-	-	-	-	-	-	106,471.70	106,471.70	106,471.70	5/31/2020	1	0.0341%	0.00
0110	154961	-	-	-	-	-	-	-	-	-	-	97,750.53	97,750.53	97,750.53	5/31/2020	1	0.0313%	0.00
0110	101GH	-	-	-	-	-	-	-	-	-	-	-	75,922.97	151,845.94	10/31/2020	6	0.0487%	0.00
0110	144374	-	-	-	-	-	-	-	-	-	-	-	178,779.95	178,779.95	5/31/2020	1	0.0573%	0.00
0110	126302	-	-	-	-	-	-	-	-	-	-	-	-	456,753.23	5/31/2020	1	0.1464%	0.00
0110	144362	-	-	-	-	-	-	-	-	-	-	-	-	100,000.00	6/30/2020	2	0.0321%	0.00
0110	148111	-	-	-	-	-	-	-	-	-	-	-	-	2,920,303.33	5/31/2020	1	0.9362%	0.01
0110	151439	-	-	-	-	-	-	-	-	-	-	-	-	157,901.70	5/31/2020	1	0.0506%	0.00
0110	121GH	-	-	-	-	-	-	-	-	-	-	-	-	1,000,000.00	5/31/2021	13	0.3206%	0.04
0110	156577	-	-	-	-	-	-	-	-	-	-	-	-	169,290.00	5/31/2021	13	0.0543%	0.01
0110	133683	1,644,165.17	1,648,125.17	1,652,085.17	1,663,965.17	1,675,845.17	1,687,725.17	1,699,605.17	1,711,485.17	1,723,365.17	1,748,565.17	1,773,765.17	1,798,965.17	1,824,165.17	11/30/2023	43	0.5848%	0.25
0110	133641	58,380.07	69,380.07	80,380.07	113,380.07	146,380.07	179,380.07	212,380.07	245,380.07	278,380.07	348,379.98	418,379.91	488,379.85	558,379.76	11/30/2023	43	0.1790%	0.08
0110	158028	-	-	-	-	-	5,000.00	20,000.00	40,000.00	50,000.00	100,000.00	150,000.00	250,000.00	350,000.00	12/31/2022	32	0.1122%	0.04

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	158030	-	-	-	-	-	5,000.00	20,000.00	40,000.00	50,000.00	100,000.00	150,000.00	200,000.00	250,000.00	12/31/2022	32	0.0801%	0.03
0110	148823	5,041,466.24	5,692,301.49	6,343,136.74	7,536,794.52	8,187,629.77	8,838,465.02	9,489,300.27	10,140,135.52	10,790,970.77	11,789,885.05	12,680,207.31	13,570,529.57	14,460,851.83	12/31/2020	8	4.6360%	0.37
0110	154585	1,637,306.22	2,219,450.50	2,801,594.78	3,383,739.06	4,448,986.62	5,388,736.05	6,384,114.71	7,124,615.99	7,775,563.27	7,913,279.96	8,050,996.65	8,188,713.34	8,326,430.03	12/31/2020	8	2.6694%	0.21
0110	148846	129,760.41	154,725.55	179,690.69	204,655.83	229,620.97	254,586.11	279,551.25	304,516.39	329,481.53	523,449.97	1,314,529.64	2,105,609.31	2,896,688.98	12/31/2020	8	0.9287%	0.07
0110	152706	33,248.70	33,248.70	33,248.70	33,248.70	33,248.70	33,248.70	99,879.56	166,510.41	233,141.26	657,194.10	1,081,247.10	1,505,300.10	1,929,353.10	12/31/2022	32	0.6185%	0.20
0110	157443	-	-	-	-	-	24,862.32	49,724.64	74,586.96	99,449.28	124,097.85	148,746.42	173,394.99	198,043.56	12/31/2022	32	0.0635%	0.02
0110	157211	-	-	-	-	-	-	45,602.20	91,204.40	150,104.97	323,626.51	354,249.15	384,871.79	415,494.43	12/31/2021	20	0.1332%	0.03
0110	127111	-	-	-	-	-	74,961.43	149,922.86	224,884.29	299,845.72	465,703.39	631,561.15	797,418.91	963,276.67	12/31/2021	20	0.3088%	0.06
0110	148854	-	-	-	-	-	49,983.61	99,967.24	149,950.87	199,934.50	299,683.50	399,432.50	499,181.50	598,930.50	12/31/2021	20	0.1920%	0.04
0110	157202	-	-	-	-	-	-	14,755.70	30,178.96	50,035.00	142,577.35	335,960.88	529,344.41	610,893.94	8/31/2020	4	0.1958%	0.01
0110	157203	-	-	-	-	-	-	16,678.33	33,356.67	50,035.01	399,566.00	488,151.01	576,736.02	665,321.03	8/31/2020	4	0.2133%	0.01
0110	157204	-	-	-	-	-	-	4,293.20	13,547.16	25,017.50	115,270.15	214,057.95	312,845.75	411,633.55	5/31/2020	1	0.1320%	0.00
0110	157205	-	-	-	-	-	-	30,401.46	60,802.92	100,069.99	740,075.25	858,188.58	976,301.91	1,094,415.24	12/31/2020	8	0.3509%	0.03
0110	157210	-	-	-	-	-	-	22,801.10	45,602.20	75,052.47	581,928.05	684,958.69	787,989.33	891,019.97	9/30/2020	5	0.2857%	0.01
0110	157215	-	-	-	-	-	-	16,678.33	33,356.67	50,035.01	175,898.00	376,317.01	576,736.02	665,321.03	8/31/2020	4	0.2133%	0.01
0110	157309	-	-	-	-	-	-	25,000.31	50,000.63	75,000.95	187,360.09	299,719.31	412,078.53	524,437.75	6/30/2020	2	0.1681%	0.00
0110	157635	-	-	-	-	-	-	265,836.22	531,672.45	797,508.68	1,418,731.42	2,039,954.14	2,661,176.86	3,282,399.58	6/30/2020	2	1.0523%	0.02
0110	157636	-	-	-	-	-	-	203,348.04	406,696.08	610,044.12	819,947.20	1,029,850.24	1,239,753.28	1,894,696.30	8/31/2020	4	0.6074%	0.02
0110	157639	-	-	-	-	-	-	151,250.06	302,500.11	453,750.16	923,283.62	1,392,817.08	1,862,350.54	2,331,884.00	10/31/2020	6	0.7476%	0.04
0110	157641	-	-	-	-	-	-	130,009.92	260,019.84	390,029.76	704,059.10	1,018,088.49	1,332,117.88	1,646,147.27	8/31/2020	4	0.5277%	0.02
0110	LI-000094	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	189,825.80	329,719.79	469,613.78	609,507.77	5/31/2020	1	0.1954%	0.00
0110	LI-000095	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	159,847.04	269,762.27	379,677.50	489,592.73	5/31/2020	1	0.1570%	0.00
0110	LI-000096	-	-	-	-	-	-	16,643.93	33,287.87	49,931.81	189,825.80	329,719.79	469,613.78	609,507.77	5/31/2020	1	0.1954%	0.00
0110	157209	-	-	-	-	-	-	7,600.37	15,200.74	25,017.49	50,178.56	75,339.63	100,500.70	125,661.77	3/31/2021	11	0.0403%	0.00
0110	157315	-	-	-	-	-	-	-	75,000.97	75,000.97	177,243.46	279,486.01	381,728.56	483,971.11	6/30/2020	2	0.1552%	0.00
0110	157642	-	-	-	-	-	-	-	-	-	-	-	306,347.31	612,694.62	12/31/2020	8	0.1964%	0.02
0110	157645	-	-	-	-	-	-	-	-	-	-	-	117,494.23	234,988.45	9/30/2020	5	0.0753%	0.00
0110	157708	-	-	-	-	-	-	-	-	-	-	-	-	108,287.94	6/30/2020	2	0.0347%	0.00
0110	144116	778,618.74	802,254.89	957,177.84	1,573,595.42	2,190,013.00	2,806,430.58	3,131,503.31	3,667,337.44	3,918,294.88	4,135,609.82	4,409,689.10	4,627,003.98	4,844,318.86	6/30/2020	2	1.5530%	0.03
0110	151775	386,747.78	398,303.51	453,300.24	520,922.97	588,545.70	656,168.43	729,354.16	802,539.89	901,851.62	1,020,588.91	1,148,645.70	1,276,702.49	1,405,409.28	12/31/2020	8	0.4506%	0.04
0110	SU-000002	214,000.00	267,500.00	321,000.00	374,500.00	428,000.00	481,500.00	535,000.00	588,500.00	642,000.00	700,333.37	758,666.70	817,000.03	875,333.36	12/31/2020	8	0.2806%	0.02
0110	SU-000010	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	11,305.21	5/31/2020	1	0.0036%	0.00
0110	SU-000130	66,730.23	88,973.64	111,217.05	133,460.46	177,947.27	222,434.08	266,920.89	311,407.70	355,894.51	400,145.87	488,648.59	577,151.31	621,402.67	6/30/2020	2	0.1992%	0.00
0110	SU-000179	883,069.40	1,248,002.20	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,078,036.80	2,172,462.68	2,266,888.56	2,361,314.44	2,455,740.32	12/31/2020	8	0.7873%	0.06
0110	SU-000344	44,486.82	66,730.23	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	88,973.64	156,206.38	223,439.12	290,671.86	357,904.60	5/31/2020	1	0.1147%	0.00
0110	SU-000404	13,346.01	17,794.68	22,243.35	26,692.02	31,140.69	35,589.36	38,258.57	38,258.57	38,258.57	42,683.71	51,533.97	69,234.51	95,785.33	5/31/2020	1	0.0307%	0.00
0110	SU-000405	(1,918.68)	(9,444.43)	(16,970.18)	10,553.19	42,939.74	67,073.54	106,560.35	146,047.16	232,318.73	271,570.09	389,324.19	624,832.37	865,835.73	6/30/2020	2	0.2776%	0.01
0110	SU-000408	26,692.08	35,589.45	44,486.82	53,384.19	66,730.24	80,076.29	91,642.86	100,540.23	109,437.60	153,688.96	242,191.68	330,694.40	463,448.50	10/31/2020	6	0.1486%	0.01
0110	SU-000098	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	5,176.37	12/31/2021	20	0.0017%	0.00
0110	139958	99,856.52	124,820.64	149,784.76	174,748.88	199,713.00	224,677.12	249,641.24	274,605.36	299,569.48	456,451.34	1,326,658.17	2,196,865.00	3,067,071.83	12/31/2021	20	0.9833%	0.20
0110	152641	212,924.79	336,784.58	428,001.14	453,823.28	453,823.28	453,823.28	453,823.28	453,823.28	495,196.20	495,196.20	495,196.20	495,196.20	495,196.20	12/31/2021	20	0.1588%	0.03
0110	SU-000001	48,935.52	62,281.57	80,076.30	97,871.03	115,665.76	133,460.49	151,255.22	164,601.27	177,947.32	206,239.63	234,531.98	302,075.69	369,619.40	12/31/2021	20	0.1185%	0.02
0110	SU-000229	41,166.20	51,457.75	73,749.30	96,040.85	118,332.40	140,623.95	162,915.50	185,207.05	223,498.60	355,008.79	486,518.90	618,029.01	749,539.12	12/31/2021	20	0.2403%	0.05
0110	SU-000351	-	-	22,243.41	44,486.82	66,730.23	102,319.70	137,909.17	173,498.64	219,764.93	281,689.80	343,614.67	432,078.77	564,774.91	8/31/2020	4	0.1811%	0.01
0110	SU-000371	-	-	7,893.60	15,787.20	23,680.80	35,521.49	47,011.84	56,665.57	71,665.57	84,935.09	98,204.61	115,897.28	133,589.95	5/31/2020	1	0.0428%	0.00
0110	SU-000372	-	-	22,243.41	44,486.82	93,422.33	142,357.84	172,942.52	203,527.20	224,880.88	255,843.31	300,075.34	388,539.44	454,887.51	5/31/2020	1	0.1458%	0.00
0110	SU-000373	-	-	35,589.47	97,871.03	177,947.32	258,023.61	302,510.42	338,099.89	368,350.94	430,275.81	518,739.91	651,436.05	727,515.19	5/31/2020	1	0.2332%	0.00
0110	SU-000374	-	-	44,486.81	88,973.62	186,844.64	284,715.66	346,997.22	378,137.99	409,278.76	471,203.63	559,667.73	736,595.93	842,752.86	5/31/2020	1	0.2702%	0.00
0110	SU-000375	-	-	8,897.37	17,794.74	26,692.11	40,038.16	52,494.47	61,391.84	61,391.84	74,661.46	87,931.08	105,623.89	123,316.70	5/31/2020	1	0.0395%	0.00
0110	SU-000396	-	-	4,448.67	8,897.34	13,346.01	17,794.68	22,243.35	22,243.35	22,243.35	48,794.17	75,344.99	128,446.62	181,548.25	5/31/2020	1	0.0582%	0.00
0110	SU-000397	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,413.93	20,379.17	28,344.41	36,309.65	5/31/2020	1	0.0116%	0.00
0110	SU-000398	-	-	2,669.21	5,338.42	8,007.63	8,007.63	8,007.63	8,007.63	8,007.63	16,857.89	25,708.15	47,833.83	92,085.19	5/31/2020	1	0.0295%	0.00
0110	SU-000399	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,045.74	26,644.46	40,693.45	54,742.44	12/31/2020	8	0.0175%	0.00
0110	SU-000400	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,413.93	20,379.17	28,344.41	36,309.65	5/31/2020	1	0.0116%	0.00
0110	SU-000401	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,045.74	26,644.46	40,693.45	54,742.44	12/31/2020	8	0.0175%	0.00
0110	SU-000052	-	-	-	-	8,897.37	17,794.74	26,692.11	35,589.48	40,038.15	62,163.83	106,415.19	172,792.23	327,671.98	5/31/2020	1	0.1050%	0.00
0110	SU-000055	-	-	-	-	33,703.32	67,406.64	101,109.96	134,813.28	186,516.60	304,270.70	422,024.80	657,532.98	893,041.16	7/31/2020	3	0.2863%	0.01
0110	SU-000070	-	-	-	-	22,243.41	66,730.22	111,217.03	155,703.84	177,947.25	200,072.93	244,324.29	332,827.01	421,329.73	12/31/2020	8	0.1351%	0.01
0110	SU-000378	-	-	-	-	8,897.37	17,794.74	26,692.11	33,810.01	33,810.01	42,656.42	51,502.83	64,772.45	82,465.26	7/31/2020	3	0.0264%	0.00
0110	147734	-	-	-	-	-	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	69,941.85	7/31/2020	3	0.0224%	0.00
0110	152704	-	-	-	-	-	49,973.26	99,946.52	149,919.78	199,893.04	450,976.26	702,059.49	953,142.72	1,204,225.95	12/31/2020	8	0.3861%	0.03
0110	SU-000343	-	-	-	-	-	6,673.02	13,346.04	20,019.06	26,692.08	77,293.55	127,895.02	178,496.49	229,097.96	5/31/2020	1	0.0734%	0.00
0110	SU-000349	-	-	-	-	-	48,713.08	97,426.16	146,139.24	194,852.32	243,507.58	292,162.84	358,510.91	424,858.98	11/30/2020	7	0.1362%	0.01
0110	SU-000203	-	-	-	149,956.04	299,912.10	449,868.16	599,824.22	749,780.28	999,736.34	1,222,573.29	1,445,410.33	1,668,247.37	1,891,084.41	6/30/2022	26	0.6063%	0.16
0110	145803	-	-	-	-	-	-	33,292.57	66,585.13	99,877.69	708,087.34	1,316,296.94	1,924,506.54	2,532,716.14	6/30/2020	2	0.8120%	0.02
0110	SU-000053	-	-	-	-	-	-	8,897.37	17,794.74	26,692.11	39,967.51	62,093.19	106,344.55	222,283.12	5/31/2020	1	0.0713%	0.00
0110	140283	-	-	-	-	-	-	-	-	-	7,660.99	15,321.97	22,982.96	30,643.95	12/31/2020	8	0.0098%	0.00
0110	SU-000088	-	-	-	-	-	-	-	-	-	19,583.33	39,166.66	58,749.99	78,333.32	12/31/2020	8	0.0251%	0.00
0110	SU-000089	-	-	-	-	-	-	-	-	-	12,916.67	25,833.34	38,750.01	51,666.68	12/31/2020	8	0.0166%	0.00
0110	SU-000191	-	-	-	-	-	-	-	-	-	6,195.19	12,390.38	16,262.38	20,134.38	6/30/2020	2	0.0065%	0.00
0110	SU-000220	-	-	-	-	-	-	-	-	-	7,384.78	14,769.56	22,154.34	29,539.12	12/31/2020	8	0.0095%	0.00
0110	SU-000221	-	-	-	-	-	-	-	-	-	9,211.94	18,423.88	27,635.82	36,847.76	12/31/2020	8	0.0118%	0.00
0110	SU-000222	-	-	-	-	-	-	-	-	-	7,384.78	14,769.56	22,154.34	29,539.12	12/31/2020	8	0.0095%	0.00
0110	SU-000223	-	-	-	-	-	-	-	-	-	8,069.98	16,139.96	24,209.94	32,279.92	12/31/2020	8	0.0103%	0.00
0110	SU-000224	-	-	-	-	-	-	-	-	-	8,069.98	16,139.96	24,209.94	32,279.92	12/31/2020	8	0.0103%	0.00
0110	SU-000241	-	-	-	-	-	-	-	-	-	8,450.61	16,901.22	25,351.83	33,802.44	12/31/2020	8	0.0108%	0.00
0110	SU-000320	-	-	-	-	-	-	-	-	-	5,410.15	10,820.30	16,230.45	21,640.60	12/31/2020	8	0.0069%	0.00
0110	SU-000321	-	-	-	-	-	-	-	-	-	5,410.15	10,820.30	16,230.45	21,640.60	12/31/2020	8	0.0069%	0.00
0110	SU-000326	-	-	-	-	-	-	-	-	-	13,525.38	27,050.76	40,576.14	54,101.52	12/31/2020	8	0.0173%	0.00
0110	137807	-	-	-	-	-	-	-	-	-	6,254.47	12,508.88	18,763.29	25,017.70	12/31/2021	20	0.0080%	0.00
0110	151763	-	-	-	-	-	-	-	-	-	22,011.00	44,022.00	66,033.00	88,044.00	12/31/2021	20	0.0282%	0.01
0110	SU-000322	-	-	-	-	-	-	-	-	-	79,101.49	133,202.98	187,304.47	241,405.96	12/31/2021	20	0.0774%	0.02
0110	144975	-	-	-	-	-	-	-	-	-	-	153,295.34	306,590.69	459,886.04	6/30/2020	2	0.1474%	0.00
0110	152992	-	-	-	-	-	-	-	-	-	-	-	(1,184.76)	(4,151.26)	12/31/2021	20	-0.0013%	(0.00)
0110	147506	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	6/30/2020	2	0.0662%	0.00
0110	147507	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	6/30/2020	2	0.0662%	0.00
0110	147513	-	-	-	-	-	-	-	-	-	-	-	-	206,352.32	6/30/2020	2	0.0662%	0.00
0110	SU-000364	-	-	-	-	-	-	-	-	-	-	-	-	57,678.59	6/30/2020	2	0.0185%	0.00
0110	00105FACK	113,347.36	116,905.78	120,464.20	124,022.62	127,581.04	131,139.46	344,624.80	344,624.80	344,624.80	459,624.80	574,624.80	937,589.21	1,063,663.61	12/31/2021	20	0.3410%	0.07
0110	00100FACK	-	-	-	-	-	-	-	-	-	-	-	8,535.15	17,070.30	8/31/2020	4	0.0055%	0.00
0110	157893	18,666.72	23,333.38	28,000.04	32,666.70	37,333.36	42,000.02	46,666.68	51,333.34	56,000.00	60,666.74	65,333.40	70,000.06	74,666.72	12/31/2020	8	0.0239%	0.00
0110	157898	-	-	-	-	-	-	-	-	-	4,666.74	9,333.40	14,000.06	18,666.72	12/31/2020	8	0.0060%	0.00
0110	149487	-	-	-	-	-	-	-	-	-	-	-	14,000.00	14,000.00	12/31/2020	8	0.0045%	0.00

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0110	00017FACK	135,600.81	140,048.09	144,495.37	275,648.90	280,096.18	284,543.46	440,536.48	444,983.76	449,431.04	449,431.04	449,431.04	453,860.81	584,996.83	12/31/2021	20	0.1875%	0.04
0110	152387	-	-	-	-	-	-	-	250,371.55	500,033.55	500,033.55	500,033.55	902,756.70	1,358,899.20	12/31/2020	8	0.4356%	0.03
0110	149166	-	-	-	-	-	-	-	-	-	-	34,000.07	83,204.89	98,713.74	12/31/2020	8	0.0316%	0.00
0110	153025	-	-	-	-	-	-	-	-	-	-	41,559.65	83,119.30	124,678.95	12/31/2020	8	0.0400%	0.00
0110	00051FACK	-	-	-	-	-	-	-	-	-	-	-	25,341.25	25,341.25	9/30/2020	5	0.0081%	0.00
0110	153022	-	-	-	-	-	-	-	-	-	-	-	27,368.55	27,368.55	12/31/2020	8	0.0088%	0.00
0110	133KU16	77,453.94	78,453.94	79,453.94	80,453.94	81,453.94	82,453.94	83,453.94	84,453.94	84,453.94	84,453.94	91,266.44	98,078.94	111,703.94	12/31/2020	8	0.0358%	0.00
0110	IT0246K	139,320.76	195,049.06	250,777.36	306,505.66	362,233.96	417,962.26	473,690.56	501,554.72	529,418.88	585,040.93	640,662.98	696,285.03	751,907.08	6/30/2020	2	0.2411%	0.00
0110	IT0453K	14,847.81	29,695.66	524,624.14	722,595.53	920,566.92	1,118,538.31	1,316,509.70	1,366,002.56	1,385,799.70	1,385,799.70	1,405,443.87	1,425,088.04	1,434,910.10	11/30/2020	7	0.4600%	0.03
0110	IT0511K	55,730.20	83,595.30	111,460.40	139,325.50	167,190.60	195,055.70	222,920.80	250,785.90	278,651.00	306,555.08	334,459.16	362,363.24	390,267.32	10/31/2020	6	0.1251%	0.01
0110	IT0560K	44,799.98	67,199.97	89,599.96	111,999.95	134,399.94	156,799.93	179,199.92	201,599.91	223,999.90	246,245.22	268,490.54	290,735.86	312,981.18	10/31/2020	6	0.1003%	0.01
0110	IT0561K	11,200.00	16,800.00	22,400.00	28,000.00	33,600.00	39,200.00	44,800.00	50,400.00	56,000.00	64,400.00	72,800.00	81,200.00	89,600.00	10/31/2020	6	0.0287%	0.00
0110	IT0604K	66,643.70	99,965.55	133,287.40	166,609.25	199,931.10	233,252.95	266,574.80	355,433.14	388,754.99	422,093.67	455,432.35	488,771.03	522,109.71	11/30/2020	7	0.1674%	0.01
0110	IT0708K	13,846.97	27,693.94	55,387.91	96,928.84	138,469.77	180,010.70	221,551.63	249,245.60	276,939.57	318,631.47	360,323.37	402,015.27	443,707.17	10/31/2020	6	0.1422%	0.01
0110	IT0458K	-	-	-	47,613.14	190,452.57	309,485.41	428,518.25	547,551.09	595,164.23	642,917.37	786,176.83	929,436.29	1,096,572.32	6/30/2020	2	0.3516%	0.01
0110	IT0559K	-	-	-	14,000.00	28,000.00	42,000.00	56,000.00	70,000.00	84,000.00	98,000.00	112,000.00	126,000.00	140,000.00	6/30/2020	2	0.0449%	0.00
0110	IT0480K	-	-	-	58,580.35	117,160.70	175,741.05	234,321.40	292,901.75	351,482.10	413,922.53	476,362.96	538,478.01	600,918.44	6/30/2021	14	0.1926%	0.03
0110	IT0419K	-	-	-	-	-	4,800.00	12,000.00	19,200.00	24,000.00	28,800.00	33,600.00	38,400.00	43,200.00	10/31/2020	6	0.0138%	0.00
0110	IT0302K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	148,800.00	292,800.00	11/30/2020	7	0.0939%	0.01
0110	IT0306K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	196,800.00	388,800.00	12/31/2020	8	0.1246%	0.01
0110	IT0612K	-	-	-	-	-	-	-	-	-	10,560.00	21,120.00	31,680.00	42,240.00	12/31/2020	8	0.0135%	0.00
0110	IT0615K	-	-	-	-	-	-	-	-	-	18,145.21	38,200.43	58,255.65	78,310.87	12/31/2020	8	0.0251%	0.00
0110	IT0627K	-	-	-	-	-	-	-	-	-	2,990.58	5,981.16	8,971.74	11,962.32	12/31/2020	8	0.0038%	0.00
0110	IT0636K	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	14,400.00	26,400.00	11/30/2020	7	0.0085%	0.00
0110	IT0652K	-	-	-	-	-	-	-	-	-	5,000.00	10,000.00	35,000.00	85,000.00	9/30/2020	5	0.0273%	0.00
0110	IT0671K	-	-	-	-	-	-	-	-	-	124,824.98	249,649.96	374,474.94	499,299.92	11/30/2020	7	0.1601%	0.01
0110	IT0693K	-	-	-	-	-	-	-	-	-	6,000.00	12,000.00	18,000.00	24,000.00	12/31/2020	8	0.0077%	0.00
0110	IT0705K	-	-	-	-	-	-	-	-	-	5,990.08	11,980.16	17,970.24	23,960.32	12/31/2020	8	0.0077%	0.00
0110	IT0609K	-	-	-	-	-	-	-	-	-	13,960.10	41,880.33	125,640.96	167,521.28	7/31/2021	15	0.0537%	0.01
0110	IT0514K	-	-	-	-	-	-	-	-	-	-	9,600.00	19,200.00	38,400.00	12/31/2020	8	0.0123%	0.00
0110	IT0606K	-	-	-	-	-	-	-	-	-	-	2,400.00	7,200.00	14,400.00	11/30/2020	7	0.0046%	0.00
0110	IT0613K	-	-	-	-	-	-	-	-	-	-	13,488.00	26,976.00	40,464.00	11/30/2020	7	0.0130%	0.00
0110	IT0614K	-	-	-	-	-	-	-	-	-	-	4,868.64	9,737.28	14,605.92	8/31/2020	4	0.0047%	0.00
0110	IT0618K	-	-	-	-	-	-	-	-	-	-	10,800.00	21,600.00	43,200.00	12/31/2020	8	0.0138%	0.00
0110	IT0644K	-	-	-	-	-	-	-	-	-	-	2,160.00	7,200.00	12,240.00	11/30/2020	7	0.0039%	0.00
0110	IT0647K	-	-	-	-	-	-	-	-	-	-	2,880.00	10,080.00	17,280.00	11/30/2020	7	0.0055%	0.00
0110	IT0649K	-	-	-	-	-	-	-	-	-	-	4,800.00	14,400.00	28,800.00	11/30/2020	7	0.0092%	0.00
0110	IT0651K	-	-	-	-	-	-	-	-	-	-	9,600.00	9,600.00	19,200.00	10/31/2020	6	0.0062%	0.00
0110	IT0672K	-	-	-	-	-	-	-	-	-	-	1,440.00	4,800.00	8,160.00	11/30/2020	7	0.0026%	0.00
0110	IT0675K	-	-	-	-	-	-	-	-	-	-	4,320.00	14,400.00	28,800.00	11/30/2020	7	0.0092%	0.00
0110	IT0680K	-	-	-	-	-	-	-	-	-	-	2,734.75	5,925.29	26,435.95	12/31/2020	8	0.0085%	0.00
0110	IT0689K	-	-	-	-	-	-	-	-	-	-	8,400.00	16,800.00	25,200.00	6/30/2020	2	0.0081%	0.00
0110	IT0690K	-	-	-	-	-	-	-	-	-	-	16,800.00	33,600.00	50,400.00	11/30/2020	7	0.0162%	0.00
0110	IT0695K	-	-	-	-	-	-	-	-	-	-	3,840.00	7,680.00	11,520.00	11/30/2020	7	0.0037%	0.00
0110	IT0701K	-	-	-	-	-	-	-	-	-	-	14,000.00	28,000.00	42,000.00	11/30/2020	7	0.0135%	0.00
0110	IT0711K	-	-	-	-	-	-	-	-	-	-	12,000.00	24,000.00	36,000.00	11/30/2020	7	0.0115%	0.00
0110	IT0712K	-	-	-	-	-	-	-	-	-	-	5,600.00	11,200.00	16,800.00	11/30/2020	7	0.0054%	0.00
0110	IT0722K	-	-	-	-	-	-	-	-	-	-	9,600.00	19,200.00	28,800.00	11/30/2020	7	0.0092%	0.00
0110	IT1087K	-	-	-	-	-	-	-	-	-	-	23,737.91	47,475.82	71,213.73	12/31/2020	8	0.0228%	0.00
0110	IT0407K	-	-	-	-	-	-	-	-	-	-	-	14,000.00	42,000.00	7/31/2020	3	0.0135%	0.00
0110	IT0452K	-	-	-	-	-	-	-	-	-	-	-	28,000.00	56,000.00	10/31/2020	6	0.0180%	0.00
0110	IT0634K	-	-	-	-	-	-	-	-	-	-	-	5,760.00	5,760.00	10/31/2020	6	0.0018%	0.00
0110	IT0637K	-	-	-	-	-	-	-	-	-	-	-	8,160.00	8,160.00	11/30/2020	7	0.0026%	0.00
0110	IT0661K	-	-	-	-	-	-	-	-	-	-	-	9,600.00	10,584.48	10/31/2020	6	0.0034%	0.00
0110	IT0668K	-	-	-	-	-	-	-	-	-	-	-	960.00	3,360.00	10/31/2020	6	0.0011%	0.00
0110	IT0673K	-	-	-	-	-	-	-	-	-	-	-	2,800.00	5,600.00	11/30/2020	7	0.0018%	0.00
0110	IT0674K	-	-	-	-	-	-	-	-	-	-	-	7,560.00	15,120.00	12/31/2020	8	0.0048%	0.00
0110	IT0681K	-	-	-	-	-	-	-	-	-	-	-	48,000.00	48,000.00	8/31/2020	4	0.0154%	0.00
0110	IT0682K	-	-	-	-	-	-	-	-	-	-	-	2,400.00	4,800.00	12/31/2020	8	0.0015%	0.00
0110	IT0694K	-	-	-	-	-	-	-	-	-	-	-	31,557.96	63,115.92	8/31/2020	4	0.0202%	0.00
0110	IT0713K	-	-	-	-	-	-	-	-	-	-	-	5,600.00	11,200.00	11/30/2020	7	0.0036%	0.00
0110	IT0715K	-	-	-	-	-	-	-	-	-	-	-	14,000.00	28,000.00	8/31/2020	4	0.0090%	0.00
0110	IT0716K	-	-	-	-	-	-	-	-	-	-	-	4,800.00	9,600.00	12/31/2020	8	0.0031%	0.00
0110	IT0718K	-	-	-	-	-	-	-	-	-	-	-	112,000.00	140,000.00	5/31/2020	1	0.0449%	0.00
0110	IT0720K	-	-	-	-	-	-	-	-	-	-	-	116,900.23	122,579.59	12/31/2020	8	0.0393%	0.00
0110	IT0723K	-	-	-	-	-	-	-	-	-	-	-	24,000.00	48,000.00	12/31/2020	8	0.0154%	0.00
0110	IT0726K	-	-	-	-	-	-	-	-	-	-	-	33,600.00	67,200.00	12/31/2020	8	0.0215%	0.00
0110	IT0569K	-	-	-	-	-	-	-	-	-	-	-	498,412.56	1,096,471.53	12/31/2021	20	0.3515%	0.07
0110	IT0628K	-	-	-	-	-	-	-	-	-	-	-	-	12,000.00	10/31/2020	6	0.0038%	0.00
0110	IT0633K	-	-	-	-	-	-	-	-	-	-	-	-	24,000.00	12/31/2020	8	0.0077%	0.00
0110	IT0656K	-	-	-	-	-	-	-	-	-	-	-	-	96,000.00	10/31/2020	6	0.0308%	0.00
0110	IT0710K	-	-	-	-	-	-	-	-	-	-	-	-	9,600.00	10/31/2020	6	0.0031%	0.00
0110	IT0724K	-	-	-	-	-	-	-	-	-	-	-	-	4,872.96	2/28/2021	10	0.0016%	0.00
0110	120756	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	63,692.34	12/1/2020	8	0.0204%	0.00
0100	122457	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	131,000.00	12/31/2025	6	0.0420%	0.00
0100	151231	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	12/31/2025	6	0.0003%	0.00
0100	157611	47,358.00	66,732.16	86,859.31	105,802.51	124,745.71	141,321.01	157,896.31	165,000.01	165,000.01	167,347.91	176,739.51	194,348.76	211,958.01	11/30/2023	6	0.0680%	0.00
0100	157615	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	44,990.10	67,295.15	90,187.18	12/31/2023	6	0.0289%	0.00
0100	152583	50,908.00	50,908.00	50,908.00	50,908.00	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	101,605.50	12/31/2028	6	0.0326%	0.00
0100	138032	135,315.20	537,698.57	546,082.29	554,466.01	562,849.73	571,233.45	579,617.17	588,000.89	596,384.61	605,281.87	614,162.79	623,066.34	631,957.54	6/30/2023	6	0.2026%	0.01
0100	139495	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	9,333.36	12/31/2025	6	0.0030%	0.00
0100	140342LGE	-	-	16,301.29	16,301.29	16,301.29	16,301.29	16,301.29	16,301.29	36,892.39	36,892.39	36,892.39	36,892.39	36,892.39	12/31/2023	6	0.0118%	0.00
0100	147819	-	-	-	-	-	-	-	-	-	85,666.70	171,333.44	257,000.18	342,666.92	12/31/2030	6	0.1099%	0.01
0100	IT0000L	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	2,390,920.13	12/31/2025	6	0.7665%	0.05
0100	141390	-	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	17,500.00	12/31/2023	6	0.0056%	0.00
0100	145402	10,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	12/31/2023	6	0.0064%	0.00
0100	149344	173,387.20	173,387.20	173,387.20	173,387.20	173,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	273,387.20	12/31/2023	6	0.0876%	0.01
0100	148396	125,083.87	156,354.85	187,625.83	218,896.81	250,167.79	281,438.77	312,709.75	343,980.73	375,251.71	441,902.53	508,553.41	575,204.29	641,855.17	12/31/2025	6	0.2058%	0.01
0100	120754	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	194,964.24	12/31/2025	6	0.0625%	0.00
0100	147831	1,808,333.32	1,989,166.65	2,169,999.98	2,350,833.31	2,531,666.64	2,712,499.97	2,893,333.30	3,074,166.63	3,255,000.00	3,435,833.33	3,616,666.66	3,797,499.99	3,978,333.32	12/31/2023	6	1.2754%	0.08
0100	148884	299,596.71	456,563.05	598,169.79	768,138.09	919,315.78	1,074,588.99	1,230,956.15	1,365,819.89	1,499,089.68	1,499,089.68	1,499,089.68	1,592,962.58	1,682,773.04	12/31/2020	8	0.5395%	0.04
0100	148885	20,626.82	25,783.52	30,940.22	364,281.92	861,716.12	1,415,566.72	1,968,471.92	2,520,603.62	2,999,216.59	4,289,910.34	4,993,629.09	5,697,347.84	6,277,803.01	6/30/2020	2	2.0126%	0.04
0100	131715	223,116.98	446,233.96	675,010.14	895,759.22	1,116,508.30	1,337,257.38	1,560,487.24	1,780,052.37	1,779,052.37	1,904,639.92	2,029,053.52	2,153,467.12	2,277,880.72	12/31/2020	8	0.7303%	0.06

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	148727	1,298,821.77	1,440,105.29	1,546,867.49	1,683,960.49	1,805,473.48	1,922,785.62	2,006,333.86	2,094,746.81	2,135,187.88	2,185,326.77	2,347,660.66	2,499,965.89	2,652,271.12	12/31/2020	8	0.8503%	0.07
0100	155386	1,019,353.32	1,024,510.02	1,576,641.72	2,128,773.42	2,680,905.12	3,234,755.72	3,787,660.92	4,339,792.62	4,883,943.04	5,239,476.79	5,595,010.54	5,950,544.29	6,306,078.04	5/31/2020	1	2.0217%	0.02
0100	157602	157,246.92	235,870.38	315,438.22	397,214.17	475,837.63	554,461.09	633,084.55	711,708.01	790,331.47	790,331.47	790,331.47	832,260.21	874,188.95	12/31/2020	8	0.2803%	0.02
0100	157584	(160,505.40)	(201,655.63)	(242,805.86)	(283,956.09)	(325,106.32)	(366,256.55)	(407,406.78)	(445,555.44)	(486,705.67)	(569,249.59)	(651,793.51)	(734,337.43)	(816,881.35)	1/31/2021	9	-0.2619%	(0.02)
0100	155292	-	-	-	-	-	-	-	-	-	23,692.95	48,751.12	73,809.29	100,041.41	12/31/2020	8	0.0321%	0.00
0100	155315	-	-	-	-	-	-	-	-	-	19,957.15	39,914.30	59,871.45	79,828.60	12/31/2020	8	0.0256%	0.00
0100	155352	-	-	-	-	-	-	-	-	-	38,131.02	74,231.37	110,331.72	148,462.74	12/31/2020	8	0.0476%	0.00
0100	155359	-	-	-	-	-	-	-	-	-	145,170.14	290,340.28	435,510.42	580,680.56	12/31/2020	8	0.1862%	0.01
0100	155361	-	-	-	-	-	-	-	-	-	120,968.32	239,904.87	360,873.19	479,809.74	12/31/2020	8	0.1538%	0.01
0100	155363	-	-	-	-	-	-	-	-	-	913,783.88	1,828,044.94	2,740,883.77	3,666,395.43	12/31/2020	8	1.1754%	0.09
0100	155365	-	-	-	-	-	-	-	-	-	140,105.60	280,211.20	420,316.80	560,422.40	12/31/2020	8	0.1797%	0.01
0100	157051	-	-	-	-	-	-	-	-	-	53,121.32	96,073.43	130,091.93	149,898.61	12/31/2020	8	0.0481%	0.00
0100	157031	-	-	-	-	-	-	-	-	-	-	-	11,739.50	11,739.50	12/31/2020	8	0.0038%	0.00
0100	157060	-	-	-	-	-	-	-	-	-	-	-	19,957.15	24,465.52	12/31/2020	8	0.0078%	0.00
0100	148882	-	-	-	-	-	-	-	-	-	-	-	125,950.57	251,901.14	12/31/2021	20	0.0808%	0.02
0100	157038	-	-	-	-	-	-	-	-	-	-	-	-	14,234.19	12/31/2020	8	0.0046%	0.00
0100	157369	-	-	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	20,279.00	6/30/2020	2	0.0065%	0.00
0100	157285	-	-	-	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	76,046.25	7/31/2020	3	0.0244%	0.00
0100	157283	-	-	-	-	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	202,790.00	8/31/2021	16	0.0650%	0.01
0100	153662	14,916,005.28	17,068,670.82	19,225,117.96	21,382,434.48	23,542,259.56	25,694,983.45	27,215,612.60	27,255,339.18	27,292,173.58	27,898,106.83	29,055,650.27	30,146,718.82	31,556,274.28	12/31/2020	8	10.1166%	0.81
0100	TMPMAGRC	-	-	-	-	-	-	-	-	-	17,483.56	29,716.25	269,849.74	396,588.23	11/30/2021	19	0.1271%	0.02
0100	TMPWKA	-	-	-	-	-	-	-	-	-	61,210.32	193,476.65	433,740.84	671,776.55	11/30/2022	31	0.2154%	0.07
0100	152433	32,802.96	78,560.96	147,197.96	215,834.96	337,169.46	458,503.96	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	510,147.51	10/31/2020	6	0.1635%	0.01
0100	447000002	194,607.29	210,416.54	226,225.79	242,035.04	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	253,607.41	12/31/2020	8	0.0813%	0.01
0100	144857	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	161,381.80	11/30/2021	19	0.0517%	0.01
0100	152513	-	-	-	36,888.25	89,585.75	142,283.25	194,980.75	247,678.25	300,375.75	300,375.75	300,375.75	300,375.75	300,375.75	10/31/2022	30	0.0963%	0.03
0100	152501	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	(0.18)	11/30/2021	19	0.0000%	(0.00)
0100	152517	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	224,120.93	10/31/2021	18	0.0719%	0.01
0100	447000022	929,193.18	960,811.68	1,013,509.18	1,869,654.41	2,093,944.41	2,318,234.41	2,456,728.16	3,364,605.41	3,501,987.33	3,554,684.83	3,741,856.33	3,898,679.08	4,025,153.08	12/31/2021	20	1.2904%	0.26
0100	447000030	977.10	977.10	977.10	8,332.77	21,507.15	34,681.53	49,810.08	62,984.46	62,984.46	62,984.46	62,984.46	62,984.46	62,984.46	11/30/2021	19	0.0202%	0.00
0100	448000019	-	-	-	-	-	-	-	-	-	22,679.00	79,979.30	148,886.05	207,467.43	12/31/2020	8	0.0665%	0.01
0100	448000031	-	-	-	-	-	-	-	-	-	1,501.40	10,510.86	29,757.47	32,760.27	12/31/2020	8	0.0105%	0.00
0100	447500003	-	-	-	-	-	-	-	-	-	-	6,948.90	11,849.22	11,849.22	11/30/2020	7	0.0038%	0.00
0100	447500004	-	-	-	-	-	-	-	-	-	-	2,955.38	2,955.38	2,955.38	9/30/2020	5	0.0009%	0.00
0100	447500007	-	-	-	-	-	-	-	-	-	-	-	-	12,060.62	12/31/2020	8	0.0039%	0.00
0100	448000018	-	-	-	-	-	-	-	-	-	-	-	-	52,735.65	12/31/2020	8	0.0169%	0.00
0100	448000022	-	-	-	-	-	-	-	-	-	-	-	-	34,086.58	12/31/2020	8	0.0109%	0.00
0100	TMPWKB	79,046.25	158,092.50	284,566.50	442,659.00	611,291.00	790,462.50	969,634.00	1,000,198.55	1,000,198.55	3,345,395.95	5,694,152.97	5,775,593.07	9,017,501.92	5/31/2021	13	2.8909%	0.38
0100	TMPMCR	-	-	57,197.50	162,592.50	267,987.50	283,796.75	283,796.75	283,796.75	283,796.75	326,587.91	326,587.91	2,624,889.91	2,653,085.96	9/30/2021	17	0.8506%	0.14
0100	406000005	-	-	-	-	-	-	-	-	-	85,482.01	170,964.02	256,446.03	379,616.29	10/31/2020	6	0.1217%	0.01
0100	406000022	-	-	-	-	-	-	-	-	-	130,638.60	250,235.62	369,832.64	509,491.22	12/31/2020	8	0.1633%	0.01
0100	406000052	-	-	-	-	-	-	-	-	-	-	53,497.50	101,725.25	149,953.00	10/31/2020	6	0.0481%	0.00
0100	406000034	-	-	-	-	-	-	-	-	-	-	-	10,539.50	31,618.50	12/31/2021	20	0.0101%	0.00
0100	406000053	-	-	-	-	-	-	-	-	-	-	-	-	56,697.50	11/30/2020	7	0.0182%	0.00
0100	150052LGE	-	-	-	-	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	42,546.93	173,400.56	5/31/2020	1	0.0556%	0.00
0100	157779LGE	-	-	-	-	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	65,205.15	177,319.16	177,319.16	5/31/2020	1	0.0568%	0.00
0100	153047LGE	-	-	-	-	-	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	24,451.93	114,549.66	5/31/2020	1	0.0367%	0.00
0100	155443LGE	-	-	-	-	-	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	845,495.04	7/31/2020	3	0.2711%	0.01
0100	156932	-	-	-	-	-	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	76,796.25	11/30/2021	19	0.0246%	0.00
0100	153080LGE	-	-	-	-	-	-	146,993.00	146,993.00	146,993.00	146,993.00	146,993.00	220,597.11	557,782.11	5/30/2020	1	0.1788%	0.00
0100	154738	-	-	-	-	-	-	-	-	-	168,592.50	168,592.50	168,592.50	168,592.50	12/1/2020	8	0.0540%	0.00
0100	156838LGE	-	-	-	-	-	-	-	-	-	-	199,670.25	199,670.25	199,670.25	12/1/2020	8	0.0640%	0.01
0100	157075LGE	-	-	-	-	-	-	-	-	-	-	-	20,020.36	20,020.36	12/1/2020	8	0.0064%	0.00
0100	149021LGE	-	-	-	-	-	-	-	-	-	-	-	-	32,032.58	5/31/2020	1	0.0103%	0.00
0100	150064LGE	-	-	-	-	-	-	-	-	-	-	-	-	74,856.44	5/30/2020	1	0.0240%	0.00
0100	152659LGE	-	-	-	-	-	-	-	-	-	-	-	-	154,085.25	5/31/2020	1	0.0494%	0.00
0100	152685LGE	-	-	-	-	-	-	-	-	-	-	-	-	32,845.24	12/31/2020	8	0.0105%	0.00
0100	154744LGE	-	-	-	-	-	-	-	-	-	-	-	-	18,239.62	12/1/2020	8	0.0058%	0.00
0100	155558LGE	-	-	-	-	-	-	-	-	-	-	-	-	320,288.16	5/31/2020	1	0.1027%	0.00
0100	155651LGE	-	-	-	-	-	-	-	-	-	-	-	-	111,465.29	5/30/2020	1	0.0357%	0.00
0100	155659LGE	-	-	-	-	-	-	-	-	-	-	-	-	46,727.20	5/30/2020	1	0.0150%	0.00
0100	156834LGE	-	-	-	-	-	-	-	-	-	-	-	-	29,724.08	12/31/2020	8	0.0095%	0.00
0100	144530	-	-	-	-	-	-	-	-	-	-	-	80,263.49	80,263.49	12/31/2020	8	0.0257%	0.00
0100	157148	-	-	-	-	-	-	-	-	-	-	-	-	8,919.77	12/31/2020	8	0.0029%	0.00
0100	156753	900,000.00	900,000.00	900,000.00	900,000.00	900,000.00	900,000.00	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	2,281,630.48	11/30/2020	7	0.7315%	0.05
0100	151249	188,380.48	188,380.48	188,380.48	188,380.48	188,380.48	188,380.48	317,295.82	376,760.96	376,760.96	376,760.96	376,760.96	376,760.96	376,760.96	11/30/2021	19	0.1208%	0.02
0100	154327	94,153.14	94,153.14	94,153.14	94,153.14	94,153.14	94,153.14	158,573.71	188,306.28	188,306.28	188,306.28	188,306.28	376,612.54	376,612.54	3/31/2021	11	0.1207%	0.01
0100	154541	-	-	-	-	-	79,361.07	228,023.92	337,043.33	446,062.74	446,062.74	446,062.74	446,062.74	446,062.74	11/30/2020	7	0.1430%	0.01
0100	147056	-	-	-	-	-	-	869,995.63	869,995.63	869,995.63	869,995.63	869,995.63	869,995.63	2,570,269.91	5/31/2020	1	0.8240%	0.01
0100	156664	-	-	-	-	-	-	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	39,643.42	11/30/2020	7	0.0127%	0.00
0100	132989	-	-	-	-	-	-	-	-	-	-	-	-	595,044.70	5/31/2020	1	0.1908%	0.00
0100	143595	-	-	-	-	-	-	-	-	-	-	-	-	991,872.29	11/30/2020	7	0.3180%	0.02
0100	147042	-	-	-	-	-	-	-	-	-	-	-	-	88,245.95	5/31/2020	1	0.0283%	0.00
0100	151578	-	-	-	-	-	-	-	-	-	-	-	-	193,340.36	5/31/2020	1	0.0620%	0.00
0100	154464	-	-	-	-	-	-	-	-	-	-	-	-	163,529.12	6/30/2020	2	0.0524%	0.00
0100	154633	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	8/31/2020	4	0.0079%	0.00
0100	154639	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	7/31/2020	3	0.0079%	0.00
0100	154640	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	7/31/2020	3	0.0079%	0.00
0100	154642	-	-	-	-	-	-	-	-	-	-	-	-	19,821.72	7/31/2020	3	0.0064%	0.00
0100	154644	-	-	-	-	-	-	-	-	-	-	-	-	24,777.15	7/31/2020	3	0.0079%	0.00
0100	133679	1,772,834.10	1,777,124.10	1,781,414.10	1,794,284.10	1,807,154.10	1,820,024.10	1,832,894.10	1,845,764.10	1,858,634.10	1,885,934.10	1,913,234.10	1,940,534.10	1,967,834.10	11/30/2023	43	0.6309%	0.27
0100	133671	4,490,985.43	4,501,985.43	4,512,985.43	4,545,985.43	4,578,985.43	4,611,985.43	4,644,985.43	4,677,985.43	4,710,985.43	4,826,985.37	4,942,985.31	5,058,985.27	5,174,985.22	11/30/2022	31	1.6591%	0.51
0100	158032	350,000.00	450,000.00	650,000.00	950,000.00	1,250,000.00	1,650,000.00	2,050,000.00	2,550,000.00	3,050,000.00	3,800,000.00	4,550,000.00	5,300,000.00	6,300,000.00	6/30/2021	14	2.0197%	0.28
0100	134898	189,724.85	189,724.85	289,724.85	289,724.85	289,724.85	289,724.85	289,724.85	289,724.85	389,724.85	389,724.85	389,724.85	389,724.85	389,724.85	12/31/2020	8	0.1249%	0.01
0100	134198	2,770,647.79	3,015,504.20	3,260,360.61	3,505,217.02	3,750,073.43	3,994,929.84	4,239,786.25	4,484,642.66	4,729,499.07	4,729,499.07	5,348,260.07	5,348,260.07	5,348,260.07	5/31/2020	1	1.7146%	0.02
0100	139991	-	-	-	-	-	-	25,999.50	51,998.98	77,998.46	330,521.25	583,044.13	835,567.01	1,088,089.89	12/31/2020	8	0.3488%	0.03
0100	LI-000088	-	-	-	-	-	-	16,635.63	33,271.28	49,906.93	466,603.52	883,300.12	1,299,996.72	1,716,693.32	5/31/2020	1	0.5504%	0.01
0100	157313	-	-	-	-	-	-	-	1,796.15	36,499.84	63,412.10	86,691.51	109,970.92	133,250.33	6/30/2020	2	0.0427%	0.00
0100	SU-000029	250,738.90	250,738.90	250,738.90	256,967.07	263,195.24	269,423.41	275,651.58	275,651.58	275,651.58	320,202.74	364,753.90	409,305.06	453,856.22	5/31/2020	1	0.1455%	0.00
0100	SU-000370	297,873.45	317,607.13	337,340.81	357,074.49	396,541.82	455,742.80	534,677.48	588,353.05	630,153.05	669,507.06	708,861.07	748,215.08	787,569.09	12/31/2020	8	0.2525%	0.02
0100	SU-000367	-	-	8,893.48	17,786.96	26,680.44	40,020.64	52,471.52	61,365.00	61,365.00	74,671.21	87,977.42	105,719.01	123,460.60	5/31/2020	1	0.0396%	0.00
0100	SU-000368	-	-	17,786.94	35,573.88	53,360.82	80,041.22	104,942.92	122,729.86	122,729.86	149,342.25	175,954.64	211,437.84	246,921.04	5/31/2020	1	0.0792%	0.00
0100	SU-000369	-	-	13,340.20	26,680.40	40,020.60	57,807.54	75,594.48	82,709.27	82,709.27	100,450.86	118,192.45	144,804.84	171,417.23	5/31/2020	1	0.0550%	0.00

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	SU-000402	-	-	1,779.47	3,558.94	4,448.69	4,448.69	4,448.69	4,448.69	4,448.69	12,435.95	20,423.21	28,410.47	36,397.73	5/31/2020	1	0.0117%	0.00
0100	SU-000403	-	-	1,779.47	3,558.94	5,338.41	7,117.88	8,897.35	8,897.35	8,897.35	16,013.34	26,604.12	40,669.62	54,735.12	12/31/2020	8	0.0175%	0.00
0100	SU-000346	-	-	-	22,233.68	44,467.36	66,701.04	111,168.37	133,402.05	133,402.05	177,756.06	222,110.07	310,818.09	532,588.16	6/30/2020	2	0.1707%	0.00
0100	147735	-	-	-	-	-	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	31,423.15	7/31/2020	3	0.0101%	0.00
0100	148822	-	-	-	-	-	47,901.30	95,802.59	146,159.45	206,338.60	594,282.12	982,225.56	1,370,169.00	1,758,112.44	12/31/2021	20	0.5636%	0.11
0100	152711	-	-	-	-	-	51,998.88	103,997.77	155,996.66	207,995.55	373,607.41	539,219.15	704,830.89	870,442.63	12/31/2021	20	0.2791%	0.06
0100	SU-000299	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	12/31/2020	8	0.0264%	0.00
0100	SU-000301	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	12/31/2020	8	0.0264%	0.00
0100	SU-000336	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	12/31/2020	8	0.0264%	0.00
0100	SU-000337	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	12/31/2020	8	0.0264%	0.00
0100	SU-000338	-	-	-	-	-	-	-	-	-	20,584.00	41,168.00	61,752.00	82,336.00	12/31/2020	8	0.0264%	0.00
0100	SU-000356	-	-	-	-	-	-	-	-	-	54,555.44	109,110.88	163,666.32	218,221.76	12/31/2020	8	0.0700%	0.01
0100	SU-000357	-	-	-	-	-	-	-	-	-	60,321.44	120,642.88	180,964.32	241,285.76	12/31/2020	8	0.0774%	0.01
0100	SU-000358	-	-	-	-	-	-	-	-	-	82,912.44	165,824.88	248,737.32	300,557.60	9/30/2020	5	0.0964%	0.00
0100	SU-000359	-	-	-	-	-	-	-	-	-	70,522.89	141,045.78	211,568.67	282,091.56	12/31/2020	8	0.0904%	0.01
0100	152632	-	-	-	-	-	-	-	-	-	10,623.63	21,247.30	31,870.97	42,494.64	12/31/2021	20	0.0136%	0.00
0100	SU-000362	-	-	-	-	-	-	-	-	-	26,624.19	53,248.38	186,369.39	319,490.40	6/30/2021	14	0.1024%	0.01
0100	SU-000347	-	-	-	-	-	-	-	-	-	-	-	7,867.01	15,734.02	8/31/2021	16	0.0050%	0.00
0100	151757	-	-	-	-	-	-	-	-	-	-	-	-	334,351.79	7/30/2020	3	0.1072%	0.00
0100	SU-000360	-	-	-	-	-	-	-	-	-	-	-	-	62,184.33	3/31/2021	11	0.0199%	0.00
0100	SU-000361	-	-	-	-	-	-	-	-	-	-	-	-	72,563.15	3/31/2021	11	0.0233%	0.00
0100	144782	(931.44)	(1,113.52)	(1,184.69)	(1,296.21)	(1,557.56)	(1,751.87)	(2,067.91)	(2,310.49)	(2,545.37)	(2,775.38)	(2,941.21)	(3,145.35)	(3,323.29)	5/31/2020	1	-0.0011%	(0.00)
0100	00029FACL	705,518.23	723,008.28	921,523.05	939,013.10	956,503.15	1,208,179.54	1,335,672.14	1,344,266.64	1,352,861.14	1,632,527.83	1,658,782.02	1,685,036.21	1,711,290.40	10/31/2020	6	0.5486%	0.03
0100	156464	25,007.61	1,011,390.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	2,025,040.43	6/30/2020	2	0.6492%	0.01
0100	00035FACL	771,924.55	800,947.80	1,336,901.46	1,366,030.12	1,749,936.28	1,779,064.94	2,314,913.19	2,343,936.44	2,701,179.56	3,051,944.05	3,403,032.99	3,754,121.93	4,105,210.87	12/31/2021	20	1.3161%	0.26
0100	00105FACL	74,512.92	75,846.70	77,180.48	78,514.26	80,292.97	81,626.75	154,929.68	154,929.68	154,929.68	210,029.60	265,129.52	497,618.19	552,718.11	12/31/2021	20	0.1772%	0.04
0100	00075FACL	-	-	-	-	-	152,047.50	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	338,052.28	8/31/2020	4	0.1084%	0.00
0100	157892	14,666.80	18,333.45	22,000.10	25,666.75	29,333.40	33,000.05	36,666.70	40,333.35	44,000.00	47,666.85	51,333.50	55,000.15	58,666.80	12/31/2020	8	0.0188%	0.00
0100	149481	-	-	-	-	-	-	-	-	-	-	-	11,000.00	11,000.00	12/31/2020	8	0.0035%	0.00
0100	149165	-	-	-	-	-	-	-	-	-	-	39,807.17	44,136.59	83,436.93	12/31/2020	8	0.0267%	0.00
0100	153021	-	-	-	-	-	-	-	-	-	-	8,109.20	17,232.05	27,368.55	12/31/2020	8	0.0088%	0.00
0100	153024	-	-	-	-	-	-	-	-	-	-	39,430.99	80,990.64	122,550.29	12/31/2020	8	0.0393%	0.00
0100	153018	-	-	-	-	-	-	-	-	-	-	-	101,365.00	101,365.00	12/31/2020	8	0.0325%	0.00
0100	IT0113CG	10,000.00	60,000.00	110,000.00	160,000.00	170,000.00	180,000.00	190,000.00	200,000.00	200,000.00	200,000.00	200,000.00	210,000.00	225,000.00	11/30/2020	7	0.0721%	0.01
0100	IT0246L	109,466.29	153,252.81	197,039.33	240,825.85	284,612.37	328,398.89	372,185.41	394,078.66	415,971.91	459,674.92	503,377.93	547,080.94	590,783.95	6/30/2020	2	0.1894%	0.00
0100	IT0511L	43,788.00	65,682.00	87,576.00	109,470.00	131,364.00	153,258.00	175,152.00	197,046.00	218,940.00	240,864.62	262,789.24	284,713.86	306,638.48	10/31/2020	6	0.0983%	0.01
0100	IT0560L	35,200.02	52,800.03	70,400.04	88,000.05	105,600.06	123,200.07	140,800.08	158,400.09	176,000.10	193,754.78	211,509.46	229,264.14	247,018.82	10/31/2020	6	0.0792%	0.00
0100	IT0561L	8,800.00	13,200.00	17,600.00	22,000.00	26,400.00	30,800.00	35,200.00	39,600.00	44,000.00	50,600.00	57,200.00	63,800.00	70,400.00	10/31/2020	6	0.0226%	0.00
0100	IT0565CG	199,723.47	299,585.18	399,446.89	499,308.60	599,170.31	699,032.02	798,893.73	898,755.44	998,617.15	1,048,394.43	1,123,060.35	1,197,726.27	1,272,392.19	7/31/2020	3	0.4079%	0.01
0100	IT0604L	52,363.02	78,544.53	104,726.04	130,907.55	157,089.06	183,270.57	209,452.08	279,269.30	305,450.81	331,645.48	357,840.15	384,034.82	410,229.49	11/30/2020	7	0.1315%	0.01
0100	IT0708L	10,879.76	21,759.52	43,519.05	76,158.34	108,797.63	141,436.92	174,076.21	195,835.74	217,595.27	250,353.19	283,111.11	315,869.03	348,626.95	10/31/2020	6	0.1118%	0.01
0100	IT0458L	-	-	-	51,580.89	206,323.61	335,275.88	464,228.15	593,180.42	644,761.31	696,493.89	851,691.59	1,006,889.29	1,187,953.31	6/30/2020	2	0.3808%	0.01
0100	IT0559L	-	-	-	11,000.00	22,000.00	33,000.00	44,000.00	55,000.00	66,000.00	77,000.00	88,000.00	99,000.00	110,000.00	6/30/2020	2	0.0353%	0.00
0100	IT0480L	-	-	-	63,462.05	126,924.10	190,386.15	253,848.20	317,310.25	380,772.30	448,078.23	515,384.16	582,346.94	649,652.87	6/30/2021	14	0.2083%	0.03
0100	IT0564CG	-	-	-	-	49,591.73	99,183.46	148,775.19	198,366.92	247,958.65	347,702.93	447,447.21	547,191.49	646,935.77	8/31/2020	4	0.2074%	0.01
0100	IT0419L	-	-	-	-	-	5,200.00	13,000.00	20,800.00	26,000.00	31,200.00	36,400.00	41,600.00	46,800.00	10/31/2020	6	0.0150%	0.00
0100	IT0302L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	161,200.00	317,200.00	11/30/2020	7	0.1017%	0.01
0100	IT0306L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	213,200.00	421,200.00	12/31/2020	8	0.1350%	0.01
0100	IT0612L	-	-	-	-	-	-	-	-	-	11,440.00	22,880.00	34,320.00	45,760.00	12/31/2020	8	0.0147%	0.00
0100	IT0615L	-	-	-	-	-	-	-	-	-	19,657.31	41,383.82	63,110.33	84,836.84	12/31/2020	8	0.0272%	0.00
0100	IT0627L	-	-	-	-	-	-	-	-	-	3,239.79	6,479.58	9,719.37	12,959.16	12/31/2020	8	0.0042%	0.00
0100	IT0636L	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	15,600.00	28,600.00	11/30/2020	7	0.0092%	0.00
0100	IT0671L	-	-	-	-	-	-	-	-	-	146,533.65	293,067.30	439,600.95	586,134.60	11/30/2020	7	0.1879%	0.01
0100	IT0693L	-	-	-	-	-	-	-	-	-	6,500.00	13,000.00	19,500.00	26,000.00	12/31/2020	8	0.0083%	0.00
0100	IT0705L	-	-	-	-	-	-	-	-	-	6,489.23	12,978.46	19,467.69	25,956.92	12/31/2020	8	0.0083%	0.00
0100	IT0609L	-	-	-	-	-	-	-	-	-	10,968.66	32,905.96	98,717.89	131,623.85	7/31/2021	15	0.0422%	0.01
0100	IT0514L	-	-	-	-	-	-	-	-	-	-	10,400.00	20,800.00	41,600.00	12/31/2020	8	0.0133%	0.00
0100	IT0606L	-	-	-	-	-	-	-	-	-	-	2,600.00	7,800.00	15,600.00	11/30/2020	7	0.0050%	0.00
0100	IT0613L	-	-	-	-	-	-	-	-	-	-	14,612.00	29,224.00	43,836.00	11/30/2020	7	0.0141%	0.00
0100	IT0614L	-	-	-	-	-	-	-	-	-	-	5,274.36	10,548.72	15,823.08	8/31/2020	4	0.0051%	0.00
0100	IT0618L	-	-	-	-	-	-	-	-	-	-	11,700.00	23,400.00	46,800.00	12/31/2020	8	0.0150%	0.00
0100	IT0644L	-	-	-	-	-	-	-	-	-	-	2,340.00	7,800.00	13,260.00	11/30/2020	7	0.0043%	0.00
0100	IT0647L	-	-	-	-	-	-	-	-	-	-	3,120.00	10,920.00	18,720.00	11/30/2020	7	0.0060%	0.00
0100	IT0649L	-	-	-	-	-	-	-	-	-	-	5,200.00	15,600.00	31,200.00	11/30/2020	7	0.0100%	0.00
0100	IT0651L	-	-	-	-	-	-	-	-	-	-	10,400.00	10,400.00	20,800.00	10/31/2020	6	0.0067%	0.00
0100	IT0672L	-	-	-	-	-	-	-	-	-	-	1,560.00	5,200.00	8,840.00	11/30/2020	7	0.0028%	0.00
0100	IT0675L	-	-	-	-	-	-	-	-	-	-	4,680.00	15,600.00	31,200.00	11/30/2020	7	0.0100%	0.00
0100	IT0680L	-	-	-	-	-	-	-	-	-	-	3,210.35	6,955.77	31,033.51	12/31/2020	8	0.0099%	0.00
0100	IT0689L	-	-	-	-	-	-	-	-	-	-	6,600.00	13,200.00	19,800.00	6/30/2020	2	0.0063%	0.00
0100	IT0690L	-	-	-	-	-	-	-	-	-	-	13,200.00	26,400.00	39,600.00	11/30/2020	7	0.0127%	0.00
0100	IT0695L	-	-	-	-	-	-	-	-	-	-	4,160.00	8,320.00	12,480.00	11/30/2020	7	0.0040%	0.00
0100	IT0701L	-	-	-	-	-	-	-	-	-	-	11,000.00	22,000.00	33,000.00	11/30/2020	7	0.0106%	0.00
0100	IT0711L	-	-	-	-	-	-	-	-	-	-	13,000.00	26,000.00	39,000.00	11/30/2020	7	0.0125%	0.00
0100	IT0712L	-	-	-	-	-	-	-	-	-	-	4,400.00	8,800.00	13,200.00	11/30/2020	7	0.0042%	0.00
0100	IT0722L	-	-	-	-	-	-	-	-	-	-	10,400.00	20,800.00	31,200.00	11/30/2020	7	0.0100%	0.00
0100	IT1087L	-	-	-	-	-	-	-	-	-	-	25,716.10	51,432.20	77,148.30	12/31/2020	8	0.0247%	0.00
0100	IT0407L	-	-	-	-	-	-	-	-	-	-	-	11,000.00	33,000.00	7/31/2020	3	0.0106%	0.00
0100	IT0452L	-	-	-	-	-	-	-	-	-	-	-	22,000.00	44,000.00	10/31/2020	6	0.0141%	0.00
0100	IT0634L	-	-	-	-	-	-	-	-	-	-	-	6,240.00	6,240.00	10/31/2020	6	0.0020%	0.00
0100	IT0637L	-	-	-	-	-	-	-	-	-	-	-	8,840.00	8,840.00	11/30/2020	7	0.0028%	0.00
0100	IT0661L	-	-	-	-	-	-	-	-	-	-	-	10,400.00	11,466.52	10/31/2020	6	0.0037%	0.00
0100	IT0668L	-	-	-	-	-	-	-	-	-	-	-	1,040.00	3,640.00	10/31/2020	6	0.0012%	0.00
0100	IT0673L	-	-	-	-	-	-	-	-	-	-	-	2,200.00	4,400.00	11/30/2020	7	0.0014%	0.00
0100	IT0674L	-	-	-	-	-	-	-	-	-	-	-	5,940.00	11,880.00	12/31/2020	8	0.0038%	0.00
0100	IT0681L	-	-	-	-	-	-	-	-	-	-	-	52,000.00	52,000.00	8/31/2020	4	0.0167%	0.00
0100	IT0682L	-	-	-	-	-	-	-	-	-	-	-	2,600.00	5,200.00	12/31/2020	8	0.0017%	0.00
0100	IT0694L	-	-	-	-	-	-	-	-	-	-	-	34,187.80	68,375.60	8/31/2020	4	0.0219%	0.00
0100	IT0713L	-	-	-	-	-	-	-	-	-	-	-	4,400.00	8,800.00	11/30/2020	7	0.0028%	0.00
0100	IT0715L	-	-	-	-	-	-	-	-	-	-	-	11,000.00	22,000.00	8/31/2020	4	0.0071%	0.00
0100	IT0716L	-	-	-	-	-	-	-	-	-	-	-	5,200.00	10,400.00	12/31/2020	8	0.0033%	0.00
0100	IT0718L	-	-	-	-	-	-	-	-	-	-	-	88,000.00	110,000.00	5/31/2020	1	0.0353%	0.00
0100	IT0720L	-	-	-	-	-	-	-	-	-	-	-	126,641.90	132,794.56	12/31/2020	8	0.0426%	0.00
0100	IT0723L	-	-	-	-	-	-	-	-	-	-	-	26,000.00	52,000.00	12/31/2020	8	0.0167%	0.00

LG&E and KU - Number of Months in CWIP after Test Year

Company	Projects	4/30/2019	5/31/2019	6/30/2019	7/31/2019	8/31/2019	9/30/2019	10/31/2019	11/30/2019	12/31/2019	1/31/2020	2/29/2020	3/31/2020	4/30/2020	In-Service Date	Variance to TYE (Months)	% of CWIP	Weighted Avg
0100	IT0726L	-	-	-	-	-	-	-	-	-	-	-	36,400.00	72,800.00	12/31/2020	8	0.0233%	0.00
0100	IT0569L	-	-	-	-	-	-	-	-	-	-	-	391,587.42	861,468.43	12/31/2021	20	0.2762%	0.06
0100	IT0628L	-	-	-	-	-	-	-	-	-	-	-	-	13,000.00	10/31/2020	6	0.0042%	0.00
0100	IT0633L	-	-	-	-	-	-	-	-	-	-	-	-	26,000.00	12/31/2020	8	0.0083%	0.00
0100	IT0656L	-	-	-	-	-	-	-	-	-	-	-	-	104,000.00	10/31/2020	6	0.0333%	0.00
0100	IT0710L	-	-	-	-	-	-	-	-	-	-	-	-	10,400.00	10/31/2020	6	0.0033%	0.00
0100	IT0724L	-	-	-	-	-	-	-	-	-	-	-	-	3,876.51	2/28/2021	10	0.0012%	0.00
		57,290,533.64	**65,230,284.64**	**75,648,360.40**	**87,939,586.82**	**103,174,807.56**	**118,432,095.61**	**137,268,211.76**	**151,402,375.41**	**163,461,147.52**	**186,633,063.22**	**217,465,844.45**	**258,005,870.18**	**311,924,588.34**		**7.49**	**100.0000%**	**8.30**

8.30 Weighted average duration until completion of projects remaining in CWIP after Test Year

Adjustments to KU Capitalization and Cost of Capital
Case No. 2018-00294
Test Year Ending April 30, 2020

I. Kentucky Industrial Utility Customers (KIUC) Direct Testimony and Exhibits of Lane Kollen - KIUC Summary of KU Revenue Requirement - KIUC Adjustments to KU Capitalization and Cost of Capital (Parts I and II)

	13 Month Average Balance	KU Proforma Adjustments	KU Adjusted Total Co. Capitalization	KU Kentucky Jurisdictional Factor	KU Jurisdictional Capitalization	Capital Ratio	Jurisdictional Adjustments	Adjusted KU Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	70,738,410	(5,339)	70,733,071	93.77%	66,326,401	1.25%	(15,278,933)	51,047,468	1.25%	3.23%	0.04%	0.04%	1,656,019
Long Term Debt	2,607,964,904	(196,820)	2,607,768,084	93.77%	2,445,304,132	45.91%	(563,299,660)	1,882,004,472	45.91%	4.38%	2.01%	2.02%	82,932,382
Common Equity	3,001,947,921	(549,856)	3,001,398,065	93.77%	2,814,410,966	52.84%	(648,327,020)	2,166,083,946	52.84%	10.42%	5.51%	7.37%	302,300,640
Total Capital	5,680,651,235	(752,015)	5,679,899,220		5,326,041,499	100.00%	(1,226,905,613)	4,099,135,886	100.00%		7.56%	9.44%	386,889,041

	Adjusted KU Jurisdictional Capitalization	KIUC Proforma Adjustment 1 KY Jurisd	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	51,047,468	(1,674,701)	49,372,766	1.25%	3.23%	0.04%	0.04%	1,601,690	(54,329)
Long Term Debt	1,882,004,472	(61,742,446)	1,820,262,026	45.91%	4.38%	2.01%	2.02%	80,211,640	(2,720,742)
Common Equity	2,166,083,946	(71,062,170)	2,095,021,775	52.84%	10.42%	5.51%	7.37%	292,383,139	(9,917,501)
Total Capital	4,099,135,886	(134,479,318)	3,964,656,568	100.00%		7.56%	9.44%	374,196,470	(12,692,571)

II. Capitalization Per Filing [2]

	13 Month Average Balance	KU Proforma Adjustments	KU Adjusted Total Co. Capitalization	KU Kentucky Jurisdictional Factor	KU Jurisdictional Capitalization	Capital Ratio	Jurisdictional Adjustments	Adjusted KU Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	47,661,487	(3,612)	47,657,875	93.77%	44,688,789	0.84%	(10,329,360)	34,359,430	0.84%	3.37%	0.03%	0.03%	1,162,950
Long Term Debt	2,607,964,904	(197,624)	2,607,767,280	93.77%	2,445,303,379	46.10%	(565,207,041)	1,880,096,337	46.10%	4.38%	2.02%	2.03%	82,848,298
Common Equity	3,001,947,921	(550,781)	3,001,397,141	93.77%	2,814,410,099	53.06%	(650,522,311)	2,163,887,788	53.06%	10.42%	5.53%	7.40%	301,994,143
Total Capital	5,657,574,312	(752,016)	5,656,822,296		5,304,402,267	100.00%	(1,226,058,712)	4,078,343,555	100.00%		7.58%	9.46%	386,005,391

III. Adjusted Capitalization - Remove CWIP net accrual [2]

	Adjusted KU Jurisdictional Capitalization	Proforma Adjustment KY Jurisd [3]	Kentucky Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	34,359,430	(780,099)	33,579,331	0.84%	3.37%	0.03%	0.03%	1,136,547	(26,404)
Long Term Debt	1,880,096,337	(42,685,823)	1,837,410,514	46.10%	4.38%	2.02%	2.03%	80,967,305	(1,880,993)
Common Equity	2,163,887,788	(49,129,042)	2,114,758,746	53.06%	10.42%	5.53%	7.40%	295,137,649	(6,856,494)
Total Capital	4,078,343,555	(92,594,963)	3,985,748,591	100.00%		7.58%	9.46%	377,241,501	(8,763,890)

41,884,355 CWIP Accrual per Sch B-5.2 F [2]

Adjustments to KU Capitalization and Cost of Capital
Case No. 2018-00294
Test Year Ending April 30, 2020

IV. Adjusted Capitalization - Remove CWIP net accrual and apply AFUDC rates [2]

	Adjusted KU Jurisdictional Capitalization	AFUDC Capital Ratio [4]	Proforma Adjustment KY Jurisd [3]	Kentucky Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	34,359,430	37.11%	(34,359,430)	-	0.00%	3.37%	0.00%	0.00%	-	(1,162,950)
Long Term Debt	1,880,096,337	29.24%	(27,074,393)	1,853,021,945	46.49%	4.38%	2.04%	2.05%	81,655,238	(1,193,060)
Common Equity	2,163,887,788	33.65%	(31,161,141)	2,132,726,647	53.51%	10.42%	5.58%	7.47%	297,645,265	(4,348,877)
Total Capital	4,078,343,555	100.00%	(92,594,963)	3,985,748,591	100.00%		7.61%	9.52%	379,300,504	(6,704,887)

V. Revenue Requirement reduction using CWIP net accrual and apply AFUDC rates

	Kentucky Adjusted KY Jurisd [3]	AFUDC Capital Ratio [4]	Component Costs [4]	Weighted Avg Cost [4]	Grossed Up Cost	Revenue Requirement
Short Term Debt	(34,359,430)	37.11%	3.37%	1.25%	1.26%	(1,162,950)
Long Term Debt	(27,074,393)	29.24%	4.38%	1.28%	1.29%	(1,193,060)
Common Equity	(31,161,141)	33.65%	10.42%	3.51%	4.70%	(4,348,877)
Total Capital	(92,594,963)	100.00%		6.04%	7.24%	(6,704,887)

1. 13 Month Average CWIP per Sch B-1
2. KU Supplemental Response to PSC 1-53 – Schedule J (Ky. PSC Feb. 15, 2019); KU Supplemental Response to PSC 1-53 – Schedule B (Ky. PSC Feb. 15, 2019).
3. 13 Month Average CWIP per Sch B-1 net accrual per Sch B-5.2 F [2]
4. Rebuttal Exhibit KWB-1

Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2018-00295
Test Year Ending April 30, 2020

I. Kentucky Industrial Utility Customers (KIUC) Direct Testimony and Exhibits of Lane Kollen - KIUC Summary of LG&E Revenue Requirement - KIUC Adjustments to LG&E (Electric) Capitalization and Cost of Capital (Parts I and II)

	13 Month Average Balance	Capital Ratio	LG&E Kentucky Electric Factor	LG&E Electric Capitalization	LG&E Adjustments to Capitalization	Adjusted LG&E Electric Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	87,367,954	1.89%	80.33%	70,182,677	(21,071,121)	49,111,556	1.89%	3.25%	0.06%	0.06%	1,602,246
Long Term Debt	2,088,568,822	45.27%	80.33%	1,677,747,335	(503,714,285)	1,174,033,050	45.27%	4.53%	2.05%	2.06%	53,387,638
Common Equity	2,437,703,817	52.84%	80.33%	1,958,207,476	(587,917,536)	1,370,289,940	52.84%	10.42%	5.51%	7.36%	190,981,664
Total Capital	4,613,640,593	100.00%		3,706,137,488	(1,112,702,942)	2,593,434,546	100.00%		7.62%	9.48%	245,971,548

	Adjusted LG&E Electric Capitalization	KIUC Proforma Adjustment 1 KY Jurisd	KIUC Kentucky Adjusted Capitalization	KIUC Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	49,111,556	(1,542,762)	47,568,795	1.89%	3.25%	0.06%	0.06%	1,551,914	(50,332)
Long Term Debt	1,174,033,050	(36,880,391)	1,137,152,659	45.27%	4.53%	2.05%	2.06%	51,710,550	(1,677,088)
Common Equity	1,370,289,940	(43,045,490)	1,327,244,450	52.84%	10.42%	5.51%	7.36%	184,982,277	(5,999,387)
Total Capital	2,593,434,546	(81,468,643)	2,511,965,903	100.00%		7.62%	9.48%	238,244,741	(7,726,807)

II. Capitalization Per Filing [(2)]

	13 Month Average Balance	Capital Ratio	LG&E Kentucky Electric Factor	LG&E Electric Capitalization	LG&E Adjustments to Capitalization	Adjusted LG&E Electric Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement
Short Term Debt	64,291,031	1.40%	80.34%	51,651,415	(15,583,450)	36,067,964	1.40%	3.36%	0.05%	0.05%	1,216,489
Long Term Debt	2,088,568,822	45.50%	80.34%	1,677,956,191	(506,246,474)	1,171,709,717	45.50%	4.53%	2.06%	2.07%	53,282,529
Common Equity	2,437,703,817	53.10%	80.34%	1,958,451,247	(590,873,018)	1,367,578,229	53.10%	10.42%	5.53%	7.40%	190,603,724
Total Capital	4,590,563,670	100.00%		3,688,058,853	(1,112,702,942)	2,575,355,911	100.00%		7.64%	9.52%	245,102,742

III. Adjusted Capitalization - Remove CWIP net accrual [(2)]

	Adjusted LG&E Electric Capitalization	Proforma Adjustment KY Jurisd [(3)]	Kentucky Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	36,067,964	(464,835)	35,603,130	1.40%	3.36%	0.05%	0.05%	1,200,812	(15,678)
Long Term Debt	1,171,709,717	(15,100,690)	1,156,609,028	45.50%	4.53%	2.06%	2.07%	52,595,837	(686,691)
Common Equity	1,367,578,229	(17,624,992)	1,349,953,237	53.10%	10.42%	5.53%	7.40%	188,147,273	(2,456,451)
Total Capital	2,575,355,911	(33,190,516)	2,542,165,395	100.00%		7.64%	9.52%	241,943,922	(3,158,820)

48,278,127 CWIP Accrual per Sch B-5.2 F [(2)]

Adjustments to LG&E (Electric) Capitalization and Cost of Capital
Case No. 2018-00295
Test Year Ending April 30, 2020

IV. Adjusted Capitalization - Remove CWIP net accrual and apply AFUDC rates (2)

	Adjusted LG&E Electric Capitalization	AFUDC Capital Ratio (4)	Proforma Adjustment KY Jurisd (3)	Kentucky Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Revenue Requirement	Incremental Revenue Requirement
Short Term Debt	36,067,964	100.00%	(33,190,516)	2,877,448	0.11%	3.36%	0.00%	0.00%	97,050	(1,119,440)
Long Term Debt	1,171,709,717	0.00%	-	1,171,709,717	46.09%	4.53%	2.09%	2.10%	53,282,529	-
Common Equity	1,367,578,229	0.00%	-	1,367,578,229	53.80%	10.42%	5.61%	7.50%	190,603,724	-
Total Capital	2,575,355,911	100.00%	(33,190,516)	2,542,165,395	100.00%		7.70%	9.60%	243,983,303	(1,119,440)

V. Revenue Requirement reduction using CWIP net accrual and apply AFUDC rates

	Proforma Adjustment KY Jurisd (3)	AFUDC Capital Ratio (4)	Component Costs (4)	Weighted Avg Cost (4)	Grossed Up Cost	Incremental Revenue Requirement
Short Term Debt	(33,190,516)	100.00%	3.36%	3.36%	3.37%	(1,119,440)
Long Term Debt	-	0.00%	0.00%	0.00%	0.00%	-
Common Equity	-	0.00%	0.00%	0.00%	0.00%	-
Total Capital	(33,190,516)	100.00%		3.36%	3.37%	(1,119,440)

1. 13 Month Average CWIP per Sch B-1
2. LG&E Supplemental Response to PSC 1-53 – Schedule J (Ky. PSC Feb. 15, 2019); LG&E Supplemental Response to PSC 1-53 – Schedule B (Ky. PSC Feb. 15, 2019).
3. 13 Month Average CWIP per Sch B-1 net accrual per Sch B-5.2 F (2)
4. Rebuttal Exhibit KWB-1

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's affirms the ratings of Kentucky Utilities Co., Louisville Gas & Electric Company, and LG&E and KU Energy LLC; rating outlooks stable

15 Jan 2019

New York, January 15, 2019 -- Moody's Investors Service ("Moody's") affirmed the ratings of Kentucky Utilities Co. (KU) and Louisville Gas & Electric Company (LGE), including the A3 Long Term Issuer Rating and Prime-2 short-term rating. Also, Moody's affirmed the Baa1 rating of LG&E and KU Energy LLC (LKE). The rating outlooks for all three issuers is stable. The affirmation of the ratings is based on the continued constructive regulatory environments, primarily in Kentucky where the two utilities have most of their operations, and the stable generation of cash flows.

Outlook Actions:

..Issuer: Kentucky Utilities Co.

....Outlook, Remains Stable

..Issuer: LG&E and KU Energy LLC

....Outlook, Remains Stable

..Issuer: Louisville Gas & Electric Company

....Outlook, Remains Stable

Affirmations:

..Issuer: Carroll (County of) KY

....Long Term Senior Secured Revenue Bonds, Affirmed A1

....Underlying Long Term Senior Secured Revenue Bonds, Affirmed A1

....Short Term Senior Secured Revenue Bonds, Affirmed P-2

....Long Term Senior Unsecured Revenue Bonds, Affirmed A1

....Short Term Senior Unsecured Revenue Bonds, Affirmed P-2

..Issuer: Jefferson (County of) KY

....Long Term Senior Secured Revenue Bonds, Affirmed A1

....Underlying Long Term Senior Secured Revenue Bonds, Affirmed A1

....Short Term Senior Secured Revenue Bonds, Affirmed P-2

..Issuer: Kentucky Utilities Co.

.... Issuer Rating, Affirmed A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Unsecured Bank Credit Facility, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: LG&E and KU Energy LLC

.... Issuer Rating, Affirmed Baa1

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Louisville & Jefferson Co. Metro. Govt., KY

....Senior Secured Revenue Bonds, Affirmed A1

..Issuer: Louisville Gas & Electric Company

.... Issuer Rating, Affirmed A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Unsecured Bank Credit Facility, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Mercer (County of) KY

....Long Term Senior Secured Revenue Bonds, Affirmed A1

....Short Term Senior Secured Revenue Bonds, Affirmed P-2

..Issuer: Muhlenberg (County of) KY

....Long Term Senior Secured Revenue Bonds, Affirmed A1

....Short Term Senior Secured Revenue Bonds, Affirmed P-2

..Issuer: Trimble (County of) KY

....Senior Secured Revenue Bonds, Affirmed A1

....Underlying Senior Secured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed A1

....Underlying Senior Unsecured Revenue Bonds, Affirmed A1

RATINGS RATIONALE

"PPL's Kentucky utilities balance the longer term risks of carbon transition and climate change with a strong balance sheet and steady cash flow metrics, thanks to a supportive regulatory environment," stated Jairo Chung, a Moody's analyst. Prospectively, KU and LGE's key financial metrics are expected to be lower than historical levels due to sizeable capital expenditures and the resetting of its rates due to tax reform in 2017. For example, the ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt is expected to decline to the low 20% level from the mid-20% level.

The affirmation of the A3 rating for KU and LGE incorporates Moody's view that the regulatory environment will continue to be supportive and allow these utilities to generate stable cash flows. It should be noted that these utilities rely heavily on coal as a fuel for their power generation, with approximately 64% of capacity using coal as fuel. However, the state of Kentucky is very supportive of the coal industry in general and coal usage specifically. This support is evidenced by various cost recovery riders such as the environmental cost recovery surcharge mechanism and the fuel adjustment clause. Under the constructive Kentucky regulatory environment, Moody's expects KU and LGE to be able to mitigate some of their carbon transition risk over time, although the transition risk is higher relative to other regulated utilities.

In addition, the outcomes of KU and LGE's regulatory proceedings have been more supportive in Kentucky. Both KU and LGE utilize a suite of tracker mechanisms, allowing timely cost recovery for utility investments, particularly environmental investment, outside of a general rate base. Also, a forward test year is used in general rate cases. Thus, KU and LGE typically begin recovering their annual investments within 12-18 months of the spend with the every other year cadence for the general rate case filings. Also, the service territories of KU and LGE have better demographics and somewhat benefit from the regional differences between metropolitan areas around Louisville and other rural areas in the east.

Moody's expects KU and LGE's key credit metrics to be lower than historical levels. The 2017 Tax Cuts and Jobs Act had a negative impact on several key financial metrics. Also, their robust capital investment programs continue to put some pressure on their metrics. However, the capital investment programs are expected to decrease over the next four years and there are no large projects within the plan, providing some flexibility within the plan. Moody's expects KU and LGE to maintain its CFO pre-WC to debt ratio in the low 20% range over the next few years.

The affirmation of LKE's Baa1 issuer rating reflects the support from the consistent and stable operations at its utility subsidiaries, KU and LGE. Although LKE's key metrics are expected to be weaker than their historical levels, including CFO pre-WC to debt in the 15% range compared to 18%-20% historical range, we do not expect any material changes to its fundamental profile. The expected decrease in the metrics are mainly due to the reduction in the cash flows related to deferred income taxes. Furthermore, LKE has $725 million of debt issued at this level under two notes outstanding. These notes are due in November 2020 and October 2021 and are likely to be either repaid or refinanced at PPL Capital Funding, Inc.

Rating Outlook

The stable outlook for KU and LGE reflects Moody's expectation that the regulatory environments will remain credit supportive. The stable outlook also incorporates Moody's view that both KU and LGE will continue to generate stable cash flow and adequate financial metrics, including a ratio of CFO pre-WC to debt in the low-20% range for KU and LGE.

Similarly, the stable outlook for LKE reflects Moody's expectation of consistently credit supportive regulatory environments for its utility subsidiaries, KU and LGE. It also incorporates in Moody's view that LKE's overall leverage remains the same and considers the stable outlook of its parent company, PPL Corporation.

Liquidity

Moody's expects all three entities to maintain an adequate but weaker liquidity profile over the next 12 months. KU and LGE have a P-2 short-term commercial paper rating and have separate credit facilities. KU's liquidity is supported by a separate $400 million syndicated credit facility expiring in January 2023 and a $198 million letter of credit facility expiring in October 2020. LGE's liquidity is supported by a separate $500 million syndicated credit facility expiring in January 2023 and a $200 million term loan credit facility expiring in October 2019, which is now current and weakening the family's overall liquidity. Furthermore, LKE's $75 million syndicated credit facility expired in October 2018, further weakening LKE's liquidity position. LKE's next long-term debt maturity is $475 million senior notes due in November 2020. The companies plan to address the recent weakness in their liquidity position in early 2019.

Factors That Could Lead to an Upgrade

KU and LG&E'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 could be considered if the regulatory environment in Kentucky improves materially and provides more favorable regulatory recovery mechanisms.

A rating upgrade for LKE would likely require a rating upgrade at KU and LGE or a material reduction of debt issued at LKE. A rating upgrade could be also considered for LKE if its financial metrics improve, including CFO pre-WC to debt at or above 22% on a sustained basis.

Factors That Could Lead to a Downgrade

A rating downgrade could be possible at KU and LGE if there is a significant deterioration in the credit supportiveness of the regulatory environments. Also, if the financial metrics deteriorate, such that CFO pre-WC to debt declines below 20% for an extended period, a downgrade could be considered for KU and LGE.

LKE's rating could be downgraded if one or both of the utility subsidiaries experiences negative rating actions or a significant deterioration in the credit supportiveness of the regulatory environments. Additionally, a rating downgrade could be possible if its financial metrics declines, including CFO pre-WC to debt below 15% on a sustained period. LKE's rating could be downgraded if there is a material increase in LKE debt level.

Kentucky Utilities Co. (KU) and Louisville Gas & Electric Company (LGE) are wholly-owned subsidiaries of LG&E and KU Energy LLC (LKE). LKE is a wholly-owned subsidiary of PPL Corporation, a diversified utility holding company headquartered in Allentown, Pennsylvania. In Kentucky, these two utilities serve approximately 1.3 million electric and gas customers and under the purview of the Kentucky Public Service

Commission. KU also has some utility operations in Virginia and they are regulated by the Virginia State Corporation Commission.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

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$ millions	Kentucky Utilities				LG&E Electric				LG&E Gas			
	Per PSC2-65	Remove FERC Account 108	Update for 2018	Updated Slippage Impact on RevReq	Per PSC2-75	Remove FERC Account 108	Update for 2018	Updated Slippage Impact on RevReq	Per PSC2-75	Remove FERC Account 108	Update for 2018	Updated Slippage Impact on RevReq
Capitalization	($21.6)	$1.5	$9.8	($10.3)	($10.5)	$0.9	($0.5)	($10.0)	($3.7)	$0.2	($0.1)	($3.6)
Rate of Return as Filed	7.56%	7.56%	7.56%	7.56%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%
Required Operating Income at Filed Rate of Return	(1.6)	0.1	0.7	(0.8)	(0.8)	0.1	(0.0)	(0.8)	(0.3)	0.0	(0.0)	(0.3)
Adjustment for Changes in Filed Rate of Return	0.1	(0.0)	(0.0)	0.1	0.1	(0.0)	0.0	0.1	0.0	(0.0)	0.0	0.0
Required Operating Income	($1.5)	$0.1	$0.7	($0.7)	($0.7)	$0.1	($0.0)	($0.7)	($0.3)	$0.0	($0.0)	($0.3)
Depreciation and Amortization	$0.6	$0.0	($0.3)	$0.3	$0.3	($0.0)	$0.0	$0.3	$0.1	($0.0)	$0.0	$0.1
Income Taxes	(0.3)	0.0	0.1	(0.1)	(0.1)	0.0	(0.0)	(0.1)	(0.0)	0.0	(0.0)	(0.0)
Other NOI Items	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NOI per Book	$0.4	$0.0	($0.2)	$0.2	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0
NOI Deficiency	($2.0)	$0.1	$0.9	($1.0)	($1.0)	$0.1	($0.0)	($1.0)	($0.3)	$0.0	($0.0)	($0.3)
Gross Revenue Conversion Factor	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Revenue Deficiency	($2.7)	$0.1	$1.2	($1.3)	($1.3)	$0.1	($0.1)	($1.3)	($0.4)	$0.0	($0.0)	($0.4)

Kentucky Utilities Company
Case No. 2018-00294
Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Schedule 13b(1)

Source: Schedule 13a - Construction Projects

Years	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2018	365,743,710	360,095,886	5,647,825	1.568%	101.568%
2017	331,452,600	353,148,308	(21,695,708)	-6.144%	93.856%
2016	257,316,496	247,479,708	9,836,788	3.975%	103.975%
2015	240,247,704	254,705,926	(14,458,222)	-5.676%	94.324%
2014	258,672,601	285,655,724	(26,983,123)	-9.446%	90.554%
2013	467,930,147	442,723,204	25,206,943	5.694%	105.694%
2012	250,621,314	298,013,293	(47,391,979)	-15.903%	84.097%
2011	203,042,999	215,256,373	(12,213,373)	-5.674%	94.326%
2010	209,036,428	183,198,611	25,837,818	14.104%	114.104%
2009	247,393,650	254,530,196	(7,136,546)	-2.804%	97.196%
Totals	**2,831,457,649**	**2,894,807,228**	**(63,349,579)**	**-2.188%**	**97.812%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**97.969%**

The Base Rate Capital Actual Cost is the Annual Actual Cost per Schedule 13(a)Non-Mechanism Construction Projects . The Base Rate Capital Budget Cost is the Annual Original Budget per Schedule 13(a)Non-Mechanism Construction Projects .

The Slippage Factor is calculated by dividing the Base Rate Capital Actual Cost by the Base Rate Capital Budget Cost. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places

*2012 = Removed the budgeted amount related to the acquisition of the Bluegrass CTs. Based on the mitigation measures required by FERC for approval LG&E and KU determined that the options were not commercially justifiable. In June 2012, LG&E and KU terminated the asset purchase agreement for the Bluegrass CTs in accordance with its terms and made applicable filings with the KPSC and FERC.

The 10-year average ratio of actual to budgeted capital construction (slippage factors) for 2008 through 2017 for the Non-Mechanism Capital Construction Projects - as filed in PSC1-13(b)	**95.373%**
10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years) - as filed in PSC1-13(b)	**96.027%**

Louisville Gas and Electric Company

Case No. 2018-00295

Calculation of Capital Construction Project Slippage Factor -Non-Mechanism Construction Projects

Schedule 13b(1)

Source: Schedule 13a - Construction Projects

Year	Base Rate Capital Actual Cost	Base Rate Capital Budget Cost	Variance in Dollars	Variance as a percent	Slippage Factor
2018	319,581,595	330,277,722	(10,696,127)	-3.239%	96.761%
2017	273,814,739	314,514,052	(40,699,313)	-12.940%	87.060%
2016	201,820,465	205,916,322	(4,095,857)	-1.989%	98.011%
2015	213,433,085	213,558,521	(125,436)	-0.059%	99.941%
2014	233,542,915	246,109,548	(12,566,633)	-5.106%	94.894%
2013	301,411,194	297,836,538	3,574,656	1.200%	101.200%
2012	198,826,795	214,793,287	(15,966,492)	-7.433%	92.567%
2011	197,524,642	226,223,175	(28,698,533)	-12.686%	87.314%
2010	203,125,349	170,001,291	33,124,058	19.485%	119.485%
2009	167,411,673	179,893,509	(12,481,836)	-6.938%	93.062%
Totals	**2,310,492,453**	**2,399,123,965**	**(88,631,513)**	**-3.694%**	**96.306%**

10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years)	**97.029%**

The Slippage Factor is calculated by dividing the Base Rate Capital Actual Cost by the Base Rate Capital Budget Cost. Calculate a Slippage Factor for each year and the Totals line. Carry Slippage Factor percentages to 3 decimal places

*2012 = Removed the budgeted amount related to the acquisition of the Bluegrass CTs. Based on the mitigation measures required by FERC for approval LG&E and KU determined that the options were not commercially justifiable. In June 2012, LG&E and KU terminated the asset purchase agreement for the Bluegrass CTs in accordance with its terms and made applicable filings with the KPSC and FERC.

The 10-year average ratio of actual to budgeted capital construction (slippage factors) for 2008 through 2017 for the Non-Mechanism Capital Construction Projects - as filed in PSC1-13(b)	**96.400%**
10 Year Average Slippage Factor (Mathematic Average of the Yearly Slippage Factors / 10 Years) - as filed in PSC1-13(b)	**97.153%**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS RATES	**)))**	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
LONNIE E. BELLAR
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 21, 2019

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Q. Please state your name, position and business address.

A. My name is Lonnie E. Bellar. I am the Chief Operating Officer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"), (collectively, the "Companies") and an employee of LG&E and KU Services Company. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut intervenor testimony on the following topics: (1) investments in transmission and distribution systems; (2) pipeline replacements for gas transmission lines; (3) gas pipeline reinforcement in Nelson County; (4) merger mitigation depancaking; (5) exclusion of revenues from Phoenix Paper-Wickliffe in forecasts; (6) expenses for Brown 1 stack repair; (7) impact on labor expense due to retirement of Brown Units 1 and 2; (8) forecasting of generation outage expenses; (9) depreciation life span of steam generating units; (10) inclusion of customer education expenses in base rates; (11) value provided by the Companies' membership in EPRI and EEI; and (12) underground gas facility locates.

(1) Investments in Transmission and Distribution Systems

Q. Are the Companies making investments to replace, upgrade and modernize their electric transmission and distribution systems?

A. Yes, the Companies are in the midst of a long term plan to improve and modernize their electric transmission and distribution infrastructure. Many of the investments contemplated by these plans and the underlying reasons for those investments are set forth in detail in the Transmission System Improvement Plan ("TSIP"), attached as

Exhibit PWT-2 to Mr. Thompson's testimony in the Companies' 2016 rate cases[1], and the Distribution Reliability and Resiliency Improvement Program ("DRRIP"), attached as Exhibit LEB-5 to my testimony in these cases.

Q. Are the investments described in the TSIP and DRRIP necessary and prudent to ensure the safety and reliability of the Companies' power delivery systems?

A. Absolutely. The Companies have an obligation to deliver safe and reliable power to customers. Aging transmission and distribution assets that are past their useful lives present safety and reliability risks to the system. The Companies have systematically evaluated those risks and developed a plan for minimizing them through implementation of the TSIP, DRRIP and related projects. Transmission asset replacements and the addition of modern circuit breakers and switching equipment have resulted in marked improvements on specific circuits that were previously consistent contributors to customer outages.[2] The Companies expect these improvements to positively impact reliability system-wide, and have set concrete and measurable goals for reliability improvements to be achieved through implementation of these programs.

Q. How are the projects described in the transmission and distribution system plans prioritized?

A. The Companies undertake a rigorous approach to business planning in making decisions on how to prioritize investments. As described in the Annual TSIP Update

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[1] *E.g.*, Direct Testimony of Paul Thompson, Case No. 2016-00370, and Exhibit PWT-2 thereto.

[2] Case Nos. 2016-00370 and 2016-00371, LG&E and KU Transmission System Improvement Plan Annual Report, June 1, 2018, at Section 4.2.

Report filed with the Commission last year,[3] the prioritization of reliability and system integrity projects varies depending on the type of asset. In general, the Companies consider a combination of the magnitude of customer impact in the event of failure, the type of asset, the age and condition of the asset as determined by field inspections, and past performance and maintenance history. Often, groups of transmission or distribution system assets can be replaced as part of a single outage to minimize customer impact and gain efficiencies in the cost of the work performed.

Q. Is KIUC's witness Kollen critical of any particular project included in the Companies' proposed transmission and distribution investments?

A. No. Mr. Kollen does not have a specific criticism of any project included in the Companies' proposed transmission or distribution investments. Nor is he critical of any aspect of the Companies' business planning process. Instead, he asserts that transmission and distribution investments are "controllable" costs that should be normalized to more closely reflect historical spending. He further argues that minimizing recovery of transmission and distribution investments will force the Companies to better prioritize their investments.

Q. Are Mr. Kollen's criticisms of the Companies' transmission and distribution investments valid?

A. In a word, no. These arguments ignore the realities of the operational business planning process. First, the Companies do not consider investments needed to improve the safety and reliability of their power delivery systems to be discretionary or subject to lengthy deferrals. If the Companies are restricted to making a certain

[3] *Id.*, Section 3.

level of investment based only upon the level of past investment, their ability to respond to the current condition of their assets is significantly impaired. This is true whether the Companies are proposing to make upward *or* downward adjustments to spending on a particular system or group of assets. Second, Mr. Kollen's arguments ignore the fact that the investments proposed in the Companies' business plans have *already* been culled and prioritized throughout the Companies' business planning process. The investments included in the TSIP and DRRIP are the result of the rigorous process of evaluating and prioritizing projects. Mr. Kollen's recommendation to curtail recovery of these investments based on historical levels should be rejected by the Commission.

(2) Pipeline Replacements for Gas Transmission Lines

Q. Why is LG&E proposing to replace certain segments of gas transmission lines?

A. The proposed replacement of multiple segments of gas transmission lines I described in my direct testimony is part of an overall strategy to achieve two related objectives: (1) promote the overall safety and reliability of LG&E's gas transmission lines; and (2) ensure that LG&E is able to demonstrate compliance with proposed PHMSA safety regulations pertaining to natural gas pipelines. In order to achieve these two objectives, LG&E proposes to perform enhanced inline inspections (ILIs) on its transmission pipelines. Running enhanced ILIs presents the best option for LG&E to gather data on its pipeline and support compliance with proposed PHMSA regulations. Current technologies allow some types of ILIs to be run only on uniform diameter pipeline, i.e., a contiguous segment of 20-inch nominal diameter pipeline. By replacing segments of 16-inch and 22-inch diameter gas transmission pipeline with 20-inch pipeline, LG&E can achieve a uniform diameter and facilitate the use of

ILI technologies on long contiguous segments of pipeline, dramatically decreasing the cost to run these tools.

Q. Are there other alternatives for running ILIs on gas transmission pipeline?

Yes, but they are both much more costly and much less accurate. One alternative is for LG&E to run ILIs on each single-diameter section of pipeline. For transmission pipelines like Western Kentucky A and B, which consist of segments of varying diameters, running ILIs on each individual segment is impractical and expensive. To the extent it could be done at all, LG&E estimates that it would cost as much as $2.5 million to run ILIs on each of the more than 20 segments of single-diameter pipeline on the Western Kentucky A and B gas transmission lines. These tools would be run every seven years in order to comply with PHMSA regulations. Conversely, if the Western Kentucky A and B transmission lines were a uniform diameter, these tools would only be run once for each continuous line, at roughly the same cost for inspection of single segment of multi-diameter pipeline.

A second method of performing enhanced ILIs is to employ the use of technology that allows enhanced ILI tools to be run on a mutli-diameter pipeline. Unfortunately, the technology needed to run ILIs on a multi-diameter pipeline is not sufficiently advanced to accommodate LG&E's system. LG&E has approached vendors and asked for proposals to develop this technology and to implement its use on LG&E's gas transmission lines. However, because enhanced ILI tools that can be used in LG&E's transmission lines are not currently available, there is no guarantee that the multi-diameter inspection tools will be effective on LG&E's gas transmission lines. Furthermore, it is likely the proposed tools would not be designed to accommodate 16-inch, 20-inch and 22-inch diameters pipelines. Therefore, since the Western Kentucky A and B lines are predominantly 16-inch and 20-inch pipelines, the 22-inch diameter segments would still need to be replaced even with the use of mutli-diameter ILI tools.

Q. Is replacing pipeline segments to achieve uniform diameter a prudent method of accomplishing the use of enhanced ILI?

A. Yes. The proposed replacement of a total of seventeen segments of the Western Kentucky A and B lines is a key component of an overall strategy to enable the effective use of enhanced ILI tools to maintain the safety and reliability of LG&E's gas transmission system and to demonstrate compliance with proposed PHMSA regulations. It is not the only strategy that LG&E is pursuing. As described above, LG&E is also continuing to pursue the approach of using enhanced ILI tools on multi-diameter pipelines. However, simply awaiting the development of this technology until it can be reliably employed on LG&E's system is not by itself a responsible course of action. The proposed replacement of pipeline segments to achieve uniform diameter is simply one prong of a multi-pronged approach to achieve enhanced pipeline safety and regulatory compliance. In addition to facilitating the use of enhanced ILI tools, replacement of these pipeline segments also modernizes older pipeline with new pipeline, enhancing the overall safety and reliability of the transmission system. LG&E will continue to evaluate the best strategy as the technology evolves, but must responsibly plan in the event that multi-diameter ILI tools do not become available over the next several years.

Q. What is Ms. Mullinax's criticism of LG&E's proposed strategy to replace segments of its gas transmission pipeline?

A. Ms. Mullinax is not critical of LGE's proposal to implement enhanced ILI tools or the prudence of LG&E's proposed investments to replace portions of its transmission pipeline to accommodate these tools. Rather, she asserts only that the $9.6 million allocated for these replacements in the forecast test period should be disallowed because LG&E has not obtained a CPCN.

Q. Will LG&E seek a Certificate of Public Convenience and Necessity ("CPCN") for the proposed pipeline segment replacements?

A. The transmission pipeline segment replacements are individual replacements of existing infrastructure in the usual course of business, and thus a CPCN is not required pursuant to KRS 278.020. Moreover, the proposed strategy to replace pipeline segments on the Western Kentucky A and B lines, Magnolia road crossings, and connection to Dixie Highway is still in the early stages. The individual segment replacements for all four of these lines are expected to cost around $91 million cumulatively. Less than fifteen percent that amount, $12.7 million, is expected to be incurred before the end of the forecasted test period. Approximately $9.6 million of the $12.7 million during the forecasted test period is projected for the Western Kentucky A and B lines. As the technology for enhanced ILI tools on multi-diameter pipeline evolves, LG&E will continue to assess whether replacement of individual pipeline segments is required to achieve safety enhancements and demonstrate compliance with proposed PHMSA regulations. If segment replacements are required and at an appropriate time, LG&E will reevaluate those replacements on a case-by-case basis to determine whether a CPCN is required.

(3) Gas Pipeline Reinforcement in Nelson County

Q. Describe LG&E's proposed reinforcement of gas distribution pipelines in Nelson County.

A. LG&E proposes to construct up to a 3.5 mile, likely 12-inch, steel high pressure distribution pipeline that will extend the Calvary Transmission pipeline from north of the Bardstown Operations Center on Bloomfield Road to the Highway 245 area on the west side of the system.

Q. Why is the reinforcement necessary?

A. To ensure reliable service to 3,400 gas customers in the Bardstown area of Nelson County. LG&E's current Bardstown medium pressure system is composed of approximately 80 miles of distribution pipeline that operates at 55 psig. The majority of the system is fed by two regulator facilities on the eastern side, with no regulator facilities to supply the west side of the system. Annual system reviews starting in the 2017/2018 winter season noted that the Bardstown medium pressure system should be monitored closely since the system is expanding away from the supply locations. The Bardstown system is heavily dependent on one of the two primary regulator facilities. If supply is lost from this regulator facility on a day with high load, up to 3,050 of 3,400 customers in Bardstown would lose service. The proposed reinforcement project would mitigate this risk by supplying additional high pressure capacity to the western side of the system.

Q. In addition to bolstering reliability to serve existing Nelson County customers, would the reinforcement project also be able to accommodate load growth?

A. Yes. The proposed reinforcement project would add additional capacity on the west side of the system to serve growing load. Since 2015, LG&E has received more than two dozen load requests and inquiries for service by the Bardstown system, with some on the western side of the existing distribution system. As discussed in LG&E's response to AG DR 1-57(b), these requests are and could be served by existing distribution, but would significantly reduce the available capacity on the western side of the system, particularly for commercial or industrial customers requiring delivery pressures above 30 psig. Reinforcement of the distribution system would provide the needed capacity to support anticipated load growth on the west side of the system.

Q. What is the current status of the Nelson County reinforcement project?

A. This project is still in the very early stages. Of the roughly $12.5 million expected cost of the project, only a small fraction – less than $32,000 – is scheduled to be incurred by the end of the forecasted test period. Included in this expected spending is route selection and some preliminary engineering and design work.

Q. If the project is still in its infancy, why was it mentioned in your direct testimony?

A. The Nelson County reinforcement project is included in the five-year business plan for the gas distribution business. In an effort to be transparent about future capital projects, I chose to summarize the project in my testimony. This project is one of many that are included in LG&E's business planning process, although only a relatively small amount of capital will be devoted to its development in the near term. LG&E assesses the need for reinforcement and the need to serve load growth system-wide based on evolving information. Adding this project to the business planning process allows LG&E to allocate funds to determine the feasibility, cost, and possible alternatives for the project.

Q. Has LG&E sought a CPCN for this project?

A. No. As currently formulated, the Nelson County reinforcement project is an ordinary extension of an existing system in the usual course of business, and thus a CPCN is not required pursuant to KRS 278.020. Regardless of whether Ms. Mullinax agrees or disagrees with this assertion, seeking a CPCN for this project at this very early stage would be premature. LG&E has not formulated engineering plans or specifications for this project, nor has it commenced construction in any respect. As set forth in my direct testimony, construction on this project, if LG&E elects to proceed with it after completion of preliminary engineering and design work, would not begin until 2021. Pursuant to KRS 278.020(1)(e), a utility must exercise CPCN authority within one year of its issuance or the certificate shall be void. LG&E will reevaluate the need for CPCN authority for this project as the preliminary work progresses. However, it bears mention even at this early stage that this reinforcement project is significantly smaller, both in pipeline length and expected capital cost, than the Bullitt County project for which the Commission required a CPCN in Case No. 2016-00371.

(4) Exclusion of Revenues from Phoenix Paper-Wickliffe in Forecasts

Q. What is Phoenix Paper Wickliffe?

A. In 2018, Global Win Wickliffe LLC ("GWW") purchased an idled paper mill located in Wickliffe, Kentucky, with plans to restart production at the mill in 2019. On September 4, 2018, KU entered into a contract to provide electric service to the

GWW plant under the Time of Day – Primary ("TODP") rate. A copy of this contract is attached to my rebuttal testimony as Exhibit LEB-Rebuttal-1. Under the terms of the contract, GWW agreed to accept initial capacity of 1,500 kVA, with adjustments to 9,400 kVA by December 1, 2018 and 26,000 kVA by March 1, 2019.

Q. Do the Companies' proposed revenue forecasts include revenue from load of Phoenix Paper Wickliffe?

A. No, but the costs to serve this load are not included, either. Exclusion of both the demand and the cost to serve demand of this single customer from the revenue requirement is appropriate. The capacity contract with GWW was executed after the load forecast used in the Companies' business plan was developed. Projecting revenue and cost to serve specific load under capacity contracts with no customer usage history is inherently speculative. For example, the cost to serve the GWW load could increase dramatically due to a transmission network constraint if the customer's capacity were to significantly exceed 26,000 kVA. Furthermore, the revenue derived from this single customer could also change significantly if the customer elected to take service under the Economic Development Rider ("EDR") offered by KU. For a single customer without usage history, both the load and the cost to serve that load can fluctuate. The Companies cannot accurately include either the revenue from speculative load or the anticipated cost to serve this load in forecasts used to determine base rates.

Q. Do the Companies' load forecasts also include expected revenue which will not actually be received due to plant closures?

A. Yes, they often do. The Companies do not continually adjust load forecasts for ratemaking purposes to account for every industrial customer that comes and goes after a forecast is made. For example, the Companies' load forecasts used in the last base rate cases did not reflect lost revenue from at least five plant closures by large electric customers in 2017 and 2018, nor was the prior idling of the Wickliffe plant in 2015 and its subsequent closure in 2016 reflected in the Companies' load forecasts. Projected revenues from a single large customer cannot be singled out for inclusion in the revenue requirement when the Companies' load forecasts also assume revenue that will never be realized due to plant closures or scaled down operations from other industrial customers.

Q. How does Mr. Kollen calculate his assumption that the Phoenix Paper load would result in $7.6 million in additional revenue?

A. The Companies asked that very question in data requests to KIUC. The electronic work papers filed contemporaneously with Mr. Kollen's testimony referenced in footnote 26 only contained a hard coded $7.620 million number. In response, Mr. Kollen produced a workpaper file in native Excel format he claimed was inadvertently excluded from the other workpapers filed contemporaneously with his direct testimony. This Excel file assumes that GWW will be billed under Rate RTS and assumes a 12 month base demand of 600,000 kVA (using 50,000 kVA per month), an intermediate demand of 533,671 kVA and a peak demand of 534,269 kVA.[4] To derive these figures, Mr. Kollen applied a pro rata portion of all demand revenue under Rate RTS to his assumed level of GWW's demand. In so doing, Mr.

[4] KIUC Response to LG&E and KU's Data Requests to KIUC, No. 3, and Excel attachment.

Kollen has made no investigation in GWW's actual or forecasted demand, nor has he provided any basis for the assumption that GWW's demand will be incurred proportionally to base/intermediate/peak demand for all customers under rate RTS.

Q. Is Witness Kollen's calculation of expected revenues from Phoenix Paper in the forecasted test period accurate?

A. Not at all. Mr. Kollen makes a number of assumptions about the GWW capacity contract, none of which are borne out by its actual terms. First, Mr. Kollen assumes that the Phoenix Paper peak demand will be 50 MW.[5] This is nearly double the capacity that GWW has agreed to accept starting on March 1, 2019. Furthermore, Mr. Kollen assumes that this load will be constant through the forecasted test period. There is no objective basis for that assumption. Under the GWW capacity contract, GWW could cancel and generate no revenue effective March 1, 2020, a full two months before the end of the forecasted test period. Further, Mr. Kollen assumes that GWW would take service under the retail transmission service ("RTS") rate, when in fact it has agreed to take service under the TODP rate. These are different rate structures and would result in different projected revenues depending on the load.

Mr. Kollen's assumptions starkly illustrate the speculative nature of estimating revenue from a single-customer load with no usage history and the offsetting costs to serve that load. Indeed, Mr. Kollen's testimony, replete with

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[5] Mr. Kollen's selection of 50 MW assumes that the Phoenix Paper plant will operate at the same peak demand as the former paper mill idled in 2015 and closed in 2016, as stated in the Companies' response to the Commission's June 22, 2017 Order in Case Nos. 2016-00370 and 2016-00371, addressing the departure of municipal customers. Mr. Kollen has not provided a foundation for his assertion that peak demand would be the same for the new operation. He simply assumes it will be the same with no analysis of or support for the GWW plant's current operations or electricity needs going forward. This assumption has no logical relationship to GWW's actual demand to date or its projected demand.

unfounded assumptions, is a strong argument for exclusion of these revenues and associated costs from the revenue requirement.

Q. If some revenue from the Phoenix Paper load is recognized, what amount is appropriate?

A. For the reasons just discussed, KU does not believe that speculative revenue from the Phoenix Paper plant in Wickliffe should be included in the revenue requirement, particularly when lost revenue from plant closures has not historically been deducted from the Companies' revenue forecasts for the purpose of setting rates. Nevertheless, if the Commission elects to assign revenue to this single contract, then it should be approximately $900,000, and not $7.62 million as Mr. Kollen proposes. $900,000 represents the approximate annual minimum demand revenue that would be generated from the GWW contract under proposed rate TODP, assuming GWW met minimum requirements under the agreement.[6] This is the only portion of revenue under the capacity contract that KU is reasonably certain to recover, and the only amount that can be reliably included in revenue forecasts, if any revenue at all is to be included.

(5) Expenses for Brown 1 Stack Repair

Q. Why is KU planning to perform repairs to the stack of Brown Unit 1?

A. Brown Units 1 and 2 will be retired at the end of February 2019. However, because the units will not be immediately demolished, KU must perform certain work on the decommissioned units to ensure the integrity of the structures and the safety of employees, contractors, and others working at the Brown generating station. Included

[6] Because this demand revenue figure assumes the rates proposed in the Companies' applications, it would change if the Commission approves a different rate design than the one proposed by the Companies in these proceedings.

in this work are necessary repairs to maintain the structural integrity of the stack of Unit 1. Upkeep and maintenance of retired generating plant to ensure the safety of the site is both prudent and reasonably incurred.

Q. How do you respond to KIUC witness Kollen's suggestion that the repairs to Unit 1' stack are non-recurring and should be deferred?

A. KU will not defer the required repairs to the Unit 1 stack. Safety-related projects are KU's first priority and the project will be performed to ensure the structural integrity of the stack. As for the accounting treatment of the expense, which is estimated at approximately $300,000, given the retirement of Brown Unit 1, KU would agree to amortize the expense over a three-year period.

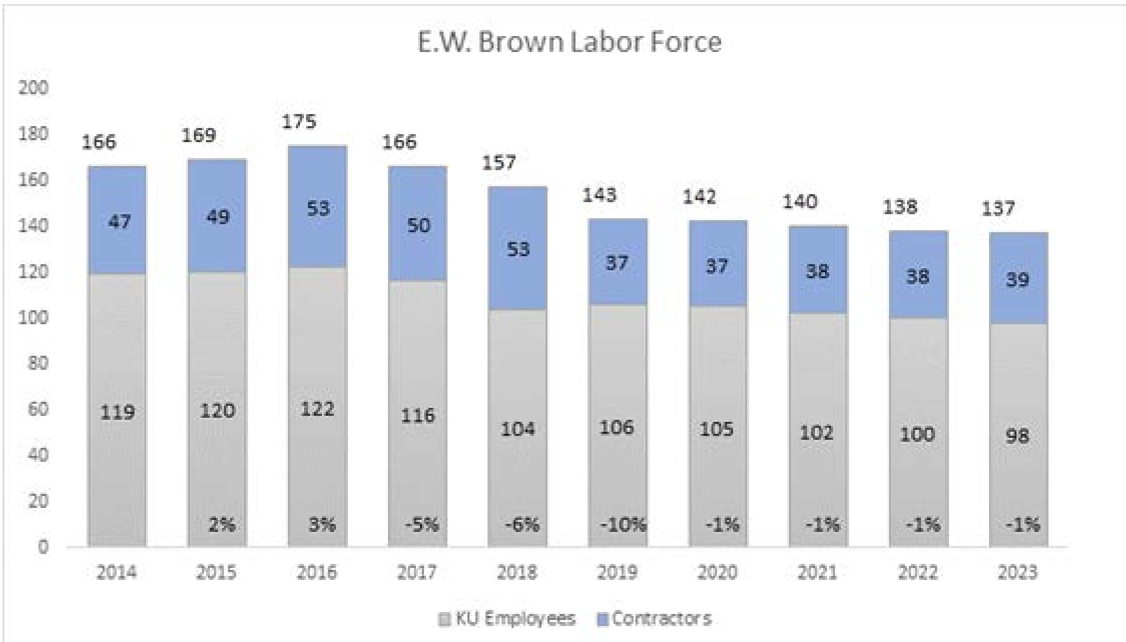
(6) Impact on Labor Expense Due to Retirement of Brown Units 1 and 2

Q. What portion of the labor expense at Brown is attributable to maintaining and operating Units 1 and 2?

A. Since 2015, only about twenty percent (20%) of the total man hours at the Brown generating station have been dedicated to maintaining and operating Units 1 and 2, compared to roughly forty percent (40%) for maintenance and operation of Unit 3, and 38-40 percent for common equipment and salaried staff. Units 1 and 2 are smaller-capacity steam generating units with a combined capacity of 280 MW, compared to the 460 MW capacity of Unit 3. Unit 3 takes significantly more headcount to maintain and operate than Units 1 and 2 combined, in part because Unit 3 is a newer and more complex unit with more auxiliary equipment (baghouse and SCR).

Q. Have the Companies significantly reduced headcount at Brown in anticipation of the retirements of Units 1 and 2?

A. Yes. In fact, these headcount reductions began in 2016, primarily by taking advantage of planned retirements of KU employees. The following chart shows the reduction of headcount at Brown since 2015, excluding headcount for combustion turbines and the Dix Dam hydroelectric facilities:



As this chart demonstrates, KU reduced employee headcount at Brown by 18, or nearly 15 percent, between 2016 and 2018.[7] From 2018 to 2019, KU will reduce contractor headcount attributable to steam generating units at Brown by 16, or more than 30 percent.

Q. Will the retirement of Units 1 and 2 result in a reduction in the workload for salaried employees at Brown?

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[7] The headcount numbers in this chart vary slightly from the figures used by Mr. Kollen in his testimony, which are based on KU's Response to KIUC DR 2-5a. There are two reasons for the discrepancy. First, Mr. Kollen uses an average of monthly headcounts to derive his annual totals, whereas KU uses the projected headcount for the last month of each period. Second, KU's headcount figures are stated as of the time of this filing, which accounts for one retirement ahead of forecast, a transfer and a departure since KU's application was filed.

A. Not materially. Salaried positions at Brown include production and maintenance managers, administrative staff, an environmental coordinator, and safety and engineering personnel. The responsibilities of these individuals will not lessen over the long term due to the retirement of Units 1 and 2.

Q. Are the headcount reductions at Brown over the past three years commensurate with the reduction of man hours due the retirement of Units 1 and 2?

A. Absolutely. As stated previously, operation and maintenance of Brown Units 1 and 2 consumed roughly 20 percent of the man hours for all steam generating units at Brown in 2015 down to 18 percent in 2018. Total headcount at Brown will be reduced from 175 in 2016 down to an expected 142 in 2020. That is a total reduction of 33 headcount, or nearly 19 percent over this time period, which closely aligns with the proportion of man hours formerly attributable to Units 1 and 2.

Q. In light of your testimony, is KIUC witness Kollen's recommendation to reduce Unit 3 payroll and contractor expense by 20 percent appropriate?

A. No, it is not at all appropriate. There is no objective basis for Mr. Kollen's assertions. He has undertaken no analysis of how headcount at Brown will be utilized post-retirement of Units 1 and 2 nor has he acknowledged KU's efforts to reduce headcount through planned retirements over the past several years. Overall reduction of headcount at Brown through 2020 is commensurate with the reduction in man hours attributable to the operation and maintenance of Brown Units 1 and 2. The Commission should reject Mr. Kollen's recommendation.

(7) Forecasting of Generation Outage Expenses

Q. How do the Companies propose to treat expenses for generator outages included in the revenue requirements?

A. As Mr. Garrett sets forth in his direct testimony, the Companies propose to continue regulatory asset and liability treatment of generator outage expense based on an 8-year average, using actual expenses from the previous four years and forecasted expenses for the next four years.[8] This is the very same accounting treatment to which all parties agreed and the Commission approved in the Companies' previous rate cases.[9]

Q. Does the proposed approach allow the Companies to recover more outage expense than they incur?

A. No. Contrary to the implication of Mr. Kollen's testimony, the regulatory asset and liability treatment proposed by the Companies allows recovery of only those generator outage expenses actually incurred, while at the same time smoothing out the fluctuations in outage expense due to the inspection cycle. Under this approach, the Companies will recover no more and no less than their prudently incurred cost for planned generation outages. The Companies only seek to recover prudently incurred outage maintenance expense through the regulatory asset and liability treatment.

Q. How does KIUC witness Kollen propose to treat generator outage expense?

A. On behalf of KIUC, Mr. Kollen is not critical of the Companies' need to conduct scheduled generator outages for major maintenance activities or the costs associated with those outages. Instead, Mr. Kollen proposes that the Companies should be required to "normalize" generation plant scheduled outage expense to an average of

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[8] *See* Direct Testimony of Chris Garrett, at 36-37.

[9] Case No. 2016-00370 and Case No. 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

the past five years, rather than what is actually forecasted in the test year. This is the very same proposal that Mr. Kollen put forth in the previous rate cases.

Q. How do you respond to Mr. Kollen's proposal to normalize scheduled outage expense based on historical spending?

A. A five-year historical average for outage maintenance expense is inappropriate to use as a predictor of future outage expense. As I described in detail in my rebuttal testimony in the Companies' last rate cases, generator outage expense is both cyclical and highly variable. Major overhauls typically occur about every eight years, depending on the type of generating unit and the condition of the unit as assessed through regular inspections and monitoring. Mr. Kollen's proposal does not accurately reflect scheduled outage maintenance activities that must be performed during the forecast test year, nor is it representative of the overall eight-year cycle of scheduled outage maintenance at the Companies' generation stations. The proposal also disregards the reality that yearly outage expense for a particular unit will vary depending on when a major overhaul is performed, among other factors. Outage expense may be lower in the years following a major overhaul, and higher as a unit approaches its next major inspection. Mr. Kollen's five-year average does not account for those variations within an 8-year cycle, whereas the Companies' approach both accounts for the 8-year cycle and allows the Companies to recover its prudently incurred costs through regulatory asset and liability treatment.

The Companies are in the best position to assess the condition of their own generating assets and to forecast the timing and extent of scheduled outage maintenance expenses for planning and budgeting purposes. The outages in the past cannot be compared to the outages in the future because of the additional environmental control equipment now installed at each generation station. As a result, the outages are reasonably expected to last longer, be more complex, and thus, cost more than the outages did in the past. Those forecasted expenses, combined with the previous four years of actual generator outage expense and a means for the Companies to recover their prudently-incurred expenses effectively addresses the variation inherent in cycled outage maintenance. Mr. Kollen's proposed approach does not.

Q. Aside from being a poor predictor of future outage expense, are there other problems with Mr. Kollen's proposal to use a five-year historical average for future outage maintenance expense?

A. Yes. Namely, if the Companies were confined to recovery of average historical outage expense, their ability to assess the current condition of generator assets and respond to those conditions with appropriate maintenance activities would be severely hindered. Conversely, the Companies' current approach allows the Companies to quickly respond to unplanned or emergent issues and defer recovery for related expenses under the regulatory asset treatment.

Q. In light of your testimony, what is your recommendation to the Commission regarding Mr. Kollen's proposed scheduled outage normalization adjustment?

A. The Commission should reject these proposed adjustments. Mr. Kollen's method for normalization of outage maintenance expense based on a five-year historical average is less likely than the Companies' current method to accurately predict future maintenance expense. Mr. Kollen's approach would also have the potential effect of precluding recovery of prudent and necessarily-incurred costs. Adoption of Mr. Kollen's proposal would severely hinder the Companies' ability to conduct real-time condition assessments of their generation resources and to respond to the results of those condition assessments to ensure that customers can be reliability served with power generation.

(8) Depreciation Life Span of Steam Generating Units

Q. What are the expected life spans Mr. Spanos has assigned to the Companies' steam generating units in his depreciation study?

A. In the depreciation study accompanying his testimony, Mr. Spanos has fixed expected life spans for currently operating steam production plant at between 54 and 64 years, depending on the unit in question.[10] In assessing the life span for each unit, Mr. Spanos considered the life spans of similar units, the age of surviving units, operating characteristics, major refurbishing of units, and information provided by the Companies' management. Mr. Spanos notes in his depreciation study that the life span for most steam, base-load units is 54 to 64 years, and his estimates were within the typical range for such units.

Q. What is KIUC witness Kollen's criticism of these conclusions?

A. Mr. Kollen is not critical of either the Companies' or Mr. Spanos's methodology and offers no substantive rebuttal testimony regarding the same. Rather, he asserts only that the life spans for currently operating generating units are fixed at levels below 65 years, which Mr. Kollen asserts is the assumed service life assigned to the generating units in the Companies' 2019 Generation Planning & Analysis business plan.

[10] *See* Exhibit JSS-KU-1 to Spanos Direct Testimony, at III-4 to III-5; Exhibit JSS-LG&E-1, at III-4 to III-5.

Q. Are Mr. Spanos's life span projections for the Companies' currently operating steam generating units consistent with the Companies' own analysis?

A. Yes, they certainly are. The Companies periodically assess the expected life spans of their generating units as part of their Integrated Resource Plan ("IRP") process. The Companies filed their most recent IRP with the Commission in the fall of 2018.[11] In that process, the Companies conduct a Long-Term Resource Planning Analysis, which presents numerous cases over a range of forecasted energy requirements, fuel prices, carbon dioxide prices, and generating unit operating lives.[12]

In that analysis, the Companies ran base, high and low resource plan scenarios using both 55-year and 65-year generating unit life spans. The Companies studied the distribution of the age of coal-fired boilers across the United States that were either retired, or have announced plans to retire, between 1970 and 2030.[13] The analysis revealed that most coal-fired units were retired between 44 years (25th percentile) and 60 years (75th percentile), with a median retirement age of 53 years.[14] The 65 years referenced in the Companies' Generation Planning & Analysis business plan represents the upper end of industry-expected life spans for coal-fired generating units according to the IRP.[15] It does not represent the individualized assessment that the Companies performed in providing Mr. Spanos information for his depreciation study.

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[11] *See Electronic 2018 Joint Integrated Resource Plan of Louisville Gas & Electric and Kentucky Utilities Company*, Ky. PSC, Case No. 2018-00348, IRP filed Oct. 19, 2018.
[12] *Id.*, Long-Term Resource Planning Analysis, at 3.
[13] *Id.*, at 9.
[14] *Id.*
[15] *Id.*.

Q. In addition to consistency with industry averages, what methodology was used in estimating the life spans of coal-fired generating units for use in Mr. Spanos's depreciation study?

A. The Companies have provided in response to data requests detailed descriptions of the criteria used for determining the life spans reflected in Mr. Spanos's study.[16] In summary, the methodology incorporates an assessment of the starting life of the unit, the industry averages referenced in the IRP and described above, and periodic evaluations of each unit for equipment age, physical inspection, operational factors such as startups and shutdowns, and maintenance and repair history. The Companies then assess the unit for any indication of an End of Life event based on those inputs, and adjust the expected life span of the unit based on the possibility of such an event. In the end, those assessments tracked closely to the average industry-wide retirement data described in the IRP.

Q. Does the expected life-span of the OVEC generating units at Clifty Creek and Kyger Creek provide good evidence of the depreciable lives of the Companies' coal-fired generating units?

A. No. Mr. Kollen asserts that because the OVEC generating units are expected to last 80 years or more based on the amendment and renewal of the ICPA through 2040, this is proof that the depreciable lives of the Companies' coal-fired generating units should be at least 65 years. The comparison is inapt. Indeed, the Commission order Mr. Kollen cites in support of his opinion plainly refutes it. In the Order approving

[16] *See* Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation, attached to KU's Response to DR DOD-1, Question 29(a); *see also* Methodology attached to KU's Responses to DR DOD-2, Question 2(b).

the amendment and renewal of the ICPA, the Commission referenced an independent engineering assessment of the condition of the OVEC generating units.[17] As paraphrased by the Commission, the assessment concluded that "largely due to the generating units having been nearly always operated in base load mode, with limited thermal cycles of the equipment, the units are expected to be operational at or near their historic operating levels through . . . 2040."[18]

Furthermore, according the Companies' study of steam generating units in their IRP, a life span of 80 years is far outside the industry norm due to the unique nature of the OVEC units. Indeed, the IRP analysis notes that fewer than five percent of coal-fired units nationwide are retired after age 67.[19]

Q. How are the Companies' coal-fired generating units different than the OVEC units?

A. As the independent engineering assessment of the OVEC units concluded, those units operated at base load mode for nearly fifty years. The primary load served by the OVEC units during that time span was AEC, a *single* customer. This is a unique use of generating plant that does not accurately translate to the generating units owned by the Companies. The Companies' units serve hundreds of thousands of native load customers and are regularly called upon to switch seamlessly between base and peak load mode. Accordingly, the OVEC units, which have likely experienced far less load following cycling than the Companies' units over a span of many years, do not

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[17] *In the Matter of: Verified Application of Louisville Gas and Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2011-00099, Order at 2-3 (Aug. 11, 2011).
[18] *Id.*
[19] *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas & Electric and Kentucky Utilities Company*, Ky. PSC, Case No. 2018-00348, IRP filed Oct. 19, 2018, Long-Term Resource Plan, at 9.

provide comparable evidence as to the useful lives of the Companies' steam generating units.

(9) Inclusion of Customer Education Expenses in the Revenue Requirement

Q. Do the Companies propose to include advertising expenses for energy-efficiency programs in the revenue requirement?

A. Certainly. The Companies have included a cumulative line item of roughly $2.3 million for advertising specifically for energy-efficiency and conservation education. As stated in the Companies' respective responses to PSC DR 3-21, these costs are for customer education efforts designed to advise customers of means to reduce their utility bills and conserve energy. The Companies have long provided this benefit to customers with Commission approval.

Q. Do these advertising efforts provide customers with a material benefit?

A. They do, by the Commission's own definition. The Commission's advertising regulation states at 807 KAR 5:016 Section 3,"Advertising expenditures by gas or electric utilities which produce a 'material benefit' include, but are not limited to the following: (a) Advertising limited exclusively to demonstration of means for ratepayers to reduce their bills or conserve energy …." The advertising contemplated by this line item does exactly that, and therefore by law provides a material benefit to customers.

Q. Why is AG witness Mullinax critical of modest advertising spending designed to make customers aware of means to reduce their consumption and lower their bills?

A. Ms. Mullinax is not critical of the value of customer education regarding demand conservation or the reasonable expenditure proposed by the Companies in furtherance of these efforts. Instead, her criticism relates to a misinterpretation of the Companies' data responses on this topic. Specifically, Ms. Mullinax claims that the Companies acknowledged that a similar program, the Customer Education and Public Information ("CEPI") Program, which ended December 31, 2018, did not result in any energy savings. That is not the Companies' position nor is it the position stated in their responses to PSC DR 3-21 and PSC DR 3-23, respectively. What the Companies stated is that no energy savings *were attributed* to the CEPI program.[20] The Companies further took the position in their most recent Demand-Side Management and Energy Efficiency (DSM-EE) proceeding that notwithstanding the cessation of CEPI, the Companies were committed to continuing customer education efforts regarding the benefits of reduced energy consumption.[21] The CEPI program was primarily designed to drive customer participation in the Companies' portfolio of DSM-EE programs. The program was terminated because DSM-EE programs were being scaled back and modified, not because CEPI itself was not providing material benefits to customers.[22]

Q. By not renewing the CEPI program, did the Companies intend to cease all spending for customer education on energy efficiency?

A. Absolutely not. As the Companies noted in the DSM-EE proceeding, the intent was always to continue to inform customers of the benefits of energy efficiency notwithstanding the lapse of CEPI. The difference between CEPI and the planned advertising spending in the forecasted test period is largely organizational. CEPI was

[20] KU Response to PSC DR 3-23; LG&E Response to PSC DR 3-21.
[21] *See, e.g.*, Case No. 2017-00441, Direct Testimony of Gregory S. Lawson at 15 (Dec. 6, 2017).
[22] *Id.*

a combined source of advertising funds and coordinated advertising strategy for the Companies' entire DSM-EE portfolio. With the changes in the DSM-EE portfolio and lapse of several programs, a centralized source for advertising and customer education on this package of programs was no longer needed. The Companies specifically noted in the testimony supporting the DSM-EE filing that advertising budgets would be maintained for each individual program.[23] By the Commission's own definition, those advertising activities provide material benefit to customers.

Q. What is your recommendation to the Commission regarding Ms. Mullinax's proposed disallowance of advertising spending for demand conservation?

A. Ms. Mullinax's proposed adjustment should not be adopted by the Commission. Under the Commission's own regulations, reasonable spending for advertising designed exclusively to inform customers of ways to reduce their utility bills and conserve energy provides a material benefit to customers. The Companies have not taken a contrary position, either in the DSM-EE proceedings or in response to Data Requests in this case. Instead, they elected not to ascribe energy savings to the CEPI program. That does not mean that energy savings were not achieved due to customer communications under CEPI. As programs like the recently-approved "WeCare" program demonstrate, the Companies remain committed to customer education efforts related to energy conservation and bill reduction, believe that they provide a material benefit to customers, and the Companies will continue to devote proportional resources toward those efforts.

[23] *Id.* at 15.

(10) Value Provided by the Companies' Membership in EPRI and EEI

Q. What is EPRI?

A. EPRI, the Electric Power Research Institute, is a non-profit organization of electric utilities that addresses challenges related to electricity such as efficiency, safety, reliability, and environmental protection.

Q. What benefits do the Companies derive from membership in EPRI?

A. By paying dues for membership in EPRI ($3.5 million in 2019), the Companies directly benefit from access to $70 million of technical training and research, enabling staff to minimize operations and maintenance costs, reduce fuel consumption, improve accuracy of emissions monitoring, prevent equipment failures, decrease outages, and lower capital expenditures. Membership in EPRI gives the Companies access to EPRI training, technical manuals, and expert staff who are frequently called upon to respond to technical questions and requests for information. Participation in EPRI provides the Companies with the expertise necessary to keep aging coal-fired generating and transmission capacity in service and running efficiently as well as access to the development of emerging technologies.

Q. Do the Companies earn a rate of return on EPRI membership dues?

A. No.

Q. Does the Companies' membership in EPRI assist them in carrying out Commission guidance on research and development activities?

A. Yes, it does. As noted in the Companies' data requests responses, the Commission has encouraged regulated utilities to pursue research and development initiatives, whether individually or through contribution to and membership in larger organizations. Specifically, the Commission has held that "[r]educing R&D spending would be short-sighted and not in the customers' long-term interest."[24] The Commission further noted that research and development "[b]enefits can be realized whether research is sponsored solely by one utility or through a larger organization funded by multiple utilities or stakeholders. The benefits of R&D may well help the Applicants in fulfilling their commitments to preserve LG&E's and KU's low rates and high quality service."[25] These are the exact type of benefits that the Companies realize through their membership in EPRI.

Q. How would customers be impacted if EPRI costs were excluded from revenue requirements?

A. Costs to ratepayers would assuredly increase. Some services provided by EPRI fulfill federal statutory requirements and would need to be acquired independently from third parties at a higher cost to ratepayers. For example, §316(b) of the Clean Water Act requires the Companies to conduct fish protection studies to ensure that certain cooling water intake structures do not cause adverse environmental impacts on fish populations. By partnering with six other electric utilities operating coal-fired generating capacity on the Ohio River as part of EPRI Program 54, *Fish Protection*, the Companies are able to spread out the cost of compliance, resulting in significant cost savings to customers. If the Companies were no-longer EPRI members, these federally-mandated studies would need to be performed by third parties and likely at higher costs. In some cases where EPRI is the single-source provider, the Companies might still need to acquire certain specific services from EPRI, but would do so

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[24] *In the Matter of: Joint Application of Powergen PLC, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger*, Case No. 2000-00095, Order at 34-35 (May 15, 2000).
[25] *Id.*

without EPRI membership discounts resulting in higher costs to ratepayers for those services.

Q. Would the cost of service to customers be lowered if the Companies withdrew from EPRI?

A. No. Loss of EPRI technical research and training would likely result in increased operation and maintenance costs, increased fuel consumption, and increased equipment failures over time. Although no formal cost-benefit analyses have been prepared pertaining to the Companies' membership in EPRI during the past five years, the Companies do conduct annual evaluations of each EPRI program based on its potential to bring value to customers, and the sum of these value estimates exceeds $13 million annually. One of many examples is the Companies' participation in EPRI Program 75, *Integrated Environmental Controls*, which performed a cost comparison of Powder Activated Carbons (PACs). Using EPRI's equipment at Ghent Station, the Companies were able to test the various PACs without risking the unit's mercury emissions. Based on the results of these tests, the Companies saved an estimated $1.5 million in PAC costs in 2019 at Ghent alone. In this same program, by using EPRI's portable catalyst test facility, Trimble County Unit 1 was able to safely verify that the minimum operating temperature could be lowered, enhancing the potential dispatch of the unit with an estimated savings of $589,000 over a 30 year period.

Q. Do the Companies regularly evaluate and modify their participation in EPRI?

A. Yes. Since 2016, the Companies have voluntarily reduced participation in EPRI by 29% from $4.9 million to $3.5 million in 2019. The Companies withdrew from certain programs that in the Companies' judgment were not generating sufficient value to ratepayers. However, as set forth above, the programs for which the Companies remain a participant provide immense value to ratepayers.

Q. Which EPRI programs do the Companies' dues currently fund?

A. The Companies are participating in the following EPRI Programs in 2019:

Program	Program Description	2019 Funding
203	Air Quality, Characterization, Assessment and Health	$638,354.44
75	Integrated Environmental Controls	$566,400.59
63	Boiler Life and Availability Improvement	$179,006.65
49	Coal Combustion Products - Environmental Issues	$175,078.11
185	Water Management Technology	$168,540.16
87	Materials and Repair	$161,170.70
69	Maintenance Management and Technology	$148,340.09
65	Steam Turbines - Generators and Auxiliary Systems	$142,150.06
54	Fish Protection	$136,061.93
183	Transmission Cyber Security	$129,396.61
94	Energy Storage and Distributed Generation	$127,343.74
196	Effluent Guidelines and Plant Wastewater Monitoring	$125,622.27
108	Operations Management and Technology	$119,618.36
77	Continuous Emissions Monitoring	$111,374.06
88	Combined Cycle HRSG and Balance of Plant	$111,245.75
64	Boiler and Turbine Steam and Cycle Chemistry	$107,652.97
194	Heat Rate Improvement	$90,380.27
200	Distribution Operations and Planning	$83,528.79
104	Balance of Plant Systems and Equipment	$54,847.00
18	Electric Transportation Technical R&D	$43,811.08
34	Transmission & Substations Asset Management Analytics	$41,828.29
37	Transmission Substation Protection and Control	$22,769.73

Each of these programs provides significant value to ratepayers and allows the Companies to reap returns on research far in excess of the Companies' dues contributions.

Q. What is EEI?

A. The Edison Electric Institute (EEI) is an association of investor-owned electric utilities in the United States. EEI provides numerous benefits to its members, including providing the opportunity for collaboration with other utilities on industry best practices, developing trends and technologies in the utility sector, resource sharing, and many other educational opportunities.

Q. What benefits do the Companies derive from membership in EEI?

A. As the Companies outlined in response to AG DR 2-65, EEI membership provides the Companies with valuable information and resources that benefit the Companies' operations and, as a result, benefit ratepayers. The Companies' participation in EEI's mutual assistance program is a concrete example. During times of severe disruption to the Companies' power delivery systems, due to weather or otherwise, the Companies can leverage their participation in EEI's mutual assistance program to bring much-needed resources to Kentucky to assist in restoration efforts. These resources come in the form of personnel, equipment, and other assistance provided by EEI mutual assistance members. Such support is invaluable in times of emergency recovery. The Companies also participate in a number of other programs, including the Spare Transformer Equipment Program (STEP) outlined in the Companies' responses to data requests, which enhance the Companies' ability to respond to threats and increase the overall reliability and resilience of the electric power system.

Q. Have the Companies excluded from the revenue requirement any portion of EEI dues?

A. Yes, the Companies have excluded from the revenue requirement and do not seek to recover in these cases any dues associated with influencing legislation, consistent with the Commission's previous orders on this topic. Ms. Mullinax asserts that Commission precedent requires the Companies to exclude from the revenue requirement 45.35 percent of the dues paid to EEI. This is based on the Commission's orders from Case Nos. 2003-00433 and 2003-00434, respectively, in which the Commission stated that it "has reviewed the description of the various activities funded by the EEI dues, and finds that the portion of the dues associated with legislative advocacy, regulatory advocacy, and public relations should be excluded for rate-making purposes."[26]

As this language clearly indicates, the Commission excluded 45.35% of the Companies' EEI dues based on information reviewed at the time of the order indicating that this was the percentage of EEI dues devoted to advocacy and public relations. The Commission did not hold that 45.35% of the Companies EEI dues should be excluded for all time going forward, but rather that dues devoted to advocacy should be excluded, whatever percentage they may represent. Ms. Mullinax has made no showing whatsoever that the information upon which the Commission relied nearly fifteen years ago is still valid today.

Q. How have the Companies determined what portion of EEI dues to exclude from the revenue requirement?

A. KU proposes to exclude $70,071.48 in EEI dues from the forecasted test period, and LG&E proposes to exclude $52,553.68 in EEI dues for the same period.[27] These amounts are derived directly from EEI's invoices. Those invoices specifically set out

[26] *See, e.g. In the Matter of: An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 51 (Jun. 30, 2004).
[27] LG&E Response to AG DR 1-92(b); KU Response to AG DR 1-92(b).

the percentage of membership dues and the percentage of industry issues support related to influencing legislation.[28] Combined, those categories account for roughly 14 percent of the Companies' EEI membership dues, and that amount has properly been excluded from the revenue requirement.

Q. In light of your testimony, what your response to AG witness Mullinax's proposal to reduce the amount of EPRI and EEI membership dues included in the revenue requirement?

A. Ms. Mullinax's proposed adjustments should be rejected by the Commission. There is no objective basis for Ms. Mullinax's proposed adjustments to these dues. As demonstrated by my testimony and the Companies' responses to Data Requests, the membership in both EPRI and EEI provide immense benefits to the Companies and, by extension, their Kentucky ratepayers. These benefits far outweigh the dues paid to these organizations. The cost to replace necessary research services and statutory compliance provided to the Companies by EPRI would far exceed the current dues paid to the organization. Likewise, the EEI dues included in base rates go only to activities that support the Companies' operations and accrue to the benefit of all ratepayers.

<u>(11) Underground gas facility locates</u>

Q. Has LG&E struggled in recent years to maintain 48-hour compliance with underground gas facility locate requests?

A. Yes, as LG&E's response to the Commission's Fourth Set of Data Requests, No. 9 indicates, LG&E has at times not met the 48-hour response time for underground gas

[28] *See* EPRI Invoices, Attachment to LG&E Response to AG DR 1-98.

facility locate requests. The reasons for the resulting backlog are explained in detail in LG&E's response to Request No. 11 of the same set of data requests. Primarily, they relate to contractor resource adequacy available to address the high variability of locate request volume.

Q. Has LG&E addressed the backlog and is it currently providing timely responses to underground gas facility locate requests?

A. Yes, as of December 21, 2018, the late ticket backlog for underground facility requests had been entirely eliminated to due to significant expenditures for additional contractor resources. LG&E entered into agreements with two new contractors in December, and initial results with these contractors have been very good. LG&E's on-time completion rate improved to approximately 97 percent in January 2019. LG&E fully expects that positive trend to continue.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public

My Commission Expires:

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

CONFIDENTIAL INFORMATION REDACTED

KUCES082614

Account Number [redacted]

CONTRACT FOR ELECTRIC SERVICE

This contract made and entered into this 4 day of September, 2018 by and between Kentucky Utilities Company ("Company") and Global Win Wickliffe LLC ("Customer").

WITNESSETH:

Beginning September 6, 2018, or as soon thereafter as connection is made, Company will sell and deliver to Customer at the 13,800 volt bushings of Company's transformers all Customer's electric capacity and energy requirements defined as 3 phase, 60 cycle, alternating current, nominal voltage at the point of delivery of 13,800 volts, metered and billed as Primary service.
Secondary, Primary, Transmission

Customer requires an estimated Contract Capacity of 26,000 kVA or kW, as is appropriate.

Each month Customer will pay to Company for all capacity provided and energy delivered to Customer in the preceding billing period an amount determined in accordance with the

Time of Day – Primary (TODP) Rate Schedule and, as may be appropriate, the
__________ Rider, contract attached if required, and the
__________ Rider, contract attached if required, and the
__________ Rider, contract attached if required.

COMMENTS:

Customer's contract capacity shall be 1,500 kVA or kW, as is appropriate, at the effective date of this contract, but shall be adjusted on each of the adjustment dates listed below to the corresponding capacity level and shall remain at that level until the next listed adjustment date.

Adjustment Date	Adjusted Capacity Level
12/1/2018	9,400 kVA
3/1/2019	26,000 kVA

This contract shall take effect on the stated effective date and remain in effect until one year following the latest adjustment date set forth above. Thereafter, this contract will be automatically renewed for successive periods of one (1) year each, subject to termination at the end of any year upon either party giving written notice of termination to the other party at least 90 days prior to termination date.

[redacted]

In the event Customer fails to maintain a satisfactory payment or credit record, Customer otherwise become a new or greater credit risk, or Customer's load increases beyond 26,000 kVA, as determined by

KUCES082614

Company in its sole discretion, Company reserves the right to require a new or additional deposit from Customer. Customer shall immediately give Company written notice of any contemplated material increase in load beyond 26,000 kVA. If Customer fails to immediately give Company written notice of any material increase in load beyond 26,000 kVA or refuses to provide any new or additional security deposit required by Company, Company reserves the right to (1) hold Customer liable for any damage done to meters, transformers, or other equipment of Company caused by such material increase in Customer's connected load, and (2) discontinue service to Customer.

TARIFF PROVISIONS: It is mutually agreed that Company's terms and conditions and applicable rate schedule, as from time to time approved by and on file with the Public Service Commission of Kentucky, are made a part of this contract as fully as if written here.

IN WITNESS WHEREOF, the parties hereto have caused this contract to be executed by their duly authorized representatives the day and year shown above.

KENTUCKY UTILITIES COMPANY

By Paul Weis

Paul Weis, Manager Business Services
Official Capacity

Attest

Global Win Wickliffe LLC

By

DIRECTOR OF STRATEGY
Official Capacity

Rachel Ferguson
Attest

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

Table of Contents

Section 1 – Introduction and Overview

Q. Please state your name, position, and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202. I submitted Direct Testimony in this proceeding on September 28, 2018, which contained a statement of my qualifications, experience, job responsibilities, and previous testimony before the Commission.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) respond to Jeremy I. Fisher's testimony on behalf of the Sierra Club and his erroneous conclusions regarding the Companies' participation with the Ohio Valley Electric Corporation ("OVEC") in a wholesale power contract known as the Inter-Company Power Agreement ("ICPA");[1] and (2) respond to Stephen J. Baron's testimony on behalf of the Kentucky Industrial Utility Customers, Inc. and his inappropriate recommended adjustments to forecasted billing demands and associated revenues for KU and LG&E's forecast of the Retail Transmission Service ("RTS") class.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit to my direct testimony:

Rebuttal Exhibit DSS-1	Sierra Club Beyond Coal campaign

[1] OVEC and its wholly owned subsidiary, Indiana-Kentucky Electric Company, own and operate two coal-fired power plants in Ohio and Indiana and supply power to the Companies and other sponsor utilities through the ICPA, which currently has a term through June 2040.

Rebuttal Exhibit DSS-2	OVEC Board Meeting Agendas
Rebuttal Exhibit DSS-3	Comparison of Actual to Forecast OVEC Demand Charges

Q. In your opinion, how should the Commission view Mr. Fisher's testimony on behalf of the Sierra Club?

A. The Commission should disregard Mr. Fisher's testimony as it contains no analysis of or recommendations on the issues in these base rate cases. Furthermore, his two "fundamental" recommendations would create duplicative work for the Commission and should be addressed (if at all) in the Companies' Integrated Resource Plan ("IRP") case, which the Commission has already ordered to begin later this year.

Specifically, the first recommendation asks the Commission to "expressly reaffirm the Companies' obligation to obtain Commission approval (as fair, just, and reasonable) of any future OVEC-related changes that the Companies may wish to implement and that may impact the Companies' ratepayers."[2] The full text of this recommendation has the dubious dual distinction of being irrelevant to these proceedings—Mr. Fisher does not recommend any rate or tariff changes—and with apparently asking the Commission to exceed its statutory authority, which Daniel K. Arbough addresses in his rebuttal testimony.

Mr. Fisher's second recommendation is equally irrelevant to these proceedings: he asks the Commission to initiate a new proceeding that revisits the 2011 Commission approval of the ICPA and do so in a manner that seems primarily focused on engaging in speculation about hypothetical future decisions that is a cross between a base rate case, a fuel adjustment case, a debt authorization case, and an IRP. According to Mr.

[2] Fisher at 6.

Fisher, this new proceeding would look at future dispatch of the OVEC units, existing and future environmental regulations, and future OVEC operating costs (e.g., fuel costs). To me, this type of data regarding what the future might look like was already filed by the Companies in their IRP on October 19, 2018 and can be addressed as part of that process.

Furthermore, the Companies' annual planning process is focused on providing reliable, low cost electric service to our customers. That process has benefited customers for decades. Therefore, initiating a case to focus exclusively on hypothetical future decisions involving a single resource, in this case OVEC, is not an efficient use of Commission resources. When there are real decisions to be made that require Commission approval, the Companies will make the appropriate filings with the Commission.

Q. Why do you believe Mr. Fisher is so focused on having the Commission initiate a new proceeding focused just on OVEC and the ICPA?

A. It's no secret: Mr. Fisher's employer, the Sierra Club, wants to shut down coal plants. Indeed, they have a hundred-million-dollar campaign to eradicate coal-fired energy from the United States: the Beyond Coal campaign.[3] Their goal is explicit, as the following graphic taken from their home page shows:[4]

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[3] https://content.sierraclub.org/coal/. *See also* https://www.reuters.com/article/us-usa-coal-bloomberg/bloombergs-charity-donates-64-million-to-war-on-coal-idUSKBN1CG2M5 (showing donations to Beyond Coal campaign of more than $100 million); page archived at https://web.archive.org/web/20190208140419/https://www reuters.com/article/us-usa-coal-bloomberg/bloombergs-charity-donates-64-million-to-war-on-coal-idUSKBN1CG2M5.

[4] https://content.sierraclub.org/coal/ (image captured on Feb. 8, 2019). The Beyond Coal Campaign page as viewed on Feb. 8, 2019, is available on the Internet Archive at https://web.archive.org/web/20190208135509/https://content.sierraclub.org/coal/.

Therefore, when Mr. Fisher calls the OVEC generation plants "aging, outmoded," he is following his employer's lead.[5] This is almost the precise language used on the Sierra Club's website (see Rebuttal Exhibit DSS-1) to describe their Beyond Coal campaign. The Sierra Club's website states, "Coal is an outdated, backward, and dirty 19th-century technology," hence Mr. Fisher's use of the word "outmoded" whose synonyms are words and phrases such as old fashioned, out of date, obsolete, and antiquated. Given that one of the primary objectives of the Beyond Coal campaign is "to close all coal plants in the US," it is not surprising that Mr. Fisher's testimony supports this pre-determined outcome.

Q. How did the Sierra Club respond to the Companies' request that it provide "all of Sierra Club's board meeting minutes and materials that relate to their Beyond Coal campaign, analysis of coal plants, views of the future of coal plants, and views of renewables"?[6]

[5] Fisher at 4 line 10.
[6] Companies' DR No. 2 to Sierra Club.

A. Sierra Club responded by objecting wholesale to the request. Ironically, given the Sierra Club's document requests and the irrelevance of Mr. Fisher's testimony regarding the Companies' rates at issue in these proceedings, one of the reasons cited for their objection was, "The Companies' request implicates activities and seeks materials that are wholly disconnected from Dr. Fisher's testimony and are not otherwise remotely pertinent to the ultimate question in these proceedings of whether the Companies' proposed rates are just and reasonable."[7] Since Mr. Fisher provides no testimony in these proceedings regarding the "ultimate question" of whether the Companies' proposed rates are just and reasonable, logic would suggest that the Sierra Club should object to the testimony of their own witness.

With regard to Sierra Club's counsel's assertion that the Companies' request "implicates activities and seeks materials that are wholly disconnected from Dr. Fisher's testimony," his claim is demonstrably false. The Companies accepted the Sierra Club's invitation to "peruse Sierra Club's webpages, if they wish to learn about general Sierra Club matters that are not related to these proceedings."[8] What we found was directly related to Mr. Fisher's testimony—though I will grant that it, like Mr. Fisher's testimony, was wholly irrelevant to these proceedings. It took little effort to find a press release from Sierra Club's Beyond Coal campaign directly addressing OVEC's Clifty Creek and Kyger Creek facilities, attacking them as "dirty, outdated coal plants" and chastising Ohio legislators for introducing legislation related to the plants' funding, which Sierra Club styled, "Mission: Ohio Coal Bailout by Any Means

[7] Sierra Club's Response and Objection at 3.
[8] Sierra Club's Response and Objection at 3.

Necessary."[9] In other words, it took almost no effort to locate a publicly available document obviously related to Mr. Fisher's testimony and directly responsive to the Companies' request. It seems unlikely at best that Sierra Club could not have located that document—and perhaps more like it—with any reasonable effort. They simply chose to object rather than respond; one can only speculate why.

But again, I will concede that Sierra Club's effort to shutter the OVEC units is irrelevant to these proceedings. Unfortunately for Sierra Club, that means Mr. Fisher's testimony is equally irrelevant.

Q. In your opinion as the Companies' vice president in charge of resource planning, is coal a "19th century technology"?

A. No. The only thing that today's coal generating plant has in common with one from the late 1800s is that it burns coal to create heat that boils water to generate steam to drive a turbine and ultimately a generator. Calling coal a "19th century technology" is like calling a modern wind turbine a 17th century BC technology because the Babylonian emperor Hammurabi is alleged to have planned the use of wind powered machines for an irrigation project.[10] In fact, according to a recent Forbes story, there are over 200,000 MW of coal plants under construction in the world (comparable to the existing coal capacity in the U.S.) and another 450,000 MW being planned.[11]

Q. What are some examples of Mr. Fisher's testimony being influenced by his employer's Beyond Coal campaign?

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[9] https://content.sierraclub.org/press-releases/2017/05/mission-ohio-coal-bailout-any-means-necessary (viewed on Feb. 14, 2019); archived at https://web.archive.org/web/20190214210433/https://content.sierraclub.org/press-releases/2017/05/mission-ohio-coal-bailout-any-means-necessary.

[10] http://www.outwoodmill.com/history/history-windmills/

[11] https://www.forbes.com/sites/judeclemente/2018/11/15/global-coal-demand-increased-in-2017/#4b88d665661c

A. While Mr. Fisher attempts to justify this "shut coal down" conclusion with various examples and innuendo, from a factual perspective, his testimony suffers from confirmation bias – the tendency to interpret evidence and information as confirming one's existing beliefs. The following are some examples of what I mean by evidence of his confirmation bias:

- He goes on at length discussing the FirstEnergy Solutions ("FES") bankruptcy and why their rejection of the ICPA means the OVEC generating units are uneconomic, but he fails to mention that FES also rejected several wind contracts in the same bankruptcy proceeding.[12] Using his simplistic logic that a rejection of a contract in bankruptcy means a technology is uneconomic, I assume he would argue that those wind plants should also be shut down.
- He spends almost three pages (pp. 37 to 39) describing the analysis presented by ICF on behalf of Duke Energy Ohio ("Duke") in a case in front of the Public Utilities Commission of Ohio ("PUCO") that he claims shows that Duke's share of the ICPA costs are uneconomic. The Companies did not participate in that case and have no direct knowledge of it other than what is posted on the PUCO website, but it is interesting that Mr. Fisher fails to mention that the PUCO rejected Sierra Club's arguments and approved Duke's request for a rider to recover its ICPA costs net of market revenues. In its order, the PUCO noted the Supreme Court of Ohio (a) authorized a similar OVEC-related rider by

[12] To view the wind projects, *see* pp. 4-5 of https://cases.primeclerk.com/FES/Home-DownloadPDF?id1=ODUzNjU1&id2=0.

American Electric Power, and (b) affirmed the PUCO's finding that an OVEC-related PPA has worth as a financial hedge.[13]

- He inappropriately compares the "all-in" cost per MWh of $60.41 for energy and capacity under the ICPA in 2017 with spot energy prices paid when the Companies' were on occasion able to purchase energy at less than their own production costs and concludes that the ICPA is not economic.[14] Using his same logic, he should object to the Companies' Brown solar facility as uneconomic; after all, its average all-in cost was approximately $136/MWh in 2018,[15] which is more than both spot economy energy prices and energy and capacity from the ICPA. Using the "all-in" cost per MWh to compare different types of generating technologies to each other and with economy energy purchases is a nonsensical approach to economic analysis and resource planning.
- He cites two merchant analyses prepared by [redacted] and presented to the OVEC board as evidence that [redacted] In the particular chart he cites in his Figure 4, [redacted][16] [redacted]

[13] To view the PUCO's order, *see* http://dis.puc.state.oh.us/TiffToPDf/A1001001A18L19B43028I02536.pdf. To view the Supreme Court decision in the AEP case, *see* http://www.supremecourt.ohio.gov/rod/docs/pdf/0/2018/2018-Ohio-4698.pdf.
[14] Fisher at page 20.
[15] $2.3 million annual revenue requirement for Brown solar (based on 12/31/18 net book value) divided by Brown solar's 2018 annual generation of 16,906 MWh.
[16] Fisher at 35.

[redacted] But either that did not interest Mr. Fisher or his anti-coal bias did not cause him to question [redacted] embedded in Figure 3.[17]

- He alludes to OVEC cost increases and states that OVEC is uneconomic yet he ignores or discounts evidence to the contrary because it does not fit with his belief that coal generation needs to be "shut down."[18] He ignores the information contained in OVEC's 2017 Annual Report, which shows that OVEC has reduced its annual payroll costs by about $4.3 million (6.8 percent) from 2013 to 2017, in part by reducing employees from 781 to 666.[19] The same chart shows OVEC's fuel cost declining from $2.78/mmBtu in 2013 to $2.27/mmBtu in 2017 and equivalent availability increasing from 64.7 percent in 2015 to 75.6 percent in 2017.

[17] Fisher at 33.

[18] Fisher at 45 cites <u>one</u> concrete instance of a cost increase: "*the bankrupt FES has departed the ICPA unilaterally, and OVEC's costs to other partners <u>have increased</u> as a result.*" However, the remainder of his comments about cost increases are hypothetical (what "could" or "would" happen under certain scenarios, e.g., pp. 47-49).

[19] Fisher Exhibit JIF-02 at 38.

- He claims the 2011 URS report missed the mark on deployment of "renewable energy and storage" and that renewables, among other things, "have dramatically shortened the economic life of existing coal plants – particularly the OVEC units." He goes on to state that their "economic life is already over…." In making such claims, Mr. Fisher overlooks testimony filed on January 2, 2019, by Michael Goggin on behalf of the Sierra Club in three cases before the PUCO involving AEP's request to procure renewable generation.[20] In his testimony, Mr. Goggin states:
    - Wind and solar account for only 2.8 percent of generation in PJM (the market where the bulk of OVEC generation is sold);[21]
    - PJM market structure and rules may be impeding renewable development and PJM's capacity market is keeping energy prices lower than they otherwise might be;[22]
    - PJM's focus on fuel security in evaluating potential modifications to its capacity markets would favor generation with on-site inventory and disadvantage renewable generation.[23]

Notably, Mr. Goggin's concerns about the lack of renewable generation in PJM and that it only accounts for 2.8 percent of energy hardly lead one to the conclusion that the 2011 URS report missed the mark. Similarly, Mr. Goggin's testimony in total is highly critical of the PJM market and its rules that he feels disadvantages renewable

[20] See Mr. Goggin's testimony in PUCO Case Nos. 18-0501-EL-FOR, 18-1392-EL-RDR, and 18-1393-EL-ATA at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A19A02B65906J00350.
[21] Goggin at page 5.
[22] Goggin at page 7 and page 10.
[23] Goggin at pages 20-21.

generation are at odds with Sierra Club's position and Mr. Fisher's testimony that coal should be "shut down" and that renewables are rendering coal uneconomic.

To summarize, when one begins with the belief that coal plants should be retired, it causes one to see and cite only information that supports that preconceived notion and to ignore or hide facts to the contrary. This appears to have occurred with Mr. Fisher, rendering his testimony highly suspect and of no value to the issues before the Commission here.

Q. Is there a difference between the objective of the Sierra Club's Beyond Coal campaign and the Companies' obligation to provide reliable, low-cost electricity to its customers?

A. Absolutely. In mathematical terms the objective function of the Beyond Coal campaign is to retire coal plants and deploy alternative resources at all costs to achieve that objective. On the other hand, the Companies' objective function is to provide reliable, low-cost electricity to our customers every second of every day, and our generation fleet is planned and operated with that objective in mind. When faced with changes in technology, environmental regulations, load obligations, and fuel markets, the Companies clearly define the problem, develop and evaluate alternatives, and recommend a future course of action to this Commission.

Q. Has Mr. Fisher's previous testimony in front of this Commission demonstrated his confirmation bias against coal generation?

A. Yes. In the Companies' 2011 cases regarding the installation of new environmental control equipment at several generating plants,[24] Mr. Fisher's recommendations to the Commission were to deny the Companies' request to install controls, which would have had led to the premature retirement of almost the entirety of the Companies' coal generation fleet.[25] The justification for his recommendation was as follows:

> *"Furthermore, as the entire analytical basis for the Companies' proposed resource analysis is fundamentally flawed due to erroneous assumptions and methodologies, the Commission should deny CPCNs and rate treatment for any upgrades to the Companies' coal units at this time."*

Q. Was the Companies' analysis in those cases "fundamentally flawed"?

A. No. As I stated in my rebuttal testimony on behalf of the Companies in those cases, the "error" identified by Mr. Fisher was actually the result of his own misunderstanding and bias.[26] Despite the Companies' clear explanations, he incorrectly assumed that the Companies' natural gas price forecast was too high due to his comparison of the Companies' price forecast expressed in nominal terms (i.e., reflecting the forecasted impact of general inflation) to his own forecasts expressed in real terms (i.e., in base year dollars). An analyst that was engaged in an unbiased assessment of the

[24] *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2011-00161.
In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge, Case No. 2011-00162.
[25] See page 41 of Fisher's testimony in Case Nos. 2011-00161 and 2011-00162 dated September 19, 2011 at https://psc.ky.gov/PSCSCF/2011%20cases/2011-00161/20110919_Environmental%20Intervenors%20Direct%20Testimonies.pdf.
[26] See Sinclair Rebuttal testimony in Case Nos. 2011-00161 and 2011-00162 dated October 24, 2011 at https://psc.ky.gov/PSCSCF/2011%20cases/2011-00161/20111024_LGE%20and%20KUs%20Rebuttal%20Testimony%20with%20Petition%20and%20Joint%20Motion%20to%20Deviate%20%28Vol%201%20of%202%29.pdf.

Companies' financial analysis would be unlikely to make such a rudimentary mistake as confusing real and nominal prices. Furthermore, if after having made such a mistake and realizing that their analysis was at such odds with the Companies' analysis (who employ a number of people with advanced degrees that are highly skilled in using financial analysis tools), an unbiased analyst would have questioned whether or not the difference was explained by their own mistake rather than one by the Companies. But because Mr. Fisher's mistaken analysis supported his predetermined outcome that coal is uneconomic and should be retired, his confirmation bias led him to testify that it was the Companies' analysis that was "fundamentally flawed" rather than his own.

Q. Do the Companies have a preferred generating technology?

A. Not at all. The Companies focus on providing reliable, low-cost electric service, period. We employ and utilize a wide range of technologies based on their operating capabilities and relative economics to achieve that goal. For example, on February 4, 2019, the Companies issued a request for proposals for up to 200 MW of renewable generation, and the Companies' 2018 IRP shows cases where installing renewables generation would be the least-cost option.[27, 28] Moreover, I have personally testified in front of this Commission in cases where the Companies were recommending retiring coal plants, building natural gas-fired plants, building the Brown solar plant, installing pollution control equipment on coal units, and cancelling plans for a gas-fired plant.[29]

[27] https://lge-ku.com/newsroom/press-releases/2019/02/04/lge-and-ku-issue-request-renewable-energy.

[28] See Case No. 2018-00348, the Companies' Joint Integrated Resource Plan, Volume I, Section 5.(4), Resource Plan Summary, Table 5-15 on page 5-39.

[29] *See, e.g.*, Case No. 2014-00002, Testimony of David S. Sinclair (Jan. 17, 2014)(Companies' application sought approval of Green River 5 NGCC and Brown solar; Green River 5 application withdrawn during course of proceeding); Case No. 2011-00375, Testimony of David S. Sinclair (Sept. 15, 2011)(Companies' application sought CPCN for Cane Run 7 NGCC); Case Nos. 2011-00161 and -00162, Rebuttal Testimony of David S. Sinclair (Oct. 24, 2011)(Companies' applications sought CPCNs for environmental controls for certain coal units and recommended retirement of several coal units, including the Cane Run coal units).

The one thing that is common across all of those cases is that the Companies' actions were driven by a robust economic analysis, which evaluated a broad set of alternatives over many possible futures. In other words, the math and the analysis as to the best solution for our customers is what drove our decisions, not ideology or a preference for a particular technology.

Section 2 – OVEC Ownership and the ICPA

Q. Mr. Fisher states in his conclusion #1, "Major decisions about investments in and maintenance of these aging, outmoded plants are made through a process at OVEC over which the Companies' [sic] have little information and exert relatively little control."[30] Do you agree with his assertion that the OVEC assets are "aging" and "outmoded?"

A. The absolute age of the OVEC units is certainly not in dispute but is frankly irrelevant for purposes of these cases. (Also, everything and everyone is "aging," making it an uninformative modifier at best.) As to whether the OVEC units are "outmoded" – assuming he means something like "obsolete" or "no longer useful for modern life" – these units continue to provide reliable, cost-effective service to the Companies' customers. In fact, OVEC in recent years has invested in pollution control technologies such as flue-gas desulfurization ("FGD") to control sulfur dioxide ("SO_2") emissions and selective catalytic reduction ("SCR") to control nitrogen oxides ("NO_x")

[30] Fisher at 4.

emissions.[31] The OVEC units, like all generating units, must comply with all applicable regulations in order to continue to operate.

Q. Do you agree with the second part of Mr. Fisher's conclusion that the Companies have little information and control regarding maintenance and investments at OVEC?

A. No. The Companies are well informed about decisions regarding maintenance and investments. Two of the Companies' officers are on the OVEC Board of Directors where long-term plans and investments are reviewed and approved, and the Companies have employees that participate in the operating committee of contract party representatives, which oversees the ICPA in contract areas such as energy scheduling and billing. This level of activity and information is consistent with that commonly found in closely-held, but independently operated, minority-owned entities. Conversely, many of the Sierra Club's data requests or claims involved detailed data, roles, or functions generally available or performed directly by OVEC itself and for which the Companies have no day-to-day operational responsibility.

Q. Do you have any thoughts about why Mr. Fisher concludes that the Companies are uninformed regarding OVEC?

A. Sierra Club's data requests related to OVEC focused largely on specific items presumably intended to support its predetermined goal to shut down coal plants at all costs, such as retirement studies, decommissioning, environmental compliance, and outages. Sierra Club did not request information regarding the high level of detail that OVEC regularly provides to the Companies regarding its efforts to control costs while

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[31] See the 2017 OVEC annual report (p. 30 "*Environmental Matters*") at https://www.ovec.com/FinancialStatements/AnnualReport-2017-Signed.pdf.

maintaining high levels of performance. But I would note that in the same two board packages Mr. Fisher used to produce his Figures 3 and 4 are materials and presentations on such topics as:

- Results of continuous improvement efforts and future cost profile
- Update on boiler refractory wastage
- Budget review and approval
- Environmental compliance update
- Coal procurement strategy
- Power cost projections

I've attached the agendas from the December 2015 and December 2016 OVEC board meetings as Rebuttal Exhibit DSS-2 to illustrate the nature of the topics discussed by OVEC management with the board and to show the fatuousness of Mr. Fisher's conclusion #1.

Q. In general, is there a difference between being an owner of OVEC and a counterparty to the ICPA?

A. Yes. In many ways OVEC is a unique entity in that its shareholders (as OVEC owners) overlap, or are affiliated, with its main contractual counterparties (as ICPA customers). Despite this unique attribute, in all other ways OVEC is much like any other shareholder company in that it is the responsibility of OVEC management to run the day-to-day operations of the company with guidance and input on major issues from the OVEC board. In other words, OVEC's objectives are similar to that of any company – to manage the assets effectively and appropriately meet their various legal or economic obligations to shareholders, customers, and counter-parties/creditors.

Q. Does the OVEC board run the day-to-day operations of OVEC?

A. No. OVEC management runs the business on a day-to-day basis.

Q. Under the OVEC governance structure, what rights do the LG&E and KU officers serving as OVEC board members have to direct OVEC management to take actions?

A. As with any corporate entity, OVEC's governance process and roles are determined by state corporate law and precedent, and its specific governing documents, such as articles and bylaws. General principles of corporate law provide that the business and affairs of a company are managed under the authority and direction of the board of directors. Company management acts under the direction and control of the board of directors. The board acts through the vote of a majority of the directors present at a meeting at which a quorum is present, or by unanimous written consent in lieu of a meeting. In addition to reviewing and directing management, the board sets the company's strategic direction, monitors the company's operational and financial performance, oversees expenses and capital projects, and deals with non-routine corporate matters. The shareholders elect the members of the board of directors. Ohio corporate law and OVEC's articles and bylaws (Code of Regulations) do not generally contain any unusual or non-standard quantitative (e.g., supermajority vote or veto rights) or qualitative (e.g., limits on transaction size or type) provisions at either the shareholder or board level.

Q. Do the Companies' OVEC board representatives take into consideration the long-term interests of the Companies' customers and the implications of costs under the ICPA as they exercise their board authority?

A. Board members, when acting in their board capacities, have certain duties of care and loyalty to the entities on whose boards they serve and the shareholders of such entities. LG&E and KU's OVEC board members appropriately balance their roles as OVEC board members with their separate functions as representatives of LG&E and KU as ICPA counterparties. Furthermore, I would point out that it is not in OVEC's general interest to make uneconomic decisions, despite Mr. Fisher's concerns to the contrary.

Q. **In general, please describe the ICPA.**

A. The ICPA is the contract that governs the provision of capacity and energy from OVEC to the sponsors and payments by the sponsors to OVEC for such capacity and energy. In many ways, it is just like any other power purchase agreement ("PPA") that one might see in the wholesale electricity market. In my over two decades in the independent power and energy marketing industry, I've negotiated and reviewed many PPAs, and the ICPA has certain standard concepts that govern:

- Plant availability and operations (Article 4)
- Charging for capacity and energy (Article 5)
- Billing (Article 8)
- Term (Section 9.07)

Q. Based on your experience in the industry, are there some aspects of the ICPA that one might not typically see in a PPA?

A. Yes. Because the owners of OVEC overlap, or are otherwise affiliated, with the ICPA counterparties, the ICPA is a cost-based contract. Furthermore, because the ICPA was used as the basis for OVEC to finance its assets with essentially 100 percent debt, there are provisions such as Section 9.07 that states in part, "… no termination of the

Agreement, for whatever reason, shall release a Sponsoring Company of any obligations of liabilities incurred prior to such termination." Along those same lines, Section 11.01 says in part, "No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional."

While Sections 9.07 and 11.01 spell out certain obligations for the ICPA sponsors, Section 9.11 states, "The rights and obligations of all the parties hereto shall be several and not joint and several," which appropriately sets an important, pro-rata limit on the extent of any ICPA party's obligations, such as the Companies'. Despite the clear language of Section 9.11, Mr. Fisher, in his "non-lawyer" view implies that somehow the Companies are directly on the hook for any or all shortfalls in OVEC expenses that result from FES' rejection of the ICPA. If that were the case, then it is unlikely that the rating agencies would rate OVEC debt at less than investment grade.

Finally, the ICPA contains provisions to collect the cost of ultimately decommissioning and demolishing the OVEC units, which is not often part of a standard PPA but is not unexpected given the nature of OVEC and the purpose of the ICPA.

I'd like to point out that none of the ICPA's provisions have changed since it was approved by the Commission in 2011.

Q. You said that OVEC has used the ICPA as the basis to finance its assets. Is that common in the industry?

A. Yes. This is a standard financing mechanism for any generating plant that is not part of a regulated rate base and has been used for decades. It is especially common today for renewable projects like wind and solar generation. In order to reduce the cost of capital by increasing the amount of debt used to finance a project, a long-term, conservatively-structured PPA with creditworthy counterparties such as LG&E and KU (or a comparable regulatory obligation or tariff requirement) is required by banks and bond buyers.

<u>Section 3 – 2011 ICPA Amendment</u>

Q. Mr. Fisher states in his conclusion #2 that "the cost and risks of the OVEC contract now is, and will continue foreseeably to be, substantially higher and worse than those of alternatives."[32] He also states that the assumptions presented to the Commission in 2011 when the ICPA was approved by the Commission "are no longer valid today…." Do you agree with this conclusion?

A. Absolutely not. First of all, Mr. Fisher provides no analysis of his own, or any others for that matter, regarding the Companies' future costs under the ICPA and what he views as "alternatives" to it or, more importantly, the least-cost fleet to reliably meet our customers' electricity needs. Mr. Fisher's secondhand citing of bankruptcy filings and other consultants' testimony in other cases and jurisdictions are poor substitutes for real financial analysis of real alternatives to serve the Companies' customers. As I previously stated, using his "bankruptcy" standard of analysis, one would conclude that renewable generation is uneconomic given the initial requests for rejection of wind and solar power contracts by FES in the very same bankruptcy case involving OVEC's

[32] Fisher at 4.

ICPA[33] and the potential rejection of renewable energy contracts by Pacific Gas and Electric Co. in its recent bankruptcy case.[34]

Second, as I previously stated, no changes have been made to the ICPA's terms since it was approved by the Commission so there is no change in the risks associated with it nor in the Companies' rights and obligations associated with it. Furthermore, Mr. Fisher's citation of various consultants' testimony in other cases and jurisdictions have no bearing on the prudency of the Companies' recommendation and the Commission's order involving the 2011 ICPA amendment.

Q. In the Commission's 2011 order approving the amended ICPA, it noted that the Companies wanted to extend the term from 2026 to 2040 to take advantage of reduced financing costs. Did that occur?

A. Yes. The Companies projected that they would save approximately $900,000 per year between the extension's effective date and 2026 based on forecasted savings on debt service on bonds to be issued in 2012 and deferring potential charges for decommissioning and demolition ("D&D") charges. In addition to realizing the interest and D&D savings, actual demand charges to the Companies for these items averaged around $2 million per year less between 2012 and 2018, compared to the original forecast without the ICPA extension. This additional savings was due to deferring bond principal beyond 2026 instead of amortizing it from 2012 through 2026

[33] "Motion for Entry of an Order Authorizing FirstEnergy Solutions Corp. and FirstEnergy Generation, LLC to Reject Certain Energy Contracts as of the Petition Date", Filed by FirstEnergy Solutions Corp., United States Bankruptcy Court for the Northern District of Ohio, Akron Division, Case No. 18-50757, April 1, 2018. On August 17, 2018, FES obtained an order from the bankruptcy court authorizing it to reject its Renewable Power Purchase Agreement with Maryland Solar, LLC.

[34] "PG&E renewable energy contracts tied up in bankruptcy battle," J.D. Morris, San Francisco Chronicle, February 3, 2019. *See* https://www.sfchronicle.com/business/article/PG-E-renewable-energy-contracts-tied-up-in-13584460.php.

as OVEC initially planned. On top of the originally filed savings, as shown in Rebuttal Exhibit DSS-3 actual total demand charges to the Companies have been dramatically lower compared to the original forecast by an average of $8.5 million annually since 2012, due to OVEC's efforts to reduce capital expenditures, operating costs, and financing costs.

Q. The Commission's 2011 order stated that the Companies expected to utilize the majority of the power available from OVEC, particularly during peak periods. Did that, in fact, occur?

A. Yes. While the Companies do not have historical data on the hour-by-hour available OVEC capacity, if one assumed that 100 percent of the Companies' share was available every single hour (meaning no planned or forced outages) from 2012 through 2018, then the implied capacity factor on the Companies' share of OVEC was 56 percent. Furthermore, of the 6,018,870 MWh taken during that same period, approximately 55 percent were used during the on-peak period of Monday through Friday, hours ending 8:00 to 23:00. Thus, even though the on-peak hours represent just over 47 percent of the hours in the year, the Companies' utilized over one half of their OVEC energy during the higher value on-peak periods.

OVEC's historical and forecasted annual capacity factors are consistent with a number of the Companies' own coal units.[35] It is important to remember that the annual system load factor is typically in the mid to upper 50 percent range so only the absolute lowest cost units like Trimble County Unit 2 will tend to be fully loaded all of the time. Also, since the Companies built the natural gas-fired combined cycle Cane Run Unit

[35] See the Attachment to Filing Requirement Tab 16, Sec. 16(7)(c) – Item H, page 27.

7, natural gas prices have been such that it has operated at nearly full output most hours, thus causing other resources to be more load following. Should natural gas prices increase above around $3.80/mmBtu, Cane Run Unit 7 will assume the role of hourly load following and coal units will tend to operate at closer to their hourly rating throughout the day.

Q. The Commission's 2011 order cited the Companies' view that OVEC's energy cost would compare favorably per kWh with the Companies' other generating units. Is that the case?

A. Yes. OVEC's energy cost in the base period and the forecasted test period is approximately $24 to 25/MWh.[36] OVEC's dispatch cost ranked 17th of the Companies' 37 generating units in November 2018.[37]

Additionally, I would note that while the language of the 2011 order was focused on energy only costs, OVEC's fixed costs, including its debt, compare very favorably on a per kW of capacity basis. As Mr. Fisher points out in his testimony, OVEC's debt is about $640/kW.[38] However, despite Mr. Fisher's assertions to the contrary, that is well below the capital cost per kW of a new natural gas combined cycle like Cane Run Unit 7, which was around $900/kW, as well as other new generation resources the Companies evaluated in the 2018 IRP.[39] Furthermore, OVEC's cost per kW will decline as debt is paid off in the future.

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[36] See the response to AG 1-4(c).
[37] See the response to AG 1-147.
[38] Fisher at 48:11.
[39] See Case No. 2018-00348, the Companies' Joint Integrated Resource Plan, Volume III, 2018 IRP Resource Screening Analysis, Table 1 on page 4 of 14.

Q. Are the Companies aware of any analysis that would indicate that the units, with proper maintenance, will be unable to operate through 2040?

A. No. While lower natural gas prices and a growing number of new natural gas-fired combined cycle plants in PJM (the main market for OVEC generation) have likely impacted the dispatch of the OVEC units (just as Cane Run Unit 7 has impacted the dispatch of the Companies' coal units), OVEC management has not indicated that this is impacting the life of the units.

Q. In its 2011 order, the Commission cites findings from the URS report that: i) the units are expected to be in compliance with existing and pending environmental requirements, ii) FGDs will be installed on all of the units, and iii) coal combustion by-products will not be regulated as a hazardous waste. Did those statements turn out to be true?

A. Yes. The units are not out of compliance with existing regulations and as discussed at length in their 2017 Annual Report, OVEC is evaluating the compliance cost associated with regulations that, in many cases, are still not final almost 8 years after the URS report.[40] FGDs were constructed at all of the units as discussed in the 2011 order and finally, the EPA did not regulate coal combustion by-products as a hazardous waste.

Q. How would you characterize Mr. Fisher's conclusion #2?

A. As with other parts of his testimony, Mr. Fisher's testimony is misleading, this time in regard to events that have transpired since the Commission approved the ICPA in 2011.

[40] Fisher Exhibit JIF-02 at 30-34.

Section 4 – Long-term Economics of OVEC

Q. Mr. Fisher makes a number of conclusions regarding the Companies' knowledge of OVEC's projected costs and performance, FirstEnergy Solutions' bankruptcy, and future environmental compliance capital requirements (#3, #5, #6, #7, #8, #9, and #10). In general, do you agree with these conclusions?

A. No. As I've previously stated, the Companies are well aware of OVEC's projected costs and operational performance. However, as I've pointed out, the real objective of Mr. Fisher and the Sierra Club is to retire coal plants through any means possible, so casting aspersions on the awareness and financial analysis capabilities of the Companies' management team and employees seems to be the point of these particular conclusions.

Q. Please provide an example where Mr. Fisher is incorrect about the Companies' knowledge of OVEC's projected costs.

A. I've already testified as to the board's involvement (which includes participation by the Companies' board members) in reviewing and approving capital plans and budgets including the potential for future environmental capital projects. Furthermore, OVEC provides detailed forecasts of long-term costs in their Projected ICPA Billable Cost Summaries and OVEC management and staff are available to answer specific questions the Companies' employees may have regarding either actual bills or financial projections.

Other examples include:

- The Companies were fully aware that OVEC management was going to be meeting with rating agencies and were fully informed as to the release of those ratings.

- The Companies saw the "merchant analysis" provided to the OVEC board, even though it has no bearing on the long-term planning of vertically integrated utilities like the Companies, which have an obligation to serve their customers irrespective of forecasts of RTO market prices.
- The Companies are aware of and actively monitoring the FES bankruptcy and OVEC's responses thereto. To date, LG&E and KU believe that OVEC management has engaged well-qualified bankruptcy counsel and has reasonably and competently pursued and defended OVEC's interests in the matter, under the applicable facts, circumstances, and law. Where appropriate, LG&E and KU have participated directly in certain proceedings, such as a collateral FERC petition, an amicus curiae bankruptcy brief that was filed in opposition to the Debtors' motion for a preliminary injunction against FERC, and the submission of proofs of claims against FES and FirstEnergy Generation, LLC relating to their rejection of the ICPA.
- The Companies review each and every ICPA bill and make inquiries when appropriate. To date, LG&E and KU do not find indications that OVEC is improperly billing the Companies since the FES bankruptcy under the applicable facts, circumstances, and contract provisions. If the Companies detected such actions by OVEC, they would seek to enforce their rights under the ICPA.

Q. Mr. Fisher testifies on page 35, lines 10-11, that, "A 'Merchant Analysis' is a fairly standard valuation technique used by vertically-integrated utilities to assess if an asset has system value." Do you agree with Mr. Fisher?

A. No. Based on my decades of experience of actually working in the energy industry, the concept behind Mr. Fisher's "merchant analysis" is something one would see in an energy trading company, not a vertically-integrated utility. His "merchant analysis" is essentially a "mark-to-model" valuation of a transaction. Based on my experience, mark-to-model is of no value to vertically integrated utilities like the Companies.

Q. What do you mean by "mark-to-model?"

A. The term "mark-to-model" became somewhat infamous during the Enron era. A trading company, like Enron, must put a market value on its portfolio at the end of each trading day. The market value represents what the portfolio could be liquidated for, which is easy to do for transactions that are traded on exchanges, such as July 2019 natural gas at Henry Hub. But transactions like the ICPA are what are known as "structured transactions" in the trading world because they have a number of attributes that do not involve easily tradeable commodity contracts: uncertainty around physical plant operations, a term that extends beyond the time horizon where there is market liquidity, a delivery location that is not liquid, etc. But because structured transactions still must be valued at the end of each trading day even without a liquid market to determine their value, the trading company's risk group will develop a model of the transaction and a model of various inputs and outputs of the transaction in order to estimate its value, hence the phrase "mark-to-model."

Q. Based on your experience in the energy marketing industry, how would one go about developing a mark-to-model valuation of the ICPA?

A. The ICPA has a number of aspects that would make for a challenging, yet interesting, exercise to develop a mark-to-model tool. First, the ICPA runs through 2040 so the time horizon allows for a wide range of uncertainty around variables such as coal prices, electricity prices, and capacity prices. All of these could be influenced by not just the usual supply and demand factors but also future unknown and unknowable laws and regulations, changes in PJM market design, and rate of technology changes. Because uncertainty associated with these variables will increase over time, one would need to develop ways to model both the probability of events occurring and the interaction impacts of these events.

After having dealt with the model inputs, the ICPA model itself is essentially a series of eleven call options, one from each generating unit. These call options have several major aspects to them:

- The hourly "strike" or dispatch cost that also needs to recognize the physical operating characteristics such as minimum up and down time, start-up notice, minimum loading, and planned and unplanned outages.
- The continuing operation option that would evaluate uncertainty associated with routine maintenance costs and uncertainty around future environmental regulations and associated compliance costs.
- Timing and funding requirements associated with end of life closure costs.

As you can see, a good mark-to-model tool would be much more involved than simply a single forecast of the future.

Q. In your opinion, is the "merchant analysis" a well-developed mark-to-model value of the ICPA?

A. I have not personally reviewed the details behind the merchant valuation, but based on looking at the same charts that Mr. Fisher reviewed, I would say that it would not be a very good mark-to-model valuation. The reasons I say that are:

- The charts seem to represent only one particular forecast of the future. A robust mark-to-model valuation would look at a range of possible futures and try to assess the probability of the occurrence of various futures.
- The charts highlighted by Mr. Fisher clearly represent [redacted]
- The chart seems to assume a certain dispatch of the OVEC fleet whereas a more robust mark-to-model valuation would attempt to model the units as 11 call options with uncertain strike prices (because future coal prices are not known) and a volatility curve about future electricity prices. The merchant analysis is more akin to what a trading risk manager would call an "intrinsic" value since it appears to just look at a static set of forecasted electricity prices.

I want to stress that I am not being critical of the merchant analysis; rather, I am being critical of Mr. Fisher's attempt to portray it as something more than it is. The charts are simply one forecast among many possible futures – nothing more, nothing less.

Q. Why is a market-to-model of no value to the Companies?

A. A mark-to-model tool or "merchant analysis" is appropriate for a trading company that needs to value its portfolio every day. In contrast, vertically integrated utilities like the Companies must meet the actual energy needs of customers, which requires actual power plants. In other words, real load does not get served by a forecast of future electricity prices or depend on the daily attempt to discern the lifetime financial value a particular generating asset. If that were the case, utility resource planning would consist of a series of price forecasts rather than an evaluation of the physical performance capabilities and economics of alternative generation technologies to serve a load 8760 hours a year. Mr. Fisher's failure to recognize and understand the difference between the accounting and risk management requirements of a trading company and the load serving obligations of a vertically integrated utility is a truly fundamental flaw in his testimony.

Q. What is your understanding of Mr. Fisher's Figure 5 and how does that impact your view of the ICPA's economics to the Companies?

A. My understanding is that Mr. Fisher's Figure 5 reflects the cumulative present value difference between total OVEC costs per MWh and weighted average market prices in each year from his Figure 4, for the Companies' ownership share of generation assuming a 65% capacity factor. Assuming that Figure 5 precisely predicts the future and is applicable to the Companies (who are not merchant generators but are regulated utilities) it demonstrates that the Companies' losses would be limited to $60 million with OVEC operating, compared to a potential immediate acceleration of the Companies' approximately $115 million share of OVEC's debt if OVEC were to be shut down, which Mr. Fisher fails to acknowledge. Stated differently, even if the analysis Mr. Fisher cites were treated as unassailable and perfectly predicted the future, the Companies and their customers would stand to benefit by up to $55 million by allowing the ICPA to run its course compared to immediately retiring the generating units and paying the Companies' likely pro rata obligations. Yet Mr. Fisher narrowly interprets these market analyses only as showing potential negative acquisition value of OVEC and concludes that this indicates the end of OVEC's life. But this would be an incorrect financial decision even assuming all of these forecasts were to come true; the correct financial decision would be to continue to operate OVEC as long as revenues cover variable and stay-open costs because the margin is making a contribution to cover some of the fixed costs. This is precisely what the data show in the graphs used by Mr. Fisher to create his Figure 5.

Q. How would you characterize Mr. Fisher's conclusions #3, #5, #6, #7, #8, #9, and #10?

A. Please see my prior responses regarding the types of information access and governance roles commonly present in closely-held, yet independently operated, entities. Once again Mr. Fisher's testimony is misleading and confusing regarding both OVEC and the Companies' knowledge. Despite Mr. Fisher's assertions, OVEC's management and board, as well as the Companies' management and employees, are perfectly capable of performing the necessary analysis to determine, among other things, whether it makes economic sense in the future to install additional environmental controls or retire the generating units. These decisions are a type of financial option, and one should only exercise an option when it is "in the money" and not before. But because Mr. Fisher and the Sierra Club are only interested in one outcome – shutting down coal plants in the US – his conclusion is that no further financial analysis is required and the option should be exercised even if it is "out of the money."

<u>**Section 5 – Economics of the ICPA for LG&E and KU Customers**</u>

Q. Mr. Fisher reaches a number of conclusions (#4, #11, #12, #13) that the Companies are indifferent to how the ICPA impacts their ability to provide reliable, low-cost electric service to customers both day-to-day and over the long term. Do you think his conclusions accurately describe the Companies' attitude and approach to the OVEC assets and the execution of its rights under the ICPA?

A. Absolutely not. First, it is insulting to the employees of LG&E and KU that Mr. Fisher would conclude that we don't care about providing reliable, low-cost electric service to our customers. The Companies have a long, well-documented record of doing just that, and I can assure this Commission that our actions regarding OVEC and the ICPA are consistent with that record. Second, I am the vice president who, since 2008, has been responsible for long-term resource planning, real-time dispatch, wholesale market activities, and day-to-day oversight of the ICPA. My team and I have exercised the Companies' rights under the ICPA and have properly and prudently evaluated the ICPA in our long-term planning.

Q. Does Mr. Fisher perform any modeling or reliability studies, or provide actual "evidence" to support his conclusion #13 that OVEC provides no reliability value?

A. No. All he does is recalculate the summer peak reserve margin and claim that OVEC, in general, did not perform to his satisfaction during two cold snaps in 2014 and 2015.

Q. Is there more to doing a reliability study than just calculating summer peak hour reserve margin?

A. Definitely. The Companies describe in detail their methodology for determining the target summer reserve margin range in their 2018 IRP Reserve Margin Analysis.[41] The results of this analysis showed that the Companies' existing resources, including OVEC, are economically optimal for meeting system reliability needs.

Q. How has OVEC performed in recent years during high load events, including the recent January 2019 Polar Vortex?

A. OVEC's performance during the Companies' recent peak periods has been very good: in 2016, 2017, and 2018 the Companies received 99%, 93%, and 99% of their share of OVEC during the peak hour of the year, respectively. And most recently in January 2019, the Companies received 96% of their share of OVEC during the peak hour, which occurred during the "polar vortex" morning of January 31. Furthermore, if one wants to go back to the winter peak hours in 2014 and 2015 as Mr. Fisher wants to do, the Companies received 85 percent and 60 percent, respectively, of their OVEC share at time of system peak.

Q. How does OVEC's performance during recent high load events compare to that of the Brown solar plant?

A. First, this comparison is not very fair to Brown solar, especially concerning the winter events, because its output is driven by light intensity, which is often not good at times of winter peak when it is dark or solar panels can be covered by snow. Second, the summer peak system load is typically later in the day when the sun is not as high in the sky. Having said that, since beginning commercial operations in June 2016, Brown solar has performed at 80 percent, 76 percent, and 94 percent of its capacity during the

[41] The Companies' 2018 IRP Reserve Margin Analysis was attached to Companies' responses to AG 2-14(a) in these proceedings.

summer peak hour of 2016, 2017, and 2018, respectively, while it was at 0 percent and only 11 percent during the winter peaks of 2016/17 and 2017/18, respectively. More recently, during the bitterly cold morning of January 31, 2019, when customers' demand was highest so far this year, Brown solar produced at only 7 percent of its rated capability.

Q. Conclusions #4, #12, and #13 all essentially accuse the Companies of not properly assessing OVEC in their IRP and other long-term plans. Please explain how the Companies evaluated OVEC as a long-term resource.

A. Mr. Fisher's characterization of data contained in Table 9 from the Companies' 2018 IRP Reserve Margin Analysis is incorrect. He claims that "the OVEC units are the most expensive unit in their system on a marginal cost basis at $92/kw-yr (2021$)."[42] However, as the table clearly shows, and as the Companies explain, $92/kW-yr is the stay-open cost for the OVEC units. "When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs."[43] In order to appropriately compare unit costs, the stay-open costs and the average energy costs must be summed for each unit, which is shown in the rightmost column of the table. Compared to the sum of stay-open costs and average energy costs for Brown 3 ($84/MWh), OVEC's cost ($47/MWh) is much lower. Furthermore, the retirement of the Companies'

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[42] Fisher at 30.

[43] Companies' 2018 IRP Reserve Margin Analysis at 8. The Companies' 2018 IRP Reserve Margin Analysis was attached to Companies' responses to AG 2-14(a) in these proceedings.

marginal resources (including Brown 3) was evaluated in the Reserve Margin Analysis, in which the Companies determined that "the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units."[44] Because the sum of stay-open costs and average energy costs for Brown 3 are greater than for OVEC, it is reasonable to conclude that the reliability and generation production cost benefit for OVEC also exceeds the costs that would be saved by retirement. It is important to note that the evaluation of retiring OVEC is strictly theoretical because any such retirement decision would be effected by OVEC's governance process (not the Companies unilaterally). The Companies' existing participation in the ICPA is binding in accordance with its terms and conditions, and the specific structure and outcomes of an OVEC retirement could vary greatly.

Q. Under the ICPA, can the Companies simply stop taking energy from their share of OVEC?

A. Yes, we can stop scheduling energy and cease incurring the related energy charges (except minimum loading, as I discuss below), but we would still have to pay our share of the appropriate fixed costs as defined in the ICPA via the demand component. As I stated previously, the Companies have certain pro-rata contractual obligations that generally survive termination of the ICPA absent unusual circumstances (such as the rights of parties to reject contracts in bankruptcy proceedings). Therefore, if the Companies were to simply stop scheduling energy from OVEC that was otherwise economic, meaning lower cost than other resources, then the cost of serving our

[44] See Case No. 2018-00348, the Companies' Joint Integrated Resource Plan, Volume III 2018 IRP Reserve Margin Analysis at 3.

customers would increase. That makes no sense, so we would not do that. Also, the ICPA includes “minimum loading” provisions (set forth in Section 5.05 of the ICPA), requiring each Sponsor to either schedule delivery of its portion of OVEC’s “total minimum generating output” or pay for any increased costs caused by failure to schedule and take its minimum output. These costs are assigned directly to the responsible Sponsor, rather than spread among all Sponsors.

Q. What have been the ICPA and FES bankruptcy impacts on the Companies and their customers to date?

A. The impacts have varied. As previously indicated, OVEC has incurred slightly higher financing-related costs, such as consulting, interest, and borrowing expenses, due to adverse effects on its credit ratings. OVEC has also incurred certain costs to participate in the bankruptcy proceedings. On the other hand, with FES no longer taking energy, its previous share of energy is now available to be taken by the other sponsors based on their Power Participation Ratio by paying just the energy costs. This means the customers have the ability to get some incremental energy without paying for OVEC’s fixed costs that are no longer being paid by FES, but remain subject to further resolution and potential claims recovery or settlement, in part, via the bankruptcy process. The Companies’ share of the former FES energy per hour is small, only up to 9 MW, but from September 1, 2018, through January 31, 2019, the Companies have taken an incremental 17,127 MWh to better serve our customers.

Q. What is your opinion of Mr. Fisher and the Sierra Club's claim in their response to the Commission Staff that the Companies "paid in excess of between $9.2 million and $20.8 million" for capacity and energy under the ICPA in 2017?[45]

A. It is nonsense. As I've explained previously, Mr. Fisher's desire to add fixed and variable costs together and divide by energy to calculate an all-in cost for a generation resource is not very useful and is generally inappropriate for financial analysis. Second, his comparison of an all-in price per MWh to a market price that is based on economy energy is also inappropriate and very poor financial analysis. In fact, their data response states that "market prices in 2017 were $27.84."[46] If that price was supposed to be indicative of what any utility could use to provide reliable electric service for the year, then I believe the entire eastern US generation fleet might be uneconomic as I'm aware of no generation technology that produces power all-in for just under $28/MWh every hour of the year and certainly not in a manner that could reliably serve load 8,760 hours a year. However, based on this bad reasoning, Mr. Fisher proceeds to do bad math by comparing the $60.41/MWh all-in cost of OVEC to this economy energy price and multiplies the difference by the volume of energy that the Companies purchased. From this arithmetic he concludes that ratepayers paid $25,860,580 too much, thus inferring that the Companies could have simply defaulted on their ICPA fixed charge contractual obligations at no cost, even assuming the use of his market energy price is appropriate, which it is not. To offset his assertion that ratepayers paid in excess of $25 million in 2017 under the ICPA, Mr. Fisher credits his calculation with a range of

[45] Sierra Club Response to Commission Staff Request No. 1, p. 2.
[46] Ibid.

PJM capacity prices.[47] Even this adjustment is irrelevant as the Companies are not in PJM and cannot purchase capacity from its market.

Q. If one wanted to properly evaluate the impact on customers' energy cost of taking power under the ICPA, what would you suggest they do?

A. First, as I've explained, the Companies cannot simply walk away from the ICPA, so any analysis would have to recognize that the demand charges must be paid. Having done that, one could remove the hourly ICPA energy schedules from the actual hourly dispatch and re-dispatch the system. Since the Companies work very hard to economically dispatch the system at all times, which the Commission reviews every six months as part of the Fuel Adjustment Clause process, this exercise would show that higher cost resources would have to take the place of energy from the ICPA. Thus, customers' energy cost in 2017 would have been higher, not lower as Mr. Fisher asserts.

Section 6 – Conclusion and Recommendations Regarding Mr. Fisher's Testimony

Q. What are your conclusions and recommendations for the Commission regarding Mr. Fisher's testimony on behalf of the Sierra Club?

A. Mr. Fisher and the Sierra Club are attempting to use these rate cases to further the objectives of their Beyond Coal campaign. But as I noted before, none of Mr. Fisher's recommendations even mention these cases. Therefore, I recommend that the Commission completely disregard his testimony.

Furthermore, even though some aspects of his recommendations are more properly addressed in the Companies' upcoming IRP case, given the ideologically

[47] Ibid.

driven nature of the Sierra Club's Beyond Coal campaign (and its Beyond Gas campaign),[48] I question whether they will be able to provide any useful information or insight as it relates to addressing the fundamental purpose of an integrated resource plan – providing reliable, low-cost electricity to meet the future needs of our customers.

Section 7 – Load Forecast Issues Raised by Mr. Baron

Q. Do you agree with Mr. Baron's recommendation to update the forecast period billing demand forecasts of the RTS class for both LG&E and KU by using the actual base period values?

A. No. As I stated in my direct testimony in these cases, the Companies have a very thorough load forecasting process that strives to produce a reasonable forecast using the best available information and forecasting tools. Mr. Baron would like to create a new, simplified forecast methodology that sets the future equal to the most recent actual data but only for one particular class - RTS customers. He does not explain why this method is appropriate for the RTS class and no other. One can speculate that his recommended changes are more outcome driven, i.e., using this particular data and method would reduce the Companies' revenue requirement deficiencies, than they are based on the utilization of a better load forecasting methodology. One part of any load forecast process involves reflecting the most recent information; if the Companies were to update all of their models with more recent data (which the Companies do every year), the forecasts of all of the classes would change to some degree – some higher

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[48] https://content.sierraclub.org/creative-archive/sites/content.sierraclub.org.creative-archive/files/pdfs/100_58-Natural-Gas_FactSheet_11_low_0.pdf (viewed Feb. 8, 2019) (archived at https://web.archive.org/web/20190208195659/https://content.sierraclub.org/creative-archive/sites/content.sierraclub.org.creative-archive/files/pdfs/100_58-Natural-Gas_FactSheet_11_low_0.pdf).

and some lower. That is the nature of the load forecasting process. But it would be inconsistent at best to cherry pick particular data that might benefit Mr. Baron's clients (large industrial customers) and suggest that the load forecast should be modified solely for that class.

Q. Do you agree with Mr. Baron's statement that the LG&E and KU RTS forecasts imply "a significant decline in economic activity for large manufacturing customers in the KU and LG&E service areas"?[49]

A. No. Forecasting billed demand in the short-term is not as straightforward as Mr. Baron suggests. Because billing demand is subject to a 12-month ratchet, one cannot simply assume that changes in billing demand from year-to-year are driven solely by changes in the economic fortunes of specific customers. Also, not all RTS customers are manufacturers. For example, as I pointed out in my direct testimony on page 18, lines 5-11, the decline in LG&E RTS Base demand in the forecasted test period was impacted by a seasonal weather event that caused a large increase in actual demand in February 2018. As shown in Figure 1, base demands for LG&E RTS are consistent with the forecast as the 100% ratchet from February 2018 demand was appropriately forecasted to roll off in early 2019, prior to the start of the forecasted test period. Figure 1 also shows that removing this temporary ratchet impact from the forecast brings the billing demands in the forecasted test period in line with the historical data in the pre-ratchet time frame. Mr. Baron's simple use of the actual billing demand to forecast the future ignores this impact.

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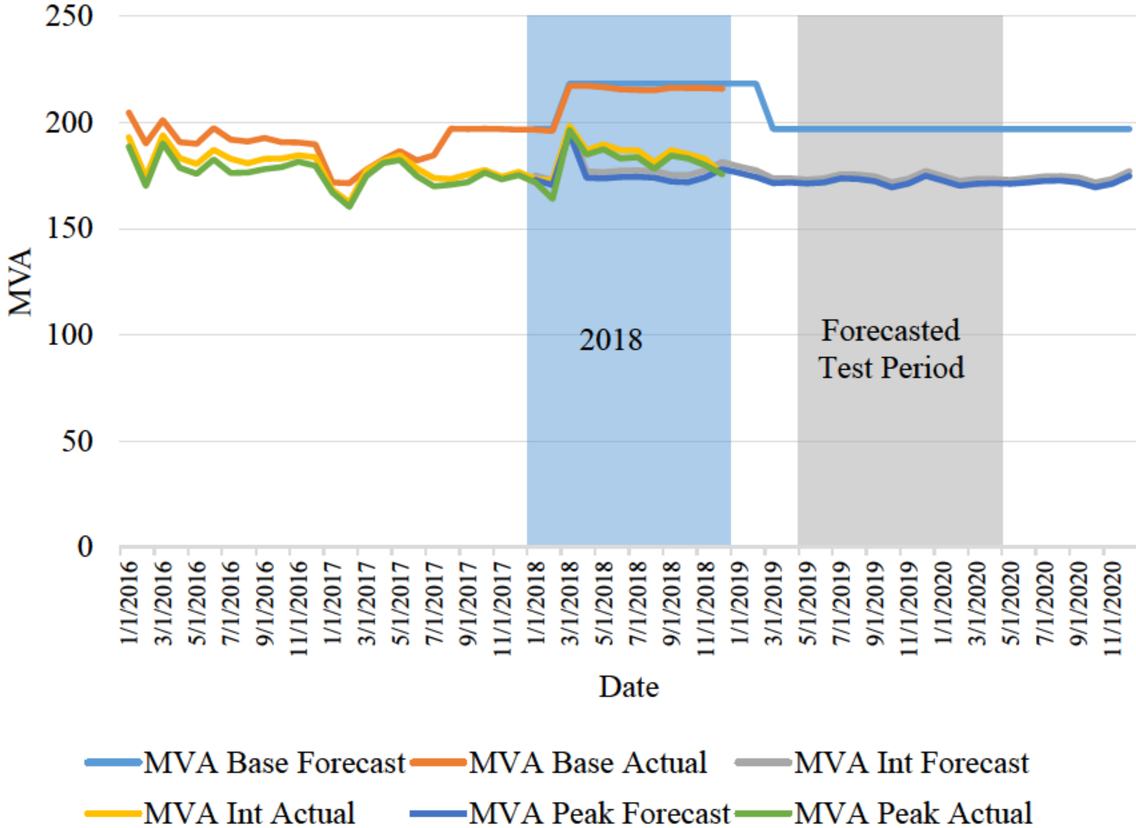
[49] Baron at 34.

Figure 1 - LG&E RTS Monthly Billing Demands



Q. What is your recommendation regarding Mr. Baron's proposed revenue adjustments for LG&E and KU RTS classes?

A. They should be ignored for the reasons that I have stated. The Companies' billing demand forecasts for the RTS class, and for that all of the load forecasts, used in these cases are reasonable.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public

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

Sierra Club's Beyond Coal Campaign:

Coal is an outdated, backward, and dirty 19th-century technology.

Not only is coal burning responsible for one third of US carbon emissions—the main contributor to climate disruption—but it is also making us sick, leading to as many as 13,000 premature deaths every year and more than $100 billion in annual health costs. The Beyond Coal campaign's main objective is to replace dirty coal with clean energy by mobilizing grassroots activists in local communities to advocate for the retirement of old and outdated coal plants and to prevent new coal plants from being built.

BEYOND COAL CAMPAIGN GOALS

- We're trying to close all the coal plants in the US. Our movement has led more than half of the coal plants to retired or commit to retire.
- We're working to replace the majority of retired coal plants with clean energy solutions such as wind, solar, and geothermal.
- We're also working to keep coal in the ground in places like Appalachia and Wyoming's Powder River Basin.

Source: https://content.sierraclub.org/coal/about-the-campaign

CONFIDENTIAL INFORMATION REDACTED

OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Agenda
Boards of Directors' Meeting
December 1, 2015

1. [redacted] [redacted]
2. [redacted] [redacted]
3. [redacted] [redacted]
4. [redacted] [redacted]
5. [redacted] [redacted]
6. [redacted] [redacted]
7. [redacted] [redacted]
8. [redacted] [redacted]
9. [redacted] [redacted]
10. [redacted] [redacted]
11. [redacted] [redacted]
12. [redacted] [redacted]
13. [redacted] [redacted]
14. [redacted] [redacted]
15. [redacted] [redacted]
16. [redacted] [redacted]
17. [redacted]

[redacted]

[redacted] [redacted]

[redacted]

OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Agenda
Boards of Directors' Meeting
December 1, 2016

1. [redacted] [redacted]
2. [redacted] [redacted]
3. [redacted] [redacted]
4. [redacted] [redacted]
5. [redacted] [redacted]
6. [redacted] [redacted]
7. [redacted] [redacted]
8. [redacted] [redacted]
9. [redacted] [redacted]
10. [redacted] [redacted]
11. [redacted] [redacted]
12. [redacted] [redacted]
13. [redacted] [redacted]
14. [redacted]

[redacted]

[redacted]

[redacted]

OVEC Demand Charge and Savings

$000	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Average**
Projected Demand Charge with Extended 2040 Contract Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Actual Demand Charge								
Actual Savings	56,037	67,087	117,988	132,973	153,074	106,822	101,241	
LG&E/KU's 8.13% Share of Actual Savings	4,556	5,454	9,592	10,811	12,445	8,685	8,231	8,539

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Ohio Valley Electric Corporation
Projected Inter-Company Power Agreement (ICPA) Billable Cost Summary
Calendar Years 2012-2018
in thousands of dollars

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018
Demand Charge							
Annual Capital Improvement Costs (excluding financed projects - major environmental projects)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt Expense and Short-Term Debt Costs (including financed projects - major environmental projects)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long-Term Debt Costs (including financed projects - major environmental projects)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Advance Billing of Debt Service (Debt Reserve)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Improvements and Debt Costs (ICPA Component A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operation and Maintenance Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Administration and General Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission and Dispatch Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Taxes (ICPA Component C)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ROE Costs (ICPA Component D)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Postretirement Benefit Obligation (ICPA Component E)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning and Demolition Obligation (ICPA Component F)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Demand Costs (ICPA Components A, B, C, D, E & F)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Ohio Valley Electric Corporation
Preliminary Inter-Company Power Agreement (ICPA) Billable Cost Summary
Assumes ICPA Contract Extension of 30 years in 2010
Calendar Years 2010 - 2040
in thousands of dollars

Demand Charge	2012	2013	2014	2015	2016	2017	2018
Projected Annual Capital Improvement Costs (excluding SCR, FGD and Other Financed Projects)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Accelerated SCR Catalyst Replacement at Kyger	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected SCR Catalyst Replacement at Clifty	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Kyger FGD Landfill Capital Costs for Phase 2 and Phase 3				[redacted]	[redacted]		
Projected Clifty FGD Landfill Capital Costs for Phase 2 and Phase 3					[redacted]	[redacted]	[redacted]
Projected Debt Expense Amortization and Short-Term Debt Costs (excluding FGD Construction Interim Debt)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected FGD Construction Interim Debt (AFUDC)	[redacted]	[redacted]					
$445 Million - 5.80% Senior Unsecured Notes - Series 2006-A - Due February 15, 2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$300 Million - 5.90% Senior Unsecured Notes - Series 2007-A-C - Due February 15, 2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$50 Million - 5.92% Senior Unsecured Notes - Series 2008-A - Due February 15, 2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$300 Million - 6.71% Senior Unsecured Notes - Series 2008-B-C - Due February 15, 2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$100 Million - Floating Rate Notes - Series 2009-A - Due February 15, 2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$100 Million - Floating Rate LOC Backed Bonds - OAQDA Tax Exempt 2009-A-D - Due February 1, 2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$100 Million - 5.625% Bonds - OAQDA Tax Exempt 2009-E - Due October 1, 2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected $100 Million Debt to be issued in 2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected $300 Million Debt to be issued in 2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Capital Improvements and Debt Costs (ICPA Component A)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Operation and Maintenance Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Administration and General Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Transmission and Dispatch Costs (ICPA Component B)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Taxes (ICPA Component C)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected ROE Costs (ICPA Component D)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Postretirement Benefit Obligation (ICPA Component E)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Projected Decommissioning and Demolition Obligation (ICPA Component F)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Projected Demand Costs (ICPA Components A, B, C, D, E & F)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
JOHN K. WOLFE
VICE PRESIDENT, ELECTRIC DISTRIBUTION OPERATIONS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

TABLE OF CONTENTS

Q. Please state your name, position and business address.

A. My name is John K. Wolfe. I am Vice President of Electric Distribution Operations for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E) (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky.

Q. Please describe your educational and professional background.

A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before the Commission?

A. Yes. I testified in the Companies' last rate case proceedings in Cases No. 2016-00370[1] and No. 2016-00371[2] and in Case No. 2018-00304,[3] which involved the Companies' application to establish a regulatory asset for extraordinary storm damages.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the issues raised in Joseph H. Crone's testimony. I will explain why the Company's proposed revisions to its Rate Pole and Structure Attachments ("Rate PSA") are necessary to protect and ensure public and line worker safety, safeguard the Company's electric distribution facilities,

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[1] *Electronic Application of Kentucky Utilities Company For An Adjustment Of Its Electric Rates And For Certificates Of Public Convenience And Necessity*, Case No. 2016-00370 (Ky. PSC filed Nov. 23, 2016).

[2] *Electronic Application of Louisville Gas and Electric Company For An Adjustment of Its Electric And Gas Rates and For Certificates of Public Convenience and Necessity*, Case No. 2016-00371 (Ky. PSC filed Nov. 23, 2016).

[3] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company For An Order Approving The Establishment of Regulatory Liabilities and Regulatory Assets*, Case No. 2018-00304 (Ky. PSC filed Sep. 12, 2018).

maintain reliable and safe electric service for the public, and shield the Company's electric service ratepayers from bearing costs related to attachment customer service.

Q. What issues does Mr. Crone raise in his testimony?

A. Mr. Crone takes exception to the proposed Rate PSA provisions dealing with (1) make-ready and maintenance requirements; (2) unauthorized attachments; (3) service drop attachments; and (4) attachment audits.

Make-Ready and Maintenance Requirements

Q. Let's begin with the proposed revisions to Rate PSA's requirements for make-ready and maintenance requirements. What is make-ready work?

A. Make-ready work is work necessary to modify existing Company facilities to make the pole capable to accommodate a proposed attachment without jeopardizing public and line worker safety or electric system integrity. For example, transformers, neutral and secondary conductors, or street lights on a Company pole may need to be repositioned before an attachment customer's facility can be attached.

Q. What does the current Rate PSA provide for make-ready work?

A. Upon receiving a completed application for an attachment to a Company structure, the Company must complete a make-ready survey within 60 days. Upon completing the make-ready survey, the Company must notify the attachment customer in writing of its decision on the application, identify all necessary changes to the attachment customer's proposed construction drawings, and state all conditions imposed on the installation or use of attachment. Within 15 days of notifying the attachment customer of the approval of its application, the Company must provide the attachment customer a written statement of the costs of any necessary Company make-ready work. The attachment customer must submit its payment within 15 days of receipt.

The Company then has 60 days to perform the make-ready work. If the Company fails to perform the make-ready work within that time, the attachment customer may perform that work at its expense using an approved contractor. The attachment customer must notify the Company upon completing the make-ready work. The Company may inspect such work prior to the construction of attachments and assess the cost of the inspection to the attachment customer.

Q. What is the Company's proposed revision to Rate PSA regarding make-ready work?

A. The revised Rate PSA requires that, prior to commencing make-ready work when the Company has failed to perform such work within 60 days, an attachment customer must notify the Company one week prior to the start of make-ready work and must have a Company-designated inspector accompany the approved contractor performing the make-ready work. It further requires the attachment customer to reimburse the Company for the cost of the inspector.

Q. Why is the Company proposing that an inspector accompany an approved contractor performing make-ready work?

A. The presence of an inspector benefits all parties, including the attachment customer. The onsite inspector is focused on protecting the public safety, assuring that the interests of electric customers and property owners are considered, and ensuring service reliability. Furthermore, the constant presence of a Company inspector on site enables the attachment customer's contractor to make real-time construction adjustments that reduce construction work time when field conditions that were unknown at the time of the application or that occurred after the application was reviewed would have otherwise brought work to a grinding halt.

To understand the need for an inspector, one must first understand the nature of make-ready work. This work is performed on the Company's energized lines and results in alterations and adjustments to facilities essential to the provision of electric service. For example, electric transformers, neutral and secondary conductors, or street lights may need to be moved or raised to accommodate the attachment customer's equipment. Performing this work incorrectly or in a substandard manner places line workers and the public at serious risk, as well as increasing the likelihood of damage to the Company's distribution facilities and disruption of electric service.

Inspectors serve as the Company's on-site representative. They have the responsibility to ensure that the contractor performs make-ready work in compliance with all applicable standards. They also are the intermediaries between the contractor and the Company's Distribution Control Center. They provide the contractor with current and essential information regarding the distribution system. Frequently, service outages must be scheduled to permit the performance of make-ready work on the Company's facilities. Inspectors maintain constant communication with the Company's Distribution Control Center and the contractors to secure work clearances and cautions on Company equipment, and coordinate any required service outages to enable the contractor's work and minimize inconvenience to electric service customers from such outages.

Inspectors also have a greater knowledge of the Company's facilities and are more familiar with unique aspects of the Company's facilities. As a result, they are more likely to spot possible problems and better equipped to assist the contractor in troubleshooting those problems.

Finally inspectors are the Company's eyes and ears at worksite. They provide the Company with immediate notice of any changes in at the worksite conditions that may have occurred since the Company approved the attachment customer's make-ready design. This is significant since, if an attachment customer is performing the make-ready work, as many as 90 days may elapse from the time the Company approves the make-ready plans and the start of any construction.

Q. If an attachment customer is using a Company-approved contractor to perform the make-ready work, why are inspectors needed?

A. A Company-approved contractor is a contractor who meets the Company's qualifications, holds the appropriate licenses, has a good safety record, understands the Company's operating procedures, and meets minimum financial requirements. The contractor's principal duty lies with the attachment customer. Its principal objective is the completion of make-ready work in a prompt manner. The contractor is not an agent of the Company nor does it represent the interests of the Company or the Company's electric service customers.

In contrast, Company inspectors place the interests of the Company's customers first. They are present to prevent unnecessary service disruptions, liaison with customers as needed, ensure that contractors do not compromise worker or public safety, enforce the Company's construction standards, and help prevent unforeseen circumstances causing delays in the attachment customer's project.

The use of onsite Company inspectors when contractors perform work on the Company's facilities is not a new practice. It is very common and a long-standing practice for the Company to have inspectors onsite accompanying contractors who perform work for the Company.

This practice is also a feature of high-volume pole attachment plans that the Commission has approved. For example, KU has a high-volume pole attachment plan with Metro Fibernet LLC that requires presence of a KU-inspector onsite whose cost is borne by the attachment customer and who may direct that work be performed in a manner that differs from that set forth in the approved-application.[4] In a separate proceeding before the Public Service Commission, a Metro Fibernet, LLC official testified about KU's process and its ability to effectively meet the attachment customer's needs. He voiced no objections to the use of an onsite inspector.[5]

Q. In your opinion will requiring inspectors to accompany contractors delay the installation of attachments?

A. No. KU's experience with high volume pole applications suggests that the use of an onsite inspector will not delay installations. Moreover, the proposed revision requiring the attachment customer to provide one week's advance notice prior to the start of make-ready work is similar to the requirements that the Federal Communications Commission ("FCC") imposes. Recently adopted FCC rules require the attachment customer to provide five days advance notice before the start of "self-help" make-ready work.

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[4] *Special Contract Filing Between Kentucky Utilities Company/Metro Fibernet LLC*, TFS 2018-00027 (Ky. PSC filed Jan. 18, 2018).

[5] Direct Testimony of John Greenbank at 16-18 (filed Sep. 5, 2018 in *CMN-RUS, Inc. v. Windstream Kentucky East, LLC*, Case No. 2018-00157 (Ky. PSC May 15, 2018)). *See also* Rebuttal Testimony of John Greenbank at 3-4 (filed Oct. 12, 2018 in Case No. 2018-00157).

As to Mr. Crone's concerns regarding a lack of inspectors, the Company has not previously experienced any shortage of inspectors and has the flexibility to quickly expand its staff to meet any reasonable changes in the need for inspectors.

Q. In his testimony, Mr. Crone states that allowing a Company inspector discretion to direct that work be performed in a manner different than that approved in the application for attachment is "a recipe for mischief, conflict, delay and increased costs." Do you agree with that statement?

A. No. There is no basis for this assertion. Allowing a Company inspector discretion to direct deviations from approved make-ready plans is reasonable, likely results in lower costs, and benefits the attachment customer by avoiding delays in construction due to unforeseen circumstances.

Mr. Crone implicitly assumes that the work site conditions are static and do not change from the time the make-ready application is reviewed and the attachment customer begins performing make-ready work. That assumption is not accurate. As many as 150 days may elapse between the completion of the field review for the proposed attachments and the commencement of work by the attachment customer's contractor. At least 90 days will elapse between when the Company approves the make-ready designs and when the attachment customer may to perform the make-ready work. During that time natural events, such as severe storms, or human actors such as other attachment customers, may alter conditions at the work site and require design changes. These changes are likely not to be detected until the contractor begins the make-ready work. Having the inspector onsite allows the Company to immediately assess changing conditions and direct appropriate changes.

The Company's experience does not support Mr. Crone's assertion that every change directed by an inspector creates delay and increases cost. The inspector's mission is to ensure safety and good construction practices, not to impede make-ready work. If an inspector finds a design change will assist or improve the construction and not adversely affect safety or service reliability, he or she can suggest such change to the contractor and approve it on the spot – thus avoiding any delay in the attachment customer's project. Moreover, a correction made during the construction process is likely to be less costly and less disruptive than a change ordered after the construction is completed and a post-inspection is conducted. Rate PSA currently permits such post-construction inspections and permits the Company to direct post-construction changes. Mr. Crone's testimony ignores this point.

Inspector-directed changes will not create "a scenario ripe for abuse that could lead to allegations of unauthorized attachments or safety violations down the road" as Mr. Crone asserts. Inspector changes will be noted on as-built drawings and the Company's GIS mapping records, thus ensuring an accurate and complete record of any inspector-directed change.

Mr. Crone's suggestion that havoc and disarray will occur as a result of disputes between attachment customer contractors and the Company's inspectors is unsubstantiated. First, discussions between contractors and inspectors regarding changes to work plans are common within the industry. Both sides generally attempt to discuss and resolve issues at the work site. If, after such discussions, the attachment customer believes the inspector-directed change is inappropriate, it may appeal that the inspector's decision to Company officials.

It is not unusual or extraordinary to invest the Company's inspector with the authority to direct changes. It is best practice. FCC rules regarding an attachment customer's right to self-help for make-ready work permit the representative of the electric utility to make final determinations on such matters, provided the decision are made on a non-discriminatory basis.[6] In a recent a decision, the FCC defended its rule, finding that the costs of the rule are "justified given its important role in promoting safe and reliable work and in establishing clear lines of authority for fieldwork at which multiple parties are present."[7]

Q. In your opinion, what effect will the proposed revisions to Rate PSA concerning make-ready work have on Charter Communications operations?

A. None. To my knowledge, the Company has been able to perform make-ready work required for Charter Communications in a timely manner. I am aware of only 5 instances in 2018 which LG&E failed to perform make-ready work for Charter Communications within 60 days.[8] On those occasions, the Company completed the make-ready; Charter Communications did not perform any make-ready work on the Company's facilities due to the Company's inability to meet the deadline. In fact, the Company is not aware of any instance where an attachment customer has used a Company-approved contractor to complete necessary make ready work due to the Company's inability to meet the 60-day timeline. Moreover, I do not currently

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[6] 47 CFR § 1.1412(d) ("The consulting representative of an electric utility may make final determinations, on a nondiscriminatory basis, where there is insufficient capacity and for reasons of safety, reliability, and generally applicable engineering purposes."

[7] *Accelerating Wireline Broadband Deployment by Removing Barriers to Infrastructure Investment*, WC Docket No. 17-84 (Aug. 3, 2018) at 27.

[8] Information regarding attachment customer self-help make-ready work is not currently available for KU. In its response to Commission Staff's Request for Information, Charter Communications refers only to instances in which LG&E failed to meet the 60-day standard. *See* Charter Communications Operating LLC's Response to Commission Staff's Initial Requests for Information, Item 2 (filed Feb. 14, 2019).

foresee any instance under normal circumstances in which Charter Communications would need to do so. However, if at any time Charter Communications or any other attachment customer elects to perform its own make-ready work, the proposed revisions to Rate PSA will increase the probability that the work will be performed safely and without adversely affecting the reliability of electric service provided to the Company's customers, and with less disruption to the attachment project.

Unauthorized Attachments

Q. Why is the Company proposing a monetary penalty for unauthorized attachments to its structures?

A. The current Rate PSA provides no monetary penalty for an attachment customer's failure to report attachments and obtain authorization to make attachments. At present the only remedy for such practices is the removal of unauthorized attachments. This remedy is impractical. Removal of attachments effectively penalizes the innocent users of the attachment customer's service, most of whom are also the Company's customers, by depriving those users of that service. It destroys any goodwill towards the Company as these users are likely to view the Company's actions, rather than the attachment customer's unscrupulous conduct, as the cause for their loss of service. Taking no action, however, places the Companies in precarious position as KRS 278.160 imposes a duty on the Company to take reasonable measures to ensure that rates on file with the Public Service Commission are properly billed and collected.

The lack of any monetary penalty encourages attachment customers to game the process, to avoid applying for approval to make attachments, and to underreport actual attachments. If unauthorized attachments are discovered, an attachment customer is currently required to pay two years of attachment fees for the unbilled service. Since the Company conduct audits only once every five years, an attachment customer can potentially avoid payment of some attachment fees even if the unauthorized attachment is discovered. The proposed penalty of $25 for each unauthorized attachment is intended to eliminate this incentive to game the process.

Q. Do you agree with Mr. Crone's assertion that the proposed penalty for unauthorized attachments is excessive and unreasonable?

A. No. The proposed penalty, which is less than 3.5 times the annual attachment fee of $7.25, is intended to discourage unauthorized attachments without being excessive. It is smaller than those assessed in other jurisdictions.

The Oregon Public Utilities Commission, for example, permits pole owners to assess a fee no greater than five times the current annual rental fee per pole if the unauthorized attachment is reported by the attachment owner to the pole owner and is accompanied by a permit application or is discovered through a joint inspection between the pole owner and attachment owner and accompanied by a permit application. If the pole owner discovers an unauthorized attachment during an inspection in which the attachment owner declined to participate, a penalty of $100 per pole plus five times the current annual rental fee per pole is permissible.[9] The Federal Communications Commission has reviewed the Oregon PUC's approach and found its use in pole attachment agreements subject to the FCC's jurisdiction was reasonable.[10]

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[9] Or. Admin. R. 860-028-0140 (2019).

[10] See *Implementation of Section 224 of the Act: A National Broadband Plan for Our Future*, Docket No. 07-245, GN Docket No. 09-51, Report and Order and Order on Reconsideration, 26 FCC Rcd 5240 (2011) ("we

Prior to its adoption of the Oregon Model in 2011, the FCC employed for eleven years a standard that permitted pole owners to assess penalties for unauthorized attachments that did not exceed five times the annual attachment fee. In 2010, Charter Communications submitted comments to the FCC in support of continued use of the five years annual fee standard for penalties.[11] In light of Charter Communications support for that standard, its position that a lesser penalty that is excessive is difficult to understand.

Q. Describe the Company's methodology for identifying unauthorized attachments.

A. The methodology for identifying unauthorized attachments is set forth in Term and Condition 14 of the Rate PSA. It provides:

> Upon thirty (30) days' prior notice to Attachment Customer, Company may conduct an audit of its Structures to verify the number, location and type of Attachment Customer's Attachments. Company shall make available to Attachment Customer the report of such audit. Such report shall indicate the location and pole number of all attachments of the Attachment Customer. **If the audit reveals that the number of Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be Unauthorized Attachments** [emphasis added].

Simply put, the results of the audit will be compared to the Company's billing records. If the number of attachments identified as belonging to an attachment customer exceeds the number in the Company's billing records, the excess attachments will be presumed to be unauthorized.

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would expect to find reasonable any unauthorized attachment provisions contained in agreements that do not exceed Oregon penalties").

11 *Implementation of Section 224 of the Act: A National Broadband Plan for Our Future*, Docket No. 07-245, GN Docket No. 09-51, Comments of Charter Communications, Inc. at 26-27 (Aug. 16, 2010).

The presumption that the difference between audit results and the Company's records represents unauthorized attachments was agreed to by all parties in the Company's last rate proceeding. The parties included the Kentucky Cable Telecommunications Association ("KCTA"), of which Charter Communications is the largest member.[12] KCTA stipulated that the current Rate PSA "was fair, just, and reasonable" and would ensure "fair and uniform treatment of Attachments Customers." Mr. Crone fails to identify the intervening event that rendered this term of the existing Rate PSA unfair and unreasonable.

The presumption presently part of Term and Condition 14 recognizes the Company's limited control over attachment customers. Attachment customers can easily place attachments on to the Company's structures without the Company's authorization or notice. The Company does not have continuous surveillance on its poles and facilities to monitor attachments. Rate PSA, furthermore, allows the placement of some attachments without prior application or notice to the Company and relies upon the post-attachment reports to the Company regarding their placement.

The presumption also recognizes that the attachment customer has a far greater interest in ascertaining and documenting the location of its assets than the Companies. The attachments are a major asset of the attachment customer's business. Like any business owner, it has a strong business incentive to maintain and safeguard its property. A key facet of safeguarding one's property is to know its location.

[12] In his testimony, Mr. Crone states that Charter Communications has 96 percent of all cable pole attachments within LG&E and KU's service areas. Direct Testimony of Joseph H. Crone, III at 2.

This interest also includes maintaining records of attachment approvals and post-attachment reporting. An attachment customer has no right to attach its facilities to the Companies' structures without the Companies' approval. Good business practice and common sense dictate that as the attachment customer is placing its own property on structures belonging to an unrelated entity must protect its assets and business operations by maintaining documentary proof that such permission had been granted and the attachment have legal right to be located on the Companies' structures.

While Term and Condition 14 creates a presumption that the difference between the number of attachments found during an audit and those listed in the Companies' record represent unauthorized attachments, this presumption is rebuttable. An attachment customer will be provided adequate opportunity to question the results of an audit and to present evidence regarding its attachments that would require adjustments to the audit results.

Q. What protections will attachment customers have against incorrect or inaccurate attachment counts?

A. First, the Company will provide all attachment customers notice of the proposed audits and will allow attachment customers the opportunity to accompany the audit teams and observe them as they perform the audit. Throughout the audit, each attachment customer will be provided a detailed report of the audit's progress and findings, including the location of each audited attachment attributed to the attachment customer and GIS files that identify the location of the attachment customer's attachments. At the conclusion of the audit, each attachment customer will be provided a final report and GIS files.

After the attachment customer has reviewed the results, it will have the opportunity to meet the Company's representatives and identify any errors or inaccuracies and provide supporting evidence. The Company will consider this evidence and make appropriate adjustments. If an attachment customer is not satisfied with these adjustments, it may file a complaint with the Public Service Commission to contest the audit's results.

Q. What is your response to Mr. Crone's assertion that the revised Rate PSA has no mechanism or process for an attachment customer to verify the assessment of unauthorized attachments?

A. The Company is not proposing any change to the existing methodology for determining unauthorized attachments. This methodology was established in the Company's last rate case proceeding and was agreed to KCTA. This methodology does not require the Company to identify a specific attachment as authorized or unauthorized.

I have in response to a prior question described the process that will be followed to permit attachment customers to challenge the audit results. Each attachment customer will have the opportunity to demonstrate the number of attachments that have been authorized to be placed on the Company's structures. Each will be provided with the audit results, including the Company's detailed accounting of each attachment, including the location and number of each pole to which an attachment has been made. An attachment customer can compare this information to its own records and challenge the audit's findings regarding the total number of unauthorized attachments.

If an attachment customer is unsatisfied with the Company's action regarding its challenge to the audit results, KRS 278.260 and the Commission's Rules of Procedure provide a means to challenge the results before the Public Service Commission.

Q. Has the Company initiated an audit of the attachments to its structures?

A. Yes. The Company advised all affected attachment customers of the audit in October 2018, or 30 days prior to moving into the attachment customer's territory, and provided each attachment customer the opportunity to participate in the audit as an observer. Despite Mr. Crone's assertion that unauthorized attachments "typically result from inaccurate and faulty audits,"[13] Charter Communications declined to participate as an observer.

Allocation of Audit Costs

Q. Describe the proposed revision to Term and Condition 14 of Rate PSA as it relates to audit costs.

A. The Company has proposed to revise Term and Condition 14 to allow the direct assessment of attachment customers for the cost of any audit performed to verify the number, location and type of an attachment customer's attachments.

Q. How would the cost of an audit be allocated under this proposal?

[13] Direct Testimony of Joseph H. Crone, III at 7 (filed .Jan. 16, 2019).

A. Under the proposed revision, each attachment customer is assessed a portion of an audit's cost based on its number of attachments. For example, if the total cost of an audit of the Company's structures cost $5,000, and the audit finds that Attachment Customer A has 500 attachments, Attachment Customer B has 500 attachments, and Attachment Customer C has 1,000 attachments, then Attachment Customer A is assessed $1,250, Attachment Customer B is assessed $1,250, and Attachment Customer C is assessed $2,500.

Q. Why should an attachment customer be directly assessed the cost of such audits?

A. Requiring attachment customers to assume the cost of an audit is consistent with longstanding ratemaking practices. An audit is the functional equivalent of meter reading. It measures the attachment customer's use of the Company facilities much in the same way that an electric meter measures a customer's use of the Company's electricity. The costs related to meters and meter reading personnel and equipment have long been included in the rates for electric service. The audit benefits customers by ensuring that every attachment customer is paying only for the number of attachments it has made, and that no Attachment Customer is receiving unlawful favorable treatment by paying for less than the actual number of Attachments made to the Company's poles and structures.

Q. Do you agree with Mr. Crone's position that an attachment customer should only pay for the portion of the audit that directly concerns and benefits it?

A. I agree with it in principle. The attachment customer should be directly assessed only for the cost of audits whose purpose is to verify the ownership, number, location and type of attachments on the Company's structures. If the audit serves additional purposes, then the costs associated with those other purposes should not be included in a cost assessment. For example, one of the purposes of the audit that the Company began in October 2018 is to verify pole ownership. The portion of costs related to this purpose would not be recovered through a direct assessment of any attachment customer.

The audits that the Company plans to perform in the future are limited in scope to enabling the Company to bill attachment customers for their use of the Company's structures.[14] Information from these audits will generally consist only of the number, location and type of an attachment customer's attachments. These planned audits will not be used to conduct required maintenance and safety inspections of the Company's facilities. The Company already has separate and distinct programs and processes in place that perform these functions.

I do not agree with Mr. Crone's assertion that a portion of the audit expenses should be attributed to the Company because these audits gather "revenue collection information." His statement is analogous to asserting that an electric or gas or water utility should bear a portion of the wages for meter readers and the cost associated with metering equipment because those employees and that equipment are used to bill customers for service. As I noted earlier, obtaining accurate usage information to

[14] The Company's pole audit currently underway was competitively bid and priced such that the two components of the audit—verification of pole ownership and counting of attachments—can be fairly apportioned if the Commission approves the proposed revisions to Rate PSA to permit the direct assessment of the pro-rata costs of the audit to the Company's attachment customers. The Company will not seek reimbursement from its attachment customers for the portion of any audit related to pole ownership verification. If the Company collects additional data not related to attachment customers during a future audit, the audit will be priced so that the expenses for that additional data can be excluded prior to determining an attachment customer's pro rata share.

ensure accurate customer billing is a critical component of providing utility service and benefits the customer by ensuing accurate bills.

Moreover, the Company is only performing these audits because attachment customers have attached facilities to Company structures. There would be no need for the audits if there were no attachments. The purpose of this revision to Rate PSA is simply to ensure that the cost causer pays the costs that it causes, which is consistent with long standing ratemaking principles.

Surcharge on Repairs and Adjustments to Non-Compliant Attachments

Q. Describe the Company's proposed revisions to Term and Condition 8j of Rate PSA.

A. The Company proposes to revise Term and Condition 8j of the existing Rate PSA to allow for assessment of a 50 percent surcharge on the cost of repairs the Company performs to correct attachments that fail to meet the Company's electric design and construction standards and applicable requirements of the National Electric Safety Code and all other applicable codes and laws. This provision applies only when an attachment customer fails to repair a non-compliant attachment within 30 days after receiving written notice of the non-compliant standard from the Company. In other words, the attachment customer always has the opportunity to avoid the surcharge by first ensuring its facilities are built and maintained in accordance with applicable standards, and then by repairing its facilities within 30 days after receiving notice of non-compliant conditions from the Company.

Q. Why is the Company proposing these revisions?

A. The Company hopes to encourage attachment customers to adopt responsible maintenance practices and to promptly repair non-compliant attachments rather than delay or defer to the Company to perform repairs.

Rate PSA currently requires an attachment customer to correct or repair non-compliant attachments within 30 days after receiving written notice from the Company of the existence of the attachment. If the attachment customer fails to perform corrective measures within that time period, then the Company can intervene, perform the necessary repairs to return the attachment to compliance with applicable standards, and assess the attachment customer the cost of repair work. Currently attachment customers have no economic incentive to timely correct non-compliant attachments. The current Rate PSA imposes no penalty for failing to correct non-compliant attachments. As a result, attachment customers simply allow the non-compliant condition to continue until the Company intervenes. The proposed surcharge would make reliance on the Company less economically attractive to attachment customers and create an incentive for the attachment customer to undertake corrective actions before the Company intervenes.

Q. How do you respond to Mr. Crone's assertion that the proposed surcharge is unreasonable?

A. Mr. Crone asserts that the surcharge is unreasonable based on his contentions that no evidence supports the use of 50 percent as an appropriate incentive and because the Company has not established a process "to determine who caused any given out of specification condition, and thus who should properly bear the cost."

As to the reasonableness of the surcharge amount, it is clear that the amount must be of sufficient magnitude to encourage attachment customers to act. Where significant corrective repairs are required, the 50 percent surcharge will encourage attachment customers to act promptly and to perform the repairs or retain outside contractors to perform them. In this regard, its magnitude is consistent with achieving its stated goal. Again, it is important to note that an attachment customer has two opportunities to act before the surcharge would apply.

I disagree with Mr. Crone's assertion that as a condition to repairing a non-compliant attachment, a process must be established to determine who caused the non-compliant condition. The proposed surcharge is based upon the sound operating position that an attachment customer has a duty to keep its facilities in good repair and compliant with all applicable codes at all times and is not excused from this duty by the actions of a third party. If its attachment represents a risk to public or worker safety or to the reliability of the public's electric service because it is not in good repair, the attachment customer should meet its responsibility to correct the deficiencies and not foist its responsibilities off onto others.

Untagged Attachments

Q. Describe the Company's proposed revision to Term and Condition 8c.

A. The Company proposes to revise Term and Condition 8c to allow the assessment of any expenses that it actually incurs to identify the owner of an untagged attachment when it is required to relocate or remove that attachment or otherwise contact the attachment's owner to effect repairs and cannot readily identify the owner because the attachment is not clearly identified or tagged.

The Company further proposes that in those cases in which the untagged attachment must be removed, relocated, or altered and the owner cannot be immediately identified, the owner of the untagged attachment will be deemed to have received notice of the Company's intent to remove, relocate or alter the attachment upon the Company's inspection of the attachment and determination that it is untagged.

Q. Why is the Company proposing to assess the attachment owner for the costs incurred to locate the attachment owner?

A. To understand the reason for this proposal, some background is required. Term and Condition 8c of Rate PSA currently requires that all attachments be tagged. It, however, exempts from this requirement any attachments in place prior to July 1, 2017, the date on which Rate PSA became effective. Rate PSA requires the owners of these exempted attachments to tag those attachments as they perform work on them.

Term and Condition 8c represents a compromise reached in the Company's last rate proceeding. In that proceeding, the Company proposed that all attachments be tagged within six months of the effective date of the proposed Rate PSA. KCTA, of which Charter Communications is the largest member, opposed any requirement for a specific date on which all attachments must be tagged. The parties ultimately agreed to require attachment owners to tag their pre-existing attachments as they perform work on those attachments, including regular maintenance and inspections.

The proposed revision to Term and Condition 8c carries forward the compromise from the last rate case proceedings. An attachment owner remains free of a specific deadline by which it must locate and tag all attachments. However, to the extent that the Company incurs costs to identify an untagged attachment's owner when the untagged attachment must be repaired or relocated and the Company must contact that owner, the proposed revision places the costs directly resulting from the lack of tag upon the party that cause the cost rather than upon electric service customers or other attachment customers.

Attachment customers that have been diligent in tagging their facilities have no reason to fear the proposed revision. Charter Communications, for example, reports that it has tagged its fiber facilities since 1994, routinely inspects its facilities for the absence of tags and, when untagged facilities are found, tags the facility as part of its maintenance work.[15] Charter Communications, however, is not the only entity attaching its facilities to the Company's structures. There are currently 96 entities that attach their facilities to KU's structures; there are 20 entities that attached their facilities to LG&E's structures. Not all of these entities engage in the same practices as Charter Communications.

Q. Why does the Company propose to deem the notice period as being to run at the time of the discovery of the untagged attachment?

A. Term and Condition 16b provides: "Upon forty-five (45) days prior written notice delivered to Attachment Customer, Company may replace, relocate, or remove any Structure and cause the alteration, relocation or removal of any Attachment,

[15] Charter Communications Operating LLC's Response to Data Requests of Kentucky Utilities Company and Louisville Gas and Electric Company, Item 5 (filed Feb. 14, 2019). Charter Communications has acknowledged that it does not routinely tag its coaxial cable plant. ("Charter does not always tag its coaxial cable plant and other facilities because these facilities are distinctive and unique to Charter and other communications attachers recognize them as Charter's facilities without tags.")

consistent with normal operating, maintenance and development procedures and prudent utility practices."

Under normal circumstances, the Company can locate the owner of a tagged attachment in a relatively short period of time after determining the need for the replacement, removal, relocation or other action. As result, the Company can generally proceed with the proposed action within 45 days. In many cases, the proposed action affects the rights and operations of other attachment customers.

In the case of untagged attachments whose owners cannot be easily identified, the proposed action may be delayed a significant period if the 45-day notice period does not begin to run until after the untagged attachment's owner is located. This delay may significantly affect the Company's operations and those of other attachment customers. The Company proposes to mitigate this delay by allowing the notice period to begin at same time it would generally begin for the owner of a tagged and readily identifiable attachment. Neither the Company nor other attachment customers should suffer inconvenience or delay solely as result of another attachment customer's failure to tag its attachment.

Q. In his testimony, Mr. Crone argues that the proposed revisions are unreasonable, and the Company should instead establish a process to identify the cause of the untagged attachment and require the appropriate party to bear the costs and responsibility to correct the situation. What is your response?

A. I disagree. The reason that an attachment lacks a tag is of little concern when necessary maintenance work cannot be performed because the attachment's owner cannot be identified and notified. Operational efficiency and safety concerns require that all attachments be tagged. The current version of Term and Condition 8c recognizes this principle and places responsibility upon the attachment owner to properly tag its facilities. It is incumbent upon attachment owners to properly tag their attachments and to take steps to identify and tag their untagged attachments.

If an attachment lacks a tag and its owner cannot be readily identified, the Company must incur additional expense to ascertain the attachment's owner for valid operational reasons, including protecting the public safety or system reliability. In emergency situations, such as the power restoration efforts after a severe storm, the tags need to be there for first responders, mutual assistance crews, and other restoration workers. Assigning those types of expenses to the cost causer is entirely reasonable. Moreover, other attachment customers should not be inconvenienced nor have their operations unduly affected by unnecessary delays resulting from a prior decision not to tag attachments or a failure to properly tag those attachments.

Service Drops

Q. Describe the proposed revisions to Term and Condition 7i of Rate PSA regarding service drop attachments.

A. The Company proposes to revise Term and Condition 7i to permit inspections of service drop attachments and assess the cost of such inspections to the attachment customer.

Q. Mr. Crone has testified that no valid reason exists to inspect service drop attachment outside of a formal audit. Do you agree?

A. No. While safety concerns regarding service drop attachments will differ from the safety concerns regarding other types of attachments, there are still important issues regarding clearances and pole integrity.

Q. Will these inspections become, as Mr. Crone asserts, an opportunity to impose needless additional costs on attachment customers?

A. No. The Company has much higher priorities than to conduct needless inspections of service drops. It does, however, require the authority to conduct inspections when a reasonable basis exists, for example when an attachment customer is not complying with applicable standards on a widespread basis. If a reasonable basis for the inspection exists, then the Company's electric service customers should not be required to assume the cost of identifying non-conforming, unsafe, or unreasonable practices.

If the Company seeks to assess the cost of these inspections on an attachment customer, it would be required under the proposed revision to articulate a reasonable basis for the inspection. If it fails to do so, an attachment customer can dispute the assessment and submit a complaint regarding the assessment to the Public Service Commission.

Q. Do you have a recommendation?

A. Yes. I recommend that the proposed revisions to Rate PSA be accepted in their entirety. Acceptance of these revisions will ensure that proper incentives are provided to attachment customers, promote the public safety, and protect and enhance the reliability of service to the Company's customers.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

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

John K. Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public (SEAL)

My Commission Expires:

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

APPENDIX A

John K. Wolfe
Vice President, Electric Distribution
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4312

Education

Bachelors in Mechanical Engineering, University of Louisville, May 1991
Graduate work in Mechanical Engineering, University of Louisville, 1991
Gas Distribution Engineering, Institute of Gas Technology, 1993
Graduate work in Business Administration, Bellarmine College, 1994-1995
E.ON Emerging Leaders Program, London Business School, 2003-2004

Professional Experience

LG&E and KU Services Company

Vice President, Electric Distribution	Jan. 2015 – Present
Director, Electric Sys. Restoration and Dist.	Feb. 2013 – Jan. 2015
Director, Operations	Nov. 2010 – Feb. 2013

E.ON U.S. LLC

Director, Operations	Mar. 2010 – Nov. 2010

Louisville Utilities Company

Manager, Operations Center	Feb. 2000 – Mar. 2010
Manager, Gas Service Center	Sep. 1997 – Feb. 2000
Group Leader Engineering and Planning	Jan. 1997 – Sep. 1997
Mechanical Engineer II	Sep. 1993 – Jan. 1997
Main Replacement Program Manager	May 1996 – Jan. 1997
Operations Auditor	Dec. 1994 – May 1996
Distribution Engineering	Sep. 1993 – Dec. 1994
Mechanical Engineer I	Jul. 1991 – Sep. 1993
Co-Op Student	Aug. 1989 - May 1991

Professional Memberships

American Society of Heating, Refrigerating and Air-Conditioning Engineers - 1991-1994
American Society of Mechanical Engineers - 1991-1994

Civic Activities

Juvenile Diabetes Research Foundation Board of Directors - 2005-2008
Leadership Kentucky - Class of 2010
High School Athletics Coach - 2007-Present
Great Lakes Mutual Assistance Group Officer - 2013-2016
Southeastern Electric Exchange Mutual Assistance Officer - 2014-2016
Edison Electric Institute Mutual Assistance and Emergency Preparedness Officer - 2015-Present
National Mutual Assistance Resource Allocation Team Officer – 2014-Present
American Red Cross Board Member - 2016-Present
Southeastern Electric Exchange Board Member - 2016-Present

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
GREGORY J. MEIMAN
VICE PRESIDENT, HUMAN RESOURCES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

Q. Please state your name, position and business address.

A. My name is Gregory J. Meiman. I am Vice President, Human Resources for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"), (collectively, the "Companies") and an employee of LG&E and KU Services Company ("Service Company"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to: (1) respond to that portion of Attorney General witness Donna Mullinax's testimony recommending a disallowance of certain retirement benefits; (2) respond to that portion of Kentucky Industrial Utility Customers witness Lane Kollen's testimony recommending a disallowance of certain retirement benefits; and (3) provide my recommendation to the Commission.

Q. Please summarize Ms. Mullinax's recommended disallowance of certain retirement benefits.

A. Ms. Mullinax recommends disallowance of any amounts contributed by the Companies to employees' 401(k) accounts to the extent those employees are eligible to receive a monthly pension benefit upon retirement from the Companies' defined benefit plan ("DB Plan"). She relies on the Commission's decisions in the Companies' 2016 rate cases[1] which disallowed those 401(k) matching contribution amounts for certain employees. She also responds to four arguments the Companies have made in support of recovery of those amounts.

[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371.

Q. Do you believe that Ms. Mullinax's reliance on the Commission's decision in the Companies' 2016 rate cases to disallow rate recovery of 401(k) matching contributions to DB Plan participants is misplaced?

A. Yes. As I explained in my direct testimony, we respectfully ask the Commission to reconsider its decision on this issue. Further, we believe the Commission's subsequent decision on the same issue in a recent Duke Energy case[2] ("Duke Energy") means that Ms. Mullinax's reliance on the Companies' 2016 cases is misplaced. In Duke Energy, the Commission reached a different decision than it reached in the Companies' 2016 rate cases. In *allowing* recovery of 401(k) matching contributions to those already participating in a *separate* pension plan (and over the same Attorney General objection Ms. Mullinax makes in the current case), the Commission stated:

> Duke Kentucky states that it has aggressively managed costs related to its retirement benefits program by closing the DDB pension plans to new hires, and, for existing employees, lock and freezing final average pay benefit formulas for all non-union employees and transitioning those employees from a final average pay formula to a more "Defined Contribution like" cash balance benefit formula. Lastly, Duke Kentucky asserts that its benefits packages, including retirement programs, as a whole are designed to be market competitive and are benchmarked to ensure that is the case.
>
> The Commission is in partial agreement with Duke Kentucky on this issue and concludes that Duke Kentucky's retirement plan expense should be *accepted as proposed*.[3]

[2] *In the Matter of: Application of Duke Energy Kentucky, Inc., for: (1) An Adjustment of the Electric Rates; (2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; (3) Approval of New Tariffs; (4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) All Other Required Approvals and Relief*, Case No. 2017-0031.

[3] Case No. 2017-000321, April 13, 2018 Order, pp. 22-23 (emphasis added).

Thus, in Duke Energy, the Commission allowed rate recovery of 401(k) matching contributions based on the following: (1) Duke Energy had aggressively managed its retirement plan costs; (2) some Duke Energy employees were transitioned to a "cash balance benefit formula"; and (3) Duke Energy's overall benefits package, including its retirement programs, are as a whole designed to be market competitive.

Q. Have the Companies aggressively managed their retirement plan costs similar to Duke Energy?

A. Yes. The Companies have not locked, frozen and replaced their DB Plan for a portion of employees like Duke Energy did. Instead, as I explained in my direct testimony, in 2005, the Companies closed or "locked" their DB Plan to *all* new entrants – both union and non-union employees -- for anyone hired (or rehired) after December 31, 2005.[4] This means that there have been no new participants eligible for the DB Plan for over thirteen years. It also means that the number of eligible participants in the DB Plan began decreasing in 2006, has been decreasing continuously since then, and will eventually reach zero. In fact, since the Companies closed their DB Plan to all new employees, approximately 47% of those participating in the DB Plan have left the Companies. Of those remaining, the average age is approximately 54 years with approximately 28 years of experience. In sum, although a portion of the employee population was grandfathered in a traditional defined

[4] Duke Energy did not close its DB Plan to new entrants until 2014, some eight years *later* than the Companies took that same action. See the September 1, 2017 direct testimony of Duke Energy witness Thomas Silinski in Case No. 2017-000321, p. 39, where Mr. Silinski states, "Duke Energy closed its pension plans to non-union new hires in 2014, and has since negotiated closing pension participation for new hires for all union groups."

benefit, all new participants were placed in the new defined contribution structure starting in 2006.

I also testified[5] that: (1) the Companies' respective defined benefit plans were merged in 2000 as a way to save on administrative costs; (2) in 2013 and again in 2014, the Companies offered voluntary lump-sum elections rather than a monthly benefit; and (3) in 2016, the Companies amended their DB Plan to make lump sum elections instead of a monthly benefit a permanent feature. These measures have effectively saved retirement plan expense and reduced employer risk. And they are similar to the measures the Commission found meaningful in its Duke Energy decision.

Q. Have the Companies transitioned any of their employees from their existing DB Plan to a "cash balance pension formula" like Duke Energy?

A. No, but that is a distinction without a difference. Simply transitioning employees from a traditional defined benefit formula to a cash balance pension formula does not necessarily equate to a benefit plan equal to a 401(k) plan. The Department of Labor has stated: "Cash balance plans are defined benefit plans." [6] Further, the Department of Labor has emphasized the characteristics of a cash balance plan:

> There are four major differences between typical cash balance plans and 401(k) plans:
>
> a. Participation - Participation in typical cash balance plans generally does not depend on the workers contributing part of their compensation to the plan; however, participation in a 401(k) plan does depend, in whole or in part, on an employee choosing to make a contribution to the plan.

[5] See my direct testimony, pp. 17-18.

[6] *Cash Balance Pension Plans*, U.S. Department of Labor, Employee Benefits Security Administration, January 2014 (copy attached hereto as Exhibit A).

> b. Investment Risks - The investments of cash balance plans are managed by the employer or an investment manager appointed by the employer. *The employer bears the risks of the investments*. Increases and decreases in the value of the plan's investments do not directly affect the benefit amounts promised to participants. By contrast, 401(k) plans often permit participants to direct their own investments within certain categories. Under 401(k) plans, participants bear the risks and rewards of investment choices.
>
> c. Life Annuities - Unlike 401(k) plans, cash balance plans are required to offer employees the ability to receive their benefits in the form of lifetime annuities.
>
> d. Federal Guarantee - Since they are defined benefit plans, the benefits promised by cash balance plans are usually insured by a federal agency, the Pension Benefit Guaranty Corporation (PBGC). If a defined benefit plan is terminated with insufficient funds to pay all promised benefits, the PBGC has authority to assume trusteeship of the plan and to begin to pay pension benefits up to the limits set by law. Defined contribution plans, including 401(k) plans, are not insured by the PBGC. [7]

So although a cash balance pension plan is a different method of calculating a defined retirement benefit, all of the major risks, specifically investment and mortality, borne by the employer offering a traditional defined benefit plan are likewise borne by the employer in the cash balance pension plan context. Just as the cash balance is another type of defined benefit formula, the defined benefits grandfathered by the Companies are expressed in different formulas which produce the benefits upon which employees have planned.

Additionally, the mere fact that some of the Companies' employees will receive a retirement benefit comprised of two funding sources is not the most

[7] *Cash Balance Pension Plans*, U.S. Department of Labor, Employee Benefits Security Administration, January 2014 (emphasis added)(copy attached hereto as Exhibit A).

important question. The crux of the matter is whether the total amount received by an employee is reasonable. Moreover, if the benefit is reasonable, it is accomplishing the larger goal of cost-effectively managing the workforce that is diverse in its composition when looking at tenure of the participants. When it is reasonable, the Commission has approved recovery of that total even if it comes from more than one funding source as shown in its Duke Energy decision.

Just as the Duke Energy witness correctly testified, “I believe that the value of the Company’s retirement benefit is what is important, rather than whether the Company chooses to deliver the value through multiple components. A one dollar bill has equal value to four quarters even though they are denominated in different forms.”[8] That argument was important to the Commission in allowing rate recovery of 401(k) matching contributions for employees who also receive a defined retirement benefit from another funding source. I share Duke Energy’s belief on this point and I further believe the Commission should reach the same conclusion in this case.

Finally, it should be noted that based upon the data provided in my direct testimony from Willis Towers Watson,[9] elimination of the 401(k) matching benefit for those employees grandfathered in the DB Plan leads to the perverse result that those employees with greater experience and service would receive a lesser valued retirement benefit than those hired after December 31, 2005. I do not accept the proposition that it is desirable to manage our commitments to the workforce in this manner.

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[8] Case No. 2017-00321, February 14, 2018 Rebuttal Testimony of Thomas Silinski, p. 9.
[9] See my direct testimony, p.22.

Q. Is the Companies' overall benefits package, including its retirement programs, designed to be market competitive like Duke Energy's?

A. Yes. Like Duke Energy, the Companies have submitted ample evidence that their overall benefits package, including retirement benefits, are consistent with market. I described the Mercer Benefits Study[10] in detail in my direct testimony. The most important findings Mercer reached are: (1) the Companies' total package of benefits is aligned with utility market medians; (2) all organizations in the Mercer Study that sponsor an ongoing DB Plan also provide 401(k) matching contributions; [11] (3) it is important to measure the level of benefits offered in the aggregate as benefit plans are designed holistically rather than in finite parts; and (4) it is also important to examine benefit levels in the context of total remuneration (compensation and benefits) as benefits and compensation are designed in tandem.

Q. Did Ms. Mullinax acknowledge the existence of the Commission's decision in Duke Energy?

A. No, she did mention it at all. For his part, Mr. Kollen acknowledges that the Commission subsequently addressed the same issue in the Duke Energy case, and concedes that, "it is not clear if, or if so, how the decision in the Duke case may affect the issue or the quantification of the issue in this proceeding."[12]

[10] The Mercer Benefits Study is attached to the Companies' Applications at Tab 60, Attachment 4.
[11] See Application, Tab 60, Attachment 4, p. 6 of 13.
[12] Kollen Direct, p. 46.

Q. You mentioned that Ms. Mullinax offers four arguments[13] in response to the Companies' arguments in favor of recovery of the 401(k) matching amounts. Do you agree with any of her four arguments?

A. No. Each is flawed.

Q. Please summarize her four arguments.

A. First, Ms. Mullinax argues that benefits packages should not be considered holistically. Second, while admitting that she is not a "benchmarking research analyst,"[14] she argues that the Mercer Benefits Study is not convincing because the comparator group Mercer used is inappropriate. Third, she argues that the Companies' efforts to control the cost of benefits are not extensive enough to justify recovery of the 401(k) matching expense. Fourth, she argues that the Companies' position on this issue shows a "misunderstanding of the Companies' responsibility."

Q. As to her first argument, should benefits packages be considered holistically?

A. Of course they should, because that is exactly the way employees and employers assess employment considerations in the real world. By their very nature, the components of total remuneration (compensation, welfare benefits, and retirement benefits) are all important considerations when employment decisions are made. At any single point in time, one particular aspect (or sub-aspect) of total remuneration might be less than market or more than market. But in the Companies' experience, existing and prospective employees will assess total remuneration in deciding whether to accept an employment offer from the Companies and whether to continue

[13] Ms. Mullinax's four arguments are set forth at pp. 27 – 31 of her testimony.

[14] See Attorney General's February 14, 2019 Response to Question 4 of the Companies' Data Requests to the Attorney General.

employment with the Companies. For example, if compensation is less than what can be earned elsewhere, but vacation benefits are more generous, employees may accept that "trade-off."

The Companies agree that all utility expenses should be maintained at fair, just, and reasonable levels. In the area of employment costs, given the constraints associated with modifying retirement benefits and the practicalities of managing a 3600-member workforce, it is both appropriate and necessary to evaluate total remuneration. Employers and employees do just that both within and outside of the regulated utility model. Finally, of course, the Companies' employment market place expert, Mercer, has opined[15] that:

> When evaluating benefits programs, it is important to look at positioning in aggregate across all benefits and employee levels, as benefit plans are designed holistically and not in finite parts. Furthermore, it is also important to view benefits in context of total remuneration (cash + benefits), as compensation and benefits should be designed and assessed in tandem.

Q. As to her second argument, did Mercer use an appropriate comparator group in its study?

A. Yes, Mercer did. Ms. Mullinax criticizes the entities used in populating Mercer's comparator group because some are west of the Mississippi River, some are west of the Rocky Mountains, some are in the Northeast, and some are not equal in size to the Companies. Mercer used its "standard peer group development process"[16] in formulating the comparator group. In that process, entities were selected based on

[15] See Application, Tab 60, Attachment 4, p. 4 of 13.
[16] See Application, Tab 60, Attachment 4, p. 2 of 13.

their similar customer size to the Companies, a local presence, or both.[17] Thus, local entities were used where possible, but the reality is that Kentucky simply does not have enough entities of similar size to the Companies to form a sufficient sample group size. Therefore, the group was scoped to include utilities with one-third to three times the customer base of the Companies, with as many local entities included as possible.[18] Finally, Mercer used utilities because, "It is Mercer's best practice to evaluate benefits against organizations most similar to the client. Thus, utility companies are the most similar to [the Companies] and are the primary market comparison."[19]

As part of her argument on this point, Ms. Mullinax claims that the Companies can use more local employment data when they choose to as evidenced by the Companies' use of more localized data when they adjusted compensation for call center employees to address a turnover problem. This is comparing apples to oranges. For large scale compensation or benefits studies used to measure a large portion of the Companies' employee population, widespread data must be used for a robust and meaningful sample size. For call center employees, whose initial hiring qualifications are more basic and fungible, and for whom heightened elasticity exists in response to a relative minor compensation adjustment, the Companies were able to obtain and use more localized data and still achieve meaningful comparison results.

[17] See the response to KU AG 1-120 and LGE AG 1-120.
[18] See the response to KU AG 2-48 and LGE AG 2-48.
[19] See Application, Tab 60, Attachment 4, p. 2 of 13.

Q. As to Ms. Mullinax's third argument, do you agree that the Companies' efforts to control the cost of employee benefits are not sufficient to justify rate recovery of 401(k) matching contributions for those in the DB Plan?

A. No, not at all. Contrary to Ms. Mullinax's argument on this point, the Commission seems to have placed great importance on Duke Energy's cost control efforts. As discussed above, the Companies have made similar cost control efforts for its retirement benefits. In fact, as to the decision to close the DB Plan to new entrants (for both union and non-union employees), the Companies did so eight years before Duke Energy did, and, therefore, reduced costs to customers for a much longer period of time.

Q. As to Ms. Mullinax's fourth argument, do you agree that the Companies have a misunderstanding of their responsibility to control retirement benefits cost?

A. Of course not. Her argument appears to be that the Companies should have immediately ceased 401(k) matching contributions for DB plan participants as a result of the Commission's decision in the Companies' 2016 rate cases. Ms. Mullinax fails to understand what is required to hire and maintain a workforce sufficient to provide safe, adequate, and reliable service.

After the decision in the Companies' 2016 rate cases and in preparation for the current cases, the Companies: (1) commissioned a robust study prepared by leading expert Willis Towers Watson to measure the entire compensation package against market which found total compensation to be at market;[20] (2) commissioned a robust study by leading expert Mercer to measure the entire benefits package against

[20] See Application, Tab 60, Attachment 3.

market which found that package to be at market;[21] (3) developed data on the effects of its retirement cost control efforts as a percentage of pay;[22] (4) have continued to implement various welfare benefit cost control measures discussed in my direct testimony); and (5) have been guided by the Commission's decision in the Duke Energy case which was decided less than ten months after the Commission decided the Companies' 2016 cases. Thus, the Companies have provided proof of the reasonableness of their compensation and benefit offerings and of their benefit cost control measures. Against the backdrop of the Commission's Duke Energy decision and in the interest of being fair to employees, the Companies' course of action since their 2016 cases has been the correct and reasonable one.

While it is the Companies' responsibility to control costs to achieve fair, just, and reasonable rates, the Companies are also responsible for providing safe, adequate, and reliable service. Of course, an adequate workforce is critical in meeting that obligation. And despite what Ms. Mullinax argues, the Companies have an obligation to treat their employees fairly. Welfare benefits can be adjusted more readily and the Companies have done just that. Retirement benefits, on the other hand, are much more difficult to change for many reasons, including legal requirements and the fact that employees have based major life decisions on the availability of those benefits.

Q. You mentioned that Mr. Kollen also proposed a disallowance of 401(k) matching contributions for DB Plan participants. Do you agree with his recommendation?

A. No. The sole basis for Mr. Kollen's recommendation on this point is the Commission's decision in the Companies' 2016 rate cases. He provides no

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[21] See Application, Tab 60, Attachment 4.
[22] See my direct testimony, p. 22.

affirmative analysis to support his recommendation. In fact, Mr. Kollen explicitly recognizes that the Duke Energy decision could impact this issue.[23] For all the reasons set forth above, we believe the decision on this issue should be different in the Companies' current cases, especially in light of the Duke Energy decision.

Q. Do you have a recommendation for the Commission?

A. Yes. My recommendation continues to be the same as set forth in my direct testimony in that I recommend the Commission permit full rate recovery for the Companies' compensation and benefits expense. We have shown those expense levels to be reasonable, supported by robust studies, and upon examination, there is nothing in intervenor testimony that would lead to a contrary result.

Q. Does this conclude your testimony?

A. Yes, it does.

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[23] Kollen Testimony, p. 46, fn. 46.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Vice President, Human Resources for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gregory J. Meiman

Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public

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

Cash Balance Pension Plans

U. S. Department of Labor
Employee Benefits Security Administration
January 2014

What is a Cash Balance Plan?

There are two general types of pension plans — defined benefit plans and defined contribution plans. In general, defined benefit plans provide a specific benefit at retirement for each eligible employee, while defined contribution plans specify the amount of contributions to be made by the employer toward an employee's retirement account. In a defined contribution plan, the actual amount of retirement benefits provided to an employee depends on the amount of the contributions as well as the gains or losses of the account.

A cash balance plan is a defined benefit plan that defines the benefit in terms that are more characteristic of a defined contribution plan. In other words, a cash balance plan defines the promised benefit in terms of a stated account balance.

How do Cash Balance Plans work?

In a typical cash balance plan, a participant's account is credited each year with a "pay credit" (such as 5 percent of compensation from his or her employer) and an "interest credit" (either a fixed rate or a variable rate that is linked to an index such as the one-year treasury bill rate). Increases and decreases in the value of the plan's investments do not directly affect the benefit amounts promised to participants. Thus, the investment risks are borne solely by the employer.

When a participant becomes entitled to receive benefits under a cash balance plan, the benefits that are received are defined in terms of an account balance. For example, assume that a participant has an account balance of $100,000 when he or she reaches age 65. If the participant decides to retire at that time, he or she would have the right to an annuity based on that account balance. Such an annuity might be approximately $8500 per year for life. In many cash balance plans, however, the participant could instead choose (with consent from his or her spouse) to take a lump sum benefit equal to the $100,000 account balance.

If a participant receives a lump sum distribution, that distribution generally can be rolled over into an IRA or to another employer's plan if that plan accepts rollovers.

The benefits in most cash balance plans, as in most traditional defined benefit plans, are protected, within certain limitations, by federal insurance provided through the Pension Benefit Guaranty Corporation.

How do Cash Balance Plans differ from traditional pension plans?

While both traditional defined benefit plans and cash balance plans are required to offer payment of an employee's benefit in the form of a series of payments for life, traditional defined benefit plans define an employee's benefit as a series of monthly payments for life to begin at retirement, but cash balance plans define the benefit in terms of a stated account balance. These accounts are often referred to as "hypothetical accounts" because they do not reflect actual contributions to an account or actual gains and losses allocable to the account.

How do Cash Balance Plans differ from 401(k) plans?

Cash balance plans are defined benefit plans. In contrast, 401(k) plans are a type of defined contribution plan. There are four major differences between typical cash balance plans and 401(k) plans:

a. **Participation -** Participation in typical cash balance plans generally does not depend on the workers contributing part of their compensation to the plan; however, participation in a 401(k) plan does depend, in whole or in part, on an employee choosing to make a contribution to the plan.
b. **Investment Risks -** The investments of cash balance plans are managed by the employer or an investment manager appointed by the employer. The employer bears the risks of the investments. Increases and decreases in the value of the plan's investments do not directly affect the benefit amounts promised to participants. By contrast, 401(k) plans often permit participants to direct their own investments within certain categories. Under 401(k) plans, participants bear the risks and rewards of investment choices.
c. **Life Annuities -** Unlike 401(k) plans, cash balance plans are required to offer employees the ability to receive their benefits in the form of lifetime annuities.
d. **Federal Guarantee -** Since they are defined benefit plans, the benefits promised by cash balance plans are usually insured by a federal agency, the Pension Benefit Guaranty Corporation (PBGC). If a defined benefit plan is terminated with insufficient funds to pay all promised benefits, the PBGC has authority to assume trusteeship of the plan and to begin to pay pension benefits up to the limits set by law. Defined contribution plans, including 401(k) plans, are not insured by the PBGC.

Is there a federal pension law that governs these plans?

Yes. Federal law, including the Employee Retirement Income Security Act (ERISA), the Age Discrimination in Employment Act (ADEA), and the Internal Revenue Code (IRC), provides certain protections for the employee benefits of participants in private sector pension plans.

If your employer offers a pension plan, the law sets standards for fiduciary responsibility, participation, vesting (the minimum time a participant must generally be employed by the employer to earn a legal right to benefits), benefit accrual and funding. The law also requires plans to give basic information to workers and retirees. The IRC establishes additional tax qualification requirements, including rules aimed at ensuring that proportionate benefits are provided to a sufficiently broad-based employee population.

The Department of Labor, the Equal Employment Opportunity Commission (EEOC), and the IRS/Department of the Treasury have responsibilities in overseeing and enforcing the provisions of the law. Generally, the Department of Labor focuses on the fiduciary responsibilities, employee rights, and reporting and disclosure requirements under the law, while the EEOC concentrates on the portions of the law relating to age discriminatory employment practices. The IRS/Department of the Treasury generally focuses on the standards set by the law for plans to qualify for tax preferences.

Are there requirements that apply if my employer converts my current plan to a Cash Balance Plan?

Yes; however, employers are not required to establish pension plans for their employees because the private pension system is voluntary. In addition, employers are allowed substantial flexibility in deciding whether to terminate or amend their existing plans. Therefore, employers generally may change by plan amendment their traditional pension plans and the benefit formulas they use.

Federal law does place restrictions on plan changes generally. For example, advance notification to plan participants is required if, as a result of the amendment, the rate that plan participants may earn benefits in the future is significantly reduced. Additionally, there are other legal requirements that have to be satisfied, including prohibitions against age discrimination. In addition, while employers may amend their plans to cease future benefits or reduce the rate at which future benefits are earned, they generally are prohibited from reducing the benefits that participants have already earned. In other words, an employee generally may not receive less than his or her accrued benefit under the plan formula at the effective date of the amendment. For example, assume that a plan's benefit formula provides a monthly pension at age 65 equal to 1.5 percent for each year of service multiplied by the monthly average of a participant's highest three years of compensation, and that the plan is amended to change the benefit formula. If a participant has completed 10 years of service at the time of the amendment, the participant will have the right to receive a monthly pension at age 65 equal to 15 percent of the monthly average of the participant's highest three years of compensation when the plan amendment is effective. This pre-amendment benefit (including related early retirement benefits) is protected by law and cannot be reduced.

In addition, there are additional restrictions that apply specifically in the case of an amendment that converts a plan formula to a cash balance plan formula. Specifically, participants must receive the sum of the pre-amendment benefit plus benefits under the new cash balance formula (as a result, there cannot be a “wear away” period during which the participant does not accrue additional benefits, as could occur if participants were merely entitled to the greater benefit). Furthermore, all benefits under a cash balance plan (including benefits accrued prior to a conversion) must be fully vested after 3 years of service.

What happens to the assets in a plan when an employer converts its traditional defined benefit plan formula to a Cash Balance Plan formula?

When an employer amends its plan to convert the plan's traditional defined benefit plan formula to a cash balance plan formula, the plan's assets remain intact and continue to back all of the pension benefits under the plan. Employers cannot remove funds from the plan, unless the plan has been terminated and has assets remaining after payment of all of the benefits under the plan.

How am I affected if I leave my job at a company that just changed its pension plan from a traditional defined benefit formula to a Cash Balance Plan formula?

If you have worked long enough to be vested under the plan, you should receive the sum of (1) the accrued benefit under the formula in effect before the amendment, and (2) the additional benefits (see response to question 6 above) you earned under the plan formula in effect after the amendment. However, you may have to wait until a retirement age under the plan to receive your benefit.

Is my employer required to give me a choice of remaining under the old formula rather than automatically switching me to the new Cash Balance Plan formula?

Neither ERISA nor the IRC requires employers to give employees the choice of remaining in the old formula. Employers have several options, including:

a. Providing no choice, replacing the old formula and applying the new formula to all participants.
b. Allowing employees to remain under the old formula, while restricting new hires to the new formula
c. Stipulating that certain employees who have reached a specific length of service or who have reached a certain age may choose to stay with the old formula

The law permits employers to have such flexibility, but whatever option applies has to satisfy legal requirements.

Under each of these options, benefits already earned by the participants, as of the effective date of the amendment that converts the old formula to a cash balance formula, may not be reduced.

What information is my employer required to give me to explain the new Cash Balance Plan formula, and when should I receive this information?

Many employers voluntarily provide helpful information about these conversions in advance of the change becoming effective. Make sure you have all the information that the employer has provided. If you are still not sure if you have enough information to understand the plan change, you have a right to contact your plan administrator and ask for more information or help in understanding the change and any choices you have in conjunction with the change.

Plan administrators are generally required to give at least 45 days' advance notice of plan amendments that significantly reduce the rate at which plan participants earn benefits in the future.

After the plan is amended, the plan administrator is required to provide all plan participants with a Summary of Material Modifications to the plan or a revised Summary Plan Description. This document will summarize the changes to your plan.

In addition, under the Age Discrimination in Employment Act (ADEA), an employer requiring an employee to sign a waiver of rights and claims when choosing between plans is required to provide enough information to enable the employee to make a knowing and voluntary decision to waive ADEA rights. In most cases, an employee must be given at least 21 days to sign the waiver and at least 7 days to revoke the agreement.

Will the conversion of my pension plan formula have an effect on my retiree health benefits?

Often, pension plans and health plans are operated independently and are administered separately. However, sometimes eligibility for retiree health benefits depends upon eligibility for pension benefits. If you have questions about your health benefits you should contact your health plan administrator. Be aware that, like pension plans, health plans generally can be amended or terminated.

What should I do if I believe my benefits under the old formula have been inappropriately reduced or that my rights have been violated?

You should immediately contact the plan administrator and discuss your concerns. Be sure to review your individual benefit statement or the information used to calculate your benefit to determine if it is correct — such as employment date, length of service, and salary.

If your concerns are not adequately addressed, or you still have questions about your situation, you should contact one of our offices.

In addition, employees who believe that they have been subject to discriminatory treatment because of their age, race, color, religion, sex, national origin, or disability may file a charge of discrimination with the Equal Employment Opportunity Commission (EEOC).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

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Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E) (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut certain arguments made in the direct testimony of intervenors in this case. Specifically, I will explain that (1) the Kentucky Industrial Utility Customers, Inc.'s ("KIUC") witness Mr. Kollen's adjustment to long-term debt is unreasonable; (2) Mr. Kollen's adjustment to normalize transmission and distribution capital expenditures is unwarranted and would disallow the recovery of prudently incurred expenditures; (3) the KIUC and United States Department of Defense ("USDOD") proposals to extend the depreciable lives of the coal-fired generating units is not prudent, (4) the Attorney General's ("AG") witness Ms. Mullinax's adjustment to directors and officers liability expense would deprive the Companies from recovering the costs of an ordinary business expenditure; (5) Ms. Mullinax's adjustment to reduce outside counsel expense is unreasonable; (6) the Sierra Club's witness Mr. Fisher's testimony regarding OVEC debt is inaccurate and misrepresents the Companies' obligations; and (7) provide a copy of the most recently issued Regulatory Research Associates report regarding returns on equity.

<u>Long-Term Debt</u>

Q. Please summarize Mr. Kollen's adjustment to the Companies' long-term debt.

A. The Companies have forecast long-term debt issuances that will occur no later than May 2019. KU is expected to have a 30-year debt issuance of $300 million, and LG&E a 30-year debt issuance of $500 million. In addition to a credit spread of 1.25%, the Companies included a forecast rate of 3.65% for the 30-year Treasury yield in calculating the weighted average cost of long-term debt for these issuances. Mr. Kollen has proposed an adjustment to use the 30-year Treasury yield as of January 10, 2019 in calculating the costs associated with the projected issuance, which was 3.0%.[1] Mr. Kollen alleges that this adjustment is appropriate because Treasury yields have fallen since the Companies filed their cases.

Q. Do you agree with Mr. Kollen's adjustment?

A. No, as Mr. Kollen's adjustment is unreasonable. The Treasury yield is not fixed and changes daily. Mr. Kollen offers no evidence that the January 10, 2019 Treasury yield bears any relationship to the forecast Treasury yields in May 2019. As such, the 3.0% yield on January 10, 2019 is an arbitrarily selected date that is not reflective of known and measurable conditions. Mr. Kollen's selected yield is already stale given that the yield moves daily. Mr. Kollen admitted in response to Commission Staff's data request that the yield may change before publication of the final orders in these proceedings.[2]

Q. Can you further describe the volatility in the 30-year Treasury yields?

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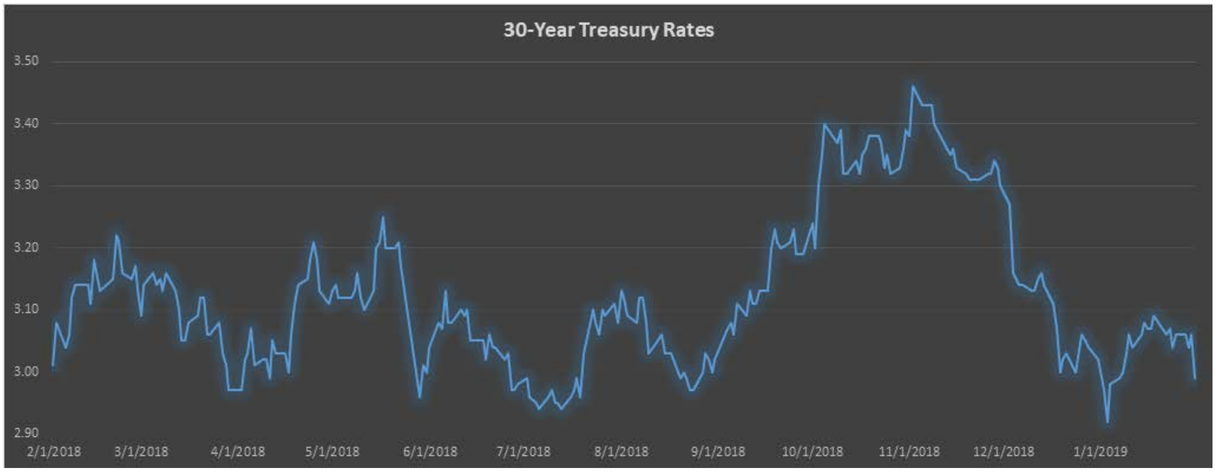
[1] Direct Testimony and Exhibits of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. ("Kollen Direct") dated January 2019 at 52.

[2] See the response to Question No. 3 from Commission Staff to KIUC.

A. Certainly. The Treasury yields have experienced material volatility in the last year. The graphic below shows the 30-year yields from February 1, 2018 through January 31, 2019.



Q. How did the Companies forecast the 3.65% Treasury yield for May 2019 debt issuances?

A. Rather than selecting the yield on any specific date, the Companies analyzed the expected trends in the yield between the date of the Companies' rate case filing and May 2019. Most significantly, the Companies considered that the Federal Reserve was expected to raise the federal funds target rate twice between the Companies' rate case filing and May 2019. The Companies obtained forecasted 30-year treasury yields from several banks in arriving at the 3.65% rate used in the filing. As can be seen from the above graph, interest rates declined unexpectedly by .60% during November and December and recent volatility suggests they could rise by that amount between now and the expected May bond issuance. As such, the Companies continue to believe their forecast of 3.65% is reasonable.

Q. Is there another reason that Mr. Kollen's adjustment is unreasonable?

A. Yes. While Mr. Kollen proposes utilizing the Treasury yield from January 10, 2019, he does not propose a similar adjustment for the credit spread that has generally increased since the Companies' rate case filing. The Companies utilized a credit spread of 1.25% for the long-term debt to be issued in May 2019, but credit spreads have also been very volatile in recent months. Investment grade utility spreads have been as low as .85% to as high as 1.45% in the past year. It is unreasonable and results-oriented to only propose an adjustment to the portion of debt costs that Mr. Kollen believes to be declining, while ignoring the other key component of the interest rate the Companies will ultimately pay. For these reasons, I recommend that Mr. Kollen's adjustment be denied.

Transmission and Distribution Capital Expenditures

Q. Please summarize Mr. Kollen's adjustment to normalize transmission and distribution capital expenditures.

A. Mr. Kollen recommends that the Commission normalize the forecast transmission and distribution capital expenditures based on the average of the Companies' inflation-adjusted actual transmission capital expenditures for 2014 through 2017.[3] Mr. Kollen alternatively proposes that the Commission normalize the forecast transmission and distribution capital expenditures based on the Companies' actual 2017 capital expenditures.[4]

Q. Do you agree with Mr. Kollen's adjustment?

A. No, because it is an extreme position that directly conflicts with the Commission's treatment of normalization adjustments and is antithetical to the use of a forward-

[3] Kollen Direct at 20.
[4] *Id.*

looking test year. The Commission has correctly disfavored normalization adjustments because they are susceptible to manipulation, argument and subjectivity. Mr. Kollen's proposed adjustment is particularly unreasonable given that he does not contest any aspect of the Companies' budgeting process that led to the forecasted expenditures or any of the individual transmission and distribution projects in the budget.

Q. Would normalizing transmission and distribution capital expenditures be comparable to the other kinds of normalization adjustments the Commission has approved?

A. No. There are only two normalization adjustments the Commission has approved in electric rate cases involving the Companies: storm damage and injuries and damages. These two exceptions exist because the revenues or expenses being normalized are essentially random occurrences without any upward or downward trend that is incorporated into the adjustment. For example, neither LG&E nor KU can predict or affect what storms may occur. Furthermore, with storm damage, and injuries and damages there is a central tendency for events to fall within a range that will typically equal a mean value when measured over time. Although the severity of storms varies from year to year, the average values of these random variables are stable and predictable over time. Although the Companies certainly endeavor to minimize injuries and the effect of storms on their service areas, these events will occur and in no discernible pattern. For these reasons, there is no reason to think that any given specific test year's storm or injuries and damages expenses are indicative of future cost because what is "normal" can only be understood in reference to a long span of time and data, objectively measured and calculated.

Mr. Kollen expressly concedes that transmission and distribution capital expenditures are not random nor unpredictable and actually *contrasts* these costs with storm damage. His direct testimony asks whether transmission and distribution capital expenditures are "controllable costs." Mr. Kollen readily admits "Yes, except in the event of damage, *such as an ice or other storm event*, or untimely age-related and/or environmental deterioration. With these exceptions, capital expenditures are incurred as the result of a budget process in which capital projects are identified and then prioritized based on various factors, primarily need and capital constraints."[5] Mr. Kollen admits that these costs are not like the types of expenses for which normalization adjustments have been approved, nor does he take issue with the Companies' budgeting process or prioritization of individual transmission and distribution capital expenditures. As explained in Mr. Bellar's rebuttal testimony, these projects are critical to the ongoing operation of the Companies' provision of reliable electric service.

Q. Please explain how this adjustment conflicts with a forecast test period.

A. Certainly. When filing rate cases, the Companies have the right to choose to use either a historical test period or a forward-looking test period to support their applications. The Companies could have utilized a historical test period of twelve consecutive calendar months, or a forward-looking test period corresponding to the first twelve consecutive calendar months the proposed increase would be in effect

[5] *Id.* at 17-18 (emphasis added).

after the maximum suspension provided in KRS 278.190(2). The proposed normalization adjustment, which is based on data from 2014 to 2017, directly conflicts with the express purpose of the forward-looking test period the Companies have utilized because it is based on historical data that occurred up to *six years* before the forecast test period in these cases end.

Q. Has Mr. Kollen demonstrated that the forecast test year level of transmission and distribution capital expenditures is not representative of the going-forward level of expense?

A. No. As explained more fully by Mr. Bellar, the Companies are in need of the planned capital expenditures, as LG&E and KU are in the midst of a long-term plan to improve and modernize their electric transmission and distribution infrastructure. These efforts are critical to providing safe and reliable electric service and are not discretionary. For example, certain expenditures will be incurred pursuant to Certificates of Public Convenience and Necessity granted to the Companies by the Commission. Mr. Bellar's direct and rebuttal testimony discusses these projects in great detail. Nevertheless, Mr. Kollen arbitrarily proposes to reduce KU's jurisdictional revenue requirement by $7.021 million and LG&E's by $3.768 million based solely on a historical data set range that Mr. Kollen selected simply to reduce this expense.

His selection of a three-year period also illustrates why normalization adjustments have been historically disfavored by the Commission because the averaging calculation can be manipulated through the selection of the period to create bias and achieve a desired end-result. Normalizing transmission and distribution capital expenditures is an example of such manipulation, because it wrongly assumes that the expense is relatively static over time. As explained by Mr. Bellar, the Companies have aging transmission and distribution assets that are past their useful lives that may present safety and reliability risks to the system and need to be addressed. Mr. Kollen's selective adjustment should be rejected because the Companies must incur these costs in providing service to customers, and Mr. Kollen has failed to demonstrate that any of the costs will be imprudently or excessively incurred.

Q. You assert that there are only two instances where normalization adjustments are utilized. Isn't the generator outage cost recovery methodology a normalization?

A. No. Normalization adjustments take an average of historical costs and assume that the future will mirror the past. The generator outage cost recovery methodology used in the 2016 rate cases for each Company was designed to set rates based on costs that vary widely each year but occur in an eight-year cycle. The methodology includes both forward-looking periods and historical costs, and allows the Companies to recover those costs in a smoothed manner thereby reducing volatility in rates. A normalization adjustment is most appropriate when the future costs are volatile and cannot be forecasted accurately. The generator outage expense and the capital expenditures for transmission and distribution can both be forecasted, and have been forecasted, by the Company in this proceeding.

Depreciation

Q. Do you have a view on the recommendations proposed by KIUC and USDOD witnesses to extend the depreciable lives of the assets?

A. I disagree with the proposals of the KIUC and USDOD witnesses to extend the depreciable lives of the coal-fired generating assets. The Companies have had their cash flows negatively impacted by the Tax Cuts and Jobs Act in 2018, and deferring depreciation costs will continue to stress the Companies' credit metrics. In addition, the rating agencies are very interested in the timeliness of recovery of costs. On page 7 of Exhibit DKA-4 to my Direct Testimony, Standard and Poor's definition of a "strong" regulatory assessment includes the following description: "The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on that asset base)." Further down on that same page the description for an "adequate" regulatory assessment includes the following: "The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on that asset base) within a reasonable time." Continuing to defer the recovery of prudently incurred capital costs is not an appropriate approach to maintain the financial strength of the Companies.

Directors and Officers Liability Insurance

Q. Please summarize Ms. Mullinax's proposed adjustment to directors' and officers' ("D&O") liability insurance.

A. Ms. Mullinax has proposed removing one-half of the Companies' D&O liability insurance expense.[6] Ms. Mullinax alleges that by maintaining D&O insurance "shareholders would benefit from payouts under the policy that would otherwise

[6] Direct Testimony of Donna H. Mullinax of January 16, 2019 on behalf of The Office of Attorney General Louisville/Jefferson County Metro Government & Lexington-Fayette Urban County Government ("Mullinax Direct") at 31.

reduce the company's below-the-line net income" "[s]hould a legal action be brought against a director and/or officer."[7] Ms. Mullinax concedes, however, that "ratepayers benefit because having the insurance improves the ability of the company to attract and retain qualified directors and officers."[8] Ms. Mullinax does not allege the amount of the coverage or the premiums the Companies forecast incurring is unreasonable in any manner or present any affirmative analysis supporting her judgment.

Q. Do you agree with Ms. Mullinax's adjustment?

A. No, as D&O insurance is an ordinary business expense that Ms. Mullinax readily acknowledges is necessary to retaining qualified directors and officers. Ms. Mullinax's argument that a legal action could result in the reduction of the Companies' below-the-line net income is unavailing; countless hypothetical events could potentially reduce net income but that has no bearing on whether an expense is properly recovered from ratepayers. It is incumbent on the Companies to maintain sufficient insurance coverage to mitigate the risks of doing business. This includes liability coverage for its employees in the field, and D&O insurance for its directors and officers.

Q. Has the Commission denied this proposed adjustment in a prior LG&E rate case?

[7] Mullinax Direct at 32.
[8] *Id.*

A. Yes. In Case No. 90-158, the AG proposed to assign 50% of the cost of D&O liability insurance to LG&E's shareholders.[9] As in this case, the AG argued that the protection provided by the insurance was for both the shareholder and ratepayer.[10] The Commission rejected this adjustment: "While there may be some benefits to shareholders, the main beneficiaries are the ratepayers. This insurance allows LG&E to induce highly qualified individuals to serve on its Board of Directors. We feel it is not proper or reasonable to include this adjustment."[11] The Commission's reasoning remains sound, as Ms. Mullinax concedes that D&O insurance is necessary to attracting and retaining qualified directors and officers. As such, this adjustment should be denied.

Outside Counsel Expense

Q. Please describe Ms. Mullinax's proposed adjustment to outside counsel expense.

A. Although Ms. Mullinax's testimony suggests she proposed eliminating the entire $1.56 million that the Companies forecasted for the outside services necessary to defend the Companies in two environmental litigation matters, she, in fact, is only eliminating 50% of that amount in her adjustment 3.10.[12]

Q. Is Ms. Mullinax's adjustment reasonable?

A. No, it is not. The Companies routinely face legal challenges regarding environmental matters from issue-focused groups and must defend the Companies in such lawsuits. Environmental groups use litigation to achieve certain policy objectives. Defending against these lawsuits is a cost of doing business that the Companies cannot avoid,

[9] In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company (Case No. 90-158) (Ky. PSC Dec. 21, 1990).
[10] *Id.*
[11] *Id.*
[12] Mullinax Direct at 37-38.

and, unfortunately, has become recurring for the Companies and other utilities across the country. The projected costs are consistent with prior cases, and are prudent expenditures. Failing to aggressively defend the Companies in these cases could result in costs that are multiples of the legal costs Ms. Mullinax is questioning.

OVEC

Q. Are you responding to certain arguments made by Dr. Fisher on behalf of the Sierra Club?

A. Yes. While Mr. Sinclair is responding to the majority of Dr. Fisher's claims regarding the Companies' power purchases from the Ohio Valley Electric Corporation ("OVEC"), I will address Dr. Fisher's arguments regarding the charges the Companies are paying to OVEC pursuant to the 2011 Inter-Company Power Agreement ("ICPA") that was approved by the Commission.

Q. Please describe the Companies' participation in OVEC.

A. The Companies, along with other utilities, are owners of OVEC and buyers of power under the ICPA. The role as a buyer of power has been referred to as being a sponsor of OVEC. By being a sponsor, the Companies have had access to low-cost energy to serve their customers. The arrangement is governed by the ICPA. With Commission approval, the Companies entered into an ICPA with the other OVEC sponsors in 2004, and the current version of ICPA in 2011. The Companies' combined power participation ratio ("PPR") of OVEC's power and associated costs is approximately 8%. Each sponsor pays a monthly demand charge that is comprised of (1) fixed operation and maintenance expenses, (2) debt service including the amortization of debt balances and interest expense, (3) taxes, and (4) decommissioning costs. The ICPA also requires each sponsor to pay an energy charge, which is largely variable fuel costs. Finally, the sponsors pay a monthly transmission charge. Each sponsor is obligated to pay its PPR multiplied by the total of each cost.

Q. Please describe Dr. Fisher's allegations regarding the Companies' obligations for OVEC's debt.

A. Dr. Fisher erroneously suggests that the Companies are acting as guarantors for OVEC's debt.[13] When the Companies sought approval of the ICPA in 2011, it was plainly explained in the verified applications that LG&E and KU "[have] not and will not act as guarantor for OVEC's debt or other securities; however, the Amended ICPA requires the Sponsors to pay for replacement costs, additional facility costs, post-retirement benefits costs, and the costs associated with decommissioning the OVEC units."[14] In addition to this representation, the entire ICPA was reviewed and approved by the Commission and has not been amended since that time. The ICPA expressly states that the sponsors' liability is not joint and several.

Q. Given these representations and the terms of the ICPA, why does Dr. Fisher suggest that the Companies are guaranteeing OVEC's debt?

A. Dr. Fisher's allegations are based on a misunderstanding of the ICPA and the impact of FirstEnergy Solutions' ("FES") bankruptcy on the Companies. FES is an OVEC sponsor that filed for bankruptcy in March 2018. FES's PPR of OVEC is 4.85%. FES petitioned the bankruptcy court to permit it to reject the ICPA to obtain relief from the payments associated with its 4.85% PPR, and the bankruptcy court's decision on that issue is presently being litigated on appeal. Dr. Fisher alleges that

[13] Direct Testimony of Jeremy I. Fisher, PhD on behalf of Sierra Club on January 16, 2019 ("Fisher Direct") at 13.
[14] Verified Applications in Case Nos. 2011-00099 and 2011-00100.

the Companies, along with the other OVEC sponsors, are paying the costs associated with FES' 4.85% PPR, which shows that the Companies and other sponsors are guaranteeing OVEC's debt by making up the costs associated with FES's share.[15]

Q. Is Dr. Fisher correct?

A. No. At present, because FES has not been paying its monthly costs to OVEC, OVEC is only recovering 95.15% of its costs. The Companies are not paying the costs associated with the bankrupt sponsor, and as explained in the proceedings in which the Commission approved the ICPA, have not and will not act as guarantors for OVEC's debt.

Q. Mr. Fisher suggests that since January 2017, OVEC started billing its sponsors to establish a debt reserve fund to cover the shortfall created by the FES debt. Is this correct?

A. No. In October 2016, Moody's updated its rating methodology for Joint Action Agencies, which are jointly owned assets that provide reliable and competitively priced energy or energy related services typically through asset ownership. OVEC is such a Joint Action Agency. Moody's measures a Joint Action Agency's financial strength in part based on the Agency's fixed obligation charge coverage ratio, which measures a Joint Action Agency's ability to repay annual debt service costs from recurring revenues net of recurring expenses, excluding one-time revenues or extraordinary charges. Moody's expressed a strong preference for Joint Action Agencies to maintain a debt service reserve account totaling one year's maximum debt service. After reviewing this rating methodology that was issued in October

[15] Fisher Direct at 13-14.

2016, in January 2017 - more than a year before FES filed for bankruptcy protection - OVEC began creating a reserve that will eventually cover a year of its debt service costs. A copy of the Moody's methodology is attached as Rebuttal Exhibit DKA-1, and the debt service reserve discussion can be found on page 20 of the exhibit. The Companies have been paying their PPR share – and no more – of the debt service reserve.

Q. Mr. Fisher suggests that by ceasing to purchase power from OVEC, the Companies' financial obligations would terminate. Is this accurate?

A. No, it is not. As explained above, the Companies pay a monthly variable energy charge and a fixed demand charge. The majority of the costs are fixed; as such, if the Companies cease purchasing power from OVEC, the Companies' customers will continue paying for most of the costs as required by the ICPA but receive none of the energy. For example, during the forecast period, 67% of KU's and LG&E's costs from OVEC will be fixed.[16] As such, the majority of the costs will continue until the fixed costs, which include the debt service costs, are retired.

Q. Mr. Fisher recommends that the Commission "expressly reaffirm the Companies' obligation to obtain Commission approval" of "any additional OVEC debt obligations."[17] Do you agree with this recommendation?

A. No, I do not. The issuance of OVEC debt does not fall within KRS 278.300, given that it is not a Kentucky utility. As such, this Commission's approval is not required.

[16] KU's Response to Item No. 45 of Commission Staff's Second Request for Information; LG&E's Response to Item No. 54 of Commission Staff's Second Request for Information.
[17] Fisher Direct at 6.

LG&E and KU will continue to obtain any necessary regulatory approvals for the issuance or assumption of securities, and any amendments to the ICPA.

<u>Return on Equity</u>

Q. Has Regulatory Research Associates recently released updated return on equity reports?

A. Yes, Regulatory Research Associates recently released an updated report that contains return on equity ("ROE") reports for investor owned utilities through December 31, 2018. A copy of the report is attached as Rebuttal Exhibit DKA-2. The table at the bottom of page 9 of this exhibit shows that the average ROE awarded in 2018 for vertically integrated utilities such as the Companies was 9.68% and the median ROE awarded was 9.75%. Mr. McKenzie discusses the report further in his rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of February 2019.

Judy Schooler

Notary Public

My Commission Expires:

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

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

US Municipal Joint Action Agencies

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Summary

This rating methodology replaces "US Municipal Joint Action Agencies" last revised on October 3, 2012. We have updated some outdated links and removed certain issuer-specific information.

This methodology explains our approach to credit ratings assigned to revenue bonds of US municipal Joint Action Agencies (JAA). JAAs are formed by a group of U.S. municipal utilities (participants) to provide reliable and competitively priced energy or energy related services typically through asset ownership. The methodology identifies the four key ratings drivers for take-or-pay projects and five key rating drivers for all-requirement agencies as shown below:

» Participant Credit Quality and Cost Recovery Framework

» Asset Quality (Take-or-Pay) / Resource Risk Management (All-Requirement)

» Competitiveness

» Financial Strength and Liquidity

» Willingness to Recover Costs With Sound Financial Metrics (All-Requirement)

This methodology is intended as a reference tool to use when evaluating credit profiles within the industry, helping companies, investors, and other interested market participants understand how key qualitative and quantitative risk characteristics are likely to affect rating outcomes.

This methodology should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This report includes a detailed rating grid, the purpose of which is to provide a reference tool that can be used to approximate credit profiles within the JAA sector. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to these issuers. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary significantly. In addition, ratings are based on our forward-looking expectations, which may be different than historical results. As a result, a grid-indicated rating is not expected to match the actual rating of each issuer.

The publication includes the following sections:

» About the Rated Universe: An overview of the Joint Action Agency sector

» About the Rating Methodology: A description of our rating methodology, including a detailed explanation of each of the key factors that drive our ratings

» Grid Limitations and Other Considerations: Comments on the rating methodology's limitations, including a discussion of other rating considerations that are not included in the grid

» Appendices: Tables including the scorecard, issuers covered in this update and definitions of key ratios

About the Rated Universe

Joint Action Agencies are formed by a group of U.S. municipal utilities (participants) to provide reliable and competitively priced energy or energy related services. Most rated JAAs were formed to provide power, though we also rate JAAs that provide natural gas, electric transmission, or telecommunications services for energy assets. The participating municipal utility systems share an obligation established through a long-term contractual arrangement to cover the JAA's operating, capital, and debt service costs. Some JAA issuers have multiple distinct project ratings that are rated on a standalone basis.

The credit quality of the JAA sector averages in the 'A' category primarily due to the member participants' strong credit quality, JAA's unregulated rate setting ability and long-term contracts with participants. Competitive rates, sound asset quality and conservative resource risk management are other factors supportive of the average sector rating. This business model suggests a fundamentally high probability of timely debt service payment.

Take-or-Pay Projects

Our approach to rating the sector divides JAAs into two broad types consisting of take-or-pay projects or all-requirement agencies. Typical characteristics of take-or-pay projects are contracts that extend to at least debt maturity, a single asset or group of assets defined upfront for the life of the debt, fixed participants' share for the life of the contract, no firm obligation by the project to deliver any energy resource, and participants' obligation to pay their respective share of all costs including debt service even if the project is not completed, operating, or capable of operating.

All-Requirement Agencies

All-requirement agencies also generally obligate participants to take the underlying energy resource and pay for their respective share of the JAA's costs through at least debt maturity similar to take-or-pay projects. That said, all-requirement agencies share many similarities with Generation and Transmission Cooperatives (G&T Cooperatives) such as an obligation to meet all of the energy resource needs of its participants. Some partial-requirements agencies are sufficiently similar to all- requirement agencies and they fall within this methodology.

Given its supply obligation, an all-requirement agency will have an energy resource portfolio typically consisting of an evolving mixture of supply contracts and physical assets to match the energy resource requirements of its participants. The evolving resource needs of the participants expose the all- requirement agency to the potential for insufficient or excess energy resource. Additionally, a participant's share of a JAA could change over time depending on a participant's energy resource needs relative to other members. Furthermore, the entrance of new members or the exit of existing members could also change participants' shares. All-requirement contracts sometimes include a provision allowing a participant member to end its participation though that member typically remains responsible for its share of the outstanding debt.

While this methodology primarily applies to JAAs, we will consider applying this methodology to municipal energy projects that have identical or substantially similar characteristics to a JAA take-or- pay project.

However, this methodology does not apply to municipal energy projects that do not have typical 'take- or-pay' contract terms (e.g. unconditional payment obligation of the participants to pay for operating, capital, and debt service cost irrespective of whether the project is completed, operating, or capable of operating). For example, for a project with an offtake contract that has conditional payments or material limitations on the obligation by its participants, Moody's will apply the 'Power Generation Projects', 'Generic Project Finance', or other appropriate methodology. These methodologies may be accessed through a link provided in the Related Research section below.

About This Rating Methodology

Our approach to rating Joint Action Agencies for both take-or-pay projects and all-requirement agencies as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

We have identified the following four key rating factors when assigning ratings to take-or-pay projects.

Take-or-Pay Projects

» Participant Credit Quality and Cost Recovery Framework (45%)

» Asset Quality (15%)

» Competitiveness (15%)

» Financial Metrics (25%)

- Adjusted Days Liquidity on Hand (10%)
- Debt Ratio (5%)
- Fixed Obligation Charge Coverage Ratio (10%)

All-requirement agencies broadly share similar factors to take-or-pay projects; however, the 'Ability and Willingness to Recover Costs and Maintain Financial Metrics' is incorporated as Factor 5.

All-Requirement Agencies

» Participant Credit Quality and Cost Recovery Framework (25%)

» Resource Risk Management (10%)

» Competitiveness (15%)

» Financial Metrics (25%)

- Adjusted Days Liquidity on Hand (10%)
- Debt Ratio (5%)
- Fixed Obligation Charge Coverage Ratio (10%)

Willingness to Recover Costs With Sound Financial Metrics (25%)

2. Measurement or Estimation of Factors in the Scorecard

We explain below how each factor and sub factor are calculated or estimated for the grid and the weighting for each individual factor and sub factor. We also explain the rationale for using each particular factor, and the ways in which we apply them during the rating process. The information used in scoring the factors and sub factors in the grid is found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.

Our ratings are forward looking and incorporate our expectations for future financial and operating performance. In assigning ratings, we attempt to look through the energy industry's characteristically volatile financial metrics, which can be caused by weather variations and fuel or commodity price changes. The rating process also makes extensive use of historic financial statements. Such historic results help us understand the pattern of a JAA's financial and operating performance and how a joint action agency compares to its peers. Analysts will use three-year average results to assess financial metrics, in order to mitigate one-time factors that might skew results. We also utilize financial projections to ascertain management's planning capability better, as well as expectations for future financial performance, rate levels, and capital and debt requirements. All financial measures incorporate our standard adjustments to the balance sheet and income statement.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match a JAA's performance on each factor and sub-factor to one of our rating categories ranging from 'Aaa' to 'B'. In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of fixed obligation charge coverage ratio is generally representative of an 'Aa' versus an 'A' rating. In other words, there is only one rating from the grid for each factor, multiple rating choices for sub-factors are not incorporated. We will further determine the JAA's position within the rating category for Factor 1. For example, participant credit quality at 'A1' is at the high end of the 'A' category and would thus score at 'A1'.

4. Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, each of the assigned scores for the factors and sub- factors generally is converted into a numeric value based on the following scale:

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

For the scoring of participant credit quality, we will utilize the interpolated numeric value that corresponds to the applicable participant credit quality. For example, participant credit quality of A1 would be scored at the interpolated numeric score of 5. The ability to distinguish between a strongly or weakly positioned participant credit quality remains an important driver of JAA ratings especially for take-or-pay projects.

Once each factor and sub-factor is scored, each factor's or sub-factor's corresponding numeric value is multiplied by its assigned weight and then summed to produce a composite weighted average score. This weighted average score is then mapped to the ranges specified in the table below, and the alpha- numeric rating is determined based on where the total score falls within the ranges.

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

As an example of how the grid works, an issuer with a composite weighted average score of 5.8 would have a grid-indicated rating of A2. We use the same procedure to derive the grid-indicated rating for each of the factors that are embedded in the discussion of the methodology. The composite weighted grid-indicated rating is then reviewed against the current rating and against any of the outlier factors that may have skewed the rating higher or lower. This comparison allows us to better assess the reasoning behind the weighting of a particular factor.

5. Limitations of the Grid and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings and additional factors that are not included in the grid that can be important in determining ratings.

The Broad Rating Factors

Our analysis of a take-or-pay project focuses on four broad factors while the analysis of an all- requirement agency incorporates an additional fifth factor:

» Participant Credit Quality and Cost Recovery Mechanism

» Asset Quality (Take-or-Pay Project) or Resource Risk Management (All-Requirement Agency)

» Competitiveness

» Financial Strength and Liquidity

» Willingness to Recover Costs With Sound Financial Metrics (All-Requirement Agency)

Rating Factor 1: Participant Credit Quality and Cost Recovery Mechanism

Why It Matters

Fundamental to the credit rating of a joint action agency is the long-term contract with its participants that allows the JAA to recover all of its costs including debt service. Since the participants typically bear all of the operating, capital, and debt service costs, the underlying participant credit quality is a major driver of the JAA's credit quality, especially for take-or-pay projects.

Given the importance of the participant credit quality, a typical JAA's rating will generally be capped to no more than two notches higher than the weighted average participant credit quality since the participants are the primary source of cash flow. If the weighted average participant credit quality is near or at speculative grade, the JAA's rating is likely to be capped at the weighted average participant credit quality for all requirement agencies or at the 'weak link' participant credit quality for a take-or- pay project (see section 'How We Measure Participant Credit Quality and Cost Recovery Framework for the Grid' for definition of 'weak link' participant).

Factor 1 also considers the joint action agency's cost recovery framework. Most joint action agencies and their participants have the statutory authority to establish their own rates and charges locally without external regulation, which provides greater certainty to timely and full cost recovery. This strength is further bolstered for most JAAs by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service.

On the other hand, cost recovery or governance issues that complicate timely and full cost recovery will override the participants' credit strength since these issues become the prevailing risk consideration. To the extent the scoring for Factor 1 is 'Baa' or lower due to cost recovery or governance issues, we will likely place greater weight on Factor 1.

Although Southern Montana Electric Generation and Transmission (not rated) is not a JAA, its default in late 2011 which was partially caused by extensive member disputes serves as a recent example of the importance of proper governance and cost recovery. The largest example remains Washington Public Power Supply System's (WPPSS) Projects 4 and 5 defaults caused by members challenging their contractual obligations. A rate regulated JAA or a JAA whose participants are rate regulated would be viewed as having a weaker cost recovery framework since any rate changes will need third party regulatory approvals. The bankruptcy filings of Cajun Electric Power Cooperative, Wabash Valley Power Association and Big Rivers Electric Corporation in the 1980's and 1990's were partially due to insufficient rate relief by its state regulators. While these examples are of G&T cooperatives, they still represent worthy examples of the added uncertainty and risk caused by third party rate regulation.

We emphasize the relatively stronger importance of participant credit quality for take-or-pay projects vs all-requirements projects in two ways. First, for take-or-pay projects we give Factor 1a weight of 45% versus a 25% weighting for all-requirement agencies, reflecting the take-or-pay project's narrow business profile and stronger contract terms. Second, the final score for each of Factors 2, 3, and 4 for take-or-pay projects is generally arrived at in two steps. In the first step, we determine scores for each of the underlying asset quality (Factor 2), competitiveness (Factor 3) and financial strength (Factor 4). We call these initial scorings the 'baseline factor assessments'. The second step involves comparing each of the baseline factor assessments to the Factor 1 score. The scores for Factors 2, 3, and 4 are then adjusted to be the higher of either the baseline factor assessment or the Factor 1 score. As noted below, there are certain exceptions.

Thus, if the assessment of Factor 1 is higher than that of the baseline factor assessments of Factors 2, 3, and 4, for a well performing, competitive take-or-pay project with strong contracts, participant credit quality will effectively represent 100% of the weight in the scorecard before notching considerations. For example, a take-or-pay project with 1.1x fixed charge coverage ratio (Factor 4(c)) would have a baseline factor assessment of 'Baa' for Factor 4(c); however, assuming Factor 1 was mapped to 'A', the final scoring for Factor 4(c) would be 'A'. The same process would be followed for Factors 4(a) and 4(b), as well as for Factors 2 and 3. The approach described above only applies if the individual baseline factor assessment is at least commensurate with a 'Baa' category and the approach does not apply if the baseline factor assessment is 'Ba' category or lower. This reflects our view that speculative grade characteristics such as poor asset quality or uncompetitive costs increase the probability that the underlying take-or-pay contract could ultimately be challenged or that some other credit negative action might be taken.

For all-requirement agencies, we incorporates a fifth factor, 'Willingness to Recover Costs With Sound Financial Metrics' (see Factor 5) given the lower weight attributed to Factor 1.

How We Measure Participant Credit Quality and Cost Recovery Framework for the Grid

We compute the weighted average participant credit quality by multiplying the percentage of the municipal utility's share in the joint action agency by the participant's credit rating or equivalent assessment, using the 10-year global corporate idealized probability of default curve. We use our published credit ratings as a measure of participant credit quality and in the absence of an underlying published credit rating, we utilize multiple approaches to assess participant credit quality (see section 'Evaluating Unrated Participants in JAAs').

For take-or-pay projects, we will generally cap Factor 1 to the lower of (a) the weighted average participant credit quality or (b) no more than 2 notches above the weak link participants' credit quality. Typically, the 'weak link' is the participant that straddles the lower 20th percentile and upper 80th percentile of all participants ranked by credit quality. We selected this threshold since the typical 25% step up provision in a take-or-pay contract allows participants aggregating up to a 20% share to default. The limit of two notches above the weak link participant reflects the higher default probability associated with weaker participant credit quality. For example if the average participant credit quality was Aa2 but the 'weak link' participant was rated A3, Factor 1 would likely be scored at A1. If the step up is lower than 25%, we will consider the appropriate threshold to arrive at the 'weak link' participant. For example, a take-or-pay project with a 15% step up would allow for participants with an aggregate 13% share to default. Thus, in this example, we would factor in the credit quality of a participant that straddles the lower 13th percentile and upper 87th percentile of all participants ranked by credit quality.

Take-or-Pay Projects (45% weight)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 1: Participant Credit Quality and Cost Recovery Framework	45%	Participant credit quality at cap is at 'Aaa'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'Aa'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'A'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'Baa' OR JAA or majority of participant rates are regulated.	Participant credit quality at cap is 'Ba' OR Below average governance or cost recovery.	Participant credit quality at cap is 'B' OR Consistent record of poor governance or cost recovery.

We will also consider whether the JAA or its participants are rate regulated and the extent of the rate regulation. If the JAA or the majority of its participants are fully rate regulated, Factor 1 could be scored in the 'Baa' category even if the participant credit quality is higher than the 'Baa' category since a JAA's regulated rate setting could pose challenges to timely cost recovery.

Additionally, we will consider the cost recovery framework and governance issues that have led or could lead to extensive delays in rate changes, under-recovery of costs, member challenges to their contractual obligations, or other credit negative outcomes. For example, participants challenging their contractual obligation are likely to map at the 'B' category and override participant credit quality.

For all-requirement agencies, Factor 1 does not explicitly incorporate the weakest participant since participants' shares can change over time due to changing resource requirements or the exit and entrance of new participants over time. Likewise, many contracts do not explicitly cap non-defaulting member step up obligations, so stronger participants may be asked to increase contributions in case a weak participant fails to pay. Additionally, an all-requirement agency's contract allows the JAA to raise rates to recover its costs and often its contract will contain an explicit provision that allows the JAA to raise rates due to a defaulting member. If the all-requirement agency is unable to recover a defaulted participant's share of the JAA costs, we may place greater weight on the weakest participant's credit quality in scoring Factor 1.

All-Requirement Agencies (25% weight)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 1: Participant Credit Quality and Cost Recovery Framework	25%	Weighted average 'Aaa' participant credit quality. JAA & participant rates unregulated.	Weighted average 'Aa' participant credit quality. JAA & participant rates unregulated.	Weighted average 'A' participant credit quality. JAA & participant rates unregulated.	Weighted average 'Baa' participant credit quality. OR JAA or majority of participant rates are regulated.	Weighted average 'Ba' participant credit quality. OR Below average governance or cost recovery.	Weighted average 'B' participant credit quality. OR Consistent record of poor governance or cost recovery.

Rating Factor 2: Asset Quality (Take-or-Pay Project) or Resource Risk Management (All-Requirement Agency)

Why it Matters

The primary rationale for the creation of a joint action agency is the cost effective delivery of an energy resource such as power, natural gas, or some other energy related service such as electric transmission. The underlying quality of the asset or resource risk management has a direct impact on quality of service, leverage capacity, competitiveness and customer satisfaction. Participant support for the JAA rooted in customer satisfaction can translate into greater willingness to establish the revenue requirements needed to keep the JAA in sound financial condition. JAAs must keep the confidence of their governing board and the participants. A lack of operational success could lead to questions as to the rationale for establishing the JAA in the first place. Poorly operating assets or poor resource risk management are likely to drive higher all-in costs for the energy resource while also potentially inducing participants to seek alternate energy resources to meet their needs. An inability of the joint action agency to ultimately deliver its resource at competitive rates could cause the participants to challenge their contractual obligations.

If a take-or-pay project's baseline factor assessment scores to at least 'Baa', the final scoring for Factor 2 will generally be the higher of (a) the score used in Factor 1 or (b) the baseline factor assessment. This approach reflects our view that the strong asset quality minimizes the likelihood that the participants could seek to challenge their obligations under the take-or-pay contract.

However, certain assets with significant event risk such as nuclear plants or assets with 'Ba' or lower characteristics do not benefit from the typical positive lift of its participant credit quality in the final scoring for Factor 2. For these types of assets, the scoring will be at the baseline factor assessment. This reflects our view that the increased asset risk could lead to asset non-performance and ultimately increases the possibility that participants will challenge their contractual obligations or take some other negative action.

Factor 2 has a slightly higher weight for take-or-pay projects relative to all-requirement agencies since take-or-pay projects typically are a single asset, which heightens operating risk. On the other hand, all-requirement agencies typically have a portfolio approach with a combination of assets, contracts and market purchases.

How We Measure Asset Quality or Resource Risk Management for the Grid

When considering asset quality for take-or pay projects, we will consider the asset diversity, technology of the project, and the quality of the operator. While take-or-pay projects are typically single assets, we consider multiple assets a credit positive since the operational diversity reduces the negative impact of a single asset outage. The underlying technology or equipment providing the resource is also a major consideration and we review aspects such as the equipment provider, equipment warranties, and operational history. We will also consider the resource operator's ability to operate the asset to ensure cost-effective and reliable operations. To the extent possible, we review the JAA's operating statistics for the relevant energy resource. For example, we will review statistics such as availability factor (% of time a unit is operational); capacity factor (% of rated capacity the generation unit runs); and heat rates (efficiency of a generator to convert fuel into electrical energy) for power generation assets.

For take-or-pay projects, the 'Aaa' and 'Aa' categories generally apply to simple, proven assets with little to no moving components such as electric transmission lines. An 'A' category would typically represent a diverse portfolio of proven, strongly operating assets covering a range of technologies. portfolios with limited diversification or single asset such as a well operating gas fired plant with a known and reputable operator would likely be scored in the 'Baa' category. Assets that would typically be in the 'Ba' or 'B' categories could include but are not limited to assets with poor operating history; projects with new, unproven technology; or projects that require sizeable new investment to meet new regulatory rules.

Take-or-Pay Projects (15% weight)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 2: Asset Quality	15%	Diversified portfolio of simple, proven assets and minimal reinvestment requirement.	Simple, proven asset(s) and minimal reinvestment requirement.	Diverse portfolio of proven assets across technologies	Standard, commercially proven asset(s).	Asset(s) with some operating challenges.	Largely unproven technology or poorly performing asset(s).

For all-requirement agencies, we assess energy resource risk management, which is broader than asset quality since all-requirement agencies typically meet their participants' resource requirements through a combination of assets and short to long-term contracts or mostly contractual arrangements. To assess resource risk management, we will consider the overall energy resource supply mix, asset quality, energy resource supply contract terms and counterparties, and the JAA's strategic plans to ensure affordable and reliable energy resource for its participants. In the context of the overall energy resource supply mix, maintaining a diverse energy resource mix increases the JAA's flexibility to manage resource demand while limiting the JAA's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single resource, or increased costs associated with a particular asset, like the cost of environmental compliance.

If an all-requirement agency heavily relies on third party resource suppliers under short and long-term contracts, we will consider the diversity and quality of the energy resource suppliers. Additionally, key underlying terms of supply contracts such as maturity, payment provisions, and amount of contracted resource will be assessed. For Factor 2, the 'Aaa' and 'Aa' rating category will be considered for all-requirement agencies that have long term supply contract(s) that typically have the following characteristics: strong 'Aaa' or 'Aa' counterparties; contract terms that extends to at least debt maturity; prices at or below market prices; and a supply contract covering all or most of the all-requirement agency's load. If counterparties are typically rated in the 'A' category and the all-requirement agency maintained a portfolio of medium to long term contracts on a rolling basis to ensure energy resource supply and price stability, the scoring for Factor 2 could be commensurate with an 'A' category. A supply portfolio with 'Baa' counterparties and consisting mostly of shorter term contracts would be commensurate with 'Baa'. The 'Ba' or 'B' category for Factor 2 typically reflect suppliers rated below investment grade or poor resource management such as high exposure to short term markets or expensive supply contracts.

For all-requirement agencies, we score Factor 2 typically based on the weakest element in the JAA's resource risk management. For example, if a power JAA had single asset or fuel concentration ranging from 56% to 75% but had wholesale market purchases at 10%, we would likely score Factor 2 in the 'Baa' category since the asset or fuel concentration is the dominant risk.

All-Requirement Agencies (10% weight)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 2: Resource Risk Management	10%	Exceptional energy resource risk management Less than 10% market purchases. OR Diverse, proven assets. Single asset or fuel less than 20% of supply. OR Long-term, competitive supply contract with Aaa rated supplier.	Very strong energy resource risk management. 10-20% from market purchases. OR Diverse, proven portfolio. Single asset or fuel comprises 20-40% of the energy resource mix. OR Long-term, competitive supply contract with Aa rated supplier.	Strong energy resource risk management. 20-30% from market purchases. OR Proven assets. Single asset or fuel comprises 41- 55% of the energy resource mix. OR Well managed portfolio of supply contracts with 'A' rated suppliers.	Average energy resource risk management. 30-40% from market purchases. OR Single asset or fuel provides 56-75% of the energy resource mix. OR Adequately managed supply portfolio with 'Baa' rated suppliers.	Below average energy resource risk management. 40-60% from market purchases. OR Single asset or fuel provides over 76 - 100% of the energy resource mix. OR Adequately managed supply portfolio with 'Ba' or lower rated suppliers.	Poor energy resource risk management. More than 60% from market purchases. OR Assets with unproven technology or history of problems OR Poorly managed supply portfolio with 'Ba' or lower rated suppliers.

Rating Factor 3: Competitiveness

Why it Matters

An important credit factor in JAA ratings is the competitiveness of the energy resource provided to its participants. Competitive resource costs represent a core rationale for a participant's role as offtaker in a JAA. We view a combination of both legal and economic incentives serving as the strongest leverage for participants to pay. Competitive prices also provide the JAA greater flexibility to raise rates compared to a JAA whose rates are already high.

On the other hand, high rates could cause pressure on the JAA's management to either lower rates or not raise rates when necessary. High rates also could negatively affect the credit quality of the participants since energy resource costs typically represent the majority of the final cost to the retail customers. High energy costs could negatively affect the participant distribution utility's ability to retain retail customers leading to lower load and higher rates to spread the same fixed costs over a lower sales base.

In the worst case scenario, participants could challenge their obligations to a joint action agency. WPPSS's $2.25 billion bond default in 1983 on Projects 4 and 5 remains an iconic example of a successful challenge.

We also recognize the ability of a JAA's participants to access major wholesale energy markets over the last decade. The increased alternatives for participants have increased the importance of price competitiveness as a key credit factor. Because of these greater supply options, we expect municipally- owned utilities to evaluate the financial benefits of a relationship with a JAA more closely.

How We Measure Competitiveness for the Grid

Our evaluation of a take-or-pay project's cost competitiveness takes into consideration the project's rate (including debt service) to its members relative to what a participant would have to pay in the wholesale market on a historic and forward-looking basis, typically over a 3-year period. In volatile market conditions, we will consider longer periods spanning a commodity price cycle that seeks to smooth the market ups and downs to determine the long-term future competitive position of the asset. We estimate regional market price benchmarks from publicly available industry data such as the Energy Information Administration (EIA) and third party data service providers, as well as data from across our portfolio of other rated issuers. We will consider other benefits that a take-or-pay project provides to its participants such as renewable power that helps meet state or local renewable portfolio standards, the project's fit within the overall participants' energy resource portfolio, or the participants' need for the asset for reliability purposes. These other benefits could result in the scoring of a project's baseline competitiveness up to the 'Baa' category even though its rates relative to market are commensurate with 'Ba' or lower. For example, a wind project with all-in costs substantially above the prevailing market price of power could be scored at 'Baa' if the wind project is an important renewable asset that allows the municipal utility participants to meet their state-mandated renewable portfolio requirements.

For take-or-pay projects, an asset that has competitive rates through all parts of the market cycle would be in the 'A' to 'Aaa' categories depending on the extent of its low rates. Assets typically in the 'Baa' category are competitive in an average market environment but could be up to 50% more expensive relative to market prices during a cyclical downturn. The 'Ba' is typically for assets that are competitive only in a high price environment while the 'B' category represents uncompetitive rates in nearly all conditions.

Take-or-Pay Projects (15% total)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 3: Competitive-ness	15%	Extremely competitive asset through market cycle.Rates more than 50% below market. OR Very strong monopoly position with no alternative.	Very competitive asset through market cycle. Rates more than 30% to 50% below market. OR Strong monopoly position with very unlikely alternatives over the long term.	Competitive asset through market cycle. Rates 0% to 30% below market. OR Quasi monopoly with plausible alternatives over the medium to long term.	Competitive asset during average market. Rates up to 50% above market lows.	Competitive asset during market highs. Rates could be 100% above market lows.	Uncompetitive asset in nearly all price environments. Rates more than 100% above market lows.

As the competitiveness of a take-or-pay project or all-requirement agency falls into the 'Ba' category or lower, the rating committee could attribute greater weight to Factor 3 given the increased probability of adverse outcomes such as participants challenging their contract obligations.

If there is no wholesale market benchmark for the underlying characteristics of the assets (e.g. electric transmission lines), we will consider the asset's monopoly position, the benefit that the asset provides to the participants, and the importance of the asset.

If a take-or-pay project's baseline factor assessment scores to at least 'Baa', the final scoring for Factor 3 will generally be the higher of (a) the score used in Factor 1 or (b) the baseline factor assessment. This approach reflects our view that the asset's competitive position minimizes the likelihood that the participants could seek to challenge their obligations under their take-or-pay contract. Baseline factor assessments at 'Ba' or lower do not benefit from this approach.

For all-requirement agencies, we will primarily consider rates charged by comparable energy resource providers in the region on a historic and forward-looking basis typically over a 3-year period. For power all-requirement agencies, we will consider peer rates charged by other power all- requirement agencies, G&T cooperatives, or other comparable rates. To the extent wholesale energy market information or peer rate data is unavailable, we also evaluate a JAA participants' retail rates against regional competitors as an indirect measure of the JAA's competitiveness since energy costs typically represent a sizeable component of retail rates.

Take-or-Pay Projects (15% total)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 3: Competitiveness	15%	Rates more than 25% below average	Rates below average by more than 10% to 25%	Rates 10% below average to less than 5% above average	Rates above average by 5% to less than 25%	Rates above average by 25% but not more than 50%	Rates at least 50% above average

Rating Factor 4: Financial Strength and Liquidity

We have identified three key financial ratios that we consider the most useful in evaluating a JAA's financial profile. The three ratios measure liquidity, leverage, and cash flow coverage:

» Adjusted Days Liquidity on Hand Ratio

» Debt Ratio

» Fixed Obligation Charge Coverage Ratio

Why it Matters

We evaluate the financial performance and position of a JAA to determine its ability to manage business risks while assuring payment of debt service. Strong liquidity and cash flow metrics indicate greater resiliency by a JAA to withstand unexpected events such as asset outages, volatility of commodity prices, economic downturn, deterioration in participants' credit quality or even disputes among participants. Strong financial metrics also provides an issuer with more time to implement any necessary rate changes and also to change rates over a longer period of time to minimize rate impact. Conversely, low liquidity and cash flow metrics force greater emphasis on a JAA's rate setting, possibly leading to more frequent and larger rate changes.

Additionally, we utilize the debt ratio as a measure of an issuer's leverage which indicates the extent of debt service costs embedded in a JAA's overall cost structure. The higher the debt and debt service, the higher the likely all-in costs and ultimately the rates a JAA will have to charge its members to recover costs. Additionally, the debt ratio indicates the extent of asset coverage for bondholders.

Furthermore, joint action agencies typically are obligated under their bond documents to meet certain financial parameters such as minimum fixed charge or debt service coverage and we take a positive view of financial performance that exceeds the minimum requirements. We review several years of financial statements in order to assess a JAA's track record over time. We also evaluate ratios to determine trends and to assess the relationships to peer medians while seeking to balance quantitative measures with qualitative factors discussed in this report.

As described in Factor 1, if a take-or-pay project's baseline financial metrics score to at least 'Baa', the final scoring for Factor 4 will generally be the higher of (a) the score used in Factor 1 or (b) the baseline factor assessment, which reflects our view that the take-or-pay project is performing equal to or better than the base case expectations.

How We Measure Financial Strength for the Grid

Financial Strength: Liquidity – Adjusted Days Liquidity on Hand Ratio (10% weight)

The assessment of liquidity to meet day-to-day operating cash flow requirements and as a cushion against unexpected situations is a key element in the financial analysis of a JAA and includes both internal and external sources of liquidity. The sources of funds are compared to the JAA's operating cash flow needs over the next year and beyond. We use a measure called the adjusted days liquidity on hand ratio which is calculated based on a JAA's available adjusted liquidity, including unrestricted cash and investments and unrestricted bank lines of credit, times 365 days divided by the JAA's annual operating and maintenance expenses.

The primary difference between the traditional days cash on hand ratio and the new adjusted days liquidity on hand ratio is the inclusion of unrestricted bank lines and certain legally required reserves as available liquidity. We may review each bank line agreement on a case-by-case basis to determine whether or not the agreement satisfies our criteria in order to be included in our assessment of a JAA's liquidity.

The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those JAAs that are financially strong with robust levels of internal liquidity and little to no reliance on external funding sources such as bank lines.

Evaluation of a Bank Line

We will incorporate available bank lines into the calculation of a JAA's liquidity based on the strength of the bank line. As part of the assessment, we will typically consider three main factors: the tenor, the counterparty's credit quality, and any restriction or covenants that could affect the bank line's availability during periods of unexpected market events or JAA credit stress.

We will consider the bank line provider's credit quality as part of our assessment since the liquidity benefit of the bank line is limited if the bank is unable to provide funds when needed by the JAA. As such, we will likely exclude bank lines provided by banks of unknown or weak credit quality.

We will also evaluate the tenor of the agreement since shorter dated credit lines represent greater renewal risk. Typically, longer dated tenors are more favorable from a credit perspective. If the external liquidity line is expiring in less than a year and we view a renewal or replacement as unlikely, the external liquidity line could be excluded even if it is free from draw restrictions or covenants.

Additionally, our analysis includes a review of loan documentation for any language that might weaken the quality of the facility by potentially blocking a borrower's access, such as a material adverse change (MAC) clause. A MAC clause is a legal provision within a credit agreement that gives lenders the right to refuse to fund a commitment should the borrower experience sufficiently adverse business or economic developments. These adverse conditions can include numerous undefined factors the bank could cite to delay or avoid the funding requirement. We will include the bank line only to the extent we believe the terms of the bank line contain no material restrictions to ensure the line's availability at the time of a potential draw on the facility.

Financial Strength: Leverage -Debt Ratio (5% weight)

We utilize the debt ratio to measure the JAA's leverage (the ratio of net funded debt divided by net fixed assets plus net working capital). We also compare the absolute level of the JAA's current debt ratio to the median for similar JAAs and evaluate the likely future trend in the ratio. Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

We recognize that a JAA's capital structure is heavily reliant on debt since a joint action agency is typically all debt funded at inception. As a result, a JAA's debt ratio is usually much higher than other municipal infrastructure issuers such as public power utilities with generation. The ratings can accommodate higher relative leverage because of the participants' contractual obligation to the JAA to pay for all costs including debt service and timely cost recovery process given the lack of third party rate regulation.

A JAA that is highly leveraged may have less financial flexibility and higher, less competitive rates compared to a less leveraged JAAs with similar amounts of owned resources relative to their size. High leverage may also prevent or limit a JAA's ability to construct or acquire new energy sources or maintain existing facilities.

Financial Strength: Cash Flow Coverage - Fixed Obligation Charge Coverage Ratio (10% weight)

We analyze short and long-term trends in financial performance to assess the stability and resiliency of the JAA. We use the fixed obligation charge coverage ratio to measure a JAA's ability to repay annual debt service costs from recurring revenues net of recurring expenses, excluding one-time revenues or extraordinary charges. The fixed charge coverage ratio is similar to debt service coverage ratio but also incorporates "debt like "obligations related to the ownership of resource assets through a take-or-pay contact.

Our fixed obligation charge coverage ratio subtracts the debt portion of the take-or-pay contractual payment from the JAA's operating expenses when calculating net revenues, and subsequently adds the debt portion of the take-or-pay contractual payment to the total debt service costs when calculating coverage.

The fixed obligation charge coverage ratio facilitates uniform comparisons of JAAs that finance generation assets on balance sheet with JAAs that finance assets off balance sheet through a separate take-or-pay project. We use the fixed obligation charge coverage ratio in the analysis of financial results to provide a more consistent comparison of JAAs, regardless of the approach to financing energy resource ownership.

A consistent and stable fixed obligation charge coverage ratio provides increased resiliency to withstand revenue and expense volatility. A stable or improving fixed obligation charge coverage ratio is an important indicator of financial stability. Declines in the coverage ratio could be indicative of financial strain or an unwillingness or inability to raise rates to fully recover the cost of service, which, in turn, could contribute to a weakening in credit quality.

For take-or-pay projects, financial performance with fixed obligation charge coverage ratios below 1.0 are modeled as 'B' for Factor 4(c) and the rating scorecard output is unlikely to be reliable to within 1-2 notches of an actual rating. A take-or-pay project that sustains below 1.0 times fixed obligation charge coverage is not consistent with investment grade characteristics and violates a fundamental assumption of timely and full cost recovery. Under-recovery of actual costs by a take-or- pay project will also likely result in Factor 1 being scored at 'Ba' or lower since difficulties in cost recovery override participant credit quality. That said, we would adjust the fixed obligation charge coverage ratio calculation for any technical factors such as accounting adjustments, timing of payments or other unusual technical issues, which could obfuscate the in-substance level of coverage.

The difference in scoring for financial metrics for all-requirement agencies and take-or-pay projects reflects the fundamentally different approaches between take-or-pay projects and all-requirement agencies as outlined in this methodology. For take-or-pay projects, the typically stronger metrics for a given sub factor reflect greater comparability to project financings especially at the higher end of the range of financial metrics. Additionally, all-requirement agencies' financial metric ranges were set to provide greater comparability to G&T cooperatives, which have many similarities to all-requirement agencies that provide power, and public power with generation.

Take-or-Pay Projects (25% total)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 4(a): Adjusted Days Liquidity on Hand (days)	10%	≥ 250	175 ≤ x < 250	100 ≤ x < 175	30 ≤ x < 100	15 ≤ x < 30	< 15
Factor 4(b): Debt ratio (%)	5%	< 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x < 150%	150% ≤ x < 225%	≥225%
Factor 4(c): Fixed charge coverage (x)	10%	≥ 3.0	2.2 ≤ x < 3.0	1.6 ≤ x < 2.2	1.0 ≤ x < 1.6	< 1.0	

All-Requirement Agencies (25% total)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 4(a): Adjusted Days Liquidity on Hand (days)	10%	≥ 250	150 ≤ x < 250	90 ≤ x < 150	30 ≤ x < 90	15 ≤ x < 30	< 15
Factor 4(b): Debt ratio (%)	5%	< 50%	50% ≤ x < 70%	70% ≤ x < 100%	100% ≤ x < 150%	150% ≤ x < 200%	≥200%
Factor 4(c): Fixed charge coverage (x)	10%	≥ 2.0	1.4x ≤ x < 2.0x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	< 1.0

Rating Factor 5: Willingness to Recover Costs with Sound Financial Metrics (All-Requirement Agencies)

Why it Matters

Independent and local rate-setting authority guided by sound bond covenants and governance is a fundamental credit strength and a heavily weighted rating factor. An all-requirement agency's business profile is significantly more dynamic relative to that of a take-or-pay project and faces greater potential need for rate changes similar to G&T cooperatives and public power utilities with generation resulting in the addition of a fifth rating factor. For example, an all-requirement agency's participants could experience resource demand growth that requires the JAA to acquire or build new energy resources.

An all-requirement agency's willingness to recover costs while maintaining a financial buffer to help mitigate the impact of modest credit stress events demonstrates the stability and certainty of cash flows inherent in a JAA's business model. On the other hand, unwillingness or inability to establish sufficient rates to maintain sound financial metrics would be contrary to the cash flow stability expected in a JAA. Generally, the willingness to implement rate increases will, at some point, affect the relative financial performance of the JAA as measured in Factor 4. Without sound rate-setting that is predictable and timely, cash flow to service debt or financial liquidity may be compromised. As such, we believe that this rating factor is often a leading indicator of the direction of future financial performance for a JAA. This highlights that some entities may have a high tolerance for exposure to risks readily anticipated through more conservative management practices and policies.

How We Measure Willingness to Recover Costs for the Grid

We evaluate the governing board's rate-setting process for its transparency and timeliness in setting the rates. A key measure is the demonstrated record of willingness to charge the rates required to recover operating and capital costs, provide a cushion for fixed obligation charge coverage ratio, and maintain sound liquidity. The number of days it takes to implement new rates and collect the additional revenues is also a major consideration.

The longer and more complicated the process, the more pressure the delay in raising rates may put on a JAA's liquidity. In the end, the willingness to establish timely new rates to meet the appropriate cost recovery requirement is weighted heavily in this rating factor. This is of particular importance when considering an all-requirement agency's capital program and whether future rates will be sufficient to manage increased debt service requirements. An all-requirement agency's willingness to enact rates and charges sufficiently and quickly to maintain the associated financial metrics for a JAA's rating category would result in a higher rating assigned to this rating factor. In cases where the management has established planning targets for financial metrics that are lower than the associated financial metrics for a JAA's rating category and the joint action agency has consistently met those targets, we may score the JAA's willingness at a level higher than its financial metrics may indicate.

We may also map Factor 5 higher than the financial metrics may indicate based on the joint action agencies' and participants' demonstrated commitment and ability to maintain financial stability and resiliency. For example, an automatic monthly adjustment at both the JAA and its participants for changes in energy resource costs is an important rating consideration given the fluctuations in energy costs over the past decade. Such adjustment mechanisms serve to narrow the potential drain on the JAA and its participants' liquidity and the resulting impact on credit quality. Another example would be a JAA increasing its liquidity in advance of a construction project to mitigate incremental construction risk.

All-Requirement Agencies (25% total)

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Factor 5: Willingness to Recover Costs with Sound Financial Metrics	25%	Strong rate setting record. Rates set to maintain financial metrics in the 'Aaa' category.	Above average rate setting record. Rates set to maintain financial metrics in the 'Aa' category.	Adequate rate setting records. Rates set to maintain financial metrics in the 'A' category.	Below average rate setting records. Rates set to maintain financial metrics in the 'Baa' category.	Below average rate setting records. Rates set to maintain financial metrics in the 'Ba' category.	Record of insufficient rate relief and history of under recovery.

Limitations of the Grid and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings and additional factors that are not included in the grid that can be important in determining ratings.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within this sector. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to these issuers and represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four to five rating factors in the grid do not constitute the exhaustive treatment of all the considerations that are important for ratings in the JAA sector. The data we apply for purposes of grid analysis are primarily historical but our ratings are forward looking and may involve forward looking forecasts. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish or otherwise disclose. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlooks, peer actions, and other factors. As a result, the grid indicated rating is not expected to match the actual rating of each issuer in each case.

In choosing the factors for this rating methodology grid, we did not include certain important factors that are common to assessing an issuer's credit quality, such as the quality and experience of management, assessments of governance, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and variable over time. Therefore, ranking these factors by rating category in the grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors. We note, however, that these excluded factors do affect those that are included in the grid (such as management's experience affecting an issuer's revenue performance over time)

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental compliance, nuclear decommissioning trust obligations, and financial controls. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, there may be instances where a JAA's competitiveness will be given greater consideration in the assigned rating than what is indicated by the weighting in the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, management quality is a consideration frequently critical to ratings though it may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by conservative management that reduces business risk and thus reduces default risk but two identical companies might be rated the same if their only differentiating feature is that one has a conservative management while the other has an extremely conservative management.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the framework presented herein will enable a good approximation of our view on the credit quality of companies in the JAA sector. We consider additional factors, including future operating and financial performance that may deviate from historic performance, the quality of the management, financial controls, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Management Quality

The quality of management is an important factor supporting an issuer's credit strength. We normally meet with senior executives to assess management's business strategies, policies, and philosophies and evaluates management's performance relative to performance of competitors and our projections. Once established, a record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its current business philosophy.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations and the proper tone at the top, and consistency in accounting policies and procedures.

Weakness in the overall financial reporting processes, financial statement restatements or delays in reporting filings can be indications of a potential breakdown in internal controls.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include capital restructuring programs, litigations, outages, and extreme weather, among others.

Notching Conventions

While the factors and sub-factors within the grid are designed to include the key rating drivers reflecting the fundamental risks of JAAs, the grid alone cannot capture some of the wide-ranging factors that may impact the credit rating.

The notching factors are designed to adjust, either upwards or downwards, a JAA's indicated rating based on other considerations not adequately addressed in the rating grid. Our analysts may or may not assign a notch upwards or downwards to a rating as this is a case by case assessment determined by a rating committee. Unless specifically provided for in this methodology (e.g. diversity), the extent of notching by a rating committee may exceed more than one notch since these considerations (e.g. contractual structure) can potentially encompass a wide deviation from the assumptions incorporated in this methodology.

Contractual Structure and Legal Environment

JAAs that have unusually strong or weak offtake contract terms, legal structures, or inherent legal environments could be notched higher or lower. For example, a court validated offtake contract that incorporates a general obligation pledge of the municipal city in addition to the municipal utility's revenues would be considered exceptionally strong resulting in up to a 1-notch lift. Additionally, an all-requirement contract with exceptionally strong provisions, such as take-or-pay features, could benefit from a positive adjustment up to 1 notch.

On the other hand, a downward notching adjustment could be made for weak contractual features such as a lack of a participant step-up provision or similar feature in a multi-party contract. The importance of the step-up provision was highlighted when Massachusetts Municipal Wholesalers Electric Company's Project No 6's (MMWEC) participants in Vermont successfully challenged their take-or-pay contracts. In this case, MMWEC had to exercise the step up provision resulting in the Massachusetts participants taking the Vermont participants' share and assuming the associated costs. Another weak contractual feature is a limitation in the offtake contract. An example is a project that has an inflation indexed annual payment cap, which can be a requirement under state law. This limitation is unusual compared to a typical take-or-pay project and this feature reduces the effectiveness of a cost pass-through mechanism under its contract.

For take-or-pay projects, the flexibility to add assets by increasing leverage or partially or fully commingle funds with other businesses could be viewed as a downward notching consideration.

Concerns regarding the legal structure such as a JAA's undivided ownership interest in a project with co-owners that are of significantly weaker credit quality could result in a downward notching adjustment.

Participant Diversity and Concentration

In conjunction with a significant step-up provision, a diverse participant pool is a source of credit enhancement and could result in an upward adjustment by up to one notch to the grid-indicated rating. A diverse participant pool with low participant concentration serves to mitigate the potential risk of one or more of a JAA's participants defaulting since the non-defaulting participants would be required to step up their respective share to cover the defaulted member's share. The larger group of participants with low concentration would allow a greater number of participants to default. That said, the diversity benefit is limited to no more than one notch since regional and sector concentration results in meaningful correlation among participants. Additionally, a lack of a step-up provision is likely to result in no upward notching for diversity while a step up provision for less than 25% could result in lower notching than indicated.

Participant diversity is measured by three equally weighted factors: (1) total number of participants, (2) aggregate share of small participants (participants with less than 1% share of the JAA) and (3) aggregate share of the five largest participants. A joint action agency that has diversity measures all or mostly in the 'strong' category would benefit from a 1-notch lift while those that average in the 'medium' category would benefit from a 0.5 notch lift.

Weight	Participant Diversity and Concentration	Strong	Medium	Low
1/3	Total number of participants	More than 30	20 to 30	Less than 20
1/3	Aggregate share of small participants (participants with less than 1% share of a JAA)	Greater than 10%	5% to 10%	Less than 5%
1/3	Aggregate share of the five largest participants	Less than 40%	40% to 50%	More than 50%

Construction Risk

We assess each JAA's construction risks and may adjust the grid-indicated rating if there is unmitigated or insufficiently mitigated risk. Construction delays and cost overruns were major drivers of energy related municipal debt defaults Washington Public Power Supply System's (WPPSS) Projects 4 and 5, which defaulted on approximately $2.25 billion of debt in 1983, is the most notable example of massive construction delays and cost overruns that precipitated the largest municipal bond payment default in history at that time.

In our evaluation of construction risk, we look to third-party consulting engineers to provide an assessment of the risks associated with a particular project. The review of a well-defined project feasibility study or independent engineer's report is often a critical component of our evaluation. Factors such as the contractor's experience and financial strength, previous experience by the joint action agency in managing construction projects, and raw construction risk are key drivers of our overall construction risk assessment. Raw construction risk can vary from projects using small, simple cycle turbines to large, complex nuclear projects. The greater the raw construction risk, the higher the probability of construction delays and cost overruns. Inclusion of first-of-kind engineering is viewed as an additional risk contributor.

Our assessment will also consider typical construction risk mitigants such as an engineering, procurement and construction (EPC) contract that is fixed price, date certain, and lump price payment with liquidated damages provisions. Performance and payment bonds or letter of credit backing a contractor's obligations can be a key credit consideration depending on the contractor's credit quality. A joint action agency that has extensive and recent experience in managing comparable construction projects is also considered a strength.

Debt Service Reserve, Debt Structure and Financial Engineering

While a typical JAA benefits from a debt service reserve sized to one year of maximum annual debt service, some JAAs have no reserves or reserves with less than one year of debt service. We believe that fully funded maximum annual debt service reserve funds are an important part of revenue bondholder security, particularly given multiple party contractual arrangements and asset concentration in a typical joint action agency. The lack of a debt service reserve fund could result in a grid-indicated rating being adjusted downward. The grid-indicated rating may be adjusted down by one notch for JAAs with less than six months of debt service reserve fund while a half notch downward adjustment is made for joint action agencies with at least a 6 month debt service reserve but less than a full year. Debt service reserves backed by low rated or unrated financial guarantors are assumed to have no value.

As an alternative to notching, we will consider subtracting the difference between a fully funded annual debt service reserve and the actual debt service reserve funding level maintained by the JAA from adjusted days liquidity on hand in cases where the JAA maintains unrestricted liquidity beyond normal working capital requirements. If the pre-notched scorecard output is not affected by the revised adjusted days liquidity on hand, no notching adjustment might be applied for lack of a one- year debt service reserve. For example, a notching adjustment for lack of a debt service reserve might not be made if an all-requirement agency's liquidity drops from 400 adjusted days liquidity on hand to 260 adjusted days liquidity on hand after netting a full year of debt service.

We will also evaluate the existing and projected debt structure and may adjust the grid-indicated rating if unmitigated risks are identified. We will look at the bond covenanted legal protections (e.g. rate covenant), the debt amortization schedule, and the exposure to variable rate debt and interest rate swap agreements. We will evaluate debt management and interest rate swap policies, board oversight of interest rate swaps, and a JAA's disclosure of the risks and exposures associated with its debt.

We evaluate exposure to unhedged variable rate instruments in relation to the JAA's liquidity and its debt management record, including the absolute level of variable rate debt. We also closely evaluate the potential for financial stress related to a change in short-term interest rates, credit market volatility, and/or a tightening of available internal and external liquidity. We assess the joint action agency's interest rate swap derivatives and the circumstances under which the JAA will be required to post collateral and the right of the joint action agency's swap counterparty to terminate the swap should certain events occur, such as a downgrade of the JAA below a certain rating level.

We will also review the JAA's bond security provisions and if they are weak against the typical and standard provisions, this may affect the credit rating. For example, rate covenants that do not contain at least a sum sufficient provision will be viewed as a major credit negative.

Unmitigated Exposure to Wholesale Power Markets

JAAs that have excess energy resource supply or were established to supply the energy resource on a wholesale basis have potential additional credit risks should the JAA's financial operations not include mitigation factors to limit the impact of wholesale market price volatility. Wholesale exposure for a take-or-pay project is highly unusual though it could have wholesale exposure indirectly through its participants. On the other hand, an all-requirement agency could have varying degrees of wholesale exposure depending on expected customer needs and supply arrangements. Some power all- requirement agencies have used margins from selling excess power into wholesale energy markets to limit participant rates. Reliance on significant wholesale margins exposes the JAA to significant cash flow volatility and ultimately contributes to participant rate volatility and could present challenges to a JAA's willingness to raise rates on a timely basis. Exposure to the wholesale power market may result in an adjustment to the grid-indicated rating unless it is mitigated by wholesale power contracts with sound counterparties, strong available liquidity that could withstand a period of lower wholesale energy margins, and a timely and transparent rate-setting process.

Evaluating Unrated Participants in JAAs

Most JAAs include both rated and unrated participants. If the participant is not rated but the general obligation of the municipality that owns the utility is rated, we will also consider the municipality's rating and make a notching adjustment to determine the utility's credit quality based on the utility's operational and financial performance. For unrated entities that have at least a 5% share of a JAA and are not owned by a rated municipality, we will apply non-public, internal ratings on the unrated municipal utility.

If information is insufficient to assign a non-public, internal rating on the municipal utility as described above or for unrated participants with less than 5% share in the JAA, we will apply the Quantitative Ratings Estimator (QRATE) to assess the municipality's credit quality and make at least one notch downward adjustment to reflect the limited information utilized in the QRATE model and enterprise risk. In cases where the QRATE model is used and the participants share is at least 3% or greater, we will take a two notch downward adjustment on the QRATE.

Appendix A: Take-or-Pay Projects Factor Grid

Factor	Sub-Factor / Description	Weight	Aaa	Aa	A	Baa	Ba	B
1. Participant Credit Quality and Cost Recovery Framework	-Participant credit quality -Cost recovery structure and governance	45%	Participant credit quality at cap is at 'Aaa'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'Aa'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'A'. JAA & participant rates are unregulated.	Participant credit quality at cap is 'Baa'. OR JAA or majority of participant rates are regulated.	Participant credit quality at cap is 'Ba'. OR Below average governance or cost recovery.	Participant credit quality at cap is 'B'. OR Consistent record of poor governance or cost recovery.
2. Asset Quality	-Asset diversity, complexity and history	15%	Diversified portfolio of simple, proven assets and minimal reinvestment requirement.	Simple, proven asset and minimal reinvestment requirement.	Diverse portfolio of proven assets across technologies.	Standard, commercially proven asset(s).	Asset(s) with some operating challenges.	Largely unproven technology or poorly performing asset(s).
3. Competitiveness	-Cost competitiveness relative to market	15%	Extremely competitive asset through market cycle.Rates more than 50% below market. OR Very strong monopoly position with no alternative.	Very competitive asset through market cycle. Rates 30% to 50% below market. OR Strong monopoly position with very unlikely alternatives over the long term.	Competitive asset through market cycle.Rates 0% to 30% below market. OR Quasi monopoly with plausible alternatives over the medium to long term.	Competitive asset during average market. Rates up to 50% above market lows.	Competitive asset during market highs.Rates could be 100% above market lows.	Uncompetitive asset in nearly all price environments.Rates more than 100% above market lows.
4. Financial Strength and Liquidity	4(a) Adjusted days liquidity on hand(days)	10%	≥ 250	175 ≤ x < 250	100 ≤ x < 175	30 ≤ x < 100	15 ≤ x < 30	< 15
	4(b) Debt ratio (%)	5%	< 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x < 150%	150% ≤ x < 225%	≥ 225%
	4(c) Fixed obligation charge coverage ratio (x)	10%	≥ 3.0	2.2 ≤ x < 3.0	1.6 ≤ x < 2.2	1.0 ≤ x < 1.6		<1.0

Appendix B: All-Requirement Agencies Factor Grid

Factor	Sub-Factor / Description	Weight	Aaa	Aa	A	Baa	Ba	B
1. Participant Credit Quality and Cost Recovery Framework	-Weighted average participant credit quality-Unregulated rate setting including participants - Cost recovery structure and governance	25%	Avg. 'Aaa' participant credit quality. JAA & participant rates unregulated.	Avg 'Aa' participant credit quality. JAA & participant rates unregulated.	Avg 'A' participant credit quality. JAA & participant rates unregulated.	Avg 'Baa' participant credit quality.OR JAA or majority of participant rates are regulated.	Avg 'Ba' participant credit quality. OR Below average governance or cost recovery.	Avg 'B' participant credit quality. OR Consistent record of poor governance or cost recovery.
2. Resource Risk Management	-Resource diversity -Asset quality and complexity-Resource supply contract terms and counterparty credit quality-Wholesale market purchase exposure	10%	Exceptional energy resource risk management. Less than 10% market purchases. OR Diverse, proven portfolio. Single asset or fuel less than 20% of supply.ORLong-term, competitive supply contract with Aaa rated supplier	Very strong energy resource risk management.10-20% from market purchases. OR Diverse, proven assets. Single asset or fuel comprises 20 - 40% of the energy resource mix.ORLong-term, competitive supply contract with Aa rated supplier	Strong energy resource risk management.20-30% from market purchases.OR Proven assets. Single asset or fuel comprises 41- 55% of the energy resource mix. OR Well managed portfolio of supply contracts with 'A' rated suppliers.	Average energy resource risk management.30-40% from market purchases. OR Single asset or fuel provides 56 - 75% of the energy resource mix.OR Adequately managed supply portfolio with 'Baa' rated suppliers	Below average energy resource risk management.40- 60% from market purchases. OR Single asset or fuel provides over 76 - 100% of the energy resource mix.OR Adequately managed supply portfolio with 'Ba' or lower rated suppliers.	Poor energy resource risk management.More than 60% from market purchases. OR Assets with unproven technology or history of problems OR Poorly managed supply portfolio with 'Ba' or lower rated suppliers.
3. Competitiveness	-Cost competitiveness relative to regional peers	15%	Rates more than 25% below average	Rates below average by more than 10% to 25%	Rates 10% below average to less than 5% above average	Rates above average by 5% to less than 25%	Rates above average by 25% but not more than 50%	Rates at least 50% above average
4. Financial Strength and Liquidity	4(a) Adjusted days liquidity on hand(days)	10%	≥ 250	150 ≤ x < 250	90 ≤ x < 150	30 ≤ x < 90	15 ≤ x < 30	< 15
	4(b) Debt ratio (%)	5%	< 50%	50% ≤ x < 70%	70% ≤ x < 100%	100% ≤ x < 150%	150% ≤ x < 200%	≥ 200%
	4(c) Fixed obligation charge coverage ratio (x)	10%	≥ 2.0x	1.4x ≤ x < 2.0x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	<1.0x
	-Rate setting record-Timeliness of rate recovery -Stability and strength of financial metrics	25%	Strong rate setting record.Rates set to maintain financial metrics in the 'Aaa' category.	Above average rate setting record. Rates set to maintain financial metrics in the 'Aa' category.	Adequate rate setting records. Rates set to maintain financial metrics in the 'A' category.	Below average rate setting records. Rates set to maintain financial metrics in the 'Baa' category.	Below average rate setting records. Rates set to maintain financial metrics in the 'Ba' category.	Record of insufficient rate relief and history of under recovery.

Appendix C: Definition of Ratios

Liquidity: Adjusted Days Liquidity on Hand (days)

((Available unrestricted cash and investments) + (eligible unused bank line)) x 365 days / (JAA's annual operating and maintenance expenses)

Leverage: Debt Ratio (%)

(Gross debt –debt service funds –interest payable and debt service reserve funds) / (Gross fixed plant assets –accumulated depreciated on plant plus net working capital (net current liquid assets unrelated to debt – net current liabilities unrelated to debt))

Financial Operating Resiliency: Fixed Obligation Charge Coverage Ratio (x)

(Annual recurring revenues plus interest income)-(recurring annual operating expenses-depreciation expense and adjusted for other non-cash items – debt service portion of payments to take-or-pay project) / (aggregate annual debt service plus debt service portion of payments to take-or-pay project).

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information.

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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RRA Regulatory Focus
Major Rate Case Decisions – January – December 2018

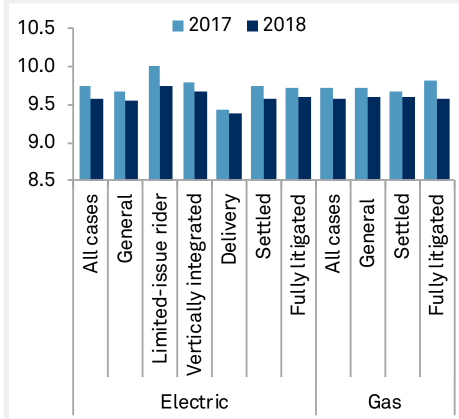
Despite a rising interest rate environment and increased volatility in financial markets in the U.S., the equity returns authorized energy utilities nationwide continued to fall in 2018. Based on data gathered by Regulatory Research Associates, a group within S&P Global Market Intelligence, the average ROE authorized electric utilities was 9.59% in rate cases decided during 2018, somewhat below the 9.74% average for cases decided in 2017. There were 48 electric ROE determinations in 2018 versus 53 in 2017. This data includes several limited-issue rider cases. Excluding these cases from the data, the average authorized ROE was 9.55% in rate cases decided in 2018, somewhat below the 9.68% average in 2017. The difference between the ROE averages including rider cases and those excluding the rider cases is largely driven by ROE premiums of up to 200 basis points approved by the Virginia State Corporation Commission in riders related to certain generation projects (see the Virginia Commission Profile).

The average ROE authorized gas utilities was also 9.59% in cases decided during 2018 versus 9.72% in 2017. There were 41 gas cases that included an ROE determination in 2018, versus 24 in 2017. The 2017 data includes an 11.88% ROE approved for an Alaska utility that was more than 130 basis points above the next-highest ROE for a gas utility that year. Absent this "outlier," the 2017 gas ROE average is 9.63%.

In 2018, the median ROE authorized in all electric utility rate cases was 9.57%, largely in line with the 9.60% median observed in 2017. For gas utilities, the median authorized ROE in cases decided in 2018 was 9.60%, equal to the 9.60% in 2017.

From a longer-term perspective, interest rates, as measured by the 30-year U.S. Treasury bond yield, fell almost steadily from the early 1980s until 2015 or so, placing downward pressure on authorized ROEs. Even though the decline has been less dramatic in the period since 1990, average authorized ROEs fell below 10% for gas utilities in 2011 and for electric utilities in 2014. While the U.S. Federal Reserve has begun to unwind its monetary policy and raise interest rates, authorized ROEs have continued to fall modestly.

Authorized return on equity (%)
Dashboard



Electric	2017	2018	
All cases	9.74	9.59	▼
General rate cases	9.68	9.55	▼
Limited-issue rider cases	10.01	9.74	▼
Vertically integrated cases	9.80	9.68	▼
Delivery cases	9.43	9.38	▼
Settled cases	9.75	9.57	▼
Fully litigated cases	9.73	9.61	▼
Gas	**2017**	**2018**	
All cases	9.72	9.59	▼
General rate cases	9.72	9.60	▼
Settled cases	9.68	9.60	▼
Fully litigated cases	9.82	9.59	▼
U.S. Treasury	**2017**	**2018**	
30-Year Bond Yield	2.89	3.11	▲

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

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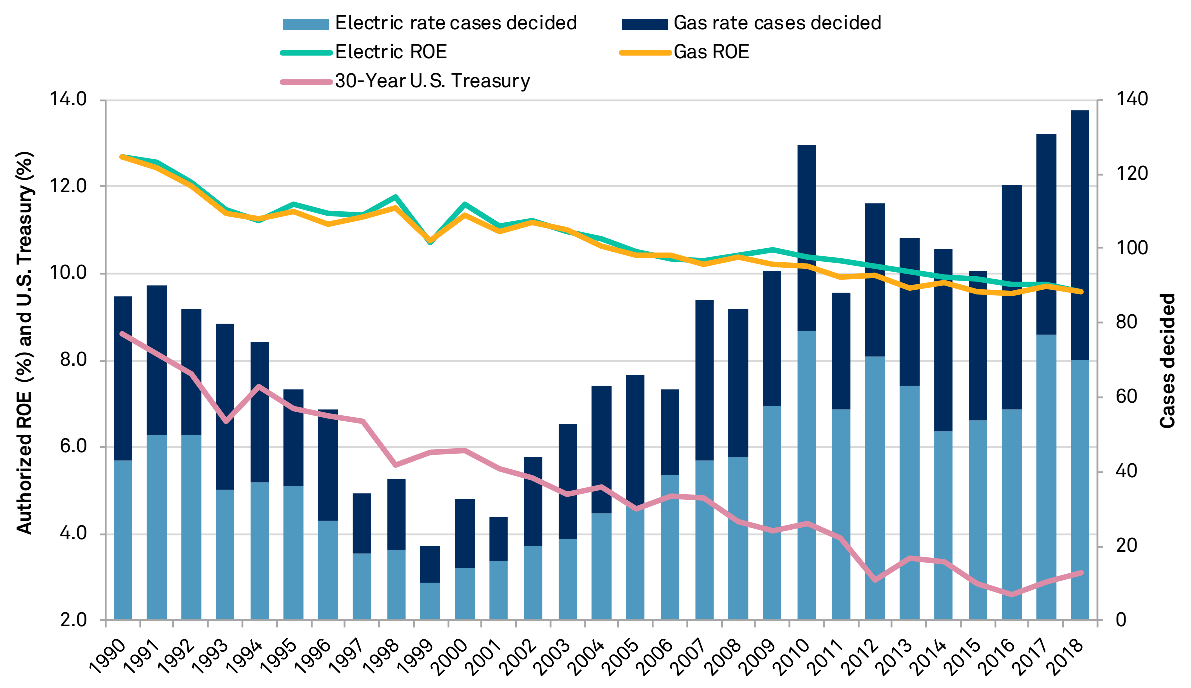
Average electric and gas authorized ROEs and number of rate cases decided



Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Rate case activity has been brisk with almost 140 cases decided in 2018, slightly above the level in 2017. In fact, since 2010 rate case activity has been robust, with 100 or more cases adjudicated in seven of the last nine calendar years. This count includes electric and gas cases where no ROEs have been specified; however, withdrawn cases are not included in this count.

Increased costs associated with environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, storm and disaster recovery, cybersecurity and employee benefits argue for the continuation of an active rate case agenda over the next few years. In addition, the need to address the impacts of the 2017 federal tax reform has caused rate case agendas to be more active than previously expected.

In addition, rising interest rates could also contribute to increased rate case activity. As the Federal Reserve moves forward with its policy initiated in 2015 to gradually raise the federal funds rate, utilities will face higher capital costs and need to initiate rate cases to reflect these higher capital costs in rates.

So far, authorized ROEs have continued to decline despite increases in interest rates in 2017 and 2018. The Federal Reserve increased the federal funds rate three times in 2017 and four more times in 2018, including the most recent change in December 2018. At that time, policymakers signaled that two more hikes are likely in 2019. However, recent commentary from Federal Reserve Chairman Jerome Powell indicates a willingness to be “patient” about hikes in 2019, with the course of policy to be dependent on data and market conditions. However, it is important to note that increases in the fed funds rate do not necessarily move in lockstep with longer-term treasuries. Thus far in 2019, the yield on the 30-year Treasury bond has decreased somewhat as the recent U.S. government shutdown and trade concerns have stoked fears of slower economic growth.

Similarly, authorized ROEs do not move in lockstep with interest rates, and it may be some time before a noticeable change in average authorized ROEs is discernible. Aside from the fact that the normal process of filing and completing rate cases takes time, intervenors continue to argue that factors such as limited-issue riders and decoupling mechanisms reduce risk and warrant lower authorized ROEs. In addition, anecdotally, RRA has observed instances where the company has argued for a higher ROE authorization based on the changes in broader interest rates, and the commission has found that the prevailing change in interest rates was not significant enough to warrant a specific adjustment to the authorized ROE.

Capital structure trends

To offset the negative impact of federal tax reform, many utilities in 2018 sought higher equity ratios, and the authorized equity ratios adopted by utility commissions were modestly higher than the levels observed in 2017. The average authorized equity ratio for electric utility cases nationwide was 48.95% in 2018, versus 48.90% in 2017. The average allowed equity ratio for gas utilities nationwide was 50.09% in 2018, versus 49.88% in 2017.

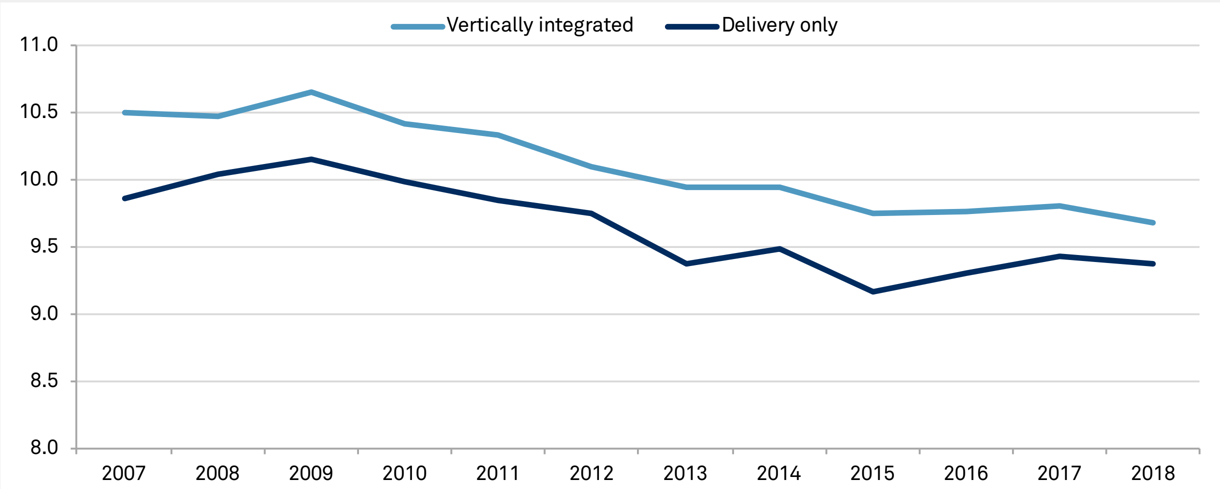
The aforementioned averages include allowed equity ratios adopted by utility commissions in Arkansas, Florida, Indiana and Michigan — jurisdictions that authorize capital structures that include cost-free items or tax credit balances. Excluding these jurisdictions, the average authorized equity ratio for electric utilities nationwide was 50.53% in cases decided during 2018 versus 50.02% in 2017. By comparison, for gas utilities, the average allowed equity ratio was 51.47% in 2018 versus 51.13% in 2017.

Taking a longer-term view, equity ratios have generally increased over the last 15 years — the average equity ratio approved in electric rate cases decided during 2004 was 46.95%, while the average for gas utilities was 45.81%. Many commissions began approving more equity-rich capital structures in the wake of the 2008 financial crisis.

A more granular look at ROE trends

The discussion thus far has looked broadly at trends in authorized ROEs; the sections that follow provide a more granular view based upon the types of proceedings/decisions in which these ROEs were established.

Average authorized electric ROEs (%)



Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA has observed that there can be significant differences between the ROE averages from one subcategory of cases to another.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations.

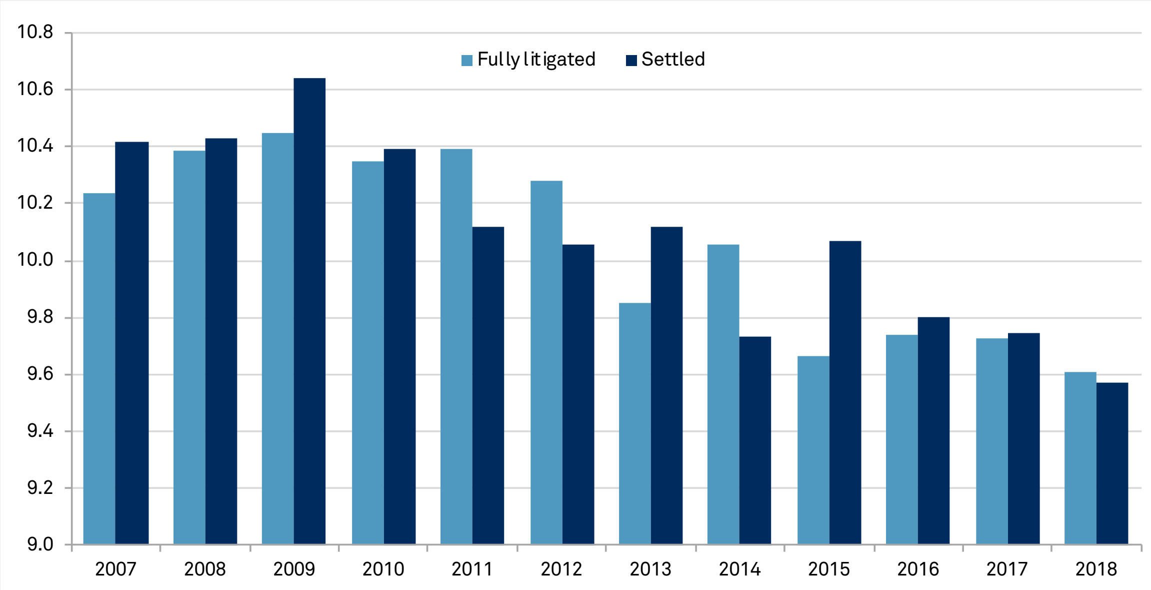
Comparing electric vertically integrated cases versus delivery-only proceedings over the past 12 years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets.

Based on rate cases concluded in 2018, the industry average ROE for vertically integrated electric utilities was 9.68%, versus 9.8% for cases decided in 2017. For electric distribution-only utilities, the industry average ROE authorized in 2018 was 9.38% versus 9.43% in 2017.

Settlements have frequently been used to resolve rate cases over the last several years, and in many cases, these settlements are "black box" in nature and do not specify the ROE and other typical rate case parameters underlying the stipulated rate change. However, some states preclude this type of treatment, and so, settlements must specify these values if not the specific adjustments from which these values were derived.

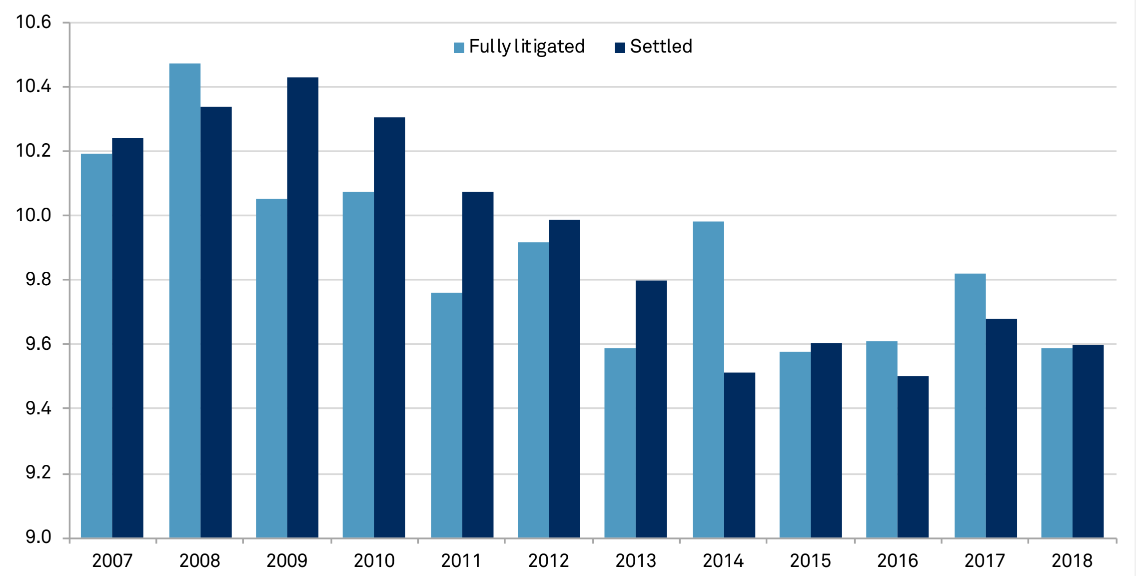
For both electric and gas cases, RRA has found no discernible pattern in the average authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others, it was higher for settled cases, and in a handful of years, the authorized ROE was similar for both fully litigated and settled cases.

Average authorized electric ROEs, settled versus fully litigated cases (%)



Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Average authorized gas ROEs, settled versus fully litigated cases (%)



Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Over the last several years, the annual average authorized ROEs in electric cases that involve limited-issue riders were typically meaningfully higher than those approved in general rate cases, driven by the ROE premiums authorized in Virginia. Limited-issue rider cases in which a separate ROE is determined have had limited use in the gas industry, as most of the gas riders rely on ROEs approved in a previous base rate case.

The table on page 7 shows the average ROE authorized in major electric and gas rate decisions annually since 1990 and by quarter since 2014, followed by the number of observations in each period. The tables on page 8 indicate the composite electric and gas industry data for all major cases, summarized annually since 2004 and by quarter for the past six quarters.

Included in the tables beginning on page 9 of this report are comparisons since 2007 of average authorized ROEs for settled versus fully litigated cases, general rate cases versus limited issue rider proceedings and vertically integrated cases versus delivery-only cases.

The individual electric and gas cases decided in 2018 are listed starting from page 11, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, the ROE and the percentage of common equity in the adopted capital structure. Next, RRA indicates the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The simple mean is utilized for the return averages. In addition, the average equity returns indicated in this report reflect the ROEs approved in cases that were decided during the specified time periods and are not necessarily representative of either the average currently authorized ROEs for utilities industrywide or the returns actually earned by the utilities.

The table and graph below track the average and median equity return authorized for all electric and gas rate cases combined by year for the last 29 years. As the table indicates, since 1990 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame. The combined average and median equity returns authorized for electric and gas utilities in each of the years 1990 through 2018 and the number of observations for each year are presented in the accompanying tables.

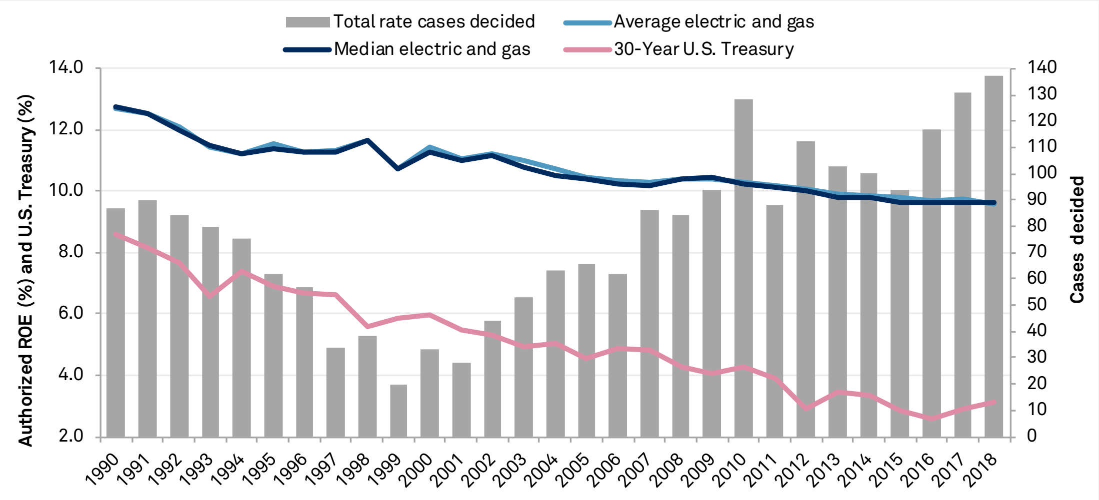
Please note: In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

Composite electric and gas annual authorized ROEs: 1990 — 2018

Year	Average ROE (%)	Median ROE (%)	No. of Observations	Year	Average ROE (%)	Median ROE (%)	No. of Observations
1990	12.69	12.75	71	2005	10.46	10.40	50
1991	12.50	12.50	73	2006	10.35	10.25	41
1992	12.06	12.00	73	2007	10.26	10.20	73
1993	11.40	11.50	68	2008	10.40	10.39	69
1994	11.23	11.22	52	2009	10.39	10.43	70
1995	11.53	11.38	41	2010	10.28	10.22	100
1996	11.26	11.25	35	2011	10.19	10.10	58
1997	11.31	11.28	22	2012	10.09	10.00	93
1998	11.64	11.65	20	2013	9.92	9.80	70
1999	10.73	10.70	12	2014	9.86	9.78	64
2000	11.44	11.25	22	2015	9.76	9.65	46
2001	11.04	11.00	20	2016	9.68	9.60	68
2002	11.19	11.16	33	2017	9.73	9.60	77
2003	10.98	10.75	45	2018	9.59	9.60	89
2004	10.72	10.50	43				

Data compiled Jan. 28, 2019
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Composite electric and gas authorized ROEs and number of rate cases



Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

ROEs authorized January 1990 - December 2018

		Electric utilities			Gas utilities		
Year	Period	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	40	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
	1st quarter	10.23	9.86	8	9.54	9.60	6
	2nd quarter	9.83	9.70	5	9.84	9.95	8
	3rd quarter	9.87	9.78	12	9.45	9.33	6
	4th quarter	9.78	9.80	13	10.28	10.20	6
2014	**Full year**	**9.91**	**9.78**	**38**	**9.78**	**9.78**	**26**
	1st quarter	10.37	9.83	9	9.47	9.05	3
	2nd quarter	9.73	9.60	7	9.43	9.50	3
	3rd quarter	9.40	9.40	2	9.75	9.75	1
	4th quarter	9.62	9.55	12	9.68	9.75	9
2015	**Full year**	**9.85**	**9.65**	**30**	**9.60**	**9.68**	**16**
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	**Full year**	**9.77**	**9.75**	**42**	**9.54**	**9.50**	**26**
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.74	9.60	19	9.68	9.55	8
2017	**Full year**	**9.74**	**9.60**	**53**	**9.72**	**9.60**	**24**
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.63	9.70	11	9.69	9.60	13
	4th quarter	9.42	9.50	11	9.55	9.60	15
2018	**1st half**	**9.59**	**9.57**	**48**	**9.59**	**9.60**	**41**

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

S&P Global
Market Intelligence

Electric utilities — summary table

	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.71	20	10.81	21	46.96	19	1,806.3	29
2005	Full year	8.44	23	10.51	24	47.34	23	936.1	31
2006	Full year	8.32	26	10.32	26	48.54	25	1,318.1	39
2007	Full year	8.18	37	10.30	38	47.88	36	1,405.7	43
2008	Full year	8.21	39	10.41	37	47.94	36	2,823.2	44
2009	Full year	8.24	40	10.52	40	48.57	39	4,191.7	58
2010	Full year	8.01	62	10.37	61	48.63	57	4,921.9	78
2011	Full year	8.00	43	10.29	42	48.26	42	2,595.1	56
2012	Full year	7.95	51	10.17	58	50.69	52	3,080.7	69
2013	Full year	7.66	45	10.03	49	49.25	43	3,328.6	61
2014	Full year	7.60	32	9.91	38	50.28	35	2,053.7	51
2015	Full year	7.38	35	9.85	30	49.54	30	1,891.5	52
2016	Full year	7.28	41	9.77	42	48.91	41	2,332.1	57
	1st quarter	6.97	15	9.87	15	47.95	15	1,028.3	24
	2nd quarter	7.11	9	9.63	14	48.77	9	597.0	19
	3rd quarter	7.43	5	9.66	5	49.63	5	558.6	10
	4th quarter	7.32	19	9.74	19	49.51	19	511.7	24
2017	**Full year**	**7.18**	**48**	**9.74**	**53**	**48.90**	**48**	**2,695.6**	**77**
	1st quarter	6.89	13	9.75	13	48.89	13	592.6	14
	2nd quarter	6.78	13	9.54	13	47.94	13	372.4	18
	3rd quarter	7.10	11	9.63	11	51.15	11	268.0	13
	4th quarter	6.81	12	9.42	11	48.12	12	643.0	22
2018	**Full year**	**6.89**	**49**	**9.59**	**48**	**48.95**	**49**	**1,876.0**	**67**

Gas utilities — summary table

	Period	ROR (%)	Number of observations	ROE (%)	Number of observations	Common equity to total capital (%)	Number of observations	Rate change amount ($M)	Number of observations
2004	Full year	8.51	23	10.63	22	45.81	22	306.0	33
2005	Full year	8.24	29	10.41	26	48.40	24	465.4	35
2006	Full year	8.44	17	10.40	15	47.24	16	392.5	23
2007	Full year	8.11	31	10.22	35	48.47	28	645.3	43
2008	Full year	8.49	33	10.39	32	50.35	32	700.0	40
2009	Full year	8.15	29	10.22	30	48.49	29	438.6	36
2010	Full year	7.99	40	10.15	39	48.70	40	776.5	50
2011	Full year	8.09	18	9.92	16	52.49	14	367.0	31
2012	Full year	7.98	30	9.94	35	51.13	32	264.0	41
2013	Full year	7.43	21	9.68	21	50.60	20	498.7	40
2014	Full year	7.65	27	9.78	26	51.11	28	544.2	48
2015	Full year	7.34	16	9.60	16	49.93	16	494.1	40
2016	Full year	7.08	28	9.54	26	50.06	26	1,263.8	59
	1st quarter	7.20	2	9.60	3	51.57	3	71.0	9
	2nd quarter	7.27	5	9.47	7	49.15	5	85.2	13
	3rd quarter	7.07	8	10.14	6	46.58	7	128.6	17
	4th quarter	7.43	9	9.68	8	52.30	9	125.8	15
2017	**Full year**	**7.26**	**24**	**9.72**	**24**	**49.88**	**24**	**410.7**	**54**
	1st quarter	7.14	5	9.68	6	51.05	6	198.0	9
	2nd quarter	7.08	7	9.43	7	50.83	6	73.8	11
	3rd quarter	6.86	15	9.69	13	48.55	15	280.8	22
	4th quarter	7.05	17	9.55	15	50.89	16	384.9	24
2018	**Full year**	**7.00**	**44**	**9.59**	**41**	**50.09**	**43**	**937.6**	**66**

Data compiled Jan. 28, 2019
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Electric authorized ROEs: 2007 - 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.42	10.33	14	10.23	10.15	24
2008	10.41	10.30	37	10.43	10.25	17	10.39	10.54	20
2009	10.52	10.50	40	10.64	10.62	16	10.45	10.50	24
2010	10.37	10.30	61	10.39	10.30	34	10.35	10.10	27
2011	10.29	10.17	42	10.12	10.07	16	10.39	10.25	26
2012	10.17	10.08	58	10.06	10.00	29	10.28	10.25	29
2013	10.03	9.95	49	10.12	9.98	32	9.85	9.75	17
2014	9.91	9.78	38	9.73	9.75	17	10.05	9.83	21
2015	9.85	9.65	30	10.07	9.72	14	9.66	9.62	16
2016	9.77	9.75	42	9.80	9.85	17	9.74	9.60	25
2017	9.74	9.60	53	9.75	9.60	29	9.73	9.56	24
2018	9.59	9.57	48	9.57	9.63	26	9.61	9.43	22

General rate cases versus limited issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.32	10.23	36	9.90	9.90	1
2008	10.41	10.30	37	10.37	10.30	35	11.11	11.11	2
2009	10.52	10.50	40	10.52	10.50	38	10.55	10.55	2
2010	10.37	10.30	61	10.29	10.26	58	11.87	12.30	3
2011	10.29	10.17	42	10.19	10.14	40	12.30	12.30	2
2012	10.17	10.08	58	10.02	10.00	51	11.57	11.40	6
2013	10.03	9.95	49	9.82	9.82	40	11.34	11.40	7
2014	9.91	9.78	38	9.76	9.75	32	10.96	11.00	5
2015	9.85	9.65	30	9.60	9.53	23	10.87	11.00	6
2016	9.77	9.75	42	9.60	9.60	32	10.31	10.55	10
2017	9.74	9.60	53	9.68	9.60	42	10.01	9.95	10
2018	9.59	9.57	48	9.55	9.57	38	9.74	9.70	10

Vertically integrated cases versus delivery-only cases

	All cases			Vertically integrated cases			Delivery only cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.30	10.20	38	10.50	10.45	26	9.86	9.98	10
2008	10.41	10.30	37	10.48	10.47	26	10.04	10.25	9
2009	10.52	10.50	40	10.66	10.66	28	10.15	10.30	10
2010	10.37	10.30	61	10.42	10.40	41	9.98	10.00	17
2011	10.29	10.17	42	10.33	10.20	28	9.85	10.00	12
2012	10.17	10.08	58	10.10	10.20	39	9.75	9.73	12
2013	10.03	9.95	49	9.95	10.00	31	9.37	9.36	9
2014	9.91	9.78	38	9.94	9.90	19	9.49	9.55	13
2015	9.85	9.65	30	9.75	9.70	17	9.17	9.07	6
2016	9.77	9.75	42	9.77	9.78	20	9.31	9.33	12
2017	9.74	9.60	53	9.80	9.65	28	9.43	9.55	14
2018	9.59	9.57	48	9.68	9.75	22	9.38	9.43	16

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas average authorized ROEs: 2007 - 2018

Settled versus fully litigated cases

	All cases			Settled cases			Fully litigated cases		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.24	10.18	22	10.20	10.40	13
2008	10.39	10.45	32	10.34	10.28	20	10.47	10.68	12
2009	10.22	10.26	30	10.43	10.40	13	10.05	10.15	17
2010	10.15	10.10	39	10.30	10.15	12	10.08	10.10	27
2011	9.92	10.03	16	10.08	10.08	8	9.76	9.80	8
2012	9.94	10.00	35	9.99	10.00	14	9.92	9.90	21
2013	9.68	9.72	21	9.80	9.80	9	9.59	9.60	12
2014	9.78	9.78	26	9.51	9.50	11	9.98	10.10	15
2015	9.60	9.68	16	9.60	9.60	11	9.58	9.80	5
2016	9.54	9.50	26	9.50	9.50	16	9.61	9.58	10
2017	9.72	9.60	24	9.68	9.60	17	9.82	9.50	7
2018	9.59	9.60	41	9.60	9.60	24	9.59	9.50	17

General rate cases versus limited issue riders

	All cases			General rate cases			Limited issue riders		
Year	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
2007	10.22	10.20	35	10.22	10.20	35	—	—	0
2008	10.39	10.45	32	10.39	10.45	32	—	—	0
2009	10.22	10.26	30	10.22	10.26	30	—	—	0
2010	10.15	10.10	39	10.15	10.10	39	—	—	0
2011	9.92	10.03	16	9.91	10.05	15	10.00	10.00	1
2012	9.94	10.00	35	9.93	10.00	34	10.40	10.40	1
2013	9.68	9.72	21	9.68	9.72	21	—	—	0
2014	9.78	9.78	26	9.78	9.78	26	—	—	0
2015	9.60	9.68	16	9.60	9.68	16	—	—	0
2016	9.54	9.50	26	9.53	9.50	25	9.70	9.70	1
2017	9.72	9.60	24	9.73	9.60	23	9.50	9.50	1
2018	9.59	9.60	41	9.60	9.60	40	9.50	9.50	1

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($M)	Footnotes
01/18/18	Kentucky Power Company	KY	6.44	9.70	41.68	2/17	Year-end	12.3	B
01/31/18	Public Service Company of Oklahoma	OK	6.88	9.30	48.51	12/16	Year-end	75.5	R
02/02/18	Interstate Power and Light Company	IA	7.49	9.98	49.02	12/16	Average	130.0	B, I
02/06/18	Mississippi Power Company	MS	6.62	8.58	50.45	12/18	Average	—	B, LIR, 1
02/09/18	Delmarva Power & Light Company	MD	—	—	—	9/17	—	13.4	B, D
02/09/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-6.0	LIR,2
02/14/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-11.5	LIR,3
02/20/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	3/19	Average	-24.6	LIR,4
02/21/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	3/19	Average	0.2	LIR,5
02/23/18	Duke Energy Progress, LLC	NC	7.09	9.90	52.00	12/16	Year-end	194.0	B
02/27/18	Virginia Electric and Power Company	VA	7.20	11.20	50.23	3/19	Average	14.9	LIR,6
03/12/18	ALLETE (Minnesota Power)	MN	7.06	9.25	53.81	12/17	Average	12.0	I
03/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	160.0	B, D, Z
03/20/18	Georgia Power Company	GA	—	—	—	12/18	—	-50.0	LIR,7
03/29/18	Consumers Energy Company	MI	5.89	10.00	40.89	9/18	Average	72.3	I,R,*
2018	**1st quarter: averages/total**		**6.89**	**9.75**	**48.89**			**592.6**	
	Observations		**13**	**13**	**13**			**14**	
04/02/18	Appalachian Power Company	VA	—	—	—	—	—	—	LIR,8
04/12/18	Indiana Michigan Power Company	MI	5.76	9.90	36.38	12/18	Average	49.1	*
04/13/18	Duke Energy Kentucky, Inc.	KY	6.83	9.73	49.25	3/19	Average	8.4	
04/18/18	Connecticut Light and Power Company	CT	7.09	9.25	53.00	12/16	Average	124.7	B, D, Z
04/18/18	DTE Electric Company	MI	5.34	10.00	36.84	10/18	Average	74.4	I, R, *
04/26/18	Public Service Company of Colorado	CO	—	—	—	—	—	—	9
04/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	10.8	
05/08/18	Kentucky Utilities Company	VA	—	—	—	12/16	—	1.8	B
05/10/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	6/18	—	2.8	LIR,10
05/16/18	Appalachian Power Company	VA	—	—	—	6/19	—	1.0	LIR,11
05/23/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	10/17	Year-end	1.9	LIR
05/30/18	Indiana Michigan Power Company	IN	5.51	9.95	35.73	12/18	Year-end	153.4	B,Z,*
05/30/18	Northern Indiana Public Service Company	IN	—	—	—	11/17	Year-end	12.6	LIR
05/31/18	Potomac Electric Power Company	MD	7.03	9.50	50.44	12/17	—	-15.0	B, D
06/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	19.7	B, D, Z
06/19/18	Oklahoma Gas and Electric Company	OK	—	—	—	9/17	—	-64.0	B,12
06/22/18	Hawaiian Electric Company, Inc.	HI	7.57	9.50	57.10	12/17	Average	-0.6	B, I
06/22/18	Duke Energy Carolinas, LLC	NC	7.35	9.90	52.00	12/16	Year-end	-13.0	B,R
06/28/18	Emera Maine	ME	7.18	9.35	49.00	12/16	Average	4.5	D
06/29/18	Hawaii Electric Light Company, Inc.	HI	7.80	9.50	56.69	12/16	Average	-0.1	B, I
	2nd quarter: averages/total		6.78	9.54	47.94			372.4	
	Observations		13	13	13			18	

(continued on next page)

Electric utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($M)	Footnotes
07/03/18	Virginia Electric and Power Company	VA	6.71	9.20	50.23	8/19	Average	3.3	LIR,13
07/03/18	Virginia Electric and Power Company	VA	7.21	10.20	50.23	8/19	Average	-11.1	LIR,14
07/10/18	Duke Energy Florida, LLC	FL	—	—	—	—	—	200.5	B, LIR, Z,15
07/25/18	Atlantic City Electric Company	NJ	—	—	—	12/18	—	—	D,16
08/08/18	Potomac Electric Power Company	DC	7.45	9.53	50.44	12/17	—	-24.1	B, D
08/21/18	Delmarva Power & Light Company	DE	6.78	9.70	50.52	12/17	—	-6.9	B, D, I
08/24/18	Narragansett Electric Company	RI	6.97	9.28	50.95	6/17	Average	28.9	B, D, Z,
08/31/18	Appalachian Power Company	WV	—	—	—	12/17	—	91.6	B, LIR, 17
09/05/18	Southwestern Public Service Company	NM	6.85	9.10	51.00	6/18	Year-end	8.1	
09/14/18	Wisconsin Power and Light Company	WI	7.09	10.00	52.00	12/20	Average	0.0	B,18
09/20/18	Madison Gas and Electric Company	WI	7.10	9.80	56.06	12/20	Average	-9.2	B
09/26/18	Otter Tail Power Company	ND	7.64	9.77	52.50	12/18	Average	7.4	B, I
09/26/18	Dayton Power and Light Company	OH	7.27	10.00	47.52	5/16	Date certain	29.8	B, D
09/27/18	Westar Energy, Inc.	KS	7.06	9.30	51.24	6/17	Year-end	-50.3	B
2018	**3rd quarter: averages/total**		**7.10**	**9.63**	**51.15**			**268.0**	
	Observations		**11**	**11**	**11**			**13**	
10/04/18	UGI Utilities, Inc.	PA	7.48	9.85	54.02	9/19	Year-end	3.2	D
10/09/18	Duke Energy Indiana, LLC	IN	—	—	—	12/17	—	14.3	LIR,19
10/29/18	Public Service Electric and Gas Company	NJ	6.99	9.60	54.00	6/18	Year-end	88.9	B, D, I
10/31/18	Indianapolis Power & Light Company	IN	6.59	9.99	39.67	6/17	Year-end	43.9	B,*
10/31/18	Kansas City Power & Light Company	MO	—	—	—	6/17	—	-21.1	B
10/31/18	KCP&L Greater Missouri Operations Company	MO	—	—	—	6/17	—	-24.0	B
11/01/18	Ameren Illinois Company	IL	6.99	8.69	50.00	12/17	Year-end	73.7	D
11/28/18	Northern Indiana Public Service Company	IN	—	—	—	5/18	Year-end	14.8	B, LIR,19
12/04/18	Commonwealth Edison Company	IL	6.52	8.69	47.11	12/17	Year-end	-26.1	D
12/05/18	Southern Indiana Gas and Electric Company	IN	—	—	—	4/18	Year-end	3.9	LIR,19
12/07/18	Southwestern Public Service Company	TX	—	—	—	6/17	—	0.0	B, I,20
12/12/18	Entergy Arkansas, LLC	AR	5.26	—	36.55	12/19	Average	189.7	B,*
12/13/18	Kansas City Power & Light Company	KS	7.07	9.30	49.09	9/17	—	-3.9	B
12/14/18	Portland General Electric Company	OR	7.30	9.50	50.00	12/19	Year-end	8.6	B
12/19/18	Duke Energy Ohio, Inc.	OH	7.54	9.84	50.75	3/17	Date certain	-19.2	B, D
12/19/18	Virginia Electric and Power Company	VA	6.86	9.20	51.37	1/20	Average	47.3	LIR,21
12/20/18	Duquesne Light Company	PA	—	—	—	12/19	—	92.7	B, D
12/20/18	PECO Energy Company	PA	—	—	—	12/19	—	24.9	B, D
12/20/18	Entergy Texas, Inc.	TX	—	—	—	12/17	—	53.2	B, I
12/20/18	Texas-New Mexico Power Company	TX	7.89	9.65	45.00	12/17	Year-end	22.8	B, D
12/21/18	Green Mountain Power Corporation	VT	5.26	9.30	49.85	9/17	Average	23.5	D
12/27/18	NSTAR Electric Company	MA	—	—	—	—	—	31.9	D,22
2018	**4th quarter: averages/total**		6.81	9.42	48.12			643.0	
	Observations		12	11	12			22	
2018	**Full year: averages/total**		6.89	9.59	48.95			1,876.0	
	Observations		49	48	49			67	

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($M)	Footnotes
01/24/18	Indiana Gas Company, Inc.	IN	—	—	—	6/17	Year-end	8.4	LIR,23
01/24/18	Southern Indiana Gas and Electric Company, Inc.	IN	—	—	—	6/17	Year-end	1.3	LIR,23
01/31/18	Northern Illinois Gas Company	IL	7.26	9.80	52.00	12/18	Average	93.5	R
02/21/18	Missouri Gas Energy	MO	7.20	9.80	54.16	12/16	Year-end	15.2	
02/21/18	Spire Missouri Inc.	MO	7.20	9.80	54.16	12/16	Year-end	18.0	
02/27/18	Atmos Energy Corporation	KS	—	—	—	9/17	—	0.8	LIR,24
02/28/18	Northern Utilities, Inc.	ME	7.53	9.50	50.00	12/16	Average	-0.1	
03/15/18	Niagara Mohawk Power Corporation	NY	6.53	9.00	48.00	3/19	Average	45.5	B, Z
03/26/18	Pivotal Utility Holdings, Inc.	FL	—	10.19	48.00	12/18	—	15.3	B, Z, I
2018	**1st quarter: averages/total**		**7.14**	**9.68**	**51.05**			**198.0**	
	Observations		**5**	**6**	**6**			**9**	
04/26/18	Avista Corporation	WA	7.50	9.50	48.50	12/16	Average	-2.1	
04/27/18	Liberty Utilities (EnergyNorth Natural Gas) Corp.	NH	6.80	9.30	49.21	12/16	Year-end	8.1	Z, I
05/02/18	Northern Utilities, Inc.	NH	7.59	9.50	51.70	12/16	Year-end	0.9	B, Z, I
05/03/18	Atmos Energy Corporation	KY	7.41	9.70	52.57	3/19	Average	-1.9	
05/10/18	CenterPoint Energy Resources Corp.	MN	7.12	—	—	9/18	Average	3.9	B, I
05/15/18	Atlanta Gas Light Company	GA	—	—	55.00	12/18	—	-16.0	B
05/29/18	MDU Resources Group, Inc.	MT	—	9.40	—	—	—	1.0	B
05/30/18	Baltimore Gas and Electric Company	MD	6.69	—	—	12/23	—	68.0	LIR, Z,25
06/06/18	Liberty Utilities (Midstates Natural Gas) Corp	MO	—	9.80	—	6/17	Year-end	4.6	B
06/14/18	Central Hudson Gas & Electric Corporation	NY	6.44	8.80	48.00	6/19	Average	6.7	B, Z
06/19/18	Black Hills Kansas Gas Utility Company, LLC	KS	—	—	—	2/18	Year-end	0.6	LIR
2018	**2nd quarter: averages/total**		7.08	9.43	50.83			73.8	
	Observations		7	7	6			11	
07/16/18	Indiana Gas Company, Inc.	WY	7.75	9.60	54.00	6/17	Year-end	1.0	B
07/20/18	Southern Indiana Gas and Electric Company, Inc.	WA	7.31	9.40	49.00	12/16	Average	-2.9	B
08/15/18	Northern Illinois Gas Company	VA	6.86	9.50	48.74	8/19	Average	3.2	LIR,26
08/21/18	Missouri Gas Energy	KY	—	—	—	12/17	Year-end	2.2	LIR,27
08/22/18	Spire Missouri Inc.	IN	—	—	—	12/17	Year-end	14.2	LIR,19
08/24/18	Atmos Energy Corporation	RI	7.15	9.28	50.95	6/17	Average	17.4	B, Z
08/28/18	Northern Utilities, Inc.	MI	5.86	10.00	40.91	6/19	Average	10.6	B,*
09/05/18	Niagara Mohawk Power Corporation	IN	—	—	—	12/17	Year-end	9.8	LIR,28
09/05/18	Pivotal Utility Holdings, Inc.	IN	—	—	—	12/17	Year-end	2.2	LIR,29
09/11/18	Indiana Gas Company, Inc.	AR	4.69	—	31.52	9/19	Year-end	5.1	B,*
09/13/18	Southern Indiana Gas and Electric Company, Inc.	MI	5.56	10.00	38.30	9/19	Average	9.0	*
09/14/18	Northern Illinois Gas Company	WI	6.97	10.00	52.00	12/18	Average	0.0	B,30

(continued on next page)

Gas utility decisions

Date	Company	State	ROR (%)	ROE (%)	Common equity as % of capital	Test year	Rate base	Rate change amount ($M)	Footnotes
09/19/18	Missouri Gas Energy	IN	6.50	9.85	46.88	12/18	Year-end	107.3	B, Z
09/19/18	Spire Missouri Inc.	MA	—	—	—	—	—	—	31
09/20/18	Atmos Energy Corporation	MO	—	—	—	4/18	—	5.4	LIR
09/20/18	Northern Utilities, Inc.	MO	—	—	—	4/18	—	2.6	LIR
09/20/18	Niagara Mohawk Power Corporation	WI	7.10	9.80	56.06	12/20	Average	4.1	B,Z
09/26/18	Pivotal Utility Holdings, Inc.	ND	7.24	9.40	51.00	12/18	Average	2.5	B, I
09/26/18	Northern Utilities, Inc.	SC	7.60	10.20	53.00	3/18	Year-end	-13.9	B,M
09/26/18	Niagara Mohawk Power Corporation	SC	8.05	—	49.83	3/18	Year-end	-19.7	M
09/28/18	Pivotal Utility Holdings, Inc.	MA	7.01	9.50	53.04	12/16	Year-end	100.8	
09/28/18	Niagara Mohawk Power Corporation	MA	7.18	9.50	53.04	12/16	Year-end	17.8	
09/28/18	Pivotal Utility Holdings, Inc.	MD	—	—	—	12/19	Average	2.0	B, LIR,32
2018	**3rd quarter: averages/total**		**6.86**	**9.69**	**48.55**			**280.8**	
	Observations		**15**	**13**	**15**			**22**	
10/04/18	CenterPoint Energy Resources Corp.	OK	—	—	—	12/17	—	5.4	33
10/05/18	Black Hills Energy Arkansas, Inc.	AR	5.62	9.61	40.43	12/17	Year-end	22.6	B
10/15/18	Chattanooga Gas Company	TN	7.12	9.8	49.23	6/19	Average	1.4	
10/26/18	Northwest Natural Gas Company	OR	7.32	9.40	50.00	10/19	Average	23.4	B
10/26/18	Columbia Gas of Virginia, Incorporated	VA	7.47	—	—	12/19	Average	2.4	LIR
10/29/18	Public Service Electric and Gas Company	NJ	6.99	9.60	54.00	6/18	Year-end	123.1	B
11/01/18	Ameren Illinois Company	IL	7.14	9.87	50.00	12/19	Average	31.7	B
11/08/18	Delmarva Power & Light Company	DE	6.78	9.70	50.52	12/17	—	-3.5	B, I
11/08/18	Kansas Gas Service Company, Inc.	KS	—	—	—	6/18	Year-end	2.4	LIR,34
11/21/18	Columbia Gas of Maryland, Incorporated	MD	—	—	—	4/18	—	3.8	B
12/03/18	Washington Gas Light Company	VA	—	—	—	12/19	Average	-1.7	LIR,26
12/04/18	Atmos Energy Corporation	TN	7.26	9.80	51.40	5/19	Average	-5.0	B,35
12/05/18	Columbia Gas of Kentucky, Incorporated	KY	7.62	—	52.42	12/19	Year-end	3.6	LIR,36
12/06/18	Columbia Gas of Pennsylvania, Inc.	PA	—	—	—	12/19	—	26.0	B
12/11/18	Washington Gas Light Company	MD	7.30	9.70	51.69	3/18	Average	28.6	
12/11/18	Washington Gas Light Company	MD	—	—	—	12/23	Average	31.7	LIR, Z,25
12/12/18	Yankee Gas Services Company	CT	7.06	9.30	53.76	12/17	Average	30.2	B, Z
12/13/18	Interstate Power and Light Company	IA	7.29	9.60	51.00	12/17	Average	13.9	B, I
12/19/18	Connecticut Natural Gas Corporation	CT	7.32	9.30	55.00	12/17	Average	19.7	B, Z
12/21/18	Public Service Company of Colorado	CO	7.12	9.35	54.60	12/16	Average	22.0	Z, I
12/24/18	Southwest Gas Corporation	NV	7.04	9.25	49.66	1/18	Year-end	-2.0	37
12/24/18	Southwest Gas Corporation	NV	6.66	9.25	49.66	1/18	Year-end	9.5	38
12/26/18	Minnesota Energy Resources Corporation	MN	6.70	9.70	50.90	12/18	Average	3.1	I
12/27/18	Northern Indiana Public Service Company	IN	—	—	—	6/18	—	-7.0	B, LIR
2018	**4th quarter: averages/total**		7.05	9.55	50.89			384.9	
	Observations		17	15	16			24	
2018	**Full year: averages/total**		7.00	9.59	50.09			937.6	
	Observations		44	41	43			66	

Data compiled Jan. 28, 2019.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Footnotes

A	Average.
B	Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent setting or specifically adopted by the regulatory body.
CWIP	Construction work in progress.
D	Applies to electric delivery only.
DCt	Date-certain rate base valuation.
E	Estimated.
F	Return on fair value rate base.
ppI	Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
LIR	Limited-issue rider proceeding.
M	"Make-whole" rate change based on return on equity or overall return authorized in previous case.
R	Revised.
Te	Temporary rates implemented prior to the issuance of final order.
Tr	Applies to transmission service.
U	Double-leverage capital structure utilized.
YE	Year-end.
Z	Rate change implemented in multiple steps.
*	Capital structure includes cost-free items or tax credit balances at the overall rate of return.
1	Decision adopted a company filing specifying a $99.3 million plant-specific retail revenue requirement. According to the company, this results in an annual rate reduction of approximately $26.8 million.
2	Rate change was approved under Rider R, which is the mechanism through which the company recovers its investment in the Bear Garden power plant.
3	Rate change was approved under Rider W, which is the mechanism through which the company recovers its investment in the Warren County generation facility.
4	Rate change was approved under Rider S, which is the mechanism through which the company recovers its investment in the Virginia City Hybrid Energy Center.
5	Rate change was approved under Rider GV, which is the mechanism through which the company recovers its investment in the Greensville County generation facility.
6	Rate change was approved under Rider B, which is the mechanism through which the company recovers the costs associated with the conversion of the Altavista, Hopewell and Southampton power stations to burn biomass fuels.
7	Reduction ordered to the nuclear construction cost recovery tariff associated with the company's two new units being built at its Vogtle plant.
8	Proposed acquisition of the Beech Ridge II and Hardin wind generation facilities and an associated rider were rejected. No initial revenue requirement had been proposed.
9	Rate case dismissed.
10	Rate change was approved under Rider DSM, which is the mechanism through which the company is permitted to collect a cash return on demand-side management program costs.
11	Rate change was approved under Rider RAC-EE, which is the mechanism through which the company recovers its investment in energy efficiency programs.
12	ROE to be used for certain riders and AFUDC purposes is 9.5%.
13	Rate change was approved under Rider US-2, which is the mechanism through which the company recovers its investment in three utility-scale solar facilities: Scott Solar, Whitehouse Solar and Woodland Solar.
14	Rate change was approved under Rider BW, which is the mechanism through which the company recovers its investment in the Brunswick Power Station.
15	Rate change pertains to the company's Citrus County CC natural gas plant that is nearing completion.

(continued on next page)

Footnotes

16 Case was dismissed without prejudice.

17 Rate change was approved under the company's joint expanded net energy cost proceeding.

18 Decision freezes electric rates at 2017 levels for 2018 and 2019.

19 Case involves company's transmission, distribution and storage system improvement charge, or TDSIC, rate adjustment mechanism.

20 Settlement called for no change to the company's base rates or the revenue requirement under the company's transmission cost recovery factor.

21 Rate change was approved under Rider U, which is the mechanism through which the company recovers its investment in projects to underground certain "at risk" distribution facilities.

22 Annual rate adjustment under the company's performance-based ratemaking plan.

23 Case established the rates to be charged to customers under the company's compliance and system improvement adjustment, or CSIA, mechanism, which includes both federally mandated pipeline-safety initiatives and projects that are permitted under the state's TDSIC statute.

24 Reflects updates to the company's gas system reliability surcharge rider since its most recent base rate case.

25 Rate change was approved under the company's Strategic Infrastructure Development and Enhancement, or STRIDE, program rider. Total is to be phased in over five years; each annual adjustment is subject to review and true-up.

26 Case involves the company's investment made under Virginia Steps to Advance Virginia Energy infrastructure program.

27 Case involves the company's pipe replacement program rider.

28 Case involves the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

29 Pertains to investments made under the company's CSIA mechanism and projects that are permitted under the state's TDSIC statute.

30 Freezes gas rates at 2017 levels for 2018 and 2019.

31 Rate case withdrawn.

32 Case relates to the company's investment in its STRIDE program; revenue requirements are collected through the infrastructure replacement and improvement surcharge, or IRIS.

33 Rate change under company's performance-based ratemaking plan.

34 Case involves company's gas system reliability surcharge.

35 Rate change under company's annual rate mechanism.

36 Case involves company's accelerated main replacement program rider.

37 Rate case parameters reflect company's Northern operations.

38 Rate case parameters reflect company's Southern operations.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2018

REBUTTAL TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Adrien M. McKenzie, and my business address is 3907 Red River, Austin, Texas 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("KPSC") addresses the testimony of Mr. Christopher C. Walters on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DOD"), and Mr. Gregory W. Tillman on behalf of Walmart Inc. ("Walmart") concerning the fair rate of return on equity ("ROE") that Louisville Gas and Electric Company ("LGE") and Kentucky Utilities Company ("KU") should be authorized to earn on its investment in providing electric and gas utility service.[1]

Ms. Donna H. Mullinax, on behalf of the Kentucky Office of Attorney General, the Louisville/Jefferson County Metro Government, and the Lexington-Fayette Urban County Government, and Mr. Lane Kollen, on behalf of the Kentucky Industrial Utility Consumers do not present expert testimony on the ROE issue. Rather, they prepare their accounting and other rate case schedules based on the assumption that the ROE for the Companies is maintained at the current level of 9.70% authorized in their prior rate cases before the KPSC, Case Nos. 2016-00370 and 2016-00371.

[1] I refer to LGE and KU collectively as "LGE/KU" or "the Companies."

Finally, I note that all of the above-mentioned witnesses ultimately accept LGE/KU's capital structure proposal. In light of this, and based on the discussion in my direct testimony supporting the proposed capital structure,[2] I do not address this issue further here.

Q4. PLEASE SUMMARIZE DOD'S ROE RECOMMENDATION.

A4. Mr. Walters recommends an ROE of 9.35% for the Companies. In arriving at this proposal, he relies primarily on discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") approaches. Within his DCF analysis, he presents two different constant growth studies and one multi-stage growth study. He develops an ROE range of 9.0%-9.7%, with the low end of the range based on a combination of his DCF and CAPM results and the upper end based on his risk premium results; his recommendation of 9.35% is the midpoint of this range.[3]

Q5. DOES MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR LGE/KU?

A5. No. Mr. Tillman does not conduct any analyses of the cost of equity. His testimony is limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Tillman expresses his concern that the Companies' 10.42% requested ROE is "excessive."[4]

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[2] McKenzie Direct at 31-34.
[3] Walters Direct at 45-46.
[4] Tillman KU Direct at 10.

A. DOD's ROE Recommendation Fails to Meet Regulatory Standards

Q6. PLEASE SUMMARIZE YOUR RESPONSE TO DOD'S ROE TESTIMONY.

A6. At 9.35%, Mr. Walters' recommendations is simply too low. It would be one of the lowest ROEs allowed for a vertically-integrated utility in the past three years.[5] In addition, it falls 35 basis points below LGE/KU's currently allowed ROE. In light of increases in capital market costs since the time of LGE/KU's last case, this outcome is not logical. The table below summarizes this change in interest rates:

REBUTTAL TABLE 1
INTEREST RATE INCREASES FROM PRIOR LGE/KU CASE

	LG&E/KU Prior Case (a)	Current Rates (b)	Increase
10-Yr. Treasury	2.19%	2.89%	**0.70%**
30-Yr. Treasury	2.80%	3.17%	**0.37%**
A Utility	3.94%	4.42%	**0.48%**
Baa Utility	4.32%	4.96%	**0.64%**

Sources: https://fred.stlouisfed.org/categories/115; Moody's Investors Service.

(a) For June 2017, corresponding to the final order period in Case Nos. 2016-00370 and 2016-00371.
(b) Average yield for three months ending January 2019.

As the table shows, interest rates have increased approximately 40 to 70 basis points since the decision period in LGE/KU's last case. With interest rates significantly higher, an ROE recommendation that is so far below the level awarded in the Companies' previous case is not realistic.

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[5] For vertically-integrated electric utilities (like LGE/KU) there have been only seven allowed ROEs at or below 9.35%, out of 70 total cases, from 2016 through 2018. S&P Global Market Intelligence, *RRA Regulatory Focus: Major Rate Case Decisions*, Regulatory Research Associates (Jan. 31, 2019; Jan. 30, 2018; Jan. 18, 2017).

Q7. HOW DOES MR. WALTERS' RECOMMENDATION COMPARE TO ROES ALLOWED BY OTHER STATE COMMISSIONS?

A7. It is considerably lower. As referenced earlier, over the past several years, there has been a small number of ROEs (7 out of 70 total cases) allowed by other state commissions for vertically-integrated utilities in the low 9.0% range. The table below summarizes the average allowed ROE since 2016:

REBUTTAL TABLE 2
TRENDS IN ALLOWED ROES

Year	**Average Allowed ROE**
2016	9.77%
2017	9.80%
2018	9.68%
Average	9.75%

Source: S&P Global Market Intelligence, *RRA Regulatory Focus: Major Rate Case Decisions*, Regulatory Research Associates (Jan. 31, 2019; Jan. 30, 2018; Jan. 18, 2017). The data is for vertically-integrated utilities.

Mr. Walters' ROE recommendation, at 9.35%, is 40 basis points below what other state regulatory commissions across the country are allowing. This is an important comparison. Allowed ROEs provide one gauge of reasonableness for the outcome of a cost of equity analysis. In considering utilities with comparable risks, investors will always seek to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities of equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms.

Q8. MR. WALTERS PRESENTS ALLOWED ROE DATA IN HIS TESTIMONY.[6] SHOULD HIS DATA BE USED IN THE CONTEXT OF THIS CASE?

A8. No. His allowed ROE information is for all electric utilities, including delivery-only companies. Of course, the Companies are vertically-integrated in that their operations also include generation facilities. As S&P Global Market Intelligence (the source for both of our allowed ROE data) states:

> Comparing electric vertically integrated cases versus delivery-only proceedings over the past 12 years, RRA finds that the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operating of generation assets.[7]

Mr. Walters' allowed ROE data is potentially misleading and should be ignored in the context of this proceeding.

Q9. HOW DOES DOD'S ROE PROPOSAL COMPARE TO AUTHORIZED RETURNS FOR THE SPECIFIC UTILITIES IN THE PROXY GROUP HE USES TO ESTIMATE THE COST OF EQUITY?

A9. The current authorized rates of return for the electric utilities in Mr. Walters' proxy group, as reported by the Value Line Investment Survey ("Value Line"), are shown on McKenzie Exhibit No. 14. As documented there, the firms in the proxy group of comparable risk utilities referenced by Mr. Walters are currently authorized an average ROE of 9.74%. It is unreasonable for Mr. Walters to presume that the Companies could attract capital for investment at an allowed ROE that falls so far below the opportunities available from utilities he himself found were comparable to them.

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[6] Walters Direct at 4-5.

[7] S&P Global Market Intelligence, *RRA Regulatory Focus: Major Rate Case Decisions*, Regulatory Research Associates (Jan. 31, 2019) ("RRA").

Q10. ARE YOU RECOMMENDING THAT THE KPSC USE ALLOWED RETURNS TO ESTABLISH THE COMPANIES' ROE DIRECTLY?

A10. No. As discussed in my direct testimony,[8] although allowed ROEs are commonly referenced as a general guidepost, this data falls short of the comprehensive analyses necessary to ensure that required regulatory standards are achieved. Nonetheless, it is important to understand that there would be a disincentive for investors to provide equity capital to LGE/KU if the Commission were to apply an unreasonably low ROE, compared to entities of comparable, or even lesser risk.

Q11. WHAT OTHER BENCHMARKS INDICATE THAT DOD'S RECOMMENDED ROE IS TOO LOW TO BE CONSIDERED REASONABLE?

A11. Expected earned rates of return for other utilities provide another useful benchmark to gauge the reasonableness of Mr. Walters' ROE recommendation. The expected earnings approach is predicated on the comparable earnings test, which was developed as a direct result of the Supreme Court decisions in *Bluefield*[9] and *Hope*[10]. This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.[11]

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings

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[8] McKenzie Direct at 63-66.

[9] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

[10] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[11] I refer to the comparable earnings and expected earnings methods interchangeably in this testimony. While comparable earnings methods tend to rely on historical data and expected earnings methods rely on projected data, the underlying principles are similar in both approaches.

approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q12. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A12. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[12] A textbook prepared for the Society of Utility and Regulatory Financial Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods." [13] The author points out that the comparable earnings method is "easily understood" and firmly anchored in the regulatory economics underlying the *Bluefield* and *Hope* cases, and notes that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.

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[12] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region in establishing a floor and ceiling for the allowed ROE. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). FERC continues to support reliance on expected earned rates of return in its proposed ROE methodology for electric utilities. See *e.g.*, *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018).

[13] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, 115-16 Society of Utility and Regulatory Financial Analysts (2010).

Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[14] The Federal Energy Regulatory Commission ("FERC") has concluded that the expected earnings approach "can be useful in validating our ROE recommendation . . . given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future."[15] More recently they reiterate this position stating "[b]ecause investors rely on Expected Earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in determining a utility's ROE."[16]

Q13. WHAT ROE IS IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR MR. WALTERS' PROXY GROUP OF ELECTRIC UTILITIES?

A13. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in Mr. Walters' proxy group are shown on McKenzie Exhibit No. 15. As shown there, reference to expected earnings implied an annual average cost of equity for his comparison group of 11.0%, once adjusted to a mid-year basis.[17] These book return estimates are an "apples to apples" comparison to the ROE recommendations of Mr. Walters.

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[14] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 395.

[15] Opinion No. 531 at P 147 (2014).

[16] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018), Appendix.

[17] As explained in my Direct testimony (p. 45, 68), because the returns reported by Value Line are based on end-of-year book values, an adjustment factor is necessary to match earnings with an average book value over the year. As shown on McKenzie Exhibit No. 51, the average of the unadjusted values is 10.7%.

Q14. WHAT IS THE EXPECTED DIRECTION OF INTEREST RATES AND HOW DOES THIS IMPACT THE EVALUATION OF A FAIR ROE IN THIS PROCEEDING?

A14. As mentioned earlier, interest rates have increased and are expected to climb further. With apprehension surrounding future Federal Reserve actions, uncertainties regarding the impact of the Tax Cuts and Jobs Act ("TCJA") and future fiscal policies, the potential for expanding federal deficits, and world-wide geopolitical exposures, the potential for significant volatility and higher capital costs is clearly evident to investors. The table below compares current interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with the average of near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts, and the EIA:

REBUTTAL TABLE 3
INTEREST RATE TRENDS

	Dec. 2018	2019	2020
10-Yr. Treasury	3.0%	3.4%	3.6%
30-Yr. Treasury	3.2%	3.6%	3.8%
Aaa Corporate	4.0%	4.5%	4.6%
Aa Utility	4.2%	5.1%	5.3%

Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 30, 2018)
IHS Global Insight, Long-Term Macro Forecast - Baseline (Jan. 10, 2019)
Energy Information Administration, Annual Energy Outlook 2019 (Jan. 24, 2019)
Wolters Kluwer, Blue Chip Financial Forecasts, (Dec. 1, 2018)

As the table shows, investors continue to anticipate significantly higher interest rates over the near-term. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my direct testimony.[18] The interest rate increases shown in the figure above are on the order

[18] McKenzie Direct at 28-29.

of 60-110 basis points through 2020, which implies higher long-term capital costs over the period when rates established in this proceeding will be in effect.

Q15. IS IT NECESSARY THAT INTEREST RATE FORECASTS, LIKE THOSE SHOWN ABOVE, BE PERFECTLY ACCURATE IN ORDER TO BE RELIED ON?

A15. No. When estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence LGE/KU's allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision making process, not the actual rates that ultimately transpire.

Q16. DOES MR. WALTERS' ACKNOWLEDGE THAT INTEREST RATES ARE PROJECTED TO INCREASE?

A16. Yes. In his testimony, he presents a table of Blue Chip Financial Forecasts which indicates that both short-term and long-term are expected to increase through the first quarter of 2020.[19] In fact, he states that for long-term rates, there is "a consensus increase of 3.1% to 3.7%."[20]

Also, in his CAPM and risk premium analyses, Mr. Walters relies on projected 30-year Treasury rates. The rate he uses is 3.7%. Given that the current 30-year Treasury rate is around 3.1%, Mr. Walters is clearly recognizing that long-term interest rates are on the rise.

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[19] Walters Direct at 10.
[20] *Id.*

Q17. WHAT OTHER EVIDENCE INDICATES THAT DOD'S RECOMMENDED ROE FAILS TO MEET REGULATORY STANDARDS?

A17. As discussed in my direct testimony, expected rates of return for firms in the competitive sector of the economy are also relevant in determining the appropriate return to be allowed for rate-setting purposes.[21] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my non-utility group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very foundation for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[22] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

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[21] McKenzie Direct at 74-78.

[22] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944).

Q18. DOES MR. WALTERS PRESENT ANY OBJECTIVE EVIDENCE THAT WOULD SUPPORT A FINDING THAT YOUR NON-UTILITY GROUP IS RISKIER THAN THE COMPANIES IN HIS PROXY GROUP?

A18. No. He presents no evidence that would contradict the principles underlying my reference to DCF cost of equity estimates for the non-utility group; nor does he dispute the results of my analysis.

Q19. WHAT ARE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A19. As shown on McKenzie Exhibit 12, page 3, from my Direct testimony the average ROEs for the non-utility group range from 9.9%-11.0%.

Q20. WHAT ELSE SHOULD BE WEIGHED IN EVALUATING THE REASONABLENESS OF MR. WALTERS' RECOMMENDED ROE?

A20. As discussed earlier and in my direct testimony, in addition to the potential for upward pressure on interest rates stemming from fiscal stimulus, the TCJA also may have negative implications for the financial strength of regulated utilities. On June 18, 2018, Moody's Investors Service ("Moody's") announced that it was changing the utility sector outlook from stable to negative.[23] Moody's stated that:

> The change in outlook primarily reflects a degradation in key financial credit ratios…The change in outlook also reflects uncertainty with respect to the timing and extent of potential changes in regulatory recovery provisions, authorized returns and equity layers or self-help options by individual companies in response to lower cash flow."[24]

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[23] Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable* (June 18, 2018).
[24] *Id.*

The change in fundamental sector outlook reflects a declining financial trend and evidences an increase in the level of uncertainty that investors associate with the utility industry.

Q21. BASED ON YOUR COMPARISON OF DOD'S ROE RECOMMENDATION WITH ACCEPTED BENCHMARKS AND IN LIGHT OF THE PROSPECT FOR HIGHER INTEREST RATES AND THE IMPACT OF THE TCJA, WHAT DO YOU CONCLUDE?

A21. Based on these comparisons, DOD's recommendations are below a reasonable outcome. Interest rates have increased since the Companies' last cases when they were granted an ROE of 9.70%, rendering ROE proposals at this level, or below, illogical and unfair. In addition, a fundamental standard underlying the regulation of public utilities, as set forth by the Supreme Court's *Bluefield* and *Hope* decisions, requires that the Companies must have the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if they are to maintain their financial flexibility and ability to attract capital. The Companies must offer investors the opportunity to earn a return that is comparable to those available from other investments of comparable risk.

If a utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both of these outcomes violate regulatory standards.

Q22. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW ACCEPTED REGULATORY BENCHMARKS?

A22. Adopting an ROE for the Companies that is below the ROEs for comparable (or lower risk) utilities could lead investors to view the KPSC's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. As S&P Global Ratings concluded, "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[25]

If the KPSC's actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, even in times of turmoil in the financial markets. It is only rational for potential investors to consider the regulatory treatment afforded to LGE/KU in evaluating whether to commit new capital to Kentucky jurisdictional utilities, and at what cost. Moreover, customers and the service area economy enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service. In evaluating the Companies' ROE in this case, the KPSC has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime.

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[25] Standard & Poor's Corporation, *Key Credit Factors For The Regulated Utilities Industry*, RatingsDirect (Nov. 19, 2013).

II. RESPONSE TO DOD WITNESS WALTERS

Q23. PLEASE SUMMARIZE YOUR RESPONSE TO DOD'S ROE TESTIMONY.

A23. There are a number of serious deficiencies in Mr. Walters' quantitative applications. I demonstrate that his ROE recommendation is biased downward and lacks credibility based on the following:

- Mr. Walters starts with the same group proxy group that I use, but then wrongfully excludes five companies, several of which have DCF results at the higher end of the range.
- Mr. Walters' DCF approach is weakened because he includes illogical low-end estimates in his final results.
- He ignores a readily available and widely followed source of analysts' growth rates in his DCF methodology.
- He relies on a multi-stage growth DCF model that wrongly assumes growth in Gross Domestic Product ("GDP") is an upper limit on utility growth.
- His risk premium analysis is flawed because he rejects the well-documented, inverse relationship between equity risk premiums and interest rate levels.
- The CAPM results reported by Mr. Walters are suspect because they are based on historical data, they fail to correct for an observed bias in the CAPM result, and they ignore the impact of company size on expected returns.

Furthermore, his criticisms of my flotation cost adjustment, and my Expected Earnings and Non-Utility DCF approaches are without merit. Taken as a whole, these flaws mean that Mr. Walters' recommended ROE falls well below a fair and reasonable level for LGE/KU.

A. Proxy Group

Q24. WHAT ARE THE PROBLEMS WITH DOD'S PROXY GROUP?

A24. Mr. Walters starts with the same group proxy group that I use, but then removes five companies. He eliminates Algonquin Power & Utilities Corp. ("Algonquin") because "it is not part of the Value Line universe and is headquartered in Canada."

He eliminates Avangrid, Inc. ("Avangrid") because "more than 80% of its stock is owned by its ultimate parent company, Iberdola S.A. ("Iberdola"), a holding company headquartered in Spain." He eliminates Emera Inc. ("Emera") because "it is headquartered in Canada and, while it is part of the Value Line universe, it is not categorized as being part of the Electric Utility industry." Fortis Inc. ("Fortis") is excluded "for being a Canada-based company." Finally, he removes The Southern Company ("Southern Company") for "its divestiture of Gulf Power and Pivotal Utility Holdings."[26] As I explain, these exclusions are not valid.

Q25. ALGONQUIN HAS NOT YET BEEN INCLUDED IN THE VALUE LINE ELECTRIC UTILITY INDUSTRY. WOULD INVESTORS NONETHELESS REGARD ALGONQUIN AS HAVING RISKS AND OPERATIONS COMPARABLE TO THOSE OF OTHER ELECTRIC UTILITIES?

A25. Yes. The historical stock price and dividend data necessary to apply the DCF model are available, and analysts' consensus earnings per share ("EPS") growth estimates are also published for Algonquin. Headquartered in Ontario, Canada, Algonquin is a North American diversified generation, transmission, and distribution utility with approximately $10 billion in total assets. Algonquin provides regulated utility services to over 782,000 customers in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, and Texas. Algonquin completed its acquisition of Empire District Electric Company (Empire District) on January 1, 2017, which more than doubled its size.[27] Since that time, a majority of Algonquin's revenues, earnings,

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[26] All references in this answer are from Walters Direct at 16-17.

[27] Empire District was included in Value Line's electric utility industry group prior to its merger with Algonquin.

and assets have been related to its regulated utility operations,[28] and investors would regard Algonquin as a comparable investment alternative that is relevant to an evaluation of investors' required rate of return.

Moreover, inclusion in Value Line's electric utility group is not a requirement. A company's inclusion in the electric utility group is a sufficient condition for inclusion in a DCF proxy group but is not a necessary condition of inclusion. While Value Line is a widely-followed, independent investor service, there are other reliable sources that investors rely upon. The objective in assembling a proxy group is not to find reasons to exclude individual companies; rather, it is to identify all of the publicly traded utilities that investors would view as comparable-risk investment opportunities. While Value Line's industry groups may serve as a useful springboard, this single source is not the final arbiter that defines the universe of alternative opportunities available to investors. Other well-recognized investment information sources relied on by investors, including *Yahoo! Finance* and Zacks Investment Research ("Zacks"), classify Algonquin as an electric or public utility, and there is no basis to distinguish between Algonquin and other firms accepted as comparable.

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[28] For example, Algonquin reported that during 2017 regulated utility operations accounted for 84% of total revenues, 94% of pre-tax earnings (ex. corporate losses), and 69% of total assets. Over 90% of Algonquin's consolidated revenue, EBITDA and assets are derived from operations in the U.S. In addition, Algonquin's dividend is denominated in U.S. dollars and Algonquin's common shares are listed on the New York Stock Exchange. https://www.sec.gov/cgi-bin/viewer?action=view&cik=1174169&accession_number=0001628280-18-002905&xbrl_type=v#.

Q26. HAS THE FAILURE TO CONSIDER ALGONQUIN IN THE PROXY GROUP BEEN RECOGNIZED AS A FATAL FLAW THAT UNDERMINES THE VERACITY OF DCF RESULTS?

A26. Yes. The question of whether or not to include Algonquin in the proxy group was a key point of contention in FERC Docket No. EL16-64-002, the most recent section 206 complaint against the transmission owning members of the ISO New England Inc. (NETOs). There, I submitted testimony detailing why it was appropriate to include Algonquin in the proxy group. The Presiding Judge agreed, concluding:

> The Commission's point of performing a DCF analysis in these cases is to define the *actual* and *complete* distribution of those "business undertakings which are attended by corresponding, risks and uncertainties" that are comparable to the NETOs, as *Bluefield* says, and to determine where the NETOs' current ROE falls in that existing distribution. Under this standard, Algonquin is no different from a business or financial risk standpoint than many of the other companies that have been included by all the DCF experts in their proxy groups.[29]
>
> * * *
>
> In view of the deliberate omissions of Algonquin, these analyses are deficient.[30]

The Presiding Judge ruled that the complainants' analyses in that case were "fatally defective,"[31] in large part based on the omission of Algonquin from the proxy group.

Q27. SHOULD BEING "CANADA-BASED" AUTOMATICALLY RULE OUT A CANDIDATE FOR THE PROXY GROUP?

A27. No. Mr. Walters cites this reason for excluding Algonquin, Emera, and Fortis. Mr. Walters does not offer any specific evidence to suggest that investors discriminate

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[29] *Belmont Mun. Light Dept.v. Cent. Me. Power Co.*, 162 FERC ¶ 63,026 at P 217 (2018) (emphasis in original).
[30] *Id.* at P 218.
[31] *Id.* at P 206.

between companies headquartered in Canada and U.S.-based firms when allocating capital. As noted above, Algonquin provides regulated utility services to over 782,000 customers in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, and Texas.

As for Emera, its acquisition of TECO Energy, Inc. ("TECO") in 2016 added Florida and New Mexico operations to its rate-regulated businesses. Emera's operations are thus dominated by its U.S.-based utilities in Florida, Maine, and New Mexico, which together accounted for approximately 82% of consolidated net income in 2017.[32]

Value Line classifies Fortis in its "Electric Utility Central" industry group. Similarly, Zacks includes Fortis in its "Utilities >> Utility – Electric Power" industry group, which is identical to the classification afforded to all but one of the firms included in Mr. Walters' proxy group.[33] In contrast to Mr. Walters' generalized alarm over Fortis' address in Newfoundland, Canada, Value Line makes no mention of the potential risks associated with the company's status as a Canadian corporation. Instead, Value Line chiefly discusses the outlook for Tucson Electric, ITC Holdings, and Central Hudson Gas & Electric, three of Fortis' U.S. subsidiaries. In fact, while Fortis may be incorporated in Canada, approximately 64% of the company's net earnings and 60% of its assets were associated with its U.S.-based utilities.[34]

Under these circumstances, it cannot be argued seriously that Algonquin, Emera, and Fortis do not operate in the United States, even if they are headquartered in Canada. The KPSC should afford no weight to Mr. Walters' unsubstantiated

[32] Emera Inc., *2017 Form 40-F*, Exhibit 99.2 at 9.
[33] Sempra Energy is classified in the "Utilities >> Utility – Gas Distribution" group.
[34] Fortis Inc., *2017 Annual Report* at 66.

assertion that these companies' status as Canadian firms would somehow disqualify them from being considered by investors as comparable investment opportunities to LGE/KU.

Q28. DID MR. WALTERS UNDERTAKE ANY ANALYSIS TO DETERMINE THE RELATIVE PORTION OF U.S. OPERATIONS FOR EACH COMPANY HE EXCLUDES FOR BEING "CANADA BASED?"

A28. No. When asked to explain his contention that being "headquartered in Canada" warrants exclusion from the proxy group, all Mr. Walters could point to were the annual returns for several global stock market indexes.[35] Of course, the returns on these market indexes say nothing about the relative risks of the individual utilities that are at issue here. Mr. Walters granted that he "did not undertake any analysis to compare the relative portion of U.S. operations for each company."[36]

Q29. MR. WALTERS ALSO CITES EMERA'S INCLUSION IN THE VALUE LINE "POWER INDUSTRY" SECTOR AS A REASON TO ELIMINATE IT. DO YOU AGREE?

A29. No. The historical stock price and dividend data necessary to apply the DCF approach are available for Emera, as are the consensus EPS growth rates from IBES and other comparable sources. Emera is primarily engaged in electricity generation, transmission, and distribution; gas transmission and distribution; and utility energy services, and serves approximately 2.5 million customers. Emera completed its acquisition of TECO on July 1, 2016. As Value Line reported, as a result of the addition of TECO's regulated utilities in Florida and New Mexico, "the percentage of profits coming from regulated businesses rises to more than 90%."[37]

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[35] Response to LGE/KU First Set of Data Requests, Case Nos. 2018-00295/2018-00294, Data Request No. 8.
[36] *Id.*
[37] The Value Line Investment Survey (Mar. 24, 2017).

Similarly, investment service, CFRA, highlighted Emera's primary focus on electric utility operations, and classified Emera in its "Electric Utilities" industry group,[38] and Emera reports as an "Electric Utility" under the Standard Industrial Classification Code (4911).[39] Thus, investors would regard Emera as a comparable investment alternative that is relevant to an evaluation of the required rate of return for the Companies, regardless of Value Line's decision to keep them in their Power industry.

Q30. DOES THE DOD PROVIDE SUFFICIENT REASONING FOR EXCLUDING AVANGRID FROM THE PROXY GROUP?

A30. No. Through its operating subsidiaries, including Central Maine Power, New York State Electric & Gas, Rochester Gas and Electric, and United Illuminating, Avangrid is engaged in regulated electric transmission and distribution utility operations in Connecticut, Maine, and New York. Avangrid is included in Value Line's electric utility industry group. The stock price, dividend, growth, and other information necessary to apply the ROE estimation approaches are all available for Avangrid. Mr. Walters eliminated Avangrid from consideration, however, because of its relationship with Spanish parent company, Iberdola.

Q31. IS MR. WALTERS' CONCERN ABOUT AVANGRID AND ITS CONNECTION WITH IBERDOLA VALID?

A31. No. While Mr. Walters correctly observes that the majority of Avangrid's common stock is owned by Iberdrola, he presents no reasoned explanation as to why this

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[38] CFRA, *Emera Incorporated*, Quantitative Stock Report (Jun. 24, 2017). CFRA, founded as the Center for Financial Research and Analysis, is one of the world's largest providers of institutional-grade independent equity research, acquired the equity and fund research arm of S&P in October 2016.

[39] *See, e.g.*, Emera Inc., *2017 SEC Form 40-F*. https://www.sec.gov/Archives/edgar/data/1127248/000119312518101807/d555438d40f.htm.

distinguishes the valuation reflected in Avangrid's stock prices from those of other publicly traded electric utilities.

Q32. MR. WALTERS CITES THE "POTENTIAL FOR INVESTOR-REQUIRED PREMIUMS BEING REFLECTED IN THE STOCK PRICE" AS A REASON TO EXCLUDE AVANGRID FROM THE PROXY GROUP.[40] DOES HE PROVIDE ANY EVIDENCE TO INDICATE THAT THIS "POTENTIAL" IS LEGITIMATE?

A32. No. In fact, Mr. Walters admits that he "has not identified specific investor required premiums" and "does not have quantitative evidence of such premiums."[41]

Q33. IS THERE ANY INDICATION THAT IBERDROLA'S OWNERSHIP INTEREST IS VIEWED NEGATIVELY BY THE INVESTMENT COMMUNITY?

A33. No. For example, other than noting Iberdrola's continued ownership stake in Avangrid, Value Line makes no mention of considerations related to Avangrid's ownership structure or any potential risk implications associated with Iberdrola's position as majority stockholder. In fact, Value Line does not raise the issue of Iberdrola's majority ownership; nor does Value Line in any way validate Mr. Walters' suggestion that Avangrid's ownership structure might somehow affect its valuation. Value Line's sole objective is to provide investors with the most complete portrayal of the risks and expectations associated with the common stocks it covers. If Iberdrola's ownership constituted an important consideration relevant to investors' evaluation, Value Line would be expected to note it, but they do not.

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[40] Walters Direct at 16.

[41] Response to LGE/KU First Set of Data Requests, Case Nos. 2018-00295/2018-00294, Data Request No. 7.

Similarly, while independent investment research firm CFRA outlined key risks to its anticipated stock price performance for Avangrid, including regulatory rulings, the service area economy, changes in interest rates, and operational concerns, the issue of corporate governance is notably absent.[42] Fitch noted that while "there is a moderate-to-strong linkage between the ratings of Avangrid and its parent, . . . Avangrid is publicly traded and has independent treasury functions, its own access to the equity market, and a separate management team."[43] Meanwhile, Moody's observed that:

> Although we acknowledge that [Avangrid] is an important component of [Iberdrola's] overall growth strategy, we believe that [Avangrid] will largely be run independently. . . . Additionally, the presence of ring fencing provisions at all the utilities limits [Iberdrola's] flexibility with regards to its ability to draw distributions from the entities, and our expectation that the aforementioned obligations under the [Guarantee and Support Agreement] will likely be transferred to [Avangrid] from [Iberdrola] both act to further de-link the two companies. That said, we continue to acknowledge that majority ownership from [Iberdrola] remains <u>a credit positive</u>. Particularly since it provides an additional venue to access liquidity at an advantageous price.[44]

It is also worth noting that <u>all</u> of the transactions that established the stock prices for Mr. Walters' proxy firms are also for minority interests. Moreover, there are wide-ranging protections applicable to minority owners in all publicly traded firms, including the requirements of the Public Company Accounting Reform and Investor Protection Act of 2002 (also known as Sarbanes-Oxley), provisions of federal securities laws, such as Section 10 of the Securities Exchange Act of 1934,

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[42] CFRA, *Avangrid, Inc.*, Stock Report (Jun. 24, 2017).
[43] Fitch Ratings, Ltd., *Avangrid, Inc.*, Full Rating Report (Oct. 19, 2016).
[44] Moody's Investors Service, *Avangrid, Inc.*, Credit Opinion (Apr. 29, 2016) (emphasis supplied).

and the rights of minority shareholders to undertake a derivative action to redress any harm to the corporation.

The Presiding Judge in FERC Docket No. EL16-64-002, recently rejected arguments similar to Mr. Walters' policy argument regarding the impact of Iberdrola's ownership, instead agreeing with testimony that I filed stating: "Avangrid should be included in [the] proxy group."[45]

Q34. MR. WALTERS SUGGESTS THAT SOUTHERN COMPANY SHOULD BE ELIMINATED DUE TO MERGER ACTIVITY. IS THERE ANY MERIT TO THIS ARGUMENT?

A34. No. In support of his position, Mr. Walters says only that "I excluded Southern Company for its divestiture of Gulf Power and Pivotal Utility Holdings."[46] On May 21, 2018, Southern Company entered into definitive transactions valued at approximately $6.5 billion for the sale of Gulf Power Co., Florida City Gas, and ownership interests in two natural gas-fired generating plants to NextEra Inc. ("NextEra"). While these transactions are not inconsequential, the notion that a merger or acquisition requires *per se* that a firm be excluded from the proxy group should be rejected. Companies involved in a merger should be accepted as proxies where there is no evidence that the data used to apply the DCF approach is distorted. Mr. Walters has presented no basis for arguing that the sale of Gulf Power to NextEra has resulted in any distortion to the inputs used to apply the DCF model.

In fact, there is no indication that this transaction has resulted in any significant, ongoing influence on Southern Company's stock price during the analysis period that would lead to distortion in the resulting DCF values. Rebuttal

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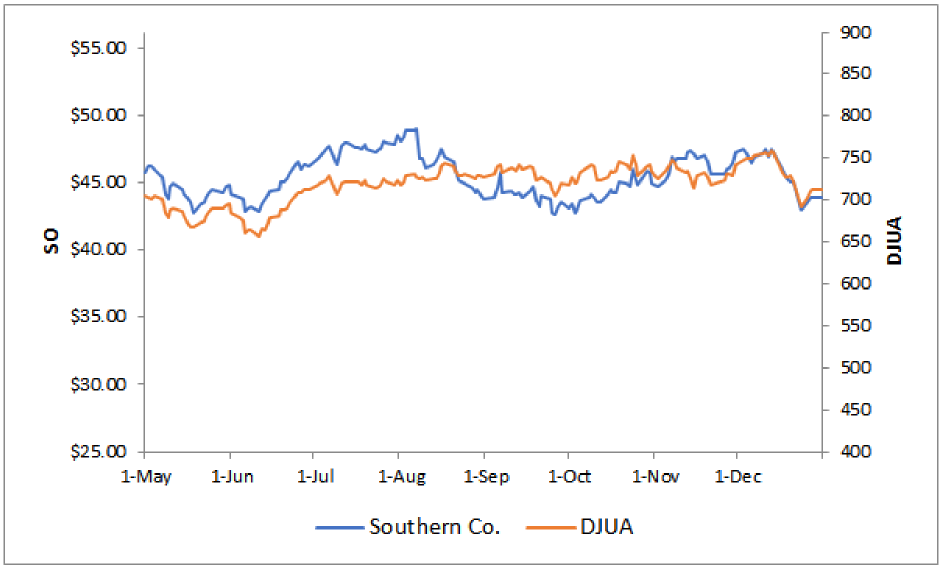
[45] *Belmont Mun. Light Dept. v. Cent. Me. Power Co.*, 162 FERC ¶ 63,026 at P 192 (2018).

[46] Walters Direct at 17.

Figure 1 below compares the closing price of Southern Company's common stock with the Dow Jones Utility Average ("DJUA") from May 1, 2018 through December 31, 2018:[47]

REBUTTAL FIGURE 1
SOUTHERN CO. STOCK PRICE V. DOW JONES UTILITY AVERAGE



As illustrated above, Southern Company's closing stock price mirrored the trend in the utility industry generally, and there is no basis to assert that the dividend yield data for Southern Company is distorted. Similarly, IBES growth rates for Southern Company published by *Yahoo! Finance* before the announcement of the transaction are comparable to the values throughout the remainder of 2018.[48] Given that its closing stock price generally mirrored the broader trend in the utility industry, and the fact that there have been no dramatic changes in growth expectations or dividend policies for the utility, there is no evidence to suggest that

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[47] The transaction closed January 1, 2019.

[48] *Yahoo! Finance* reported a growth rate of 2.70% on April 3, 2018 for Southern Company. This compares to the 1.36% value I obtained on November 17, 2018.

the transaction has led to any distortion of the DCF inputs and Southern Company is properly retained in the proxy group.

B. Discounted Cash Flow Model

Q35. HOW DOES MR. WALTERS APPLY THE CONSTANT GROWTH DCF MODEL?

A35. Mr. Walters applies the constant growth DCF model using forward-looking estimates of EPS growth based on consensus forecasts of securities analysts, as well as considering a sustainable, “br” growth rate. This is comparable to the method discussed in my testimony.

Q36. IS THERE AN OBVIOUS FLAW IN MR. WALTERS’ CONSTANT GROWTH DCF ANALYSIS?

A36. Yes. Mr. Walters fails to remove illogical values from his final constant growth DCF results. As I discuss in my Direct Testimony, when applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method. Simply removing the obvious low-end value from the DCF results presented on Walters Exhibit CCW-4 (NorthWestern Corp. at 5.91%) increases his constant growth DCF average by 21 basis points, from 9.06% to 9.27%.

Q37. IS THERE ANOTHER SHORTCOMING IN MR. WALTERS’ CONSTANT GROWTH DCF ANALYSIS?

A37. Yes. Mr. Walters elected to average all individual growth rates together, and then compute a single DCF estimate for each company. Each growth rate represents a stand-alone estimate of investors’ future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Walters' method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates – 0.0% and 14.0% – do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[49] Mr. Walters simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Walters failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. Therefore, his results are biased downward.

Q38. CAN YOU SHOW THE DOWNWARD BIAS IN MR. WALTERS' CONSTANT GROWTH ANALYSIS?

A38. Yes. For example, Mr. Walters reports a Reuters growth rate of 2.87% for Consolidated Edison.[50] Combining this growth rate with his corresponding dividend yield of 3.79% results in a cost of equity estimate of 6.66%. This implied cost of equity does not sufficiently exceed yields on current and projected public utility bonds. As a result, this illogical growth measure should have been removed from Mr. Walters' constant growth DCF analysis.

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[49] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).

[50] Walters Exhibit CCW-3.

Q39. DOES MR. WALTERS LEAVE OUT A READILY AVAILABLE, WIDELY RESPECTED SOURCE OF ANALYSTS' GROWTH RATES?

A39. Yes. Mr. Walters failed to include EPS growth rate estimates from Value Line in his analysis. He uses Value Line as an underlying source for many of his calculations, such as to compute the annualized dividend and sustainable growth terms for his DCF models and the average beta for his CAPM studies. Value Line is readily available and is widely followed by investment professionals. It is a well-recognized source of expected growth rates and Mr. Walters' DCF analysis suffers because he does not consider them.

Q40. WHAT IS THE PROBLEM WITH MR. WALTERS' MULTI-STAGE GROWTH DCF ANALYSIS?

A40. This analysis should be completely rejected. There is no merit to Mr. Walters' claim that each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by consensus analyst's projected growth for the U.S. GDP of 4.19%. He incorrectly claims that GDP growth sets a "maximum sustainable long-term growth rate" for a utility.[51] As I discuss below, there is no link between Mr. Walters' GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE.

Q41. WHAT ARE THE PRIMARY MISCONCEPTIONS UNDERLYING MR. WALTERS' REFERENCE TO GDP GROWTH?

A41. Mr. Walters' use of long-term GDP growth as an upper bound to the DCF growth rate for companies in his proxy group is not justified. There are several reasons why GDP growth is not relevant in applying the DCF model:

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[51] Walters Direct at 22.

- Practical application of the DCF model does not require a long-term growth estimate over a horizon of 25 years and beyond – it requires a growth estimate that matches investors' expectations.
- Evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks, including those in the electric utility industry.
- The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for electric utilities can and do exceed GDP growth.
- There is no evidence that investors' growth expectations for regulated electric utilities have begun to converge to that of the economy.

Q42. THE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A42. This view confuses the theory underlying the DCF model with the practicalities of its application in the real world. Analytical models such as the DCF model are inherently abstractions of reality. The underlying theory requires any number of assumptions, many of which differ considerably from the situation that confronts actual investors in the capital markets. For example, apart from a constant growth rate into perpetuity, the theory underlying the DCF model also requires that dividends, earnings, and stock prices grow at exactly the same rate forever.[52]

Such strict assumptions are never met in practice. While this notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in Mr. Walters' proxy group or for the electric utility industry as a whole. Rather than applying the DCF model in a way that is consistent with the

[52] Other theoretical models also rest on unrealistic assumptions that play no role in their practical application. For example, underpinning the CAPM is the assumption that there are no income taxes.

information that is available to investors and how they use it, the use of GDP growth seeks to mold investor behavior around the theoretical assumptions of a financial model. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Q43. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS?

A43. No. Certainly, investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, in the financial media one observes many references to three-to-five year EPS growth forecasts for individual companies and very few references to long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model to utilities.[53] But despite Mr. Walters' suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the electric utility industry. Value Line's singleness of purpose is to inform investors of

[53] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, *New Regulatory Finance*, 71 (Pub. Util. Reports, Inc., 2006).

the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2050 and beyond had direct relevance in investors' evaluation of utility common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q44. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A44. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon. As a result, in addition to the fact that there is no evidence to suggest that common stock investors reference GDP growth rates in their analysis of a specific utility's prospects, the difficulties in making long-term forecasts suggest they would be foolhardy to do so.

Q45. IS MR. WALTERS ABLE TO POINT TO ANY INVESTMENT ADVISORY REPORTS THAT DISCUSS THE IMPLICATIONS OF EXPECTED GDP GROWTH IN CONNECTION WITH THEIR EVALUATION OF INDIVIDUAL STOCKS OR THAT ADVISE INVESTORS TO CONSIDER GROWTH IN GDP AS A CEILING ON THE LONG-RUN GROWTH RATE FOR A UTILITY STOCK?

A45. No. When asked whether he was aware of such evidence, Mr. Walters refers to generalized statements that might apply to hypothetical growth "into perpetuity" but was unable to provide advisory reports that mention GDP growth in connection with their analysis of specific utility stocks.[54]

Q46. IS THERE EVIDENCE THAT LONG-TERM GDP GROWTH RATES UNDERSTATE INVESTORS' EXPECTATIONS FOR UTILITIES?

A46. Yes. Actual historical growth rates for individual firms in Mr. Walters' own proxy group refute the notion that long-term growth for utilities is constrained by GDP. For example, Value Line reports that Eversource Energy and CMS Energy each achieved earnings growth over the last 10 years of 10.0%.[55] Meanwhile, NorthWestern Corp. had 10-year EPS growth of 8.0%. These values for Mr. Walters' own proxy firms indicate that utilities can and do achieve growth over extended periods far in excess of the GDP growth rate he suggests as a limit in the multi-stage DCF model.

Q47. DO EXPECTATIONS FOR THE UTILITY INDUSTRY SUPPORT A LONG-TERM TREND TOWARDS GDP GROWTH?

A47. No. Growth rates for electric utilities are not expected to collapse beyond the next five years. At least in part, growth in the electric utility industry is created by additional infrastructure investment. Contrary to the assumption that growth trends will somehow mirror GDP, investors recognize that the electric utility industry has entered a cycle of significant capital spending on utility infrastructure.

Q48. WHAT UNDERLYING FUNDAMENTALS SUPPORT INVESTORS' CONCLUSION THAT UTILITIES ARE EMBARKING ON A PERIOD OF GROWTH THAT WILL OUTPACE THE ECONOMY AS A WHOLE?

A48. The president of the Edison Electric Institute ("EEI") observed:

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[54] Response to LGE/KU First Set of Data Requests, Case Nos. 2018-00295/2018-00294, Data Request Nos. 10-11.

[55] The Value Line Investment Survey (Oct. 26, Nov. 16, & Dec. 14, 2018).

> The improved credit quality greatly supports the continued elevated capital expenditures, which set a new record high of $113.6 billion in 2017.[56]

More recently, Regulatory Research Associates concluded that:

> The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar, and wind generations and implement new technologies. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future.[57]

Q49. DOES MR. WALTERS' OWN TESTIMONY SUPPORT THE PREMISE THAT THE GROWTH IN THE UTILITY INDUSTRY WILL EXCEED EXPECTED GROWTH IN GDP FOR THE FORESEEABLE FUTURE?

A49. Yes. On page 7 of his testimony, he refers to an RRA update which continues to emphasize the strong growth expected for the industry. A few excerpts are highlighted below:[58]

- Projected 2018 capital expenditures for the 50 gas and electric utilities in the RRA universe has stayed mostly steady at about $133.8 billion, an all-time high for the sector and nearly 14% higher than the prior forecast of $117.5 billion last fall.
- CapEx projections for the longer term increased modestly from our previous analysis in April 2018, rising to $118.9 billion for 2019 and $105.1 billion for 2020, as companies' plans for future projects solidified and new opportunities arose.

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[56] Thomas R. Kuhn, *President's Letter*, EEI 2017 Financial Review.
[57] S&P Global Market Intelligence, *RRA Financial Focus – Utility Capital Expenditures Update*, Regulatory Research Associates (Apr. 20, 2018).
[58] Walters Direct at 7.

Q50. DID A FOUNDER OF THE DCF APPROACH SUPPORT THE USE OF A GENERIC LONG-TERM GROWTH RATE, SUCH AS THE GDP GROWTH UNDER MR. WALTERS' MULTI-STAGE APPROACH?

A50. No. Professor Myron J. Gordon, who pioneered the use of the DCF approach, concluded that reference to a generic long-term growth rate, such as Mr. Walters advocates, was unsupported.[59] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[60]

Similarly, a more recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[61]

Q51. ARE THERE COMPUTATIONAL ERRORS THAT ALSO BIAS MR. WALTERS' MULTI-STAGE DCF COST OF EQUITY ESTIMATES DOWNWARD?

A51. Yes. As noted above, under his multi-stage DCF approach Mr. Walters predicted the cash flows that would accrue to investors over the next 200 years. To arrive at his estimated cost of equity, Mr. Walters used the internal rate of return ("IRR")

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[59] Myron J. Gordon, *The Cost of Capital to a Public Utility*, 100-01 (MSU Pub. Util. Studies, 1974).
[60] *Id.* at 89.
[61] Joachim Klement, *What's Growth Got to Do with It? Equity Returns and Economic Growth*, 74:78 Journal of Investing (Summer 2015).

function available in Microsoft's Excel spreadsheet program to determine the discount rate (*i.e.*, investors' required rate of return) that would equate these cash flows with the current market price of the stock.[62] This IRR calculation, however, assumes that annual cash flows are received at the end of each year, which is inconsistent with the periodic dividend payments that investors receive over the course of the year and results in a downward bias in the implied cost of equity.

Q52. DOES THE SEVERITY OF DOD'S MULTI-STAGE DCF RESULTS GIVE SOME INDICATION AS TO THE DISCONNECT BETWEEN LONG-TERM GDP GROWTH AND REALISTIC ESTIMATES OF INVESTORS' EXPECTATIONS?

A52. Yes. Mr. Walters' recommended ROE range from his multi-stage DCF approach is 7.79%-8.07%. This result is not credible and should be rejected on its face. It is over 100 basis points below his final ROE recommendation. Based on the same benchmarks that I discussed earlier, this outcome is well below any reasonable standard for a regulated electric utility ROE. The unreasonableness of his multi-stage DCF results is a direct indication of the disconnect between the long-term GDP growth rate and realistic growth expectations for utility companies.

C. Utility Risk Premium

Q53. DO THE RESULTS OF MR. WALTERS' RISK PREMIUM APPROACH BASED ON AUTHORIZED RETURNS PROVIDE A RELIABLE GUIDE TO A FAIR ROE FOR LGE/KU?

A53. No. Mr. Walters' risk premium analysis is fatally flawed because he fails to incorporate the inverse relationship between interest rates and equity risk premiums in his analysis of historical authorized rates of return. There is considerable

[62] Walters public workpaper: Exhibit CCW-2 - CCW-9, CCW-15 -16.xlsx.

empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[63]

New Regulatory Finance noted that, taken together, studies in the financial literature imply that a 100 basis point change in bond yields would imply a 50 basis point increase in the equity risk premium.[64]

As shown on Walters Exhibits CCW-11 and CCW-12, current interest rates are significantly less than those prevailing in the late 1980s and early 1990s. Given that interest rates are currently lower than the average over his study period, current equity risk premiums should be relatively higher, which Mr. Walters' analysis entirely ignores.

Q54. WHAT COST OF EQUITY ESTIMATE IS INDICATED IF MR. WALTERS' RISK PREMIUM APPROACH IS CORRECTED TO ACCOUNT FOR THIS INVERSE RELATIONSHIP?

A54. I begin with the data from Mr. Walters' two risk premium exhibits CCW-11 and CCW-12. The only adjustment I make to this data is to account for the inverse relationship between interest rates and risk premiums. Since rates are now

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[63] Roger A. Morin, *New Regulatory Finance*, 128 (Pub. Util. Reports, Inc., 2006).
[64] *Id.* at 129.

(historically) low, an upward adjustment to the base risk premium is critical. As shown on McKenzie Exhibit No. 16, adjusting Mr. Walters' risk premium analysis to account for this inverse relationship results in a current cost of equity estimate for the Companies of 10.05% using Treasury yields (page 1), or 10.01% based on public utility bond yields (page 3).

Q55. WHAT OTHER FLAWS ARE ASSOCIATED WITH MR. WALTERS' RISK PREMIUM APPLICATION?

A55. Mr. Walters subjectively chooses to truncate the data available to apply his risk premium approach by ignoring all observations prior to 1986. Mr. Walters explains that this period is selected "because public utility stocks consistently traded at a premium to book value during that period,"[65] but such manipulation of this data runs counter to the assumptions underlying the study of historical risk premiums. Ibbotson Associates noted the pitfalls of such a subjective approach:

> Some analysts estimate the expected risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future … This view is suspect …[66]

By choosing a truncated time period for his risk premium study, Mr. Walters unnecessarily introduces a subjective bias that taints his analysis and artificially lowers his results.

D. Capital Asset Pricing Model

Q56. WHAT ARE THE WEAKNESSES IN MR. WALTERS' CAPM STUDIES?

A56. Mr. Walters' CAPM analysis has several shortcomings. Most significantly, it is based almost exclusively on historical data, even though the analysis should be

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[65] Walters Direct at 34.

[66] Ibbotson Associates, *2005 Yearbook, Valuation Edition* at 80.

forward-looking. He fails to correct for an observed bias in the CAPM result. Finally, his analysis ignores the impact of company size on expected returns.

Q57. CAN YOU EXPAND ON THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE APPROACH THAT MR. WALTERS USES TO APPLY THE CAPM?

A57. The CAPM application presented by Mr. Walters is based primarily on *historical* rates of return, not current projections. Like the DCF model, risk premium methods – including the CAPM – are *ex-ante*, or forward-looking models based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM approach must be applied using data that reflects the expectations of actual investors in the market. The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Mr. Walters to apply the CAPM:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[67]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I do on Exhibit Nos. 7 and 8 to my direct testimony, the 7.32% to 8.33% historical CAPM range developed by Mr. Walters[68] falls woefully short of investors' current required rate of return.

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[67] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21.
[68] Walters Direct at 45.

Q58. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY MR. WALTERS?

A58. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[69]

Similarly, in *Orange & Rockland Utilities*, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[70] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[71]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

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[69] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, 280, Docket No. 080677-E1 (Dec. 23, 2009).
[70] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[71] *See New York Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).

Q59. WHAT IS THE PRIMARY DIFFERENCE BETWEEN MR. WALTERS' SO-CALLED "FORWARD-LOOKING" CAPM ANALYSIS AND THE APPROACH DESCRIBED IN YOUR DIRECT TESTIMONY?

A59. As Mr. Walters observes, the appropriate market return ("R_m") to use in applying the CAPM is the "[e]xpected return for the market portfolio."[72] The fundamental difference between my approach and that of Mr. Walters is that, while my analysis actually looks to the future return expectations of investors in the capital markets, Mr. Walters' "forward-looking" CAPM is actually based almost entirely on historical data. As Mr. Walters explains:

> I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market.[73] [emphasis added]

In other words, the relatively small portion of Mr. Walters' "forward-looking" market return constituting inflation is based on projected data, but the actual return on the market itself is completely backward looking.

Mr. Walters essentially presents two variants of a CAPM using historical data. Neither one of these approaches is consistent with the assumptions of the CAPM because as noted above, the CAPM seeks to determine the expected return, and is predicated on the forward-looking expectations of investors. Mr. Walters' use of historical returns in the CAPM is inconsistent with the underlying presumptions of the model.

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[72] Walters Direct at 39.
[73] *Id.* at 41.

Q60. WHAT ABOUT MR. WALTERS' CRITICISM THAT YOUR FORWARD-LOOKING ESTIMATE OF THE MARKET RATE OF RETURN IS NOT REASONABLE?[74]

A60. As noted earlier, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature and has been recognized by other regulators. Mr. Walters' criticism of my forward-looking CAPM approach seems to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is higher than the historical benchmarks he cites. But estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology. As noted earlier, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of required rates of return, the CAPM is best applied using data that reflects the expectations of actual investors in the market. Rather than look backwards to a risk premium based largely on historical data, as Mr. Walters advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

All quantitative methods used to estimate the cost of equity have their own strengths and weakness. Mr. Walters does not suggest that the CAPM model is "wrong" to focus on forward-looking projections instead of backward, historical results, nor does he claim that looking to the future, as I have done, is a misapplication of the CAPM. Instead, Mr. Walters simply believes that the result of applying the CAPM in a manner that is consistent with the underlying assumptions produces a result that he views as being too high.

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[74] *Id.* at 53.

Q61. HAVE OTHER REGULATORS RELIED ON A FORWARD-LOOKING DCF APPROACH SIMILAR TO THE ONE PRESENTED IN YOUR DIRECT TESTIMONY AS A MEANS OF ESTIMATING THE MARKET COST OF EQUITY?

A61. Yes. I base my CAPM approach on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return estimate to apply the CAPM. For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return based on an analysis analogous to the approach described in my direct testimony:

> Q. How was the expected rate of return on the market portfolio estimated?
>
> A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Salomon Smith Barney, Performance and Weights of the S&P 500: Second Quarter 2001. The estimated weighted averaged expected rate of return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[75]

Moreover, the market cost of equity relied on in my analysis represents a weighted average expected return for the dividend paying firms in the S&P 500. Growth expectations for some firms fall below expected trends GDP, while projections for other firms are considerably more optimistic. Similarly, the composition of the S&P 500 is not static and growth rates for one company may

[75] Direct Testimony of Rochelle Langfeldt, Illinois Commerce Commission Docket No. 01-0423 at 23-24 (2001).

moderate over time, while for others they may increase. On balance, however, the growth rates used in my study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index as a whole. This contradicts Mr. Walters' position that investors' growth expectations should be constrained by forecasted GDP growth when estimating the market cost of equity.

Q62. DOES MR. WALTERS FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN APPLYING THE CAPM?

A62. Yes. Mr. Walters fails to reflect the size adjustment in his CAPM application. According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Mr. Walters should have incorporated an adjustment to recognize the impact of size distinctions between his proxy companies, as measured by the average market capitalization.

Q63. IS THERE ANY MERIT TO MR. WALTERS' CONTENTION THAT A SIZE ADJUSTMENT SHOULD NOT BE APPLIED TO UTILITIES?[76]

A63. No. First, Mr. Walters implies that I am proposing to apply a general size risk premium in arriving at a fair ROE for LGE/KU; but this is not correct. Rather, this adjustment merely corrects for an observed inability of the CAPM to fully reflect the impact of size distinctions by market capitalization that the beta value does not

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[76] Walters Direct at 55-56.

otherwise capture, but which is acknowledged by empirical research. My consideration of the impact of firm size does not adjust for KU's or LGE's size relative to the proxy group; nor is it applied to the results of the DCF, risk premium, or expected earnings approaches. Rather, it is specifically tied to the CAPM because empirical research indicates that beta does not capture an increment of risk related to firm size.

Mr. Walters' observation that the "size adjustments relied on by Mr. McKenzie reflects companies that have unadjusted beta estimates well in excess of 1.00" says nothing at all about the relevance of a size adjustment.[77] Of course, there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are important distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure – beta – which captures stock price volatility relative to the market. Within the CAPM paradigm, the degree of regulation, the nature of competition in the industry, the competence of management, and every other firm-specific consideration are boiled down to a single question; namely, how much does the stock's price fluctuate in relation to the market as a whole? Beta is the measure of that variability, and research demonstrates that beta does not fully account for the impact of firm size.

The fact that the size premiums reported by *Duff & Phelps* were not estimated on an industry-by-industry basis provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by *Duff & Phelps* to quantify the size premium, and firm size has

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[77] *Id.* at 55.

important practical implications with respect to the risks faced by investors in the utility industry. As *Duff & Phelps* concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[78]

Q64. MR. WALTERS REJECTS YOUR USE OF THE EMPIRICAL CAPITAL ASSET PRICING MODEL ("ECAPM") BECAUSE HE SAYS IT AMOUNTS TO DOUBLE COUNTING WHEN USED WITH VALUE LINE ADJUSTED BETAS.[79] WHAT IS YOUR RESPONSE?

A64. As I state in my Direct Testimony,[80] the ECAPM is simply a variant of the traditional CAPM approach that is designed to correct for an observed bias in the CAPM result. The modification reflected in the ECAPM is distinct from the Value Line adjustment of estimated betas for the demonstrated tendency to regress toward the mean. The Value Line adjustment is intended to make betas estimated based on historical returns better estimates of forward-looking betas. Further, while Mr. Walters asserts that there is "no academic support" for the use of adjusted betas in alternative versions of the CAPM,[81] this is not accurate. For example, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital* noted that "[t]he assertion that risk premiums are proportional to NYSE betas is shown to result in downward (upwards) biased predictions of the cost of equity for a public utility having a NYSE beta that is less (greater) than unity," and concluded that

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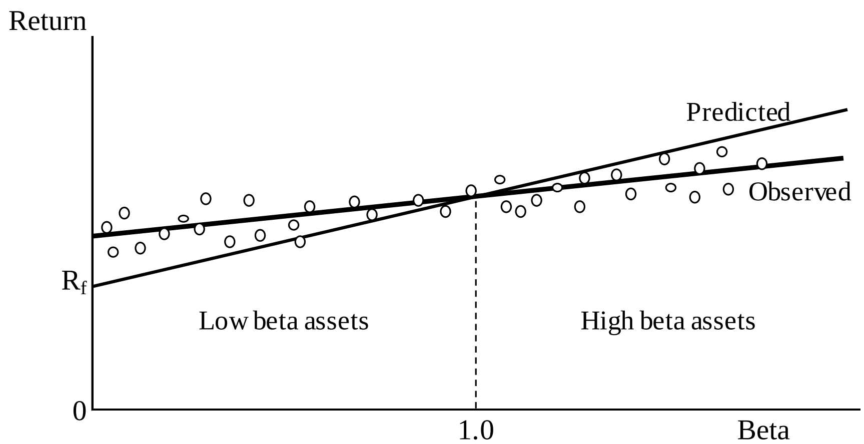
[78] *Duff & Phelps, 2016 Valuation Handbook,* 4-27 (2016).
[79] Walters Direct at 58-59.
[80] McKenzie Direct at 55-58.
[81] Walters Direct at 61.

adjusted betas, such as those published by Value Line, are "better predictors than are unadjusted betas."[82]

The ECAPM reflects a distinct refinement to adjust for a systematic tendency of low beta portfolios to over-earn and high beta portfolios to under-earn relative to the predictions of the CAPM capital market line. This is illustrated graphically in the figure below:

REBUTTAL FIGURE 2
CAPM – PREDICTED VS. OBSERVED RETURNS



The ECAPM reflects a refinement to adjust for a systematic tendency of low beta portfolios to over-earn and high beta portfolios to under-earn relative to the predictions of the CAPM capital market line. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns, and both are useful for improving the traditional CAPM results.

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[82] Robert Litzenberger, Krishna Ramaswamy, and Howard Sosin, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital*, 369-393 Journal of Finance (May 1980).

E. Other ROE Issues

Q65. MR. WALTERS ACCUSES YOU OF "MANIPULATING" YOUR DCF RESULTS BECAUSE YOU REMOVED SEVERAL LOW-END VALUES FROM YOUR RESULTS AND ONLY REMOVED ONE HIGH-END ESTIMATE.[83] IS THIS A VALID CRITICISM?

A65. No. I evaluate low-end values against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. In my Exhibit No. 5, I retained an upper end cost of equity estimate of 16.4%, but I also kept low-end estimates in the 7.0% range which are assuredly far below investors' required rate of return.

Q66. MR. WALTERS SUGGESTS THAT USING THE MEDIAN WOULD BE A BETTER APPROACH THAN REMOVING OUTLIERS IN DEALING WITH EXTREME DCF RESULTS.[84] DO YOU AGREE?

A66. No. Similar to my earlier discussion of Mr. Walters' DCF averaging technique, I believe that each ROE result represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that a median of several outcomes might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying return separately. Without considering the underlying data, and including ROE estimates that do not reflect investor expectations, Mr. Walters' median approach biases his results downward.

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[83] Walters Direct at 51.
[84] *Id.* at 51.

Q67. MR. WALTERS CONTENDS THAT THE EXPECTED EARNINGS ANALYSIS YOU USED IS NOT A REASONABLE METHOD FOR ESTIMATING A FAIR ROE FOR LGE/KU.[85] DO YOU AGREE?

A67. No. The appeal of the expected earnings approach is that it does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q68. DO YOU AGREE WITH MR. WALTERS THAT A METHODOLOGY HAS TO DEPEND ON MARKET DATA TO BE USEFUL IN EVALUATING INVESTORS' REQUIRED RETURN?[86]

A68. No. Mr. Walters wrongly contends that because the expected earnings approach is based on accounting data and not market data, it should be rejected. While I agree that market-based models are certainly important tools in estimating investors' required rate of return, in my opinion, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages. As discussed earlier, a very simple, conceptual principle is that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If LGE/KU is only allowed the opportunity to earn a 9.35% return on the book value of its equity investments, as recommended by Mr. Walters, while other

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[85] *Id.* at 65.
[86] *Id.* at 65-66.

utilities are expected to earn an average of 11.0%,[87] the implications are clear – the Companies' investors will be denied the ability to earn a return commensurate with other opportunities of comparable risk.

Q69. DO YOU AGREE WITH MR. WALTERS' FLOTATION COST DISCUSSION?

A69. No. Mr. Walters rejects a flotation cost adjustment because he claims it "is not based on known and measurable LG&E costs."[88] Mr. Walters seems to agree that flotation costs can be included in the cost of equity analysis as a part of the cost of raising capital, but he argues that such an adjustment should be rejected in this case. KU and LGE have been and will continue to invest significant amounts of equity capital to serve the public. The equity capital necessary to support this investment is supplied by proceeds from past stock issues and through retained earnings. The earnings base of this equity is permanently reduced by the amount of past flotation costs. Without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will further undercut the Companies' ability to earn their authorized ROE.

III. RESPONSE TO WALMART WITNESS TILLMAN

Q70. DOES MR. TILLMAN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR LGE/KU?

A70. No. Mr. Tillman does not conduct any analyses of the cost of equity. His testimony is limited to a presentation of selected data concerning previously authorized ROEs.

[87] The average expected return on book equity for 2021-23 calculated for Mr. Walters' proxy group, as shown on McKenzie Exhibit No. 15.

[88] Walters Direct at 49.

Based on this limited review, Mr. Tillman expresses his concern that a 10.42% ROE for LGE/KU is "excessive."[89]

Q71. DO YOU AGREE WITH MR. TILLMAN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE KPSC'S EVALUATION?

A71. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q72. DOES THE DATA PRESENTED BY MR. TILLMAN CONFIRM YOUR CONCLUSION THAT DOD'S ROE RECOMMENDATION IS TOO LOW?

A72. Yes. Mr. Tillman cites an average allowed ROE for vertically-integrated utilities of 9.75% for 2016 through the present,[90] which confirms my earlier conclusion that the 9.35% ROE recommendations of Mr. Walters falls well below average returns authorized for other utilities and is insufficient to meet the requirements of regulatory standards.

Q73. DO YOU AGREE WITH THE INFERENCE THAT MR. TILLMAN DRAWS FROM HIS REVIEW OF ALLOWED ROES?

A73. No. While a review of historical authorized ROEs can provide a general benchmark, it is not a substitute for a thorough analysis of the cost of capital, such as that contained in my direct testimony and supporting LGE/KU's 10.42% requested ROE. As discussed in detail earlier, data concerning historical allowed ROEs reported by RRA can be informative, but do not substitute for a comprehensive application of primary methods.

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[89] Tillman KU Direct at 10.

[90] *Id.* at 16. This is the same data that I reference in Rebuttal Table 2 above.

Q74. YOU PREVIOUSLY NOTED THAT RRA DATA MAY NOT BE REPRESENTATIVE OF THE CIRCUMSTANCES APPLICABLE TO A SPECIFIC CASE.[91] CAN YOU PROVIDE A RELEVANT EXAMPLE?

A74. Yes. Capital market conditions prevailing during the rate proceedings that make up historical average returns are one factor that is not necessarily comparable to the facts of this case. As I noted earlier, higher interest rates since LGE/KU's last proceeding are one objective fact that support an increase in the Companies' allowed ROE. Similarly, interest rates have increased since the time of the regulatory decisions on which Mr. Tillman's data is based. Specifically, I compared average public utility bond yields for the three months ended January 2019 with those for the three-month period immediately preceding the month of each ROE decision underlying the 9.68% average for 2018 reported on page 3 of GWT-5.[92] This comparison indicates that long-term capital costs have increased since the time of these decisions, with utility bond yields now being approximately 40 basis points higher, on average.

Q75. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. TILLMAN'S ADMONITION (PP. 8-9) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A75. First, it is important to note that the determination of the ROE is made by investors in the capital markets and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Tillman

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[91] McKenzie Direct at 63-66.
[92] This ROE corresponds to those reported by RRA for vertically integrated electric utilities.

wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Tillman ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Companies would undoubtedly continue to meet its service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q76. DO YOU AGREE WITH MR. TILLMAN'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A76. No. While Mr. Tillman attempts to distinguish the risks of the Companies based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the LGE/KU and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q77. WHAT IS CWIP?

A77. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q78. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A78. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC. To finance the costs of construction, utilities such as LGE/KU must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant, especially in the case of a large construction program, and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.

Q79. IS THERE ANY MERIT TO MR. TILLMAN'S CONTENTION (P. 13) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS ONTO RATEPAYERS?"

A79. No. Including CWIP in rate base will ease the financial pressure associated with the Companies' capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and the ability to attract capital, including CWIP will not have a significant impact on the overall investment risks of LGE/KU or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Tillman.

Q80. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A80. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed the inclusion of CWIP in rate base

> include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[93]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the interest of investors and customers, and the KPSC has routinely allowed electric utilities to include CWIP in rate base.[94] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[95]

Q81. IS MR. TILLMAN'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A81. No. As discussed in Mr. Blake's rebuttal testimony, Mr. Tillman's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Companies' ROE. Mr. Tillman has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of LGE/KU's credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the

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[93] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

[94] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).

[95] *Promoting Transmission Inv. through Pricing Reform*, Order No.679, 116 FERC ¶ 61,057at P 115 (2006). *See also*, *Promoting Transmission Inv. through Pricing Reform*, Order No. 679-A, 117 FERC ¶ 61,345 at PP 114-115 (2006), *order on reh'g and clarification*, 119 FERC ¶ 61,062 (2007).

Companies. Mr. Tillman fails to address these realities, which further disprove his assessment and recommendations.

Q82. MR. TILLMAN POINTS TO THE USE OF FORECAST TEST YEARS AS A RISK-REDUCING RATE MECHANISM FOR LGE/KU. WOULD THIS FEATURE IMPLY A LOWER ROE FOR THE COMPANIES IN THIS CASE?

A82. No. As I point out in my Direct Testimony, investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry, and the relative impact is already considered in the data for my proxy group. As a result, any mitigation in risks associated with LGE/KU's ability to attenuate regulatory lag through adjustment mechanisms or their election of a future test year is already reflected in the results of the quantitative methods presented in my testimony. The KPSC's adjustment mechanisms and the Companies' election to use a future test year act to level the playing field, placing LGE/KU on equal footing with its peers in the industry. As a result, no adjustment to the ROE is justified or warranted.

Q83. YOU PREFACED YOUR TESTIMONY WITH THE OBSERVATION THAT NEITHER MS. MULLINAX OR MR. KOLLEN PRESENTED ANY ANALYSES OF A FAIR ROE FOR LGE/KU. DOES THEIR TESTIMONY IN ANY WAY SUPPORT A CONTINUATION OF THE EXISTING 9.7% ROE?

A83. No. As Ms. Mullinax made clear, "[t]he OAG/Cities are not supporting ROE testimony in these proceedings."[96] Accordingly, while the 9.70% ROE established in Case Nos. 2016-00370 and 2016-00371 provided one basis on which to illustrate

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[96] Mullinax Direct at 11.

a hypothetical revenue deficiency, her testimony provides no evidence to justify a continuation of this ROE in this proceeding.

Similarly, Mr. Kollen noted that "KIUC has not retained an expert to perform an independent study of the required return on equity."[97] Nevertheless, Mr. Kollen opines that the KPSC should "simply continue the present authorized 9.7% return on equity."[98] As "support," Mr. Kollen offers an *ad hoc* reference to the DCF study contained in my testimony, as well as to RRA data for allowed ROEs. Neither of these general observations provide a basis for a continuation of the existing 9.70% ROE.

Q84. WHAT PARTICULAR CONCERN DO YOU HAVE WITH RESPECT TO MR. KOLLEN'S TESTIMONY?

A84. Apart from my response to the use of RRA data, which is fully articulated earlier in rebuttal to Mr. Walters and Mr. Tillman, there is no justification for Mr. Kollen's suggestion that it would be appropriate to rely solely on the results of the DCF model in evaluating a fair ROE for LGE/KU. The actual return investors require is unobservable. Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely theoretical tools and generally produce a range of estimates, based on different assumptions and inputs. The DCF method is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges produced by the different approaches can vary materially.

[97] Kollen Direct at 53.
[98] *Id.* at 55.

In my experience, investors, financial analysts, and regulators routinely consider the results of alternative approaches. It is widely recognized that no single method can be regarded as a panacea; with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[99] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> [N]o single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models. Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[100]

No single approach provides a fail-safe means to estimate investors' required ROE and Mr. Kollen's suggestion to contrary should be rejected.

Q85. MR. KOLLEN CLAIMS THAT THE KPSC HAS BASED ITS FINDINGS ENTIRELY ON THE RESULTS OF THE DCF MODEL.[101] IS THIS AN ACCURATE CHARACTERIZATION?

A85. No. As support for his assertion, Mr. Kollen cited two orders from 1989 and 1992.[102] Meanwhile, in Case No. 2016-00370, the KPSC concluded that "[b]ased

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[99] *Nw. Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036, at 61,188 (1997).

[100] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, 84 (Society of Utility and Regulatory Financial Analysts, 2010).

[101] Kollen Direct at 54.

[102] *Kentucky Industrial Energy Customers, Inc. Response to Kentucky Utilities Company and Louisville Gas and Electric Company's Initial Data Requests*, Question No. 4.

on the entire record developed in this proceeding, we find that KU's required ROE falls within a range of 9.20 percent to 10.20 percent."[103] The KPSC explicitly noted the various alternative methodologies employed by the witnesses in that proceeding,[104] while making no pronouncements regarding the relative merits of any one approach. In fact, it would have been impossible for the KPSC to arrive at an ROE range of 9.20% to 10.20% based only on the results of the DCF model.[105]

Q86. HAVE OTHER REGULATORY AGENCIES RECOGNIZED THE IMPORTANCE OF CONSIDERING ALTERNATIVES TO THE DCF MODEL WHEN EVALUATING A FAIR ROE?

A86. Yes. FERC recently proposed significant modifications to its approach for determining allowed ROEs for electric utilities under its jurisdiction, announcing its intention to give equal weight to the results of the DCF model and the exact same CAPM, risk premium, and expected earnings approaches presented in my direct testimony in this proceeding.[106] As FERC concluded:

> The Commission should not limit itself to using only the DCF model or restrict itself when applying judgment to ROE model results. Since state regulatory commissions, corporate finance professionals, and investors use multiple methods and exercise judgment when estimating the cost of equity, it is perfectly reasonable for the Commission to rely on multiple models and exercise judgment when setting the base ROE in this proceeding.[107]

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[103] Kentucky Public Service Commission, Case No. 2016-00370, Order at 18 (Jun. 22, 2017) (emphasis supplied). The KPSC made a similar finding in Case No. 2017-00321. After restating the results of the DCF, CAPM, ECAPM, and risk premium approaches to exclude flotation costs, the KPSC noted again that its authorized ROE was "[b]ased on the entire record." Kentucky Public Service Commission, Case No. 2017-00321, Order at 40 (Apr. 13, 2018).

[104] *Id.* at 16.

[105] The DCF range supported by Mr. Baudino, on behalf of the Kentucky Industrial Utility Customers, Inc., was 8.51% to 9.53%; by Dr. Woolridge, on behalf of the Office of Attorney General, was 8.55% to 8.9%; while the average values produced by my DCF application ranged from 8.4% to 9.5%.

[106] *Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018).

[107] *Id.* at P 37 (quotations omitted).

Mr. Kollen's misguided suggestion that the DCF model provides support for a continuation of the existing 9.70% ROE is inconsistent with the KPSC's recent findings, as well as sound regulatory practice and capital market evidence, and should be rejected.

Q87. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A87. Yes.

VERIFICATION

STATE OF TEXAS	)	
	)	**SS:**
COUNTY OF TRAVIS	)	

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of February 2019.

(SEAL)

Notary Public

My Commission Expires:

11/28/2020

ALYSSA MARIE HUTCHESON
NOTARY PUBLIC
STATE OF TEXAS
NOTARY ID 13091229-9
11/28/2020

STATE ALLOWED ROEs

WALTERS GROUP

		(a)
		Allowed
No.	**Company**	**ROE**
1	Alliant Energy	10.50%
2	Ameren Corp	8.70%
3	Black Hills Corp.	9.37%
4	CMS Energy Corp.	10.00%
5	Consolidated Edison	9.00%
6	DTE Energy Co.	10.00%
7	Duke Energy Corp.	10.23%
8	Entergy Corp.	9.95%
9	Eversource Energy	9.64%
10	Exelon Corp.	9.58%
11	NorthWestern Corp.	10.10%
12	PPL Corp.	9.70%
13	P.S. Enterprise Group	9.60%
14	Sempra Energy	10.30%
15	WEC Energy Group	9.55%
16	Xcel Energy Inc.	9.60%
	Average	**9.74%**

(a) The Value Line Investment Survey (Oct. 26, Nov. 16, & Dec. 14, 2018).

WALTERS GROUP

		(a)	(b)	(c)
No.	**Company**	**Expected Return on Common Equity**	**Mid-Year Adjustment Factor**	**Adjusted Return on Common Equity**
1	Alliant Energy	10.5%	0.9999	10.5%
2	Ameren Corp	10.5%	1.0275	10.8%
3	Black Hills Corp.	10.0%	1.0403	10.4%
4	CMS Energy Corp.	14.0%	1.0405	14.6%
5	Consolidated Edison	8.5%	1.0188	8.7%
6	DTE Energy Co.	11.0%	1.0371	11.4%
7	Duke Energy Corp.	8.5%	1.0158	8.6%
8	Entergy Corp.	11.0%	1.0347	11.4%
9	Eversource Energy	9.5%	1.0185	9.7%
10	Exelon Corp.	9.5%	1.0268	9.8%
11	NorthWestern Corp.	9.0%	1.0201	9.2%
12	PPL Corp.	13.5%	1.0407	14.0%
13	P.S. Enterprise Group	11.0%	1.0230	11.3%
14	Sempra Energy	12.0%	1.0479	12.6%
15	WEC Energy Group	12.0%	1.0166	12.2%
16	Xcel Energy Inc.	10.5%	1.0279	10.8%
	Average	10.7%		**11.0%**

(a) The Value Line Investment Survey (Oct. 26, Nov. 16, & Dec. 14, 2018).

(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

REVISED WALTERS RISK PREMIUM

TREASURY BOND YIELD

	(a) Treasury Bond Yield	(a) Authorized Electric Returns	(a) Indicated Risk Premium
1986	7.80%	13.93%	6.13%
1987	8.58%	12.99%	4.41%
1988	8.96%	12.79%	3.83%
1989	8.45%	12.97%	4.52%
1990	8.61%	12.70%	4.09%
1991	8.14%	12.55%	4.41%
1992	7.67%	12.09%	4.42%
1993	6.60%	11.41%	4.81%
1994	7.37%	11.34%	3.97%
1995	6.88%	11.55%	4.67%
1996	6.70%	11.39%	4.69%
1997	6.61%	11.40%	4.79%
1998	5.58%	11.66%	6.08%
1999	5.87%	10.77%	4.90%
2000	5.94%	11.43%	5.49%
2001	5.49%	11.09%	5.60%
2002	5.43%	11.16%	5.73%
2003	4.96%	10.97%	6.01%
2004	5.05%	10.75%	5.70%
2005	4.65%	10.54%	5.89%
2006	4.99%	10.34%	5.35%
2007	4.83%	10.31%	5.48%
2008	4.28%	10.37%	6.09%
2009	4.07%	10.52%	6.45%
2010	4.25%	10.29%	6.04%
2011	3.91%	10.19%	6.28%
2012	2.92%	10.01%	7.09%
2013	3.45%	9.81%	6.36%
2014	3.34%	9.75%	6.41%
2015	2.84%	9.60%	6.76%
2016	2.60%	9.60%	7.00%
2017	2.90%	9.68%	6.78%
2018 (d)	3.06%	9.59%	6.53%
AVERAGE	5.54%	11.08%	5.54%

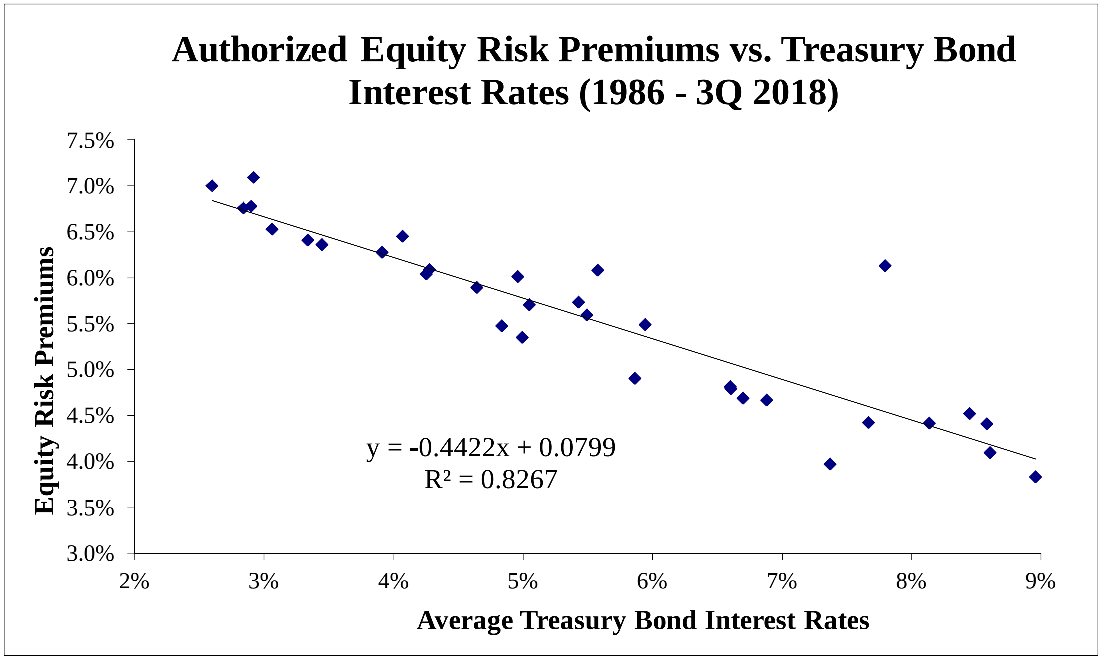
IMPLIED COST OF EQUITY

Projected Treasury Bond Yield (b)	3.70%
Average Treasury Bond Yield Over Study Period	5.54%
Change in Bond Yield	-1.84%
Risk Premium/Interest Rate Coefficient (c)	-44.22%
Adjustment to Study Period Risk Premium	0.81%
Average Risk Premium Over Study Period	5.54%
Interest Rate Adjustment	0.81%
Adjusted Equity Risk Premium	6.35%
Projected Treasury Bond Yield (b)	3.70%
Implied Cost of Equity	**10.05%**

(a) Exhibit CCW-11.
(b) Walters Direct at 38.
(c) See regression data on page 2 of this Exhibit.
(d) Data includes January - September, 2018.

REVISED WALTERS RISK PREMIUM

REGRESSION OUTPUT - TREASURY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.909253356
R Square	0.826741666
Adjusted R Square	0.821152687
Standard Error	0.003976416
Observations	33

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00233895	0.00233895	147.9235716	2.46101E-13
Residual	31	0.000490168	1.58119E-05		
Total	32	0.002829119			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.079879857	0.002129475	37.51152384	2.12573E-27	0.075536763	0.08422295	0.075536763	0.08422295
X Variable 1	-0.442248773	0.036362015	-12.16238347	2.46101E-13	-0.516409592	-0.36808795	-0.516409592	-0.368087954

REVISED WALTERS RISK PREMIUM

UTILITY BOND YIELD

	(a) Moody's "A" Rated Public Utility Bond Yield	(a) Authorized Electric Returns	(a) Indicated Risk Premium
1986	9.58%	13.93%	4.35%
1987	10.10%	12.99%	2.89%
1988	10.49%	12.79%	2.30%
1989	9.77%	12.97%	3.20%
1990	9.86%	12.70%	2.84%
1991	9.36%	12.55%	3.19%
1992	8.69%	12.09%	3.40%
1993	7.59%	11.41%	3.82%
1994	8.31%	11.34%	3.03%
1995	7.89%	11.55%	3.66%
1996	7.75%	11.39%	3.64%
1997	7.60%	11.40%	3.80%
1998	7.04%	11.66%	4.62%
1999	7.62%	10.77%	3.15%
2000	8.24%	11.43%	3.19%
2001	7.76%	11.09%	3.33%
2002	7.37%	11.16%	3.79%
2003	6.58%	10.97%	4.39%
2004	6.16%	10.75%	4.59%
2005	5.65%	10.54%	4.89%
2006	6.07%	10.34%	4.27%
2007	6.07%	10.31%	4.24%
2008	6.53%	10.37%	3.84%
2009	6.04%	10.52%	4.48%
2010	5.46%	10.29%	4.83%
2011	5.04%	10.19%	5.15%
2012	4.13%	10.01%	5.88%
2013	4.48%	9.81%	5.33%
2014	4.28%	9.75%	5.47%
2015	4.12%	9.60%	5.48%
2016	3.93%	9.60%	5.67%
2017	4.00%	9.68%	5.68%
2018 (d)	4.18%	9.59%	5.41%
AVERAGE	6.90%	11.08%	4.18%

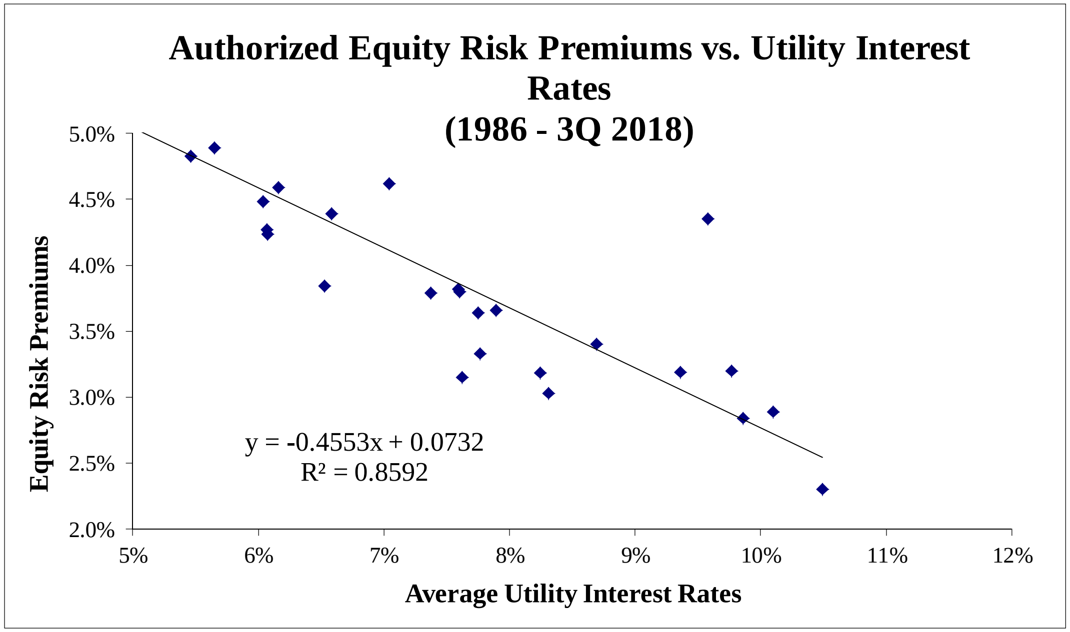
INDICATED COST OF EQUITY

Current Baa Utility Bond Yield (b)	4.94%
Average Treasury Bond Yield Over Study Period	6.90%
Change in Bond Yield	-1.96%
Risk Premium/Interest Rate Coefficient (c)	-45.53%
Adjustment to Study Period Risk Premium	0.89%
Average Risk Premium Over Study Period	4.18%
Interest Rate Adjustment	0.89%
Adjusted Equity Risk Premium	5.07%
Current Baa Utility Bond Yield (b)	4.94%
Implied Cost of Equity	**10.01%**

(a) Exhibit CCW-12.
(b) Walters Direct at 38.
(c) See regression data on page 4 of this Exhibit.
(d) Data includes January - September, 2018.

REVISED WALTERS RISK PREMIUM

REGRESSION OUTPUT - UTILITY BOND YIELD



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.926944369
R Square	0.859225863
Adjusted R Square	0.854684762
Standard Error	0.003735176
Observations	33

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002639783	0.002639783	189.2109049	9.67557E-15
Residual	31	0.000432498	1.39515E-05		
Total	32	0.00307228			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.073179866	0.002375055	30.8118682	8.10697E-25	0.068335911	0.078023822	0.068335911	0.078023822
X Variable 1	-0.455310881	0.03310053	-13.75539548	9.67557E-15	-0.522819857	-0.38780191	-0.522819857	-0.387801905

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
CHRISTOPHER M. GARRETT
CONTROLLER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

TABLE OF CONTENTS

Q. Please state your name, position, and business address.

A. My name is Christopher M. Garrett. I am the Controller for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your rebuttal testimony?

A. The purposes of my rebuttal testimony are to rebut intervenor testimony on the issues of (1) the use of capitalization as the Companies' method of valuation; (2) depreciation; (3) scheduled outages; and (4) various other matters. I also provide an adjustment to the Companies' revenue requirements due to the November ice storm and execution of refined coal agreements.

I. USE OF CAPITALIZATION AS THE METHOD OF VALUATION

Q. Do any intervenors argue that the Companies' use of capitalization is inappropriate?

A. Yes. Kroger witness Bieber identifies that capitalization is larger than rate base and argues that the use of capitalization is inappropriate. Mr. Bieber is the only witness that contests the Companies' use of capitalization as the appropriate method of valuation. In fact, AG witness Mullinax states that she calculated the return requirement based on capitalization and "defer[s] to . . . the Companies' approach."[1]

Q. Does Mr. Bieber argue that the Companies should use rate base as their method of valuation?

[1] AG Response to Commission Staff 1-2.

A. No. Mr. Bieber does not seem to suggest that the Companies should use rate base as their valuation methodology, but instead simply argues that the Companies should not earn a return on the portion of their proposed capitalization that is in excess of rate base. Because Mr. Bieber fails to identify that any portion of the Companies' capitalization was imprudent, the Commission should reject Mr. Bieber's result-oriented request to disallow the Companies' reasonable and prudent costs to serve customers.

Q. Has Kroger witness Bieber submitted written testimony to any regulatory commission regarding the difference between rate base and capitalization?

A. No. In response to a data request from the Companies, Mr. Bieber provided the cases in which he has submitted written testimony.[2] Mr. Bieber has not submitted written testimony about the difference between rate base and capitalization to this Commission or any other regulatory commission. Indeed, Mr. Bieber's total experience testifying before regulatory commissions is limited to fewer than ten other cases.

Q. Does capitalization remain the most appropriate valuation methodology for the Companies?

A. Yes. Like the use of Construction Work in Progress described in the Rebuttal Testimony of Kent W. Blake, the Companies have used capitalization for decades. The Companies have committed to capitalization because of their belief that it is the most objective measure of valuation that reflects the actual value of assets used to provide service to customers. While capitalization and rate base are essentially the

[2] Kroger/Walmart Response to KU/LG&E 1-1.

same in this proceeding, rate base relies on a theoretical calculation, i.e. a lead lag study, to determine the extent to which the Company funds its working capital. In contrast, capitalization does not require the use of a lead lag study as it represents the actual capital invested in the business and is the more objective valuation method.

Unlike Mr. Bieber suggests, the Companies are not using capitalization because it produces a higher revenue requirement in this case. In fact, the Companies have supported the use of capitalization in many cases in which capitalization produced a lower revenue requirement. And further, the Companies have committed to continuing to use capitalization in future cases, even if it produces a valuation that is lower than rate base.[3]

Q. Does Kroger witness Bieber provide any evidence to show that the Companies' longstanding use of capitalization is unreasonable or imprudent?

A. No. Kroger witness Bieber relies on the sole fact that rate base exceeds capitalization to justify a departure from the Companies' historic practice of using capitalization. Mr. Bieber fails to present any substantial evidence to otherwise support his position or critique the detailed rate base – capitalization reconciliation provided by the Companies in their applications and subsequent data requests. Instead, Mr. Bieber simply assumes that the difference between rate base and capitalization somehow shows the investment in facilities are not used or useful in providing service or is evidence of unreasonable amounts of capitalization. Neither is correct or supported by this record. The Companies' historic use of capitalization is especially important as KRS 278.290 and Commission precedent require the Commission to consider a

[3] KU Response to AG 1-30; LG&E Response to AG 1-30.

utility's historic method of property valuation when fixing the value of property. As I identified in my direct testimony, the Commission stated in Case No. 2000-00080 that it "will consider using an approach different than that previously used" only if a justification exists.[4] Mr. Bieber attempts to distinguish this case by noting that the Commission approved the lower valuation methodology for the utility in Case No. 2000-00080. Mr. Bieber ignores the fact that the valuation methodology selected by the Commission was also the valuation methodology the utility had historically used.

Q. Should the Commission consider Kroger witness Bieber's argument about assets that are "used and useful" in providing service to customers?

A. No. Throughout his testimony, Mr. Bieber argues that capitalization reflects a valuation in excess of the assets that are "used and useful" in providing service to customers. The Commission has made clear that this standard is not a requirement, explaining that the Commission "is under no statutory obligation to apply a used and useful standard exclusively, or any other single, rigid standard."[5]

And Kentucky courts have equally made clear that the mechanical application of the "used and useful" standard by the Commission is not a requirement, with the Court of Appeals stating: "A strict adherence to 'used and useful' is not necessary for the courts to determine if PSC rates are lawful and reasonable."[6]

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[4] *In the Matter of: The Application of Louisville Gas & Electric Company to Adjust and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 9 (Ky. PSC Sept. 27, 2000). The Commission considered whether LG&E had presented sufficient evidence to support changing the property valuation methodology it had traditionally used.

[5] *In the Matter of: An Investigation of Big Rivers Electric Corporation's Rates for Wholesale Electric Service*, Case No. 9885, Order at 8 (Ky. PSC Aug. 10, 1987); *In the Matter of: Big Rivers Electric Corporation's Notice of Changes in Rates and Tariffs for Wholesale Electric Service and of a Financial Workout Plan*, Case No. 9613, Order at 36 (Ky. PSC Mar. 17, 1987).

[6] *Nat'l-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W.2d 503 (Ky. App. 1990).

The portions of KRS Chapter 278 applicable to these proceedings do not require the application of the "used and useful" standard to this issue. Only where a utility serves two or more municipalities is the commission required to apply the used and useful standard.[7]

Having said this, there is no basis to support the argument that capitalization reflects a valuation in excess of the assets that are used and useful in providing service to customers.

Q. Does Mr. Bieber's proposed revenue requirement adjustment justify a departure from the Companies' longstanding history of using capitalization?

A. No. Mr. Bieber has failed to present any substantial evidence to support his position. His recommendation is simply result-oriented without the support of any affirmative evidence showing that the differences between capitalization and rate base are unreasonable, imprudent, or the result of unregulated operations. The difference between the two numbers alone does not justify a departure from the Companies' long-standing, historical practice. Furthermore, the difference between capitalization and rate base that Mr. Bieber identifies is incorrect and overstated. The Companies made a subsequent filing on January 11, 2019 to reduce capitalization for the debt issuance issue discussed below, making the difference between rate base and capitalization approximately one percent of each company's rate base and capitalization, as shown below.[8]

[7] KRS 278.290(3).

[8] KU Supplemental Response to PSC 1-53 – Schedule A (Ky. PSC Jan. 11, 2019); LG&E Supplemental Response to PSC 1-53 – Schedule A (Ky. PSC Jan. 11, 2019). KU and LG&E also filed supplemental responses to PSC 1-53 on February 15, 2019, which updated Schedule B-5.2. The table reflects the updated values filed on February 15, 2019.

	KU	LG&E Electric	LG&E Gas
Capitalization	$4,078,343,555	$2,575,355,911	$783,383,775
Rate Base	$4,053,646,882	$2,542,261,745	$773,415,175
Difference	$24,696,673	$33,094,166	$9,968,600
% of Capitalization	0.61%	1.29%	1.27%
% of Rate Base	0.61%	1.30%	1.29%

These differences are not substantial enough to justify an abrupt departure from the Companies' long-standing use and more objective measure of capitalization.

II. DEPRECIATION

A. Extension of Asset Lives

Q. Please briefly describe the adjustments proposed by KIUC and USDOD regarding their proposals to reduce depreciation expense by extending asset lives.

A. Both KIUC and USDOD request the extension of asset lives for certain steam generation plant. KIUC witness Kollen argues that the Commission should use 65-year lives to set the depreciation rates for all of the Companies' coal-fired generating units. USDOD witness Selecky argues that the depreciation lives of five of the Companies' coal-fired generation units should be increased by three years. Additionally, KIUC witness Kollen rejects the Companies' proposal to shorten the depreciation lives for ash ponds and recommends the Commission use the remaining lives of the generating stations based on the 2015 depreciation study.

Q. Do the Companies agree with the extensions to asset lives that intervenors recommend?

A. No. The Companies dispute the intervenor-proposed asset lives. Mr. Bellar and Mr. Spanos explain in their rebuttal testimonies why the Companies' depreciation lives are appropriate and do not need to be modified.

Q. Does the extension of plant lives create savings for ratepayers?

A. No. Depreciation expense is simply the recovery of capital investments made by the Companies. Lower depreciation expense is exactly offset by higher net plant, causing customers to pay higher capital costs on the net plant, such that on a present value basis, assuming the Companies' weighted average cost of capital matches the discount rate used, the customer should be indifferent to depreciation rates. While KIUC witness Kollen and USDOD witness Selecky may wish to reduce depreciation rates for current customers in the short-term, any extension in asset lives passes the depreciation cost on to future customers. Shifts like this proposal in depreciation policies can affect the timing of cost recovery, but not the magnitude of cost recovery. In other words, it is a matter of paying now, or paying more (in nominal value terms) later.

Furthermore, the intervenor requests to extend depreciation rates are made without any apparent concern for the effect of this treatment on the Companies' cash flow, capital needs, financial position, or impact on customers in the future. These potential issues could lead to increased costs for ratepayers.

Q. Do the Companies' proposed depreciation rates minimize intergenerational inequities?

A. Yes. It is important that depreciation rates be set at a level that minimizes inter-generational inequities. In other words, the customers who benefit from the energy produced by the Companies' power plants should pay for the cost of those plants as opposed to leaving that cost to be borne by future generations. The Companies commissioned Mr. Spanos to perform a depreciation study on the Companies' steam generation assets to ensure depreciation rates are set at a level that minimizes inter-generational inequities and provides for the full recovery of the cost of these power plants.

B. Brown Unit 1 and 2 Ash Pond Depreciation Rate

Q. Please describe KU's error in the calculation of the Brown Unit 1 and 2 ash pond depreciation rate.

A. As KIUC witness Kollen identifies, the weighted average depreciation rate for Brown 1 and 2 is 2.32%. In its calculation of depreciation expense, KU incorrectly used a 24.68% depreciation rate. KU calculated the amount of this error in discovery[9] and included the correction in its supplemental response to PSC 1-53 filed on January 11, 2019.

C. Ash Pond Depreciation Rates

Q. Please describe the Companies' omission of ash pond depreciation rates.

A. The Companies stopped recording depreciation expense for the ash ponds effective July 1, 2017. In discovery, the Companies explained that the ash pond rates were inadvertently listed as a zero rate as part of the settlement agreement in the 2016 rate cases.[10] As a result of the Commission's order in Case No. 2016-00026, whereby the closure costs would be amortized for ratemaking purposes rather than recovered through depreciation rates, the ash pond assets were moved to separate depreciation

[9] KU Response to KIUC 1-35.
[10] KU Response to KIUC 1-34; LG&E Response to KIUC 1-32.

groups in the previous depreciation study, which resulted in the omission. The depreciation study filed in this case corrects this omission.

Q. Were customers harmed by this inadvertent omission?

A. No. Customers are not paying additional depreciation on the ash ponds due to the omission in the settlement agreement in the 2016 rate cases. Those depreciation rates approved in Case No. 2016-00026, despite this flaw, were the depreciation rates used to calculate the depreciation expense currently embedded in retail rates. Further, based on group depreciation, assets are recovered over the life of the assets within the group. Thus, not every asset is individually depreciated. Additionally, rates are established in rate cases after assets have been placed in service, which means that the entire group of assets are recovered over the life of the group. The life of the ash ponds were not previously presented in the last depreciation study. Therefore, earnings were not overstated by the amount of the omission.

Q. How does KIUC witness Kollen propose to account for this issue?

A. KIUC witness Kollen argues that the failure to record the ash pond depreciation expense since July 1, 2017 through the beginning of the test year on April 30, 2019 results in the understatement of accumulated depreciation and the overstatement of capitalization. Mr. Kollen recommends that the Commission reduce common equity capitalization by the error in accumulated depreciation.

The Companies strongly disagree with this adjustment for the reasons noted above. Customer rates and KU’s depreciation expense reflect the depreciation rates approved in Case No. 2016-00026. Thus, there is no adjustment in capitalization to be made. Furthermore, even if an adjustment in capitalization were to be made, it would not be taken against only the common equity portion of capitalization but rather across all sources of capitalization in accordance with the Companies' balanced capital structures.

D. Revenue Requirement Calculations for Book Depreciation Changes

Q. Do the calculations proposed by KIUC witness Kollen and USDOD witness Selecky account for all of the revenue requirement impacts associated with a change in book depreciation?

A. No. Mr. Kollen's and Mr. Selecky's calculations for the proposed adjustments to book depreciation fail to adjust rate base and capitalization for the reduction in depreciation expense. Such an adjustment is necessary because any reduction in depreciation expense recovery in revenues causes a corresponding increase in capitalization and rate base for the reduction in accumulated depreciation less the increase in accumulated deferred income tax ("ADIT"). Additionally, when book depreciation expense is decreased as a result of using longer depreciable lives, the revenue requirement is increased by the lower excess ADIT amortization. "Protected" excess ADIT is reduced (refunded to customers) over the remaining book lives of property that gave rise to the deferred taxes using the Average Rate Assumption Method ("ARAM"). For any change made to extend the book lives of property, an adjustment is required to reduce the excess ADIT amortization to avoid a potential normalization violation. The corresponding capitalization and excess ADIT adjustments were not included as part of either Mr. Kollen's or Mr. Selecky's proposed adjustments. The impact of these corrections to the revenue requirement are shown in Rebuttal Exhibit CMG-1.

III. SCHEDULED OUTAGES

Q. Does KIUC witness Kollen claim a normalization adjustment should be made to the Companies' revenue requirements for scheduled generation outage expense?

A. Yes. KIUC witness Kollen asserts that the planned generation outage expense in the test year does not represent the going forward level of this expense based on historical data.

Q. Please briefly describe the Companies' use of the eight-year average of generator outage expenses.

A. As I explained in my direct testimony, the Companies used historical expenses for years 2015 through 2018[11] and forecasted expenses for years 2018 through 2022 to develop the eight-year methodology for recovering the outage expense included in the forecasted test year.

The evidence shows that the eight-year methodology has worked well, provides a transparent method of recovery of the Companies' prudently incurred costs without the volatility, and avoids the over- or under-recovery issues associated with normalization adjustments.

Q. Have the Commission and the Companies generally rejected normalization adjustments like those KIUC witness Kollen presents for planned generation expense?

A. Yes. The Commission and the Companies historically have not used normalization of operations and maintenance expenses for ratemaking purposes, because such adjustments are susceptible to manipulation by the periods chosen or the data

[11] 2018 includes six months of actual (January-June) and six months of forecasted (July-December) outage expense.

included for the adjustment. Allowing such selective and result-oriented adjustments would give rise to a series of selective adjustments, the purpose of which would be to try to offset one another for the benefit of either the customer or the shareholders.

It is for this good reason that the Commission has declined to allow such selective adjustments in the past; the exceptions are only for good cause, such as for storm damages and injuries and damages. The normalization concept is susceptible to being manipulated to achieve a certain outcome. Approval of this proposed adjustment would be a significant change to the established rate-making process.

Q. Do normalization adjustments introduce greater subjectivity into the ratemaking process?

A. Yes. *All* normalization adjustments introduce subjectivity into the rate case process that would not otherwise exist because every normalization adjustment is based upon a time period typically selected on the basis of judgment. Subjectivity and the risk of selective manipulation are inextricably entangled with normalization adjustments.

Q. What is your recommendation regarding outage normalization?

A. For the reasons stated above, it is my recommendation that the Commission deny the KIUC adjustment to normalize planned generation outage expense.

As discussed, the Companies recognize that outage expense may vary from period to period given the eight-year cycle and nature of the work. However, the Companies are unable to capitalize these costs absent the Commission granting deferral accounting treatment.

IV. THE COMPANIES REBUT VARIOUS OTHER INTERVENOR ADJUSTMENTS

A. Overstatement of Capitalization for First Mortgage Bond Issuances

Q. Please describe the error in the Companies' calculation of the thirteen-month average of Capitalization and why the Companies' subsequent correction appropriately adjusts the short-term debt component of capitalization.

A. As the Companies explained in discovery,[12] the Companies inadvertently omitted offsetting reductions to s*hort-term* debt balances when calculating total capitalization related to the forecasted issuance of First Mortgage Bonds ("FMB") in May 2019. This resulted in the approximate overstatement of Kentucky jurisdictional capitalization by $22 million for KU, $18 million for LG&E Electric operations, and $5 million for LG&E Gas operations.[13] The impact of the omission on the Companies' revenue requirements is a decrease of $0.964 million for KU; a decrease of $0.912 million for LG&E's Electric operations; and a decrease of $0.173 million for LG&E's Gas operations. The Companies identified this correction in their supplemental responses to PSC 1-53 filed on January 11, 2019. The issuance of the long-term debt at these levels and retirement of the short-term debt is consistent with the Companies' long standing business practice of using short-term debt until it rises to a level that can be cost-effectively refinanced in the form of long-term debt.

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[12] KU Response to KIUC 2-24; LG&E Response to KIUC 2-23.

[13] KU attachment to Response to Kroger/Walmart 2-1; LG&E attachment to Response to Kroger/Walmart 2-1. The capitalization impact is significantly smaller than the size of the FMB issuance because only one of the 13-monthends (4/30/2019) used in the average short-term debt capitalization calculation was misstated.

Q. Please describe the errors in KIUC witness Kollen's quantification of the effects of the overstatement of Capitalization related to the issuance of First Mortgage Bonds.

A. KIUC witness Kollen argues that the Companies' error overstated KU's revenue requirement by $0.944 million and LG&E's electric revenue requirement by $1.393 million. With respect to his calculation for LG&E electric operations, he reduced capitalization by net proceeds (principal less debt issuance costs) from LG&E's $500 million FMB issuance, rather than the amount of the gross issuance of $500 million that would be used to retire short-term debt of $300 million (the other $200 million will be used to redeem LG&E's $200 million term loan). The impact of this caused Mr. Kollen to overstate the reduction to capitalization by $12 million ($195 million / 13 months * 80.33% Electric Jurisdictional Factor) for LG&E Electric operations. For KU, he also used net issuance proceeds rather than the full $300 million FMB issuance. The impact of this caused Mr. Kollen to understate the reduction to capitalization by $0.2 million ($3 million / 13 months * 93.77% KY Jurisdictional Factor). Finally, in his calculation, he incorrectly reduced the long-term debt component of capitalization rather than the short-term debt component of capitalization. Mr. Kollen's calculation to reduce the long-term debt portion of capitalization will not allow the Companies to appropriately recover their full interest costs on the FMB long-term issuances that will occur no later than May 1, 2019.

B. Cash Working Capital

Q. Does AG witness Mullinax incorrectly apply a cash working capital adjustment to capitalization?

A. Yes. In Ms. Mullinax's Schedules 1.1, she proposes the same adjustments to jurisdictional rate base and jurisdictional capitalization which is rather confusing and odd given that the majority of Ms. Mullinax's adjustments relate to cash working capital derived from the lead lag study. As the Companies explained in discovery, cash working capital is a component of rate base, not capitalization.[14] Adjustments for cash working capital only impact rate base because capitalization already includes the funding of working capital. Accordingly, Ms. Mullinax's adjustments to capitalization relating to the lead lag study are incorrect in application and should be rejected.

C. Baseline ECR Beneficial Reuse Operating Expense Credit

Q. Please explain the baseline ECR beneficial reuse operating expense credit.

A. In this proceeding, KU proposes to remove all beneficial reuse revenues and expenses from its base rates, and have all beneficial reuse revenues and expenses flow through the Environmental Cost Recovery (ECR) mechanism. As previously approved, KU runs all beneficial reuse revenues and expenses through its ECR mechanism; however, at the time of that approval, KU had a credit associated with beneficial reuse at its Ghent plant included in base rates. KU's current ECR filings include an adjustment to remove this credit in order to avoid double counting. With base rates being set in the current proceeding, KU proposed to simplify its ECR filings by removing this adjustment.

Q. Do the Companies agree with AG witness Mullinax's proposed adjustment regarding the ECR beneficial reuse operating expense credit?

[14] KU Response to Kroger/Walmart 1-6(c); LG&E Response to Kroger/Walmart 1-6(c).

A. No. Ms. Mullinax proposes simply to reinstate the credit that existed in a past rate case. While this unnecessary complication provides the appearance of a reduction in base rates, that impact will be offset by an increase of the same amount in ECR filings, with no net impact on the bills of KU's retail customers.

D. Amortization of Storm Damage Regulatory Assets

Q. Please describe the July 2018 Storm regulatory asset.

A. In Case No. 2018-00304, the Commission approved the Companies' requests to establish regulatory assets to account for the expenses incurred by the Companies to repair and restore service caused by severe thunderstorms beginning on July 20, 2018 ("July 2018 Storm"). The Commission ordered that the amortization and rate recovery of the regulatory assets be determined in the Companies' pending rate cases.

Q. Do you have additional information about the actual expenses the Companies incurred for the July 2018 Storm?

A. Yes. KU and LG&E have established regulatory assets in the amount of $4,791,953 and $2,463,048, respectively, for the July 2018 Storm as of January 31, 2019.

Q. Over how many years have the Companies proposed to amortize the July 2018 Storm regulatory assets?

A. Consistent with the amortization periods of the Companies' similar storm regulatory assets, the Companies have requested amortization of the July 2018 Storm over five years.[15] This results in annual amortization of $958,391 and $492,610 for KU and

[15] *See, e.g., In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset*, Case No. 2011-00380, Order (Ky. PSC Dec. 27, 2011). Following Case No. 2011-00380, KU proposed a 5-year amortization period in Case No. 2012-00221 for the amortization of the 2011 Windstorm Regulatory Asset, which was approved in the settlement agreement. The Commission also approved a 5-year amortization period for the 2003 Ice Storm Regulatory Asset in Case No. 2003-00434.

LG&E, respectively, and represents an increase of $13,736 for KU and $14,515 for LG&E in the forecasted test year compared to the original filing.

Q. Over what period does AG witness Mullinax argue that the Companies should amortize the July 2018 Storm regulatory assets?

A. Ms. Mullinax recommends that the regulatory assets for the July 2018 Storm be amortized over ten years instead of the five years the Companies proposed. Ms. Mullinax provides little support for her recommendation and relies solely on the Commission's approval of a non-unanimous stipulation that set forth a ten-year amortization period for the Companies' regulatory assets for the 2008 Wind Storm and the 2009 Winter Storm. That stipulation specified that it "shall not have any precedential value in this or any other jurisdiction."[16] And the ten-year amortization period was agreed to in exchange for other valuable consideration as part of the stipulation. Accordingly, the stipulation certainly is not evidence of the reasonableness to the ten-year period. Ms. Mullinax ignores the fact that the Commission has consistently approved the amortization of the Companies' similar storm regulatory assets over five years and provides no affirmative evidence to support the ten-year period.

When asked for further explanation of why a ten-year amortization period is more appropriate for the storm damage regulatory asset, Ms. Mullinax advances only

[16] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2009-00548, Appendix A: Stipulation and Recommendation, Section 6.12, p. 19 (Ky. PSC July 30, 2010); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Appendix A: Stipulation and Recommendation, Section 6.12, p. 19 (Ky. PSC July 30, 2010).

an argument lacking evidence that recovery of the storm costs over a longer period contributes to rate stability.[17]

Q. Does LG&E have a pending request for establishment of a regulatory asset for storm damage?

A. Yes. In Case No. 2019-00017, LG&E requests authority for the establishment of a regulatory asset to account for expenses incurred to repair damage and restore service to its customers caused by the ice storm on November 14, 2018 ("November 2018 Ice Storm"). Should the Commission grant authority to establish the regulatory asset for the November 2018 Ice Storm, LG&E requests that it be amortized over a five-year period consistent with the July 2018 Storm.

Q. Do you have additional information about the estimated expenses LG&E incurred for the November 2018 Ice Storm?

A. Yes. LG&E has estimated the expenses incurred for the November 2018 Ice Storm to be approximately $6,477,082. Based on a five-year amortization period, the Company requests $1,295,416 in amortization costs be recovered through base rates in this proceeding.

E. Amortization of Tax Reform Regulatory Liabilities

Q. Do the Companies agree with AG witness Mullinax's recommendation to amortize unprotected excess ADIT over a six-year period?

A. No. The Companies propose a 15-year amortization period, which the Companies have shown is appropriate.

[17] AG Response to Commission Staff 1-1.

Q. Why is a 15-year amortization period for the unprotected excess ADIT appropriate?

A. As the Companies explained in Case No. 2018-00034, excess ADIT balances are largely driven by differences in book and tax accounting for pension expense. In Case Nos. 2014-00371 and 2014-00372, amortization of actuarial gains and losses in the Companies' pension expense was set at 15 years and that ratemaking treatment was carried forward in Case Nos. 2016-00370 and 2016-00371. In executing the original *Offer and Acceptance of Satisfaction* in Case No. 2018-00034, the parties discussed and agreed to use a 15-year amortization period for non-property-related excess ADIT to be consistent with the ratemaking treatment being provided to the amortization of actuarial gains and losses in the Companies' pension expense. This approach minimizes intergenerational inequities by allowing the customers paying for the pension costs to receive the corresponding tax benefits. Ms. Mullinax iterates the importance of the matching principle, but ignores that a 15-year amortization period best minimizes intergenerational inequities.

In the original *Offer and Acceptance of Satisfaction* in Case No. 2018-00034, the parties, including the Attorney General, also considered and agreed to the 15-year amortization period with awareness of the stress that the Tax Cuts and Jobs Act placed on the credit metrics and ratings of utilities across the country.

Q. Did the Companies propose the same amortization period for excess ADIT created by state tax reform?

A. Yes. The Companies proposed the same methodology for the amortization of the excess ADIT created by the reduction in the state corporate income tax rate in Case No. 2018-00304.

Q. If the amortization period for unprotected excess ADIT is changed in this proceeding, should rate base and capitalization also be adjusted?

A. Yes. The regulatory liability for excess ADIT is included in both capitalization and rate base, therefore, any change in the amortization period would result in a corresponding change in capitalization and rate base. Ms. Mullinax incorrectly failed to make an adjustment to capitalization and rate base for her proposed change in the amortization period as part of her revenue requirement calculation.[18]

F. Interest Synchronization

Q. Do the Companies agree with AG witness Mullinax's recommended interest synchronization adjustment?

A. No. Ms. Mullinax calculates her interest synchronization adjustment by multiplying her recommended capitalization by the weighted cost of debt. Because the Companies disagree with Ms. Mullinax's recommended capitalization, they also disagree with her interest synchronization adjustment.

V. REFINED COAL AGREEMENTS

Q. Are there any other updates the Companies would like to make to their revenue requirements?

A. Yes. The Companies recently executed refined coal agreements at its Trimble County and Mill Creek generating stations.

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[18] AG Response to Commission Staff 1-2(b).

Q. What is the effect of the refined coal agreements on the Companies' revenue requirements?

A. As shown on Rebuttal Exhibit CMG-2, the refined coal agreements decrease LG&E's revenue requirement by approximately $7.8 million. The reduction to KU's revenue requirement is approximately $1.7 million.

Q. Does this conclude your testimony?

A. Yes, it does.

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public

My Commission Expires:

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

Exhibit CMG-1 is being provided in a separate file in Excel format.

KU Estimated Payments/Fees from Refined Coal Projects

Tinuum Exclusivity and Fees Agreement

		2019 Amortization								2020 Amortization					
	($000)	**Balance at Apr '19**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Total Test year Amort**	**Filed Forecasted Test Yr**
Trimble Co		$ 239	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	**$ 89**	**$** -

Notes:

1 May 2019 amortization based on 32 months (May 2019 thru Dec 2021)

Trimble Clean Fuels, LLC Agreement

		2019 Estimated Fees							2020 Estimated Fees					
	($000) KY Juri	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**Total Test year**	**Filed Forecasted Test Yr**
Trimble Co		$ 143	$ 132	$ 145	$ 143	$ 137	$ 151	$ 149	$ 115	$ 162	$ 144	$ 99	$ 49	**$ 1,568**	**$** -

Total	**$ 1,658**	**$** -
Change in Revenue requirement	**$ 1,658**	

Notes:

1 Agreement signed October 2018

2 Monthly fees based on forecasted generation at each site. Will be paid through December 2021 (Term of the agreements) if not terminated earlier.

The allocation percentages are as follows:

Kentucky	94.101%
FERC	2.060%
Virginia	3.839%

LGE Estimated Payments/Fees from Refined Coal Projects

Tinuum Exclusivity and Fees Agreement

($000)	Balance at Apr' 19	2019 Amortization May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020 Amortization Jan	Feb	Mar	Apr	Total Test year Amort	Filed Forecasted Test Yr
Trimble Co	$ 234	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	**$ 83**	**$ 40**
Mill Creek	$ 785	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	$ 23	**$ 278**	**$ 134**
Total	$ 1,019	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	**$ 360**	**$ 174**

Notes:

1 Amortization through April 2019 in base rates
2 May 2019 amortization based on 32 months (May 2019 thru Dec 2021)

Agreements - Mill Creek Clean Fuels, LLC and Trimble Clean Fuels, LLC

($000)	2019 Estimated Fees May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020 Estimated Fees Jan	Feb	Mar	Apr	Total Test year	Filed Forecasted Test Yr
Trimble Co	$ 145	$ 158	$ 176	$ 169	$ 167	$ 84	$ 128	$ 161	$ 177	$ 161	$ 177	$ 118	**$ 1,822**	**$ -**
Mill Creek	$ 468	$ 486	$ 539	$ 528	$ 429	$ 411	$ 404	$ 537	$ 535	$ 471	$ 596	$ 358	**$ 5,761**	**$ -**
Total													**$ 7,943**	**$ 174**
Change in Revenue requirement													**$ 7,769**	

Notes:

1 TC agreement signed October 2018
2 MC agreement signed Jan 2019
3 Monthly fees based on forecasted generation at each site. Will be paid through December 2021 (Term of the agreements) if not terminated earlier.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

And

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

AND LOUISVILLE GAS & ELECTRIC COMPANY

Filed: February 22, 2019

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. ARE YOU THE SAME JOHN J. SPANOS WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony, I respond to the depreciation-related recommendations of Kentucky Industrial Utility Customers ("KIUC") witness Lane Kollen and United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") witness James Selecky. There are two specific depreciation issues I will address. The first is the life spans for the Company's coal-fired steam power plants. Both Mr. Kollen and Mr. Selecky have recommended longer life spans than those I have proposed, which, for the plants in question, my proposed life spans are the same as the current life spans used for each facility. Given the numerous factors influencing the economics of operating coal-fired generation, I do not believe that their proposals to increase the life spans for these facilities are appropriate. The second is the service life of the Company's ash ponds which will be closed in the coming years. Only Mr. Kollen has raised this issue. He recommends depreciating these assets over a period of time that is longer than their service lives. His proposal is inappropriate as it is inconsistent with GAAP and regulatory principles and will result in intergenerational inequity.

II. THE LIFE SPAN METHOD

Q. WHAT IS THE OBJECTIVE OF DEPRECIATION?

A. The objective of depreciation is to allocate, in a systematic and rational manner, the full cost of an asset (original cost less net salvage) over its service life. The Uniform System of Accounts ("USofA") requires this in General Instruction 22-A:

> *Method*. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value[1] of depreciable property over the service life of the property.

Thus, the USofA confirms that depreciation represents the allocation of the full costs of a company's assets (original cost less any net salvage) over their service lives – that is, over the period of time the assets are providing service. Costs are allocated over the service lives of the assets so that customers pay for the costs of the assets that provide them service. Current customers should not pay for the costs of assets that have already been retired or those that will not receive a benefit. Similarly, future customers should not have to pay for the costs of assets that are no longer in service because current customers pay too little for their service.

Q. Please explain the concept of a "life span."

A. For certain types of facilities, referred to as "life span property," all assets at the facility will be retired concurrently. A textbook example of a life span property is a power plant. When the plant is retired, all assets at the plant will be retired (whether installed the day the plant went into service or were placed into service recently). The retirement of the

[1] The USofA defines service value as the original cost less net salvage. Code of Federal Regulations, Title 18, Chapter 1, Subchapter C, Part 101, Definitions.

entire facility is referred to as the “final retirement” or “terminal retirement.” The period of time from the original year the plant was placed into service to the final retirement is the “life span” of the facility.

Not all assets at a facility will be retired as final retirements. Some components of life span property will be replaced during the life span of the overall facility. When such assets are retired or replaced, they are referred to as “interim retirements.” New assets installed subsequent to the original installation of the facility up to the test year date are referred to as “interim additions.” Interim retirements need not be minor items. For example, the Company will replace boiler feed pumps at its coal-fired power plants prior to the final retirement of the facilities. The retired feed pumps will be interim retirements and the new boiler feed pumps that replace the retired pumps will be interim additions.

Q. HOW IS DEPRECIATION DETERMINED FOR LIFE SPAN PROPERTY IN ORDER TO MEET THE OBJECTIVE OF DEPRECIATION YOU SET FORTH ABOVE?

A. The life span method allows for costs to be equitably allocated over the life span of the facility as well as over the lives of interim retirements. When the life span method is used, a “probable retirement date” is estimated. The probable retirement date represents the point in time in the future when it is most probable that the life span facility will be retired. The use of a probable retirement date allows depreciation to be calculated so that each vintage of assets at the facility will be depreciated by the time of the estimated retirement date. As a result, both the original installation and interim additions that have occurred to date are recovered over the appropriate period of time.

The life span method also allows for the estimation of interim retirements. This is most commonly achieved with the use of "interim survivor curves," which estimate what percentage of plant will be retired each year. However, in some instances, such as interim retirements of larger assets such as ash ponds, it is necessary to separately identify large interim retirements and depreciate these assets over their expected useful life.

III. LIFE SPANS OF COAL-FIRED POWER PLANTS

Q. WHAT HAVE YOU PROPOSED FOR THE LIFE SPANS OF THE COMPANY'S COAL-FIRED POWER PLANTS?

A. For the Company's coal plants, the life spans I have proposed are consistent with the life spans used for the Company's current depreciation rates, with the exception of Brown Units 1 and 2 which will be retired in 2019.

Q. HOW ARE LIFE SPANS TYPICALLY ESTIMATED?

A. A power plant is typically retired as the result of an economic decision. As a plant ages and becomes more expensive to operate, and as new technologies become more efficient and economical relative to existing generation, it eventually becomes economical to replace the existing plant. The retired plant may be able to physically operate for a longer period of time but it would be a more costly option to keep the plant in service.

Thus, the process of estimating the life spans of the Company's power plants is more than determining how long a plant could physically last, but must also consider the economic decision as to when to replace the plant with newer generation. Factors considered in determining life span estimates include the life spans and experience of other similar facilities for the Company and others in the industry; an understanding of technological, regulatory and operational changes that could impact the life of a facility; and an understanding of other factors that impact the economics of operating a facility, such as fuel prices for both the plant at issue and for competing sources of generation.

Q. IN ESTIMATING THE LIFE SPANS FOR LG&E AND KU'S FACILITIES, WERE THESE TYPES OF FACTORS CONSIDERED?

A. Yes. The estimation of life spans for the Company's facilities incorporated these types of factors. The Companies performed their own analyses of the most appropriate life span for each facility.[2] I also performed an independent review based on my experience and knowledge of other facilities in the industry. In my judgment, the recommended retirement dates in the depreciation studies represent the most reasonable probable retirement dates for each facility.

Importantly, the life spans recommended for the Company's coal plants at issue in this proceeding are the same as those currently used for the Company. Due to a number of factors, such as new technologies of generation, low natural gas prices and environmental recommendations, I do not believe it would be appropriate to increase the life spans of the Company's coal-fired generating facilities. Doing so would risk having too long of life spans, resulting in intergenerational inequity and the risk of stranded costs if the plants are retired earlier than the retirement dates used for depreciation purposes.

Q. WHAT HAVE MR. KOLLEN AND MR. SELECKY PROPOSED FOR THE LIFE SPANS OF THE COMPANY'S COAL PLANTS?

A. Both have proposed to increase the life spans for many of the Company's coal plants. Mr. Kollen states that he recommends "that the Commission use 65-year [life spans] to set the depreciation rates for the Company's coal-fired units."[3] Mr. Selecky states that

[2] See the response to US DOD 2-2.

[3] Kollen at 49:24-25. I note that this statement in his testimony is not entirely accurate. For certain plants his life spans are different from 65 years.

he proposes "that the currently approved life span for Mill Creek 1 and 2, Brown 3 and Ghent 1 and 2 be increased by three years."[4]

Q. WHAT ARE THE BASES OF THEIR PROPOSALS?

A. Mr. Kollen's proposal is based on two primary factors: 1) his interpretation of a business planning document produced by the Company and 2) the life spans of the Clifty Creek and Kyger Creek power plants. Mr. Selecky's proposal is based primarily, if not entirely, on his misinterpretation of email correspondence between myself and the Company.

Q. DO EACH OF THEIR PROPOSALS RESULT IN LONGER LIFE SPANS THAN THOSE USED FOR THE COMPANY'S CURRENT DEPRECIATION RATES?

A. Yes. In each case, Mr. Kollen and Mr. Selecky have proposed to increase the life spans of these coal-fired facilities.

Q. IS IT REASONABLE TO LENGTHEN THE LIFE SPANS OF THE COMPANY'S COAL PLANTS?

A. No. In my judgment, particularly based on the experience of both LG&E and KU as well as others in the industry, it is not appropriate to increase the life spans of the Company's coal plants. Across the country, many coal plants have been retired earlier than expected and many have had shorter life spans than 65-years. The same is true of the Company's experience. In 2015, the Companies retired multiple coal units and the Company plans to retire Brown Units 1 and 2 in 2019. The Company also retired the Pineville plant in 2002 and Cane Run Units 1, 2 and 3 in 1985. Most of these had a life span of less than 60 years, as can be seen in the table below.

[4] Selecky at 23:12-13.

Table 1: Life Spans of Retired or Planned to Be Retired LG&E and KU Coal-Fired Power Plants

Unit	In-Service Year	Retirement Year*	Life Span
Cane Run Unit 1	1954	1985	31
Cane Run Unit 2	1956	1985	29
Cane Run Unit 3	1958	1985	27
Cane Run Unit 4	1962	2015	53
Cane Run Unit 5	1966	2015	49
Cane Run Unit 6	1969	2015	46
Tyrone Unit 1	1947	2007	60
Tyrone Unit 2	1948	2007	59
Tyrone Unit 3	1953	2013	60
Green River Unit 1	1950	2003	53
Green River Unit 2	1950	2003	53
Green River Unit 3	1954	2015	61
Green River Unit 4	1959	2015	56
Brown Unit 1	1956	2019	63
Brown Unit 2	1963	2019	56
Pineville	1951	2002	51

*Retirement year represents the year unit no longer was generating electricity. This is not the same date assets were removed from service as shown in the depreciation study.

As can be seen in the table, the plants that the Company has retired have had shorter life spans than 65 years (and also had life spans that were shorter than the 63 years Mr. Selecky proposes). Further, the average life span of these retired plants was approximately 50 years, which is even shorter than the life spans I have proposed for most of the Company's remaining coal-fired power plants. Additionally, while some of the older plants have had longer life spans, the Company's newer plants have tended to have shorter experienced life spans (with the exception of Cane Run Units 1, 2 and 3), which is consistent with the experience of many in the industry. For example, all of the plants in the table above that were installed since 1960 have had life spans less than 60 years.

The shorter life spans for plants built over the last 40 years is due to the many additional factors, such as the influx of renewable energy sources, lower natural gas prices, environmental regulations and efficiencies of coal.

Q. WHY HAVE NEWER COAL-FIRED POWER PLANTS TENDED TO HAVE SHORTER LIFE SPANS THAN OLDER PLANTS?

A. As I noted above, three of the primary factors that have resulted in the retirement of coal-fired power plants have been new technologies of generation (both efficient gas combined cycle plants and renewables), low fuel prices for natural gas generation and environmental regulations. The impact of these factors on existing coal-fired generation became significant in the mid-to-late 2000s, whereas these factors did not have as much of an impact prior to this time period. Thus, a power plant installed in the 1940s would have been in service for 60 years before these factors began to significantly impact the economics of the plant. This allowed older plants to attain longer life spans. However, a plant placed in service in the 1970s or 1980s would be much younger (20 or 30 years of age) in the mid-to-late 2000s, which has tended to, on average, result in shorter life spans for newer coal-fired power plants.

Q. MR. KOLLEN DISCUSSES TWO PLANTS, CLIFTY CREEK AND KYGER CREEK, IN SUPPORT OF HIS PROPOSAL TO INCREASE THE LIFE SPANS FOR LG&E AND KU'S PLANTS. IS HIS ARGUMENT PERSUASIVE?

A. No. Mr. Kollen's discussion of the experience of these two plants does not change that both Company-specific and industry-wide information supports shorter life spans than he has proposed. As shown in Table 1, the Company's experience has shown that LG&E's and KU's plants have typically experienced shorter life spans than what Mr. Kollen expects for Clifty Creek and Kyger Creek. Indeed, as Mr. Kollen notes, Clifty

Creek and Kyger Creek were both installed in the mid-1950s. All of the Company's plants installed in this timeframe (Cane Run 1, 2, and 3, Tyrone Unit 3, Green River Units 3 and 4 and Brown Unit 1) have been retired or are planned to be retired and on average had life spans in the 55-year range. This information is more relevant to the determination of the life spans of the Company's power plants than the two plants cited by Mr. Kollen.

Further, there are a number of examples of power plants of the same vintage as the Company's remaining fleet of coal plants that either have retired or are planned to be retired that had or will have shorter life spans than those proposed by Mr. Kollen (and proposed by the Company). The Company's generating units that are at issue in this proceeding have all been installed since 1971 (Brown Unit 3 is the oldest coal-fired unit expected to remain in service beyond 2019). There have been a number of plants installed since 1971 that either have been or are planned to be retired. For example, Nevada Power has retired its Reid Gardner plant and plans to retire the Navajo plant (of which it is a co-owner) by the end of 2019. The life spans of the six units at these plants (each has three units) range from 37 to 48 years. Indianapolis Power & Light retired its Harding Street Station Units 1 and 2 in 2016, resulting in a 43-year life span. MidAmerican Energy closed its Neal Unit 2 plant in 2015, resulting in a life span of 43 years. Public Service Company of Oklahoma's Northeastern Unit 4 plant was retired in 2016 and had a life span of 36 years. The Saint John's River Power Park ("SJRPP") plant was retired in 2018. The two units at this plant had life spans of 30 and 31 years.

Additionally, the Boardman plant in Oregon is planned to be retired by end of 2020, which will result in a 40-year life span. Duke Energy Progress's Asheville plant is planned to be closed in 2019, resulting in a 48-year life span. Public Service Company of Oklahoma plans to retire its Northeastern Unit 3 plant in 2026, resulting in a life span of 46 years. These are just a few examples of coal-fired units being retired many years prior to age 65.

Q. HAS THERE BEEN RECENT ANNOUNCEMENTS OF COAL FIRED PLANT RETIREMENTS IN KENTUCKY LESS THAN 65 YEARS?

A. Yes. Tennessee Valley Authority has announced the closure of units at their Paradise and Bull Run facilities. The Paradise facility will retire in 2020 and the three units will have a life span between 50 and 54 years. The Bull Run facility will have a life span of 56 years.

Q. WHAT OTHER REASON DOES MR. KOLLEN CITE IN SUPPORT OF HIS RECOMMENDED LIFE SPANS?

A. Mr. Kollen also cites to a planning document to support a 65-year life span. However, the Company has explained that the document he cites was not intended to provide detailed estimates of the life spans of the Company's facilities.[5] Instead, it is for planning capital expenditures for the Company's fleet of plants. Because the estimated life spans of the Company's facilities extend beyond a typical capital and operational planning period, there is not the need for detailed life span estimates for the Company's generating plants in the planning document cited by Mr. Kollen.

However, as noted by the Company in the response to Question No. 33 in KIUC's first set of interrogatories (which Mr. Kollen has attached to his testimony), the Company explained that shorter life spans were considered in the recent integrated resource plan

[5] See KU's response to KIUC Data Request Set 1, Question No. 33.

and the PPL Climate Assessment Report. Both of these are more relevant to determining life spans than the planning document to which Mr. Kollen refers. Further, as noted in the same response, the Company reviewed the life span estimates in more detail for the depreciation study. The resultant life spans, which for the plants in question are the same as the life spans currently used for each facility, are the most appropriate estimates and should continue to be used.

Q. CAN YOU SUMMARIZE THE FUNDAMENTAL FLAWS OF MR. KOLLEN'S DEPRECIATION POSITION?

A. Yes. First, Mr. Kollen selects an arbitrary 65-year life span for all units which does not consider any planning for meeting generating requirements or unit capabilities. Second, his calculations just extend the remaining lives to a life span of 65 years without properly calculating the interim survivor curve and net salvage components. A longer life span creates more interim retirements and more net salvage, which requires more depreciation expense than he has proposed. Third, he changes the recovery pattern of the ash ponds to the life spans currently in place instead of calculating the rates to the 65-year life span he is proposing for the related units. This contradicts with the arguments he makes in his testimony. Finally, he has attempted to make depreciation expense a results-oriented exercise without truly following the concept and definition of depreciation. These flaws in his calculations incorrectly reduce this proposed position by $15 million for the two companies. These flaws cannot be considered a reasonable approach.

Q. WHY HAS MR. SELECKY PROPOSED LONGER LIFE SPANS FOR SOME OF THE COMPANY'S COAL UNITS?

A. Mr. Selecky's proposal is based primarily on his interpretation of an email I had sent to the Company regarding discussions held prior to the completion of the analysis of the life spans for the Company's assets. The email alluded to three-year increases in life spans for Mill Creek 1 and 2, Brown 3 and Ghent 1 and 2. However, Mr. Selecky's discussion of this email does not place it in the proper context and, in fact, my statements in this email does not lead to his conclusion that the life spans for these units should be increased.

Q. WHAT DOES MR. SELECKY STATE ABOUT THIS EMAIL?

A. Mr. Selecky states that "[i]n reviewing emails from Mr. Spanos to Company representatives, I discovered that Mr. Spanos had intended to increase the lives of these five units."[6]

Q. IS THIS AN ACCURATE SUMMARY OF WHAT YOUR EMAIL STATED?

A. No. Additionally, while I can understand that the language in the email may be somewhat ambiguous without the proper context, this context was in fact explained to Mr. Selecky in discovery.[7] His testimony is contrary to the context provided to him in discovery.

Q. WHAT DID THE EMAIL CITED BY MR. SELECKY STATE?

A. The email in question was addressed to Sara Wiseman, Manager of Property Accounting for LG&E and KU. It stated:

> Sara:
>
> This creates an issue from our last discussion. We had planned to extend Mill Creek 1 and 2, Brown 3 and Ghent 1 and 2 by 3 years. Does that mean we should not do that step and keep the retirement dates you supplied today.
>
> With that said, I am available most of the rest of the week except this afternoon.
>
> John

[6] Selecky at 23:19-20.
[7] See the response to US DOD-2 Question No. 8, which Mr. Selecky attached to his testimony in Exhibit JTS-11.

Q. WHAT IS THE CONTEXT OF THE EMAIL?

A. During the conduct of the depreciation study, I had conversations with LG&E and KU personnel regarding the life spans. As noted above, LG&E and KU had been performing analyses of the proper life spans for these facilities. Based on a discussion prior to this email, my understanding was that the Company's analysis would support an increase to the life spans of three years for these facilities. Based on this understanding, we had planned to run calculations with these increased life spans. However, the Company's analysis did not actually support an increase in life spans for these accounts.

Q. WHY DO YOU BELIEVE MR. SELECKY HAS INTERPRETED THIS EMAIL DIFFERENTLY?

A. Mr. Selecky has selectively interpreted my email incorrectly. My email does not indicate that I believed that increases in the life spans was more appropriate than keeping them the same as in the previous depreciation study (which is what was ultimately decided). Rather, based on an earlier discussion, I had planned to perform calculations with the longer life spans because that was my understanding of the Company's analysis at the time. As noted in the email, this understanding was not consistent with the conclusion of the Company's analysis. Additionally, my statement that "this creates an issue from our last discussion" was not intended to convey that I disagreed with the decision to keep the life spans the same. Indeed, as noted in the discussion above, the experience of LG&E and KU and others in the industry would, if anything, support shorter life spans (not longer life spans). Instead, the "issue" to which I referred in the email was completing calculations by the deadlines established for preparing for the rate case. Because of the need to rework calculations I had performed, I was concerned with the timing of the completion of my final calculations.

Q. DOES MR. SELECKY PROVIDE ANY OTHER REASONS IN SUPPORT OF HIS PROPOSAL?

A. Mr. Selecky provides few other reasons in support of his proposal on page 24 of his testimony. I have responded earlier in my testimony to the few he discusses.

Q. DOES MR. SELECKY PROVIDE WORKPAPERS TO SUPPORT HIS DEPRECIATION POSITION?

A. No. The only depreciation workpapers provided by Mr. Selecky was the responses to discovery provided by the Company. In other words, Mr. Selecky has not performed any of his own depreciation analysis.

Q. WHAT DO YOU CONCLUDE WITH REGARD TO THE LIFE SPANS OF THE COMPANIES COAL-FIRED POWER PLANTS?

A. Based on a number of factors discussed above, the life spans used in the depreciation study, which are the same as currently approved for the Company, are most appropriate to use for the development of depreciation rates in this proceeding.

IV. ASH PONDS

Q. WHAT HAVE YOU PROPOSED FOR THE COMPANY'S ASH PONDS?

A. The Company plans to close and remediate the ash ponds for Brown, Ghent 1, Mill Creek and Trimble County in the coming years. Accordingly, these assets will reach the end of their service life in the next few years. My proposal is that, consistent with the USofA and accounting principles, the costs for these ash ponds should be recovered over their remaining service lives.

Q. WHAT ARE THE REMAINING SERVICE LIVES FOR THE ASH PONDS?

A. The remaining service lives are from now until the ponds are closed.

Q. WHY SHOULD THE COSTS FOR ASH PONDS BE RECOVERED OVER THEIR SERVICE LIVES?

A. As noted in Section II, the General Instruction 22-A of the USofA requires that "[u]tilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the <u>service life</u> of the property" (emphasis added). Because the end of the service lives of ash ponds corresponds with their closure date, the costs of ash ponds should be recovered by the time they are closed.

If, instead, the recovery of ash pond costs were deferred until after they are closed, then future customers would have to pay for assets that are no longer providing electric service. This would be inequitable, particularly because those future customers would also have to pay the costs of dry-ash disposal equipment that will replace the ash ponds. It is not equitable to ask future customers to pay for two generations of ash disposal equipment, while not having current and past customers pay their fair share of the ash ponds that provided service to them.

Q. WHAT IS MR. KOLLEN'S PROPOSAL?

A. Mr. Kollen proposes that "the Commission set depreciation rates to recover the remaining net book value over the remaining lives of the generating units, consistent with the Companies' prior depreciation studies."[8] That is, Mr. Kollen proposes that the costs of these ash ponds be depreciated over a period of time that is much longer than the ponds' service lives.

Q. MR. KOLLEN NOTES THAT IN PREVIOUS DEPRECIATION STUDIES THE ASH PONDS WERE DEPRECIATED OVER THE LIFE SPANS OF THE

[8] Kollen at 51:5-7.

RESPECTIVE GENERATING UNITS. WHY HAVE YOU CHANGED THE DEPRECIABLE LIVES OF THESE ASH PONDS?

A. I have proposed to change the service lives used for depreciation because the expected service lives of these assets have changed. Previously, the expectation for the Companies (and for most coal-fired facilities) was that ash ponds would be closed when the power plant was closed. However, we now know that this will not be the case. Because the service lives of the ash ponds are known to be shorter than the life spans of the facilities, the depreciation rates need to be changed to incorporate this information.

Q. WHAT SUPPORT DOES MR. KOLLEN PROVIDE TO SUPPORT HIS PROPOSAL FOR ASH PONDS?

A. Mr. Kollen provides very little support for his proposal. Other than noting that the previous depreciation study used the life spans of the related facilities, Mr. Kollen states that GAAP does not require an increase to the "depreciation rates to reflect the forecast closure dates" and that "[t]here is no compelling reason to increase the depreciation rates and accelerate the recovery of the remaining costs given the fundamental fact that the Companies will recover these costs as well as a return on those costs until they are fully recovered."[9]

Mr. Kollen is incorrect on both of these assertions. First, as discussed above, there are multiple compelling reasons to recover the costs of ash ponds over their service lives, including the requirements of the USofA and that deferring recovery of these costs (as Mr. Kollen proposes) will result in intergenerational inequity. Mr. Kollen's statement to the contrary actually provides another reason to reject his proposal. If the recovery of

[9] Kollen at 50:20 - 51:10

these costs are deferred, then future customers will have to pay a return on the unrecovered costs (in addition to paying for the return of these costs) after the ash ponds are retired, which makes his proposal even more inequitable.

Mr. Kollen's assertion with regard to GAAP requirements is also fundamentally incorrect. Paragraph 360-10-35-4 of FASB ASC states the following:

> The cost of a productive facility is one of the costs of the services it renders during its useful economic life. <u>Generally accepted accounting principles (GAAP) require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility.</u> This procedure is known as depreciation accounting, a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.

Thus, there is a GAAP requirement that the depreciation rates for ash ponds be increased to recognize the closure dates of ash ponds, because GAAP requires these costs to be spread over the "expected useful life of the facility." Because the useful lives of the ash ponds will end upon their closure, GAAP requires these costs to be recovered through depreciation by the dates of the pond closures. Also, as noted above, the USofA has a similar requirement that costs be allocated over the service lives of the facilities.

Thus, Mr. Kollen's proposal is one that contravenes both regulatory[10] and GAAP requirements. Given that he has not provided any reason to deviate from these requirements, other than his own opinion that the Commission should not follow these requirements, there is no valid reason to adopt Mr. Kollen's position. Instead, the

[10] I note here that in KIUC's response to LG&E and KU's First Set of Interrogatories, Question No. 7, Mr. Kollen acknowledges that "[t]he USOA instructions generally require that plant be depreciated over its estimated service lives."

depreciation rates I have proposed for ash ponds, which will recover their costs over their expected service lives, are most appropriate.

VIII. CONCLUSION

Q. IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN YOUR DEPRECIATION STUDIES THE RATES THE KENTUCKY PUBLIC SERVICE COMMISSION SHOULD ADOPT IN THIS PROCEEDING FOR LG&E AND KU?

A. Yes, these rates appropriately reflect the rates at which the value of LG&E and KU's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric and gas rates in this matter and for the Companies to use for booking depreciation and amortization expense going forward.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is President (formerly Senior Vice President) of Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 21st day of February 2019.

__________________(SEAL)

Notary Public

My Commission Expires:

February 20, 2023

Commonwealth of Pennsylvania - Notary Seal
Cheryl Ann Rutter, Notary Public
Cumberland County
My commission expires February 20, 2023
Commission number 1143028
Member, Pennsylvania Association of Notaries

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2018-00294**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 22, 2019

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Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain errors by the Attorney General's witness Donna H. Mullinax; various intervenors' arguments concerning rate design, tariff issues, and revenue allocation; several proposed revenue and rate base adjustments, including the claim by Ms. Mullinax that certain gas construction work by LG&E requires a certificate of public convenience and necessity; several issues raised by Joseph H. Crone III testifying for Charter Communications Operating, LLC; several issues raised by the Kentucky School Boards Association ("KSBA"); and low-income advocates' concerns.

<u>Ms. Mullinax's Rounding Errors</u>

Q. Ms. Mullinax reduces her recommended electric revenue increases by amounts she asserts are the same the Companies used "due to rounding in the Solar Share and Electric Vehicle programs shown in their schedules."[1] Is she correct in how she characterizes and uses the amounts she cites to reduce revenue requirements?

[1] Mullinax at 13.

A. No. As an initial matter, Ms. Mullinax incorrectly states, "The Companies' calculated-electric-operations revenue deficiencies are less than the Companies' revenue requests."[2] On the contrary, as I stated in my direct testimony, all of the Companies' revenue requests are less than the Companies' revenue deficiencies, not the other way around.[3]

More importantly and as I explained in my direct testimony, the proposed increase in forecasted test period electric revenues for each of the Companies differs from—and is less than—the electric revenue deficiency for two separate and unrelated reasons: (1) the number of decimal places in the proposed charges cannot be carried out far enough to exactly equal the revenue deficiency; and (2) it is necessary to adjust revenues by imputing revenues for the Solar Share and Electric Vehicle programs as discussed in the direct testimony of Mr. Seelye.[4] The first item does indeed result from rounding; rates carried to a reasonable number of decimal places and applied to billing determinants will almost never exactly equal a revenue requirement. But that rounding effect is not an adjustment to the revenue requirement; rather, it is a concession to the mathematical reality that revenue requirements and rates applied to billing determinants do not exactly match.

The second item is a true reduction to the electric revenue requirement for each of the Companies resulting from the imputation of revenue for the Solar Share and Electric Vehicle programs discussed in the direct testimony of Mr. Seelye.[5] LG&E's Schedule M-2.1-E shows the correct amount of revenue to impute for the

[2] Mullinax at 13.
[3] Conroy Direct at 11-12 and 38.
[4] Conroy Direct at 11.
[5] Conroy Direct at 11-12.

Solar Share and Electric Vehicle programs for LG&E, namely $90,078. Likewise, KU's Schedule M-2.1 shows the correct amount of revenue to impute for the Solar Share and Electric Vehicle programs for KU, namely $199,767.

Ms. Mullinax erroneously conflates the rounding effect and the imputed revenue from the Solar Share and Electric Vehicle programs into a single "rounding in the Solar Share and Electric Vehicle programs" value for each of the Companies that overstates the appropriate revenue adjustment for KU ($203,466) and understates the appropriate revenue adjustment for LG&E ($87,527).[6] The Commission should disregard Ms. Mullinax's conflated adjustments and use the Companies' revenue imputation values instead to make the appropriate revenue requirement adjustments.

Q. Does Ms. Mullinax make a rounding error regarding her calculation of LG&E's gas revenue requirement?

A. Yes. Ms. Mullinax applies the Companies' calculated rounding amount ($865) to her calculated revenue deficiency to arrive at her recommended revenue increase.[7] The error is clear: Because Ms. Mullinax did not attempt to create rates based on her calculated revenue deficiency, she cannot have applied those rates to billing determinants to have arrived at a rounding amount. Simply applying the Companies' calculated rounding amount to her proposed revenue deficiency is not a valid method for arriving at a recommended revenue increase. To do that requires the extra work of creating rates and applying them to billing determinants, which work Ms. Mullinax has not done. The Commission should therefore disregard the rounding adjustment Ms. Mullinax applies to her recommended LG&E gas revenue increase.

[6] Mullinax Exh. DHM-1 at 2 (KU Schedule 1); Mullinax Exh. DHM-2 at 2 (LG&E-E Schedule 1).
[7] Mullinax Exh. DHM-3 at 2 (LG&E-G Schedule 1).

<u>**Rate Design and Tariff Issues**</u>

Q. Has any party contested the Companies' proposed rate design for their secondary and primary time-of-day electric service (Rates TODS and TODP)?

A. No. Gregory W. Tillman states on behalf of Walmart, Inc. that he does not oppose the Companies' proposed changes to the Rate TODS billing determinants.[8] Similarly, James T. Selecky states on behalf of the United States Department of Defense and all other Federal Executive Agencies ("DoD-FEA") that he does not oppose the Companies' proposed Rate TODP rate design.[9] Because no party opposes the Companies' proposed changes to the rates designs for Rates TODS and TODP, the Companies ask that they be approved.

Q. Mr. Selecky proposes to add a 60-minute demand exemption provision to LG&E's Retail Transmission Service rate (Rate RTS), which exemption currently exists for Rate TODP.[10] Do you agree with his proposal?

A. No. The Companies made the cited revision to Rate TODP to achieve a stipulation in the Companies' 2016 rate cases, not because there was a cost-of-service justification for the concession. As I noted in my rebuttal testimony in those cases, the underlying reason for a customer's demand does not affect the fact of the demand, and it is the fact of the demand, or more importantly the fact that the demand could occur, that causes a utility to incur costs to build facilities of sufficient capacity to handle customers' demands, regardless of the demands' various causes. Therefore, from a pure cost-causation perspective, Mr. Selecky's proposal continues to lack support.

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[8] Tillman at 23-24.
[9] Selecky at 19.
[10] Selecky at 20-21.

I would also note that the Rate TODP provision Mr. Selecky seeks to expand has not been used a single time since the Companies put it in place following their 2016 rate cases. It has therefore been a nullity to date, and the Companies see no reason to expand it now; indeed, because it has not been used and has no cost-of-service justification, the Commission should consider directing the Companies to remove the exemption from the Companies' Rate TODP tariff provisions.

Q. Have you prepared a summary exhibit indicating changes that the Companies have made to their tariffs since they filed their applications in these proceedings, have proposed to make to their tariffs during the pendency of these proceedings, and will make to the Companies' tariffs during the remaining pendency of these proceedings?

A. Yes. Since the Companies filed their proposed tariffs in these proceedings on September 28, 2018, there have been numerous tariff filings unrelated to these proceedings in which changes to language, rates, or terms and conditions have been approved and are or will be effective prior to the conclusion of these proceedings. For example, the Commission issued Orders in Case No. 2017-00441 on October 5, 2018 and October 25, 2018 in which the DSM tariff sheets were modified. In addition, there have been a number of changes to language during responses to data requests throughout these proceedings. To ensure the Commission and all parties have a succinct summary of all such changes, I have caused to be prepared the exhibit attached to my testimony as Conroy Rebuttal Exh. RMC-1.

<u>Revenue Allocation</u>

Q. Has the testimony of the intervenors that addressed revenue allocation caused you to change your position about the Companies' proposed revenue allocation?

A. No. Of the four intervenor witnesses that addressed revenue allocation (Stephen J. Baron, Mr. Selecky, Mr. Tillman, and Glenn A. Watkins), only Messrs. Selecky and Watkins opposed the Companies' proposed revenue allocation approach.

Notably, the proposed alternative revenue allocations of Messrs. Selecky and Watkins are opposed to each other. Mr. Selecky believes residential customers' rates should be increased relatively more, with more revenue being allocated to residential customers and away from all other non-lighting rate classes.[11] Though the Companies agree with reducing interclass subsidies, Mr. Selecky's proposal does not comport with the ratemaking principle of gradualism.

Contrary to Mr. Selecky, Mr. Watkins argues that "any overall revenue increase (or decrease) granted in this case be assigned to individual rate classes and schedules on an equal percentage basis," which would have the effect of relatively decreasing the Companies' proposed revenue allocation to residential customers and relatively increasing the revenue allocation to all other customer classes.[12] But the basis for Mr. Watkins's position is that the Companies' cost of service study is fatally flawed and therefore cannot be used to allocate revenue, and in the absence of a cost of service study one should allocate revenue in equal proportions to all rate classes.[13] Mr. Seelye explains at length why Mr. Watkins is incorrect about the Companies' cost of service study, but it is also important to note that there are now two other cost of service studies in the record of this proceeding, and they both agree directionally

[11] Selecky at 12-13.
[12] Watkins at 21.
[13] Watkins at 20-21.

with the Companies' study.[14] Therefore, there is ample cost-of-service support for the Companies' proposed revenue allocations.

When considering Mr. Selecky's and Mr. Watkins's testimony and proposals on this issue, I believe it is a sign of the reasonableness of the Companies' revenue allocations that these two intervenors have argued for diametrically opposed changes to the Companies' proposal.

The other two intervenors' witnesses who addressed revenue allocation did not oppose the Companies' approach, at least conceptually. Mr. Baron states regarding the Companies' proposed revenue allocation methodology, "Conceptually, I do support the Companies' approach."[15] He nonetheless argues for a modification to it that would leave the residential customer increase (Tier I) relatively the same, relatively increase the revenue increase allocated to smaller non-residential rate classes (Tier II) and decrease the revenue increase allocated to large, primarily industrial customers (Tier III).[16] He asserts his proposed allocations would actually result in essentially the same level of bill impact to residential customers, but would shift revenue away from industrial customers and onto commercial customers.[17] This is hardly surprising; Mr. Baron is a witness for industrial customers. But it is also faulty because Mr. Baron's rationale for modifying the Companies' proposed revenue allocation depends on taking into account the separate and temporary bill credit being provided to customers through April 2019 concerning the federal Tax Cuts and Jobs

[14] *See* Baron at 8-19; Selecky at 13-19.
[15] Baron at 24.
[16] Baron at 28.
[17] Baron at 29-30.

Act ("TCJA").[18] That credit and the methodology for applying the credit does not affect the cost to serve customers on a prospective basis, and it does not affect class rates of return on a prospective basis. Moreover, the Companies have fully accounted for the TCJA and recent changes to Kentucky income taxes in their proposed rates and revenue allocations. Therefore, I do not believe the Commission should adopt Mr. Baron's recommended modification to the Companies' proposed revenue allocation, and I would note again Mr. Baron's fundamental agreement with the Companies' revenue allocation methodology.

Finally, Mr. Tillman states, "At the proposed revenue requirement, Walmart does not oppose the Company's revenue allocation."[19] He does recommend using ¼ of any reduction to the Companies' revenue request to reduce interclass subsidies and using the remaining ¾ to reduce revenue requirements proportionately for all rate classes. Though this is the most reasonable of the intervenors' proposed alternatives, the Companies believe their proposed allocation best comports with ratemaking principles of gradualism and rate continuity, and it is therefore the most appropriate revenue allocation even if the Commission approves a revenue increase for the Companies that is less than requested.

<u>Operating Income Issues</u>

Q. Testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), Lane Kollen proposes to revise the current sharing of off-system sales margins from the current ratio of 75% to customers and 25% to the Companies

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[18] Baron at 24-31.
[19] Tillman KU at 23; Tillman LG&E at 21.

to a ratio of 90% to customers and 10% to the Companies.[20] How do you respond?

A. I do not agree with Mr. Kollen's proposal. He provides no justification or explanation for his proposal; he merely asserts he believes changing the ratio to the Companies' detriment will not affect their incentive to engage in off-system sales.

With all due respect to Mr. Kollen, the current 75%-25% off-system sales margins splitting arrangement was negotiated and agreed to by all parties to the Companies' 2014 rate cases, including the KIUC, the party on whose behalf Mr. Kollen is testifying in this proceeding.[21] That splitting of margins was and is highly favorable to customers. It appears the Commission agreed because it approved the settlement reached in those cases, which created the Off-System Sales Adjustment Clause for each of the Companies and removed off-system sales margins from base rates entirely; it is now addressed entirely through the Companies' Fuel Adjustment Clauses.[22] Therefore, in addition to being entirely unsupported, Mr. Kollen's proposal is of dubious propriety to address in these base-rate cases.

Also, I would note that volatility in off-system sales margins, upon which Mr. Kollen remarks, occurs largely due to weather changes.[23] The Companies' forecast of such margins assumes normal weather in the forecasted test year.

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[20] Kollen at 28-30.

[21] Case Nos. 2014-00371 and 2014-00372, Settlement Testimony of Kent W. Blake Exh. 1 (Settlement Agreement) (Apr. 20, 2015).

[22] Case Nos. 2014-00371 and 2014-00372, Order (June 30, 2015).

[23] Kollen at 29.

<u>Purchased Power Adjustment Rider Proposal</u>

Q. Mr. Kollen proposes a Purchased Power Adjustment Rider to recover or refund purchased power expense that is more or less than what is recovered through base rates.[24] Do the Companies agree with his proposal?

A. The Companies agree that a purchased power rider may have some merit; however, it should be implemented in a manner that is simple and straightforward similar to the manner in which the Off-System Sales Adjustment Clause discussed previously was implemented. It would certainly stand to reason that a tracker for volatile purchased power demand costs would be logical just as purchased power energy costs flow through a tracking mechanism and would remove any unintended incentives on how the Companies may negotiate the components of future purchased power contracts. The Companies believe implementing such a rider, which could result in either a credit or charge depending on whether actual purchased power demand charges are less than or greater than the amounts embedded in base rates, could be beneficial for customers and the Companies by ensuring cost recovery, but no more as it relates to Commission-approved purchased-power agreements.

<u>Merger Mitigation Depancaking</u>

Q. Both Ms. Mullinax and Mr. Kollen address the Companies' Merger Mitigation Depancaking expenses.[25] What is the Companies' position on this issue?

A. It is important to bear in mind that the Companies continue to pay merger mitigation de-pancaking ("MMD") transmission rates; they have merely asked the Federal Energy Regulatory Commission ("FERC") for relief from those obligations for the

[24] Kollen at 30-32.
[25] Mullinax at 45-47; Kollen at 32-34.

benefit of their retail customers. Receiving a favorable FERC order—and when the issue might finally be resolved following a FERC order—is not at all certain. Indeed, FERC recently issued an order tolling the time for it to act on the Companies' request for 180 days; FERC's order is now due by July 29, 2019, likely assuring the outcome of that proceeding will not be known before rates set in these proceedings will take effect.[26] It is therefore appropriate to retain the Companies' MMD costs in the Companies' base rates. Indeed, the MMD expense was a condition imposed upon the Companies by FERC upon their exit from the Midwest Independent Transmission System Operator, Inc. ("MISO") and was necessary to continue mitigation concerns resulting from the 1998 merger of KU and LG&E.[27] Under the doctrine of federal preemption, state commissions with jurisdiction over retail sales may not disallow recovery of FERC-approved rates, terms, or conditions imposed upon a seller of wholesale power. The MMD expense falls squarely within that category and is therefore not subject to exclusion from the revenue requirement by the Commission.

However, while the Companies could argue that the consideration of a future change in one single component of cost of service is akin to single-issue ratemaking, the Companies do believe there is some merit in Mr. Kollen's position that the appropriate means of addressing the possibility that FERC will reduce or eliminate the Companies' MMD obligations is a regulatory liability.[28] This approach would provide a means by which the Companies' retail customers receive all of the benefits, with no regulatory lag, if the Companies are successful in their proceeding at FERC.

[26] FERC Docket Nos. EC98-2-001 and ER18-2162-000, 166 FERC 61,068, Order Tolling Time for Action on Request under Federal Power Act Section 203 (Jan. 30, 2019).
[27] MISO is now the Midcontinent Independent System Operator.
[28] Kollen at 32-34.

That approach also adheres much more closely to the known-and-measurable ratemaking standard than does Ms. Mullinax's proposal to remove MMD costs from rates and address such costs in the future with a regulatory asset.[29] Ms. Mullinax's approach would all but ensure under-recovery of such costs for at least some time after new rates go into effect.

Late Payment Charge

Q. How do you respond to Ms. Mullinax's position regarding the Companies' late payment charge credit proposal?[30]

A. To understand why Ms. Mullinax's criticisms and recommendation are misplaced, it is helpful to summarize what the Companies have proposed regarding the late payment charge. As I testified previously, the Companies propose to waive a residential customer's late payment charge if the customer requests it and has not incurred a late payment charge in the previous eleven billing cycles. This would allow residential customers who ordinarily pay on time but occasionally pay late not to be charged while retaining a general incentive for customers to pay on time. As Mr. Seelye described in his testimony, the Companies arrived at their revenue adjustments to account for the proposed credit (i.e., assuming less miscellaneous revenue from late payment charges, in turn requiring increased base-rate revenue) by calculating the late-payment-charge revenue received in 2017 from customers who had only one late payment charge after eleven months of not having a late payment charge.[31]

[29] Mullinax at 45-47
[30] Mullinax at 25-26.
[31] Seelye Direct at 66-67.

Ms. Mullinax criticizes the Companies for how they calculated the revenue adjustments for this proposal, asserting that the Companies have assumed more late payment charge credits than will actually occur because the Companies do not plan to advertise the availability of the late payment credit.[32] She proposes instead to assume ***nobody*** will avail themselves of the credit (i.e., to assume the Companies will charge and collect all billed late payment charges) and allow the Companies to create regulatory assets to address any credits they do provide.[33]

Ms. Mullinax's proposal and reasoning are flawed for at least three reasons. First, in addition to the publicity of having the waiver provision plainly stated in the Companies' tariffs, the Companies will train their call center representatives to inform qualifying customers who call about a late payment charge that a waiver is available. Second, although the Companies do not at this time intend to broadly advertise this annual waiver for late payment, it is unreasonable to assume that information about the waiver will not become broadly known through mass media and internet sources if the Commission approves it. Third and perhaps most importantly, Ms. Mullinax's regulatory asset proposal is highly impractical. The Companies' current customer care system could not track such waivers and report them to the appropriate accounting systems for recording as a regulatory asset without incurring significant programming costs. The costs of such implementation could easily approach or exceed the value of the waiver. Therefore, in addition to being substantively flawed, Ms. Mullinax's proposal would be practically unworkable.

[32] Mullinax at 25-26.
[33] Mullinax at 25-26.

<u>Gas Transmission Line Replacement Projects</u>

Q. Ms. Mullinax argues the Commission should disallow any cost related to separate gas transmission line replacement projects, which she calls the "Uniform Diameter Transmission Line Replacement," until LG&E seeks and obtains a certificate of public convenience and necessity.[34] Do you agree?

A. No. Ms. Mullinax attempts to construe a series of geographically distinct gas transmission line replacements to be a single large capital project requiring a CPCN. As Mr. Bellar explains in his rebuttal testimony, LG&E's plans to replace pipeline segments on the Western Kentucky A and B lines, Magnolia road crossings, and connection to Dixie Highway are still in the early stages. Those individual segment replacements—if completed—are cumulatively expected to cost approximately $91 million. Only about ten percent of that amount, $9.6 million, is expected to be incurred during the forecasted test period. As Mr. Bellar notes, LG&E will continue to assess whether replacement of individual pipeline segments is required to achieve safety enhancements and regulatory compliance. If segment replacements are required, LG&E will assess those replacements on a case-by-case basis to determine whether a CPCN is required. That assessment will include considering that the proposed replacements are just that—replacements of existing facilities in the usual course of business, not construction of new facilities.

Also, the Commission order Ms. Mullinax cites as supporting the need for a CPCN actually does not do so regarding the $9.6 million of project cost included in the test year. She cites the Commission's June 22, 2017 order in LG&E's most recent

[34] Mullinax at 16-17.

base rate case as support for her assertion that a CPCN is required here.[35] In the order she cites, the Commission does indeed state that a single 10-12 mile new gas pipeline built to improve reliability and serve new customers and with a projected capital cost of $27.6 million required a CPCN (which the Commission granted in the same order).[36] Notably, none of the different, geographically distinct pipeline replacement projects LG&E plans to undertake in the test year comes close to being 10-12 miles in length or to having a capital cost of $27.6 million. Also, as I noted above, these are transmission line replacement projects in the usual course of business, not construction of new facilities.

In addition, Ms. Mullinax overlooks a more analogous situation addressed in the Commission's final orders in the Companies' 2016 base-rate cases.[37] In those orders, the Commission acknowledged that the Companies were engaging in a Transmission System Improvement Plan ("Transmission Plan") that involved replacing transmission assets to enhance reliability and engaging in several maintenance programs and making capital investments in line sectionalization.[38] KU stated it would spend approximately $149 million between July 1, 2016, and June 30, 2018,[39] and LG&E stated it would spend approximately $28 million over the same period,[40] on the Transmission Plan as part of a total of $511 million in transmission capital investments that the Companies projected to spend over the five-year period beginning 2017. The Commission did not suggest a CPCN would be required for that

[35] Mullinax at 17.
[36] Case No. 2016-00371, Order at 31 (June 22, 2017).
[37] Case No. 2016-00370, Order at 27-28 (June 22, 2017); Case No. 2016-00371, Order at 30-31 (June 22, 2017).
[38] *Id.*
[39] Case No. 2016-00370, Order at 27-28 (June 22, 2017).
[40] Case No. 2016-00371, Order at 30-31 (June 22, 2017).

significant *replacement* program, but rather required the Companies to file annual reports over the five-year Transmission Plan period.[41] Therefore, it would be inconsistent with that Commission determination to require a CPCN for a much less extensive and less capital intensive set of gas line replacement projects.

Finally, it is noteworthy that Ms. Mullinax did not question the prudence of this safety-driven set of investments, and no other party has done so. The Commission should therefore disregard her proposed rate-base adjustment.

<u>Rate PSA Provisions Regarding Audit and Inspector Costs</u>

Q. In your direct testimony, you discuss revisions to the current Rate PSA to permit the direct assessment on attachment customers of the cost of attachment audits. Do you have any clarifications to that testimony?

A. Yes. Audits are necessary to ensure that attachment customers are accurately billed for the services that they receive and that attachment customers are observing the application and permitting procedures contained in Rate PSA. Therefore, the Companies believe it is reasonable that attachment customers cover the cost of these audits. Mr. Seelye discusses necessary adjustments to miscellaneous revenues to reflect payment of audit costs by attachment customers.

[41] Case No. 2016-00370, Order at 28 (June 22, 2017); Case No. 2016-00371, Order at 31 (June 22, 2017).

KSBA Issues

Q. Do you dispute KSBA witness Ronald L. Willhite's assertion that the Companies received a "windfall" by ending the subsidized school rates when the Companies filed their base-rate applications in these proceedings on September 28, 2018?[42]

A. Yes. Contrary to Mr. Willhite's assertions, there is no "inadvertent oversight" or ambiguity in the Commission's June 22, 2017 orders concerning this issue. The Commission stated: "Therefore, the Commission will place a limit on the amount of time the pilot tariffs will be in effect and finds that the pilot tariffs should be effective for three years, or until [the Company] ***files*** its next rate case, whichever is earlier."[43] The Commission is well aware of the difference between the filing of a rate case and when rates are effective; indeed, the Commission demonstrated that understanding in the quoted sentence by using both terms in contradistinction. What is certainly clear from the Commission's order is that the explicitly subsidized rates for schools were not favored, and that the Commission sought to have them end sooner rather than later. Therefore, although Mr. Willhite's desire to characterize the Commission's orders as being unclear on this point is understandable, it simply has no basis in the plain text of the orders.[44]

Also, if the KSBA believed the Commission's orders contained an "inadvertent oversight," the time to seek correction or rehearing was within 30 days of the orders' issuance, not a year and a half later. Notably, other parties did exactly

[42] Willhite KU at 3-4; Willhite LG&E at 3-4.

[43] Case No. 2016-00370, Order at 20 (June 22, 2017)(emphasis added); Case No. 2016-00371, Order at 23 (June 22, 2017)(emphasis added).

[44] The Commission made clear in its October 30, 2018 Order in Case No. 2017-00441 that Rates SPS and STOD expired with the filing of the base rate case when it stated "those rate schedules were terminated on September 28, 2018, without the need for any approval by the Commission."

that.[45] But the KSBA chose not to exercise its rights in that regard, which rights have long since been extinguished.

The Companies therefore were fully in compliance with the Commission's June 22, 2017 orders and their own tariffs issued under the Commission's orders when they terminated service under Rates SPS and STOD on September 28, 2018, the date on which the Companies filed the applications that initiated these proceedings. Yet again, if the KSBA believed the Companies had acted outside their tariffs, it could have initiated customer complaints against the Companies on that ground. But none of the Rate SPS or STOD schools chose to file such a complaint. Therefore, the Commission should disregard Mr. Willhite's criticism of the Companies' strict compliance with the clear wording of the Commission's orders and the Companies' Commission-approved tariffs.

Q. Mr. Willhite also criticizes the Companies for beginning service under Rates SPS and STOD for participating schools on August 18, 2017.[46] How do you respond?

A. Mr. Willhite's claims in this regard are fully addressed by the Companies' responses to data requests KSBA 1-12(d)-(f) and KSBA 2-12. But I will address his claims here, as well.

It is helpful to recall the timeline of events preceding the beginning of service under Rates SPS and STOD on August 18, 2017. First, the Companies and the intervenors to the Companies' 2016 base-rate cases—which included KSBA—had reached a stipulation by April 19, 2017, to propose Rates SPS and STOD for Commission approval. KSBA knew at that time that it would be responsible for

[45] *See, e.g.*, Case Nos. 2016-00371 and 2016-00372, KIUC Motion for Rehearing (July 17, 2017).
[46] Willhite KU at 3; Willhite LG&E at 3.

identifying candidate schools to the Companies. The Commission issued its orders approving the pilot rates on June 22, 2017. But KSBA did not email its constituents until two weeks later (July 6),[47] and did not provide a list of candidate schools to Companies until almost a month later: July 20, 2017.[48]

The Companies then had to analyze the proposed participants and consult with KSBA to confirm which schools could participate.[49] The Companies then had to receive rate-change authorizations from the participating schools, which occurred from August 8 through 17.[50] For administrative ease the Companies chose to transfer all of the participating schools to the new rates effective August 18, the day following the receipt of the last authorizations.[51] The Companies therefore moved with all reasonable speed regarding beginning service for schools under Pilot Rates SPS and STOD.

Finally, contrary to Mr. Willhite's assertions, the Companies did not have tariff authority to retroactively make adjustments to participating schools' bills "to reflect the rate change effective on bills on and after July 1, 2017."[52] To do so would have violated the Companies' Optional Rates provision at Sheet No. 97.1: "In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service." Therefore, for the Companies to have compensated or retroactively changed the rates under which the affected schools took service—which is equivalent to a

[47] *See* KSBA Response to Companies' DR No. 2 Attachment at 1.
[48] *See* KSBA Response to Companies' DR No. 2 Attachment at 2.
[49] *See* KSBA Response to Companies' DR No. 2 Attachment at 2-6.
[50] *See* KSBA Response to Companies' DR No. 2 Attachment at 6-10.
[51] *See* KSBA Response to Companies' DR No. 2 Attachment at 6-10. *See also* Companies' response to KSBA 2-12(e).
[52] Willhite KU at 3; Willhite LG&E at 3.

refund—would have violated their tariffs. And I must note again that if KSBA or the schools being served under Rates SPS and STOD believed the Companies were not acting in accordance with their tariffs, they could have filed complaints against the Companies with the Commission, but none did. These are proceedings about ***prospective*** rates, making their complaints about perceived past issues irrelevant.

<u>**Low-Income Advocates' Concerns**</u>

Q. Do you have any comments concerning the testimony filed by Marlon Cummings for the Association of Community Ministries, Cathy Hinko of behalf of the Metropolitan Housing Coalition, and Melissa Tibbs on behalf of the Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc.?

A. Yes. First, the Companies do understand that low- and fixed-income customers face financial difficulties that other customers do not. That is why, as I discussed at length in my direct testimony, the Companies do their best to provide assistance, including significant shareholder-funded assistance, to low- and fixed-income customers.[53] Regarding shareholder contributions, the Companies have committed to provide at least $1.45 million annually through June 30, 2021, to support low-income programs, all of which is in addition to shareholder funds contributed to the WinterCare and WinterHelp programs. These contributions are in addition to funds contributed by other customers to those programs. The Companies also provide the WeCare DSM-EE program, late-payment charge forgiveness for customers receiving authorized agency assistance, and the FLEX Program to extend bill payment deadlines for

[53] Conroy Direct at 45-50.

customers with fixed incomes. The Companies also have HEA charges of $0.30 for KU and $0.25 for LG&E to help customers in need. In sum, the Companies take low-income issues seriously and have done so for years.

But it is also important to recognize the legal constraints that exist concerning rates for low-income customers. For example, more than a decade ago the Commission clearly stated that special low-income rates are not permissible, and it has never deviated from that position.[54] Less than two months ago, the Commission stated it could not consider affordability in determining the reasonableness of rates.[55] Therefore, although the information the low-income advocates have provided regarding the difficulties low- and fixed-income customers face is sobering, it cannot be used to create special rates for those customers.

Ms. Hinko seeks to contest the latter point.[56] But she notably overlooks the requirement of KRS 278.170(1) not to discriminate with regard to rates or service for "doing a like and contemporaneous service under the same or substantially the same conditions." She likewise does not address the U.S. Supreme Court opinion the Commission cited in its recent order regarding using affordability as a criterion in ratemaking.[57] Instead, Ms. Hinko cites authorities that do not stand for the proposition that affordability for a certain segment of a single customer class may be taken into account, which is what the Commission was pointing out in its January 3,

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[54] *In the Matter of Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 82-84 (Feb. 28, 2005).
[55] Case No. 2018-00358, Order (Jan. 3, 2019).
[56] Hinko at 11-14.
[57] Case No. 2018-00358, Order at 3 (Jan. 3, 2019), *citing Gainesville Util. Dept. v. Fla. Power Corp.*, 402 U.S. 515, 528 (1971) ("But focus on the willingness or ability of the purchaser to pay for a service is the concern of the monopolist, not of a governmental agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable price.").

2019 order.[58] It appears clear the Commission has better support for its argument than Ms. Hinko does for hers.

Regarding Ms. Hinko's assertions regarding disparate racial impacts,[59] the Companies, as they both desire to do and are required to do under KRS 278.170, provide service on a non-discriminatory basis. They do not maintain data on the race of their customers, and would not do so even if they could. The Companies are grateful to serve diverse communities with a diverse workforce, and find Ms. Hinko's regular accusations of racial bias to be offensive.

Oddly and incorrectly, Ms. Hinko asserts that LG&E has proposed to reduce kWh and Ccf charges for residential customers, and therefore that LG&E has proposed to undercut both energy efficiency and solar development by reducing energy rates.[60] Ms. Hinko is simply mistaken on these points. LG&E has proposed to increase its kWh and Ccf rates.

Finally, contrary to Ms. Tibbs's assertions,[61] increasing the Companies' residential Basic Service Charge actually helps WeCare customers, who have above-average energy consumption.[62] Customers who receive WeCare are those most in need, and they tend to have above-average usage, which is why recovering fixed costs through fixed charges is particularly helpful to them. As I also noted in my direct testimony, one of the advantages of recovering fixed cost through fixed charges rather

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[58] Case No. 2018-00358, Order at 3 (Jan. 3, 2019).
[59] Hinko at 4-10.
[60] Hinko at 10-11.
[61] Tibbs at 13-15.
[62] *See, e.g.*, KU Response to CAC 1-15 and 1-16.

than volumetric charges is that it smooths the impact of usage spikes, particularly those caused by extreme weather.[63]

<u>The Companies' Errata Filings</u>

Q. Do you have any comments regarding Mr. Baron's testimony on revenue requirement adjustments resulting from the Companies' January 11, 2019 errata filing?

A. Yes. Concerning Mr. Baron's assertion regarding revenue requirement adjustments resulting from the Companies' January 11, 2019 errata filing, the Companies agree those adjustments are appropriate to consider to the extent they are not already accounted for in other adjustments the Commission might ultimately require. It would not be appropriate to double-count those adjustments by making them *ab initio* and then inadvertently making them again via other adjustments that begin with the Companies' filed revenue requirement.

The Companies made a second errata filing on February 15, 2019, resulting in no changes to LG&E's revenue requirements and a small increase ($1,261) to KU's revenue requirement relative to the January 11, 2019 errata filing amount. It would be appropriate to account for this filing, as well, to the extent it is not already accounted for in other adjustments the Commission might ultimately require.

Q. Does this conclude your testimony?

A. Yes, it does.

[63] Conroy at 15-16.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of February 2019.

Judy Schooler

Notary Public

My Commission Expires:

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

Louisville Gas and Electric Company
Tariff Changes Since September 28, 2018

LG&E Electric Tariff:

- ***Changed by Commission Approval:***
  - CSR (eff 12/01/18)
    - Verbiage change to the Automatic Buy-Through Price section
    - Stamped tariffs provided 11/30/18
    - Sheet Nos. 50.2 and 51.2
  - DSM (eff 01/01/19)
    - Annual budget filing
    - Added DSM verbiage to the FLS tariff
    - Order dated 10/05/18, corrected order dated 10/25/18
    - Case No. 2017-00441
    - Sheet Nos. 30.1, 86, 86.1, 86.2, 86.3, 86.4, 86.5, 86.6, and 86.7
  - Line Extension Plan (eff 01/02/19)
    - Estimated average cost differential
    - Stamped tariffs provided 12/19/18
    - Sheet No. 106.4
- ***Proposed Tariffs Changed Through Responses to Data Requests:***
  - Solar Share
    - Updated the tariff annotations
      - PSC 2-1(k)
      - Sheet Nos. 72.1, 72.2, and 72.3
  - Pole and Structure Attachment Charges (PSA)
    - Updated the tariff annotations
      - PSC 2-1(h)
      - Sheet Nos. 40-40.25
    - Update language regarding audits within 2 year period
      - PSC 3-1(g)
      - Sheet No. 40.18
  - General Service Rate
    - Updated language to the availability section
      - PSC 3-1(a)
      - Sheet No. 10
  - Lighting Service
    - Added language for Asterisk regarding LED offerings
      - PSC 3-1(b)
      - Sheet No. 35.2
  - Terms and Conditions – Deposits
    - Removed language regarding refunds/credits on anniversary dates of the deposit
      - PSC 3-1(d)
      - Sheet No. 102
  - Terms and Conditions – Line Extension
    - Addition of “Non-Residential” verbiage
      - PSC 4-20
      - Sheet No. 106.1, 106.2

- ***Projected to Change Prior to 5/1/19 Rate Case Implementation:***
  - DSM Balancing Adjustment (eff 04/01/19)
    - Annual Update
    - Sheet No. 86.7

<u>LG&E Gas Tariff:</u>

- ***Changed by Commission Approval:***
  - LAUFG and GSC (eff 11/01/18)
    - Annual LAUFG update and quarterly GSC update
    - Order dated 10/15/18
    - Stamped approval effective 11/01/18
    - Case No. 2018-00302
    - Sheet Nos. 5, 9, 10.1, 15.1, 20.1, 21, 21.1, 30.2, 30.6, 35.1, 36.3, 36.8, 51.1, 51.2, 59.5, and 85
  - DSM (eff 01/01/19)
    - Annual budget filing
    - Order dated 10/05/18, corrected order dated 10/25/18
    - Case No. 2017-00441
    - Sheet Nos. 86, 86.1, 86.2, 86.3, 86.4, and 86.5
  - GSC (eff 02/01/19)
    - Quarterly update
    - Order dated 01/17/19
    - Stamped tariffs provided 02/19/19
    - Case No. 2018-00403
    - Sheet Nos. 5, 9, 10.1, 15.1, 20.1, 21, 21.1, 30.2, 30.6, 35.1, 36.8, 51.1, 51.2, and 85
- ***Proposed Tariffs Changed Through Responses to Data Requests:***
  - Terms and Conditions – Deposits
    - Removed language regarding refunds/credits on anniversary dates of the deposit
      - PSC 3-1(d)
      - Sheet No. 102
  - Terms and Conditions – Main Extension
    - Addition of "Non-Residential" verbiage
      - PSC 4-20
      - Sheet No. 106
- ***Projected to Change Prior to 5/1/19 Rate Case Implementation:***
  - DSM Balancing Adjustment (eff 04/01/19)
    - Annual update
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  - GSC (eff 05/01/19)
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Kentucky Utilities Company
Tariff Changes Since September 28, 2018

KU Tariff

- ***Changed by Commission Approval:***
  - CSR (eff 12/01/18)
    - Verbiage change to the Automatic Buy-Through Price section
    - Stamped tariffs provided 11/30/18
    - Sheet Nos. 50.2 and 51.2
  - DSM (eff 01/01/19)
    - Annual budget filing
    - Added DSM verbiage to the FLS tariff
    - Order dated 10/05/18, corrected order dated 10/25/18
    - Case No. 2017-00441
    - Sheet Nos. 30.1, 86, 86.1, 86.2, 86.3, 86.4, 86.5, 86.6, and 86.7
  - Line Extension Plan (eff 01/02/19)
    - Estimated average cost differential
    - Stamped tariffs provided 12/19/18
    - Sheet No. 106.4
- ***Proposed Tariffs Changed Through Responses to Data Requesst:***
  - Solar Share
    - Updates to the tariff annotations
      - PSC 2-1(k)
      - Sheet Nos. 72.1, 72.2, and 72.3
  - Pole and Structure Attachment Charges (PSA)
    - Updates to the tariff annotations
      - PSC 2-1(h)
      - Sheet Nos. 40-40.25
    - Update language regarding audits within 2 year period
      - PSC 3-1(g)
      - Sheet No. 40.18
  - General Service Rate
    - Updated language in the availability section
      - PSC 3-1(a)
      - Sheet No. 10
  - Lighting Service
    - Added language for Asterisk regarding LED offerings
      - PSC 3-1(b)
      - Sheet No. 35.2
  - Terms and Conditions – Deposits
    - Removed language regarding refunds/credits on anniversary dates of the deposit
      - PSC 3-1(d)
      - Sheet No. 102
- ***Projected to Change Prior to 5/1/19 Rate Case Implementation:***
  - DSM Balancing Adjustment (eff 04/01/19)
    - Annual update
    - Sheet No. 86.7

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2018-00295**

REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
MANAGING PARTNER
THE PRIME GROUP, LLC

Filed: February 22, 2018

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Exhibits

Rebuttal Exhibit WSS-1 – Percentage of Energy Cost to Total Revenue Requirement

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Rebuttal Exhibit WSS-4 – Mathematical Equivalency of Net Cost Rate Base and Cash Working Capital for Depreciation Accruals

Rebuttal Exhibit WSS-5 – Response to Commission Data Request Regarding Lead-Lag Studies Submitted by Other Utilities in Kentucky

Rebuttal Exhibit WSS-6 – Revised Response to AG Data Request Regarding Fuel Stock, Materials and Supplies, and Other Items

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is William Steven Seelye. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. Did you submit direct testimony in this proceeding?

A. Yes. I submitted testimony on behalf of Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") in support of the Companies' cost of service studies, proposed revenue allocation, proposed rates, and the lead-lag studies.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the direct testimonies of the Attorney General's ("AG's") witnesses Glenn A. Watkins concerning class cost of service, revenue allocation, and rate design and Donna H. Mullinax concerning the lead-lag studies; Kentucky Industrial Utility Customers, Inc.'s ("KIUC's") witness Stephen J. Baron concerning class cost of service and revenue allocation; United States Department of Defense and all other Federal Executive Agencies ("DOD's") witness James T. Selecky concerning class cost of service, revenue allocation, and Substitute Gas Sales Service -- Rate SGSS; Walmart Inc. ("Walmart's) witness Gregory W. Tillman concerning class cost of service, revenue allocation and rate design; Kentucky School Boards Association ("KSBA's") witness Ronald L. Willhite concerning the expired special school rates; and Charter Communications Operating, LLC's ("Charter Communication's") witness Joseph H. Crone III concerning the Companies' proposed audit provision for pole attachments.

Q. Please summarize your testimony.

A. The following is a summary of my rebuttal testimony:

1. Walmart's witness Tillman and KSBA's witness Willhite do not oppose the Companies' electric cost of service studies, which use the Loss-of-Load-Probability (LOLP) method for allocating production fixed costs. KIUC's witness Baron and DOD's witness Selecky submit alternative cost of service studies which use the 12-CP and 6-CP methods. KIUC's and DOD's cost of service studies produce class rates of return that are similar to those from the Companies' cost of service studies. Because LOLP is used by the Companies to jointly plan their generation systems, the Companies' cost of service studies more accurately reflect the actual cost of providing service to customers.

2. AG's witness Watkins did not submit a cost of service study. He criticizes the Companies' studies, claiming that they place too much emphasis on capacity. Because the amount of generation capacity installed by KU and LG&E does not depend on energy utilization, Mr. Watkins' criticisms of the Companies' cost of service studies are without merit and should be disregarded.

3. KIUC's witness Baron, DOD witness Selecky, and Walmart Witness Tillman agree with grouping the electric rate classes into four tiers as proposed by the Companies. However, Mr. Baron recommends assigning a larger portion of the proposed electric revenue increases to customers served under the Tier II rate classes (GS, PS, AES, LS, RLS, and SC) and recommends lower increases for Tier III rate classes (TODS, TODP, RTS, and FLS). Because the Tier II rate classes have higher rates of return than the Tier III rate classes, Mr. Baron's recommendation would assign too large of an increase to Tier II rate classes. Mr. Selecky proposes to allocate larger portions of the rate increases to the residential rate classes. AG's witness Watkins proposes to increase all rate class tiers by the same percentage regardless of their class rates of return. I recommend that the Commission approve the Companies' proposed allocation of the revenue increase because it strikes the appropriate balance between cost of service

principles, economic development, and gradualism.

4. AG's witness Watkins opposes increases to the residential Basic Service Charges. He proposes to leave the Basic Service Charges at their current levels. He does not address the Basic Service Charges for the non-residential rate classes. In recommending leaving the residential Basic Service Charges at their current levels, Mr. Watkins performs an analysis that omits fixed distribution costs classified as customer-related costs using the zero-intercept methodology, which has been approved by the Commission in numerous rate cases. It is my recommendation that the Companies' proposed Basic Service Charges should be approved, regardless of the revenue requirements authorized by the Commission in these proceedings.

5. AG's witness Watkins opposes the Companies' proposal to implement a daily Basic Service Charge. A daily Basic Service Charge is more accurate, is easier for customers to understand when bills are prorated for customer change-outs and creates greater optionality for possible future implementation of prepaid metering and other programs. Mr. Watkins failed to offer valid reasons for opposing a daily charge.

6. AG's witness Watkins opposes separating energy charges into fixed and variable cost components for informational purposes. He offers no valid reason for keeping this information from customers and other stakeholders.

7. In its Orders in the Companies' last rate cases, the Commission ruled that the pilot rates for schools would be eliminated when the Companies' filed rate cases. The pilot school rates were terminated on September 28, 2018, when the Companies filed their rate case applications in the current proceedings. KSBA witness Willhite recommends that these pilot rates be reinstated. However, he does not provide a cost of service study that supports the reasonableness of the pilot rates which were eliminated pursuant to the Commission's Order. A study performed under my supervision demonstrates that there is no cost justification for reinstating the pilot school rates.

8. DOD witness Selecky opposes the 100% demand ratchet proposed by LG&E for Substitute Gas Sales Service (SGSS). However, Mr. Selecky does not oppose the Base Demand ratchet for KU and LG&E's large customer electric rates, which recover essentially similar fixed costs. Only one customer takes service under SGSS. Mr. Selecky claims that a 70% demand ratchet is appropriate because of system load diversity. However, an analysis of demands for the SGSS customer indicates that the customer's maximum demand occurs at the same time as LG&E's system peak. Therefore, there is no demand diversity under SGSS.

9. AG witness Mullinax recommends reductions to the Companies' proposed Cash Working Capital included in Rate Base. Ms. Mullinax's proposed modifications are inappropriate and conceptually flawed.

10. Charter Communications' witness Crone opposes the proposed tariff provisions requiring pole attachment customers to reimburse the Companies for the cost of auditing pole attachments. Because audits are necessary to ensure that parties are not attaching to poles without authorization from the Companies, it is reasonable that attachment customers reimburse the Companies for the cost of these audits. However, it has come to our attention that the fees for such audits were not included in other miscellaneous revenues in Schedule M-2.3_for KU and Schedule M-2.3-E_for LG&E. Therefore, the Companies are proposing to adjust other miscellaneous revenue to include these audit fees.

II. COST OF SERVICE STUDIES

A. ELECTRIC COST OF SERVICE STUDIES

Q. Were KU and LG&E's electric cost of service studies addressed by the intervenor witnesses in this proceeding?

A. Yes. The Companies' electric cost of service studies were addressed in direct testimony submitted by KIUC's witness Baron, DOD's witness Selecky, AG's witness

Watkins, KSBA witness Willhite, and Walmart witness Tillman.

Q. Please summarize the intervenor witnesses' position on the electric cost of service studies?

A. To the extent that there is disagreement with KU and LG&E's cost of service studies on the part of the intervenor witnesses, the area of disagreement concerns the allocation of production fixed costs. The Loss of Load Probability (LOLP) methodology was used to allocate fixed production costs in the Companies' electric cost of service studies. As explained in my direct testimony, LOLP is a key metric used by the Companies to plan their production resources. LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. LOLP takes into consideration the magnitude of the load, installed generation capacity by season and forced outage rates. For the cost of service studies, LOLP was calculated for each hour of the test year based on the hourly loads for the test year and the characteristics of the Companies' generating facilities, including capacity and forced outage rates. Hourly loads for each rate class were then weighted by the LOLP for each hour to determine LOLP weighted hourly load for each rate class. The weighted loads for each rate class were then summed for the test year to determine the production fixed cost allocators.

Q. What are the positions of the intervenor witnesses regarding the LOLP methodology?

A. KSBA's and Walmart's witnesses do not oppose the LOLP methodology. KSBA's witness Willhite states that "LOLP is an appropriate method for allocating production costs in the Cost of Service Study." (See *Testimony of Ronald L. Willhite*, Case No. 2018-00294, at p. 8, line 9, and *Testimony of Ronald L. Willhite*, Case No. 2018-00295, at p. 8, line 10.) Similarly, Walmart's witness Tillman states that "Walmart does not oppose the Company's proposed cost of service study." (See *Direct Testimony of Gregory W. Tillman*, Case No. 2018-00294, at p. 19, lines 18-19, and *Direct Testimony of Gregory W. Tillman*, Case No. 2018-00295, at p. 18, lines 8-9.) This is consistent with the testimony that Mr. Tillman submitted in KU and LG&E's previous rate cases, where he stated more explicitly that "Walmart does not oppose the use of the LOLP methodology or the Company's proposed COSS." (See *Direct Testimony of Gregory W. Tillman*, Case No. 2016-00370, at p. 18, lines 9-10, and *Direct Testimony of Gregory W. Tillman*, Case No. 2016-00371, at p. 17, lines 9-10.)

KIUC's witness Baron opposes the LOLP method but acknowledges that the LOLP methodology produces "relatively similar results" to his proposed methodology. (*Direct Testimony and Exhibits of Stephen J. Baron*, Case Nos. 2018-00294 and 2018-00295, at p. 15, lines 6-7.) Mr. Baron recommends the 12 coincident peak method ("12 CP"), which allocates production fixed costs on the basis of the sum, or average, of each class's contribution to the 12 monthly system peak demands. (*Id.*, at p. 13 *et seq.*)

DOD's witness Selecky recommends using a 6 CP method for allocating fixed production and transmission costs. This is in contrast to the testimony that he submitted in LG&E's 2016 rate case, in which he stated:

LOLP can serve as a method for allocating fixed generation and

> transmission costs to customer rate classes. In other words, allocating fixed production and transmission costs on the basis of the LOLP links the cost of service methodology to the measurements used by LG&E and KU to plan the system. (Direct Testimony of James T. Selecky, *Case No. 2016-00371*, p. 11, Case No. 2016-00371, lines 4-8.)

Mr. Selecky went on to state that he "would recommend that the Commission abandon the BIP method for the reasons stated above and utilize the LOLP method for purposes of determining the allocation of fixed costs." (*Id*., at p. 12, lines 12-14.) Like the 12 CP method, Mr. Selecky's 6 CP approach produces results that are similar to the Companies' LOLP methodology.

While not offering a cost of service study of his own, or recommending a particular allocation methodology, AG's witness Watkins criticizes the LOLP method because it is not widely used, because he claims that it does not comport with the LOLP method described in the NARUC Electric Utility Cost Allocation Manual, and because he claims that the LOLP factors generated by the Companies' planning models produce "anomalous results". As I will explain, Mr. Watkins' criticisms are without merit. His criticisms are merely red herrings intended to persuade the Commission to adopt an across-the-board rate increase for all rate classes.

Q. Do any of the intervenor witnesses offer alternative cost of service studies?

A. Yes. KIUC witness Baron and DOD witness Selecky offer alternative cost of service studies. Mr. Baron proposes the 12 CP method, and Mr. Selecky proposes a 6 CP method. Mr. Baron's 12 CP method allocates production fixed costs on the basis of class coincident peak demands for twelve months. (*Op. cit*., at p. 13.) Mr. Selecky's

6 CP method allocates production and transmission fixed costs on the basis of class coincident peak demands during the four summer months of June through September and the two winter months of January and February. (*Op. cit.*, at p. 16.) As mentioned earlier, the witnesses for KSBA and Walmart express agreement with the Companies' cost of service methodology and therefore did not offer alternative studies, and while the AG's witness did not agree with the Companies' cost of service studies, he did not offer an alternative study.

Q. How do KIUC's and the DOD's cost of service studies compare to the Companies' cost of service studies?

A. Their studies produce results that are generally in line with KU and LG&E's studies. The following table (Table 1) compares the class rates of return from KU's LOLP study to KIUC's 12 CP and DOD's 6 CP studies:

TABLE 1

Kentucky Utilities Company
Class Rates of Return

KU's Cost of Service Study
Compared to KIUC's and DOD's Studies

	KU's COS LOLP	**KIUC's COS 12 CP**	**DOD's COS 6 CP**
Tier I – Residential	3.03%	2.96%	2.41%
Tier II – GS, PS, AES, LS, RLS, OSL	11.14%	11.44%	12.35%
Tier III – TODS, TODP, RTS, FLS	5.17%	5.12%	5.74%
Tier IV – LE, TE	17.84%	14.77%	17.71%

Table 2 shows the same comparison but of for LG&E:

TABLE 2 Louisville Gas and Electric Company Class Rates of Return LG&E's Cost of Service Study Compared to KIUC's and DOD's Studies			
	LG&E's COS LOLP	**KIUC's COS 12 CP**	**DOD's COS 6 CP**
Tier I – Residential	2.69%	3.37%	2.77%
Tier II – GS, PS, SC, LS, RLS, OSL	12.29%	11.38%	12.10%
Tier III – TODS, TODP, RTS, FLS	10.06%	8.72%	10.03%
Tier IV – LE, TE	17.60%	12.73%	12.26%

Comparing the results from the three cost of service studies indicates that the LOLP method, 12 CP method, and 6 CP method produce similar results. For the major rate classes in Tiers I, II, and III, Mr. Selecky's cost of service studies produce results that are closer to the Companies' studies than Mr. Baron's studies. This is not surprising because Mr. Baron's 12 CP includes loads for Spring and Fall shoulder months that have little or no bearing on production fixed costs. The largest differences in class rates of return are for Tier IV; however, these rate classes account for very small percentage of the Companies' total revenue.

Q. Do you have any comments concerning the three cost allocation methodologies?

A. Yes. I don't have strong objections to the use of either the 12 CP method or the 6 CP method. They are standard methodologies that allocate fixed production costs on the basis of class contributions to system demands. Because the Companies must have sufficient capacity to meet maximum system demand, using a CP allocation method is not unreasonable. However, the LOLP method more accurately reflects the actual cost of providing service. As I explained in my direct testimony, LOLP is a key metric used by the Companies to jointly plan their generation resources. LOLP is a measure of the probability of the utility not having the resources to meet its demand in a particular hour. LOLP has been used for years in the Companies' resource planning processes and is a key measure for determining the Companies' reserve margin requirements. The Companies do not use the sum of their 12 or 6 monthly system demands in resource planning.[1] For this reason, the LOLP is the superior methodology. However, between the 6 CP methodology and the 12 CP methodology, the 6 CP method more accurately allocates fixed production costs for KU and LG&E's systems.

Q. Are there other advantages of the LOLP method over the 12 or 6 CP methods?

A. Yes. The LOLP method is more robust and therefore provides more reliable results. Both the 12 CP and 6 CP methodologies allocate fixed production costs on the basis of a small set of hours during the year. The 12 CP method allocates all fixed production costs on the basis of load for only 12 hours during the year, the system peak hour for each month during the year. The 6 CP method is even more problematic

[1] In resource planning, the Companies also perform reserve margin analyses to ensure that they have adequate capacity at the time of the combined system peak. This might suggest the use of a single CP (1 CP) approach but not a 12 CP or 6 CP approach; however, the use of a 1 CP approach would limit the allocation of fixed production costs to a single hour during the year, further impairing the "robustness" of the determination of cost of service for each rate class. Furthermore, relying on a 1 CP, 6 CP, or 12 CP increases the likelihood of free ridership for classes such as lighting being allocated zero production costs.

in this regard because it allocates fixed production costs on the basis of only 6 hours during the year. The LOLP method, on the other hand, allocates fixed production costs on the basis of loads and LOLPs (i.e., load-weighed LOLPs) for over a thousand hours during the year. Because it is not as dependent on the values of a small set of 12 or 6 data points, the LOLP method is more robust and therefore more reliable.

Furthermore, relative to CP methods, the LOLP method captures seasonal variability in generation capacity ratings. For example, the Companies' traditional generating resources have higher capacity ratings during the winter months than during the summer months. During the summer months, the higher ambient temperatures will reduce the capacity ratings of their steam and combustion turbine generating resources. However, the Companies' solar generating facilities will have lower or even zero capacity during winter peak hours. The Companies' run-of-the-river hydroelectric units will also experience seasonal variability. Unlike the 12- or 6-month CP methods, the allocation factors calculated in the Companies' LOLP models take this seasonal variation in capacity into consideration.

Q. How do you respond to the intervenor witnesses' criticism that the LOLP method is not commonly used in the utility industry?

A. A methodology should not be rejected simply because it is not widely used in the industry. To my knowledge, the Modified Base-Intermediate-Peak ("Modified BIP") methodology that the Companies used in past rate cases was not used by any other utilities. The Modified BIP methodology bears essentially no similarity to the Standard BIP that is described in NARUC's *Electric Utility Cost of Service Manual*, yet the Modified BIP methodology was used by LG&E, and eventually by KU, for a number of years. The Modified BIP methodology was developed by LG&E during the early 1980s because the Standard BIP methodology produced unreasonable results for its generation resources at that time, which in the early 1980s consisted almost entirely of base-load coal fired units. The Standard BIP methodology would have resulted in higher costs during the off-peak period than during peak periods. But over time, as LG&E and KU's generation mix changed, as the combined LG&E and KU systems began to exhibit dual summer and winter peaks, and as the cost of natural gas decreased relative to coal, neither the Modified BIP methodology nor the Standard BIP produced reasonable results. Therefore, in the Companies' last rate case proceedings, the Companies began to transition to the LOLP methodology, which allocates costs on the basis of a key metric used in the Companies' resource planning process. While I agree that the 12 CP method proposed by Mr. Baron is a widely used cost of service methodology for allocating fixed production costs, the LOLP method adheres more closely to the Companies' resource planning process. As I mentioned earlier, the Companies do not use the sum of their 12 system peaks for generation resource planning; they rely heavily on LOLP.

Q. AG's witness Watkins offers a number of other criticisms of the LOLP method. Please respond to those.

A. It is important to keep in mind that Mr. Watkins' criticisms are offered from the perspective that production fixed costs should be allocated based on how generation resources are *used* rather than based on the amount of *capacity that is installed*. Mr.

Watkins has testified in a number of KU and LG&E rate cases, and his position regarding the allocation of fixed production costs is that they should be allocated on the basis of the *use* of the resources rather than on the *capacity* required to serve each rate class. The cost-of-service method he typically recommends is principally based on the amount of *energy* that is produced from the Companies' generation resources rather than on the *capacity* installed to serve each rate class. Mr. Watkins' comments therefore stand in stark relief to positions put forward by KIUC witness Baron and DOD witness Selecky. Mr. Baron and Mr. Selecky propose to allocate fixed production costs based on peak demands. The thread that runs through Mr. Watkins' criticisms is that the Companies' cost allocation method does not consider generation during each hour of the year. Mr. Watkins states that "Mr. Seelye's generation allocation factors only consider loads during the highest peak periods even though it has been established that the vast majority of the Companies' investment in generation facilities is ascribed to base-load units that were planned, designed and are utilized to serve customers' loads throughout the year." (*Direct Testimony of Glenn A. Watkins*, Case Nos. 2018-00294 and 2018-00295, at p. 16, lines 7-10.) Mr. Watkins' claim that the "vast majority" of the Companies' investment in generation facilities consists of base load units is erroneous. Mr. Watkins' claim may have been true during the early 1990s and before, but it is no longer true today. Since the early 1990s the Companies have installed a significant amount of generation capacity consisting primarily of large-frame natural gas combustion turbine units and combined-cycle combustion turbine units. In fact, Mr. Watkins' claim is contradicted in his own testimony. The load duration curve shown on page 10 of his testimony indicates that approximately half of the Companies' combined load is served from generating units he designates as "base-load units". Furthermore, in the electric industry as it exists today, particularly with the relatively low cost of natural gas and the emergence of new generation and storage technologies, the distinction that Mr. Watkins wants to make between base, intermediate and peak units no longer has the meaning that it did in the late 1970s and early 1980s, when the distinction between these categories of units was framed for purposes of cost of serve studies.

But despite Mr. Watkins' erroneous claim about the amount of "base-load capacity" installed by KU and LG&E, he is correct that the LOLP method primarily – and *appropriately*, I would add – considers loads during the peak hours of the year. Generation resources are sized to meet peak demands; they are not sized to meet the annual utilization of the facilities, as Mr. Watkins argues. Increased peak demand will result in the need for additional generation resources, whereas greater utilization of the Companies' generation resources will not result in additional resources. In fact, greater utilization of the generation resources during off-peak periods will typically result in lower unit costs. Therefore, with respect to cost of service, generation resources should be allocated on the basis of peak demands, not on the basis of utilization, as Mr. Watkins suggests.

Q. Can you provide an example of how the base-intermediate-peak designation that Watkins continues to use no longer has the same relevance that it did decades ago?

A. Yes. During the late 1970s through the early 2000s, there was a clear distinction between base load units such as coal-fire steam generating units and intermediate units such as gas-fired combined cycle generating units. During that time frame, coal-fired units had higher capacity cost but significantly lower running cost (energy cost) than gas-fired combined cycle units. Today, largely because of the relatively lower cost of natural gas, the running cost of a gas-fired combined cycle generating unit is typically about the same as the running cost of a coal-fired steam generating unit. In the case of older, less efficient steam units, the running cost of a combined cycle generating unit will often be lower than the running cost of a steam unit. This is one of several reasons that coal-fired steam generating units are no longer being installed in the United States. Thus, Mr. Watkins' distinction between base and intermediate generating units is an artifact from decades ago.

Q. Are there other flaws in Mr. Watkins' criticisms of the LOLP method?

A. Yes, Mr. Watkins makes a number of inaccurate and misleading claims. He states that under the Companies' LOLP methodology, "the class contributions during hour 1 would receive 80% weight with the development of the allocation factor [0.4% ÷ (0.4% + 0.1%)] with class contributions in hour 2 receiving 20% weighting." (*Id.*, at p. 15, lines 25-28.) Mr. Watkins' claim is erroneous and misleading. The reality is that the hour with the highest LOLP is only weighted 7.121%, not 80% as claimed by Mr. Watkins. The second highest LOLP hour is only weighted 5.917%, and not 20% as Mr. Watkins claims. He seems to be suggesting that production fixed costs are allocated on the basis of loads for only two hours during the year. In reality, with the

LOLP method, the Companies' fixed costs are allocated on the basis of class demands during 2,745 hours during the year, based on varying degrees of weighting. The hours during the year with the highest loads do indeed receive the highest LOLP weighting, but it is a distortion to suggest that loads for only two hours during the year account for 100% of the allocation. Indeed, one of the benefits of the LOLP method over the 12 CP proposed by KIUC witness Baron and the 6 CP method proposed by DOD witness Selecky is that the LOLP method does not allocate cost on the basis of just 12 or 6 hours during the year. The LOLP method allocates costs on the basis of class loads for thousands of hours during the year, at various weighting levels.

Q. Mr. Watkins criticizes the LOLP method because it relies heavily on peak period demands to allocate generation capacity costs. Is this a valid criticism?

A. No. While Mr. Watkins criticizes the Companies' cost of service studies for their over-reliance on peak demand for the allocation of generation capacity costs, he makes just the opposite point elsewhere in his testimony. In his discussion of the residential customer charge, Mr. Watkins states:

> As a matter of cost causation, the Companies must plan and install relatively more capacity for heating/air conditioning customers than for small volume customers. This additional capacity comes at a cost such that cost to serve a high load factor (low annual volume) customer is significantly less than that for a low load factor (high annual volume) customer. (*Id*., at p, 31, lines 14-18.)

Yet, regarding production capacity costs, Mr. Watkins claims that "cost causation for generation costs relates to the energy/capacity tradeoff between various generation resources." (*Id*., at p. 9.) With respect to generation capacity costs, Mr. Watkins is confusing cost causation with the use or optimization of capacity. What *causes* capacity to be built is the shortage of capacity due to high LOLP factors or low reserve margins. The energy/capacity tradeoff between various generation resources does not *cause* the generation capacity to be added and is therefore not related to *cost causation*. During the past 60 years or more, the Companies have installed new generating capacity to meet their peak demand requirements, most often due to growth in their peak demands. Therefore, what necessitates the amount of capacity installed by the Companies is the peak demand on their system. This is precisely the reason that the KIUC and DOD witnesses are proposing to allocate generation capacity costs on basis of coincident peak demands. By confusing the *use of capacity* with *cost causation*, Mr. Watkins would assign the high capacity cost steam units to all hours of the year and the low capacity cost single-cycle peaking units to the peak hours. Of course, on a unit cost basis, this would result in higher generation capacity cost during off-peak periods than during on-peak periods, which is a nonsensical result. This is precisely the problem that LG&E encountered with the Base-Intermediate-Peak methodology during the late 1970s and early 1980s.

Q. Mr. Watkins claims that the LOLP method is not consistent with the way that the Companies' generation resources are planned. Is he correct?

A. Absolutely not. Mr. Watkins states that the Companies' cost of service studies "do not comport with the manner in which the Companies generation resources were planned and built and therefore, do not reflect cost causation." (Id., at p. 2, lines 14-16.) This claim is incorrect. The Companies have used LOLP as a key planning metric for many years. The Companies selected the LOLP methodology *because* of its use in resource planning.

Q. Mr. Watkins claims that because the total capacity of supply resources – i.e., generating units, CSR loads, and purchases – is greater than system demands, it is impossible that the Companies would not be able to meet their load obligations and therefore the LOLP should be zero. Is he correct?

A. No. Mr. Watkins' assertion indicates a lack of understanding of probabilistic modeling. While numerous other factors come into play -- such as planned outages, level of the load, CSR demand, and seasonal capacity of the Companies' generation resources -- LOLP is also driven by the joint probability of forced outages of the Companies' generation resources. As long as generation resources' outage rates are not equal to zero, there is a probability (LOLP), however small, that the Companies cannot meet their load obligations. With his Schedule GAW-4, Mr. Watkins also purports to show that for several peak load hours supply (generation resources, CSR, and purchases) is not fully utilized but there is positive expected unserved energy and LOLP. However, Mr. Watkins is confusing the Companies' hourly dispatch model results with the results of the LOLP model. The results of the two models are incommensurable and should not be directly compared because they are developed for different purposes. The dispatch model randomly simulates a *deterministic* outage scenario for the development of an hourly forecast of system operations, while the LOLP model applies a *stochastic* approach using numerical convolution techniques to calculate the joint forced outage probabilities for the Companies' generating units to evaluate the system's expected reliability. Therefore, for a given hour, the supply results from the dispatch model represent just a deterministic (non-stochastic) outage scenario while the results from the LOLP model represent the availability of resources reflecting probabilistic (stochastic) outage scenarios for the Companies' generation resources. Because a deterministic model does not result in unserved demand does not mean that there is zero loss of load probability. In plain English, Mr. Watkins is comparing apples to oranges.

Q. Mr. Watkins suggests on pages 13-14 of his testimony that the LOLP analysis did not consider curtailable loads. Is he correct?

A. No. Curtailable loads under the Companies' Curtailable Service Riders (CSR) were modeled as resources in the development of the LOLP factors. Mr. Watkins failed to submit a data request inquiring how CSR loads were modeled and assumes that they were not included, which is incorrect.

Q. Mr. Watkins criticizes the LOLP method because he cannot verify, replicate, or validate the Companies' model. Is this a valid criticism?

A. No. The PROSYM model used by KU and LG&E to calculate the LOLPs is a longstanding and proven system planning software used in the electric utility industry. KU and LG&E have purchased a license from ABB to use the software. PROSYM is a standard model that has been used by over 130 companies worldwide to evaluate production energy and reliability costs. PROSYM is a recognized model in the industry; the results of PROSYM have been accepted by regulatory commissions all over the United States in the evaluation of utilities' integrated resource planning efforts. Furthermore, KU and LG&E have used PROSYM in their resource planning efforts for decades. While LG&E and KU would not be permitted to provide the source code used by ABB in PROSYM, nor do the Companies have the source code, ABB's technical sheets on PROSYM's LOLP algorithms were provided in response to AG 1-139, which was subject to a non-disclosure agreement that the AG's witness signed. Furthermore, the Companies validated the reasonableness of PROSYM's LOLP model results using an Equivalent Load Duration Curve ("ELDC") model developed by the Companies.

Q. Did the AG request an on-site visit to verify the reasonableness of the LOLP calculations?

A. No. The AG could have requested an on-site visit to verify the reasonableness of the LOLP calculations but did not do so.

Q. Did the AG's witness offer any criticisms of the methodologies that the Companies used to allocate other costs in the electric cost of service studies, such as transmission, distribution, billing and administrative and general costs?

A. No.

Q. Did the AG's witness Watkins submit an alternative cost of service study?

A. No.

Q. What is your recommendation regarding the electric cost of service studies in this proceeding?

A. It is my recommendation that the Commission should accept the Companies' cost of service studies for use as a guide in allocating the revenue increase and in designing rates. While I don't have strong objections to the cost of service studies offered by the KIUC and DOD witnesses, the Companies' cost of service studies are superior and should be approved by the Commission. The AG's criticisms of the Companies studies are without merit and should be ignored.

B. GAS COST OF SERVICE STUDIES

Q. Did any of the intervenor witnesses offer comments on or criticisms of LG&E's gas cost of service study?

A. No.

III. ALLOCATION OF THE REVENUE INCREASES TO THE RATE CLASSES

A. APPORTIONMENT OF THE ELECTRIC INCREASES

Q. Did any of the intervenor witnesses address the Companies' proposed apportionment of the revenue increase to the rate classes?

A. Yes. The allocation of the electric revenue increase is addressed by AG witness Watkins, KIUC witness Baron, DOD witness Selecky, and Walmart witness Tillman.

Q. In order to frame the discussion, please briefly summarize the Companies' proposed allocation of the revenue increase.

A. The Companies proposed a tier-based approach to allocate the overall revenue increase to the rate classes. Using this approach, individual rate schedules are grouped into the following four tiers that generally reflect cost of service and customer characteristics.

- Tier I includes the residential rate classes (RS, VFD, RTOD-Energy, and RTOD-

Demand.

- Tier II includes the small to medium commercial and industrial ("C&I") rate classes (GS, PS, AES-KU, LS, RLS, OSL, and LG&E's special contract).
- Tier III includes the large customer rate classes (TODS, TODP, RTS, FLS).
- Tier IV includes two special lighting rates with high rates of return (LE and TE).

For the Tier I rate classes, the Companies are recommending an increase of one percentage point above the overall increase for each company. For the Tier III rate classes, the proposed increase would be one percentage point below the overall increase for each company. The Companies are not proposing increases for the Tier IV rate classes; however, these are small rate classes in terms of both revenues and numbers of customers served. Tier II would be assigned a residual increase to produce the overall revenue increase proposed by the Companies. For KU the proposed increase for the Tier II rate classes was 0.50 percentage points below the overall increase, and for LG&E the proposed increase for the Tier II rate classes was 0.44 percentage points below the overall increase. In developing this framework for apportioning the increases to the rate classes, along with the other considerations that were addressed in my direct testimony, the Companies were seeking to balance the elimination of inter-class subsidies with the ratemaking principles of rate continuity and gradualism. I continue to have confidence that the Companies are striking the proper balance.

Q. What do the intervenor witnesses recommend?

A. Walmart's witness Tillman agrees with the Companies' proposed allocation of the revenue increase. He states that "[a]t the proposed revenue requirement, Walmart does not oppose the Company's revenue allocation." (Op. cit., at p. 23, lines 9-10.) However, he recommends that if the Commission reduces the Companies' proposed revenue increases then one quarter of the reductions should be applied proportionately to reduce the Company's proposed increases for rate classes with a current rate of return greater than 100 percent. (Id., at p. 23.)

DOD's witness Selecky proposes a more vigorous approach in eliminating inter-class rate subsidies than proposed by the Companies. Mr. Selecky proposes larger increases to the residential rate classes. KIUC's witness Baron proposes to shift a significant portion of the increase from the large customer rates to the small-and medium C&I rates.

AG's witness Watkins proposes the same percentage increase for all rate classes. Mr. Watkins' proposal to apply the same percentage increase to the residential rates as all other classes would not eliminate the subsidies currently being provided by the other rate classes. In terms of the percentage increase to the residential rate classes, the Companies' proposal falls between the AG's position on the one end -- which does not address class subsidies -- and DOD's position on the other end – which takes a more vigorous stance in eliminating class subsidies.

Q. What is your reaction to DOD's position?

A. DOD puts forward a more forceful proposal for the elimination of inter-class subsidies than the Companies' proposal. Therefore, the difference between the Companies' positions and DOD's recommendation is a matter of the degree to which subsidies are addressed in this proceeding. Mr. Selecky proposes larger increases to residential rates to address the subsidies that those rate classes are receiving. Specifically, for KU, Mr. Selecky recommends that "the Residential increase should be increased by 2 percentage points over the system average and the additional revenues generated by this increase should be used to reduce the Tier 2 and 3 proposed increases [proportionately]." (*Op. cit.*, at p. 12, lines 18-22.) Thus, Mr. Selecky is proposing to increase KU's residential rates by an additional 1 percentage point above what is proposed by KU. For LG&E, Mr. Selecky recommends that "the Residential increase should be 3 percentage points over the system average" or 2 percentage points above what LG&E is proposing. While the DOD's recommendations do more to eliminate inter-class subsidies, particularly as it relates to the elimination of subsidies currently received by the residential rate classes, the Companies' proposal addresses the elimination of subsidies in a more gradual manner.

Q. Please address KIUC's witness Baron's recommendation?

A. Mr. Baron proposes to adopt the Companies' tiered approach, but he would apply the percentage-point differences proposed by KU and LG&E so that they include the revenue increase due to the pro forma elimination of the Tax Cuts and Jobs Act ("TCJA") surcredits. Mr. Baron's proposal has the effect of significantly lowering the base rate revenue increase to the large customer rates grouped in Tier III and significantly increasing the small and medium C&I rates included in Tier II. The impacts of Mr. Baron's proposal on Tier I and Tier IV are not materially different from what was proposed by the Companies. The obvious problem here is that even according to Mr. Baron's own 12 CP cost of service study, the Tier II rate schedules indicate higher rates of return than the Tier III rate schedules. The following table compares the rates of returns for Tier II to the rates of return for Tier III from Mr. Baron's own cost of service study:

Tier	**Rate Schedules**	**KU**	**LG&E**
II	GS, PS, AES, LS, RLS, OSL, SC	11.44%	11.38%
III	TODS, TODP, RTS, FLS	5.12%	8.72%

Mr. Baron's proposal is to shift revenue from Tier III, which has lower rates of return, to Tier II, which has higher rates of return. Once again, the difference between the Companies' position and the KIUC's position is a matter of degree. In my direct testimony, I discussed the importance of applying a lower percentage increase for large customers, particularly large manufacturers, which have greater options for where they locate their operations. I also addressed the importance of continuing to maintain competitive rates for large manufacturing customers. While small and medium C&I customers tend to be anchored to a geographic region because of their customer base, large manufacturers typically have greater options about where they locate or expand their facilities, and energy costs are frequently a major factor in their decision-making processes. The Companies' approach does more to address the rate subsidies provided by small and medium C&I customers than KIUC's approach. KIUC's approach, on the other hand, is more aggressive in lowering the increases to large customers. Ultimately, it is necessary to balance a set of multiple objectives. In my judgment, the Companies' proposal strikes a better balance than KIUC's proposal between the elimination of inter-class subsidies and encouraging economic development in Kentucky.

Q. Please address the AG's proposal to increase all rates by the same percentage?

A. In his direct testimony, Mr. Watkins states that the "OAG [Office of Attorney General] has advised me that in the absence of a reasonable and appropriate class cost allocation study, the Commission's long-standing practice is to distribute any overall revenue increase to individual classes on an equal percentage basis." (Op. cit., at p. 21, lines 1-3.) Needless to say, this is a profoundly unsatisfactory position. The AG had the opportunity to submit its own cost of service study but failed to do so. Both KIUC and DOD made the effort to submit cost of service studies of their own. If nothing more, KIUC and DOD were able to test the reasonableness of the Companies' studies. While the Companies' LOLP methodology is superior to the 12 and 6 CP methods proposed by Mr. Baron and Mr. Selecky, the methods they used are standard in the industry and produced results that were similar to the Companies' cost of service studies. Furthermore, their studies generally support the Companies' proposed apportionment of the revenue increase. In an effort that was much like throwing mud against the wall to see if anything sticks, Mr. Watkins offered a handful of flawed and easily rebutted criticisms of the Companies' cost of service studies. Mr. Watkins is also critical of the 6-CP method proposed by DOD and the 12-CP method proposed by KIUC. (See AG's response to Question 16 and 17 of the Commission Staff's data request in Case No. 2018-00294 submitted February 14, 2017.) Ultimately, the Companies' cost of service methodology is sound, and their proposed apportionment of the revenue increases is sound. The AG's proposal to ignore inter-class subsidies and apply the same percentage increase to each rate class should be rejected.

Q. Please compare the Companies' proposed increases to those of the intervenors.

A. The following table (TABLE 3) shows the percentage base rate revenue increases by rate class grouping (tier) using the apportionment proposed by the KU to those proposed by KIUC, DOD, and the AG:

TABLE 3

**KENTUCKY UTILITIES COMPANY
PROPOSED APPORTIONMENT OF
THE INCREASE BY PARTY**

Tier	Description	KU	KIUC	DOD	AG
I	Residential	8.11%	8.07%	9.10%	7.11%
II	Small & Medium C&I	6.61%	7.72%	5.96%	7.11%
III	Large C&I	6.11%	5.15%	5.51%	7.11%
IV	Special Lighting	0.00%	-0.14%	0.00%	7.11%
Overall Increase		7.11%	7.11%	7.11%	7.11%

The following table (TABLE 4) shows the percentage base rate revenue increases by rate class grouping (tier) using the apportionment proposed by the LG&E to those proposed by KIUC, DOD, and the AG:

TABLE 4

**LOUISVILLE GAS AND ELECTRIC COMPANY
PROPOSED APPORTIONMENT OF
THE INCREASE BY PARTY**

Tier	Description	KU	KIUC	DOD	AG

I	Residential	4.09%	4.01%	6.09%	3.09%
II	Small & Medium C&I	2.65%	3.41%	1.17%	3.09%
III	Large C&I	2.09%	1.32%	0.92%	3.09%
IV	Special Lighting	0.00%	0.00%	0.00%	3.09%
Overall Increase		3.09%	3.09%	3.08%	3.09%

The purpose of these tables is to show the impact of the various proposals for apportioning the increases to the rate classes. I am not suggesting that the intervenors agree with the Companies' overall revenue increases.

Q. What is your recommendation regarding the apportionment of the revenue increases to the rate classes.

A. It remains my recommendation that the Commission approve the revenue increase allocations proposed by the Companies. The Companies' proposal strikes the appropriate balance between the following objectives: (1) eliminating inter-class rate subsidies, (2) giving due consideration to the level of charges for large-use customers who have greater options with respect to the geographic regions where they locate their operations; and (3) giving due consideration to the ratemaking principles of rate continuity and gradualism.

B. APPORTIONMENT OF THE GAS INCREASES

Q. Did any of the intervenor witnesses offer comments on or criticisms regarding LG&E's proposed apportionment of the gas rate increases?

A. No.

IV. RESIDENTIAL RATE DESIGN

Q. Please provide a quick overview of the Companies' proposed changes to the Basic Service Charges for residential service.

A. The Companies are proposing two changes. First, the Companies are proposing to structure the Basic Service Charge as a daily rather than a monthly charge. This change will apply to all electric rate schedules that have Basic Service Charges and will apply to all gas rate schedule that are billed on a CCF basis. Second, KU and LG&E are proposing to increase the Basic Service Charge for electric service from $12.25 per month to a charge *equivalent* to $16.13 per month ($0.53 per day). The Companies' cost of service studies would support a Basic Service Charge of $23.89 per month for KU and a Basic Service Charge of $20.34 for LG&E. LG&E is proposing to increase the Basic Service Charge for gas service from $16.35 per month to a monthly equivalent of $19.78 ($0.65 per day).

Q. Are the Companies also proposing to break out the energy charge into fixed and variable cost components?

A. Yes, KU and LG&E are proposing that the energy charge be broken down into a Variable Energy Charge component and an Infrastructure Energy Charge. This change is for informational and educational purposes only and will not affect customers' bills. The Companies want customers, stakeholders and employees to be aware that two types of costs are included in the energy charge for Rate RS and other rates that have a two-part rate structure consisting of a Basic Service Charge and an Energy Charge.

Q. Did the AG's witness Watkins address the Companies' proposed Basic Service Charges for residential service?

A. Yes. Mr. Watkins recommends that the electric Basic Service Charge remain at its current level of $12.25 per month and that LG&E's gas Basic Service Charge remain at the current level of $16.35 per month. He also opposes the adoption of a daily charge and the Companies' proposal to break out the energy charge in to variable and fixed cost components for informational purposes.

Q. Did Mr. Watkins provide valid cost justification that supports leaving the current Basic Service Charges at their current levels?

A. No. He provides calculations that omit significant amounts of customer-related costs and arrives at a monthly customer charge of $6.55 for KU, $4.20 for LG&E-Electric, and $12.14 for LG&E-Gas. (See Mr. Watkins' Schedule GAW-5 and Schedule GAW-6.) He provides no explanation for why he is proposing a $12.25 Basic Service Charge for electric service, when his cost analysis only supports $6.55 for KU and $4.20 for LG&E. Either he has little faith in his own analyses, or he feels that proposing such low customer charges would diminish the credibility of his analysis.

Q. Did the Company use a standard cost of service methodology to calculate customer costs?

A. Yes. In the cost of service studies filed by KU and LG&E distribution costs were classified as demand- and customer-related using the zero-intercept methodology. With the zero-intercept analysis, a statistical analysis is performed to determine the fixed-cost components of overhead conductor, underground conductor, and transformers that do not vary with demand, but would still vary with the number of customers. This methodology has been used for decades for both KU and LG&E. The Commission found LG&E's cost of service studies utilizing the zero-intercept methodology submitted in Case No. 90-158 and in Case No. 2000-080 to be reasonable. The Commission also found the cost of service study submitted by Union Light Heat and Power in Case No. 2001-00092, which also utilized the zero-intercept methodology, to be reasonable. Furthermore, the zero-intercept methodology has been used in every cost of service study filed by both KU and LG&E since the early 1980s, including the cost of service studies filed in Case Nos. 2016-00370 and 2016-00371, the Companies' last general rate case filings.

Q. Did Mr. Watkins rely on the results of the Companies' zero-intercept analysis when he performed his analysis of customer costs?

A. No. Mr. Watkins ignored the results of the zero-intercept analysis when he performed his customer cost analysis that excluded numerous customer-related costs. The analyses that he included in his Schedules GAW-5 and GAW-6 excluded cost components for overhead conductor, underground conductor and line transformers which the Commission has traditionally considered to be customer related. The Commission has rejected this minimalist and non-conforming approach in past orders. For example, see the Commission's Order in Case No. 2000-080 dated September 27, 2000, at pages 75-76.

Q. Is there academic support for recovering fixed distribution costs through the application of a customer charge (i.e., a Basic Service Charge)?

A. Yes. In the well-known treatise *Electricity Pricing* by Lawrence J. Vogt published in 2009, the author states:

> The *Customer Charge* is intended to recover a number of fixed costs that are not directly dependent on either the monthly volumes of energy use or the capacity required by the customer, although the customer-related costs of larger customer may indeed be greater per delivery point than for smaller customers. Specifically, customer-related costs include the investment and expenses in metering equipment and service lines along with a minimal portion of secondary distribution lines, line transformers, and the primary feeder system of poles, conduit, and conductors. (Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, CRC Press, 2009, at p. 273.)

Mr. Vogt goes on to state that the "zero intercept methodology provides a rational basis for separating the cost of a device between its customer and demand components." (*Id*., at p. 500.)

In support of his position, Mr. Watkins cites Bonbright's *Principles of Public Utility Rates* where the author discusses the "minimum system methodology", which was a commonly-used methodology in the 1950s, when Mr. Bonbright was writing his book. (*Direct Testimony of Glenn A. Watkins*, at p. 36.) An obvious problem with Mr. Watkins' reliance on Bonbright's comments about the minimum system approach is that KU and LG&E do not use the minimum system methodology in their cost of service studies. The Companies use the *zero-intercept methodology,* which is a statistical methodology that bears no resemblance to the *minimum system methodology* discussed by Bonbright. In the 1950s, when Mr. Bonbright was writing his book, utilities did not have the computer capability to run the weighted regression analyses needed to apply the *zero-intercept methodology*. The zero-intercept methodology didn't come into common practice until the 1970s when digital computers began to be used to perform cost of service studies.[2] It is impossible to speculate on what Mr. Bonbright, who retired in 1960, would have had to say about the *zero-intercept methodology,* which wasn't used until many years later.[3]

Q. Mr. Watkins claims that the Companies' proposed Basic Service Charges are contrary to "efficient pricing". Is he correct?

A. No. Mr. Watkins has a confused notion of marginal cost pricing. Mr. Watkins states:

> Perhaps the best known micro-economic principle is that in competitive markets (i.e., market in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost result from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, *it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing*. (*Id*., at p. 24) (Emphasis added.)

The underscored sentence in this passage, in particular, discloses a serious misunderstanding of marginal costs and efficient pricing. A fundamental misconception that Mr. Watkins seems to have is that *fixed costs* are short-run marginal costs. Fixed costs, which principally consist of plant-related costs, are

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[2] For example, the cost of service study that LG&E conducted in 1976 was prepared using handwritten columnar accounting sheets without the use of a digital computer. The "zero-intercept methodology" was first used by LG&E in a study performed in 1979 using a mainframe computer.

[3] The minimum system method continued to be widely used in marginal cost analysis. In a survey conducted by NERA in the early 1990s it was reported that the minimum system method was the most widely used method for calculating marginal customer costs. See Hathie Parmesano and William Bridgman, *The Role and Nature of Marginal and Avoided Costs in Ratemaking*, NERA, January 1992.

considered “long-run marginal costs.” The majority of KU and LG&E’s cost of service consists of fixed costs and are therefore considered *long-run marginal costs*. The only short-run marginal costs are fuel and variable operation and maintenance expenses. As shown in Rebuttal Exhibit WSS-1, only 35.38% of KU and LG&E’s revenue requirements are variable costs, and the remaining 36.14% are fixed costs. Mr. Watkins wants to focus on the “economic efficiencies” of the Companies’ variable expenses, which only make up only about 36% of the Companies’ cost of service. Mr. Watkins claims that a “full discussion of the calculus involved in determining marginal costs is not appropriate here.” (*Id*.) Perhaps Mr. Watkins should have given more careful consideration to the calculus involved in marginal cost analysis, because, if he had, he might not have ignored over 64% of the Companies’ costs in his discussion of marginal cost pricing.

Q. In what way did Mr. Watkins oversimplify marginal costs?

A. Based on economic theory, electric utility costs are a function of four independent variables – the quantity of energy consumed (q_e), the demand for power at the time of the utility’s system peak (q_{cp}), customers’ individual maximum demands (q_{ncp}), and the number of customers served (q_c). The relationship of COST as a function of the four variables q_e , q_{cp} , q_{ncp} , and q_c can be represented by:

$$\text{COST} = \text{COST}\,(q_e\,,\,q_{cp}\,,\,q_{ncp}\,,\,q_c)$$

Marginal cost is defined as the change in COST due to a change in any one of these four variables. But COST is a function of at least four independent variables, so there are four different marginal costs representing a change in COST due to a change in each of the four independent variables. Mathematically, a change in a function (such as COST) due to a change in a variable (such as a change in peak demand, for example) is represented by what is called a derivative. If there is only one variable, such as q_{cp} then marginal cost (MC) would be represented by:

$$MC = \frac{dCOST}{dq_{cp}},$$

which means that marginal cost (MC) is equal to a change in COST due to a change in q_{cp}. But COST is not a function of one variable, it is a function of four variables. Therefore, there are four types of marginal costs -- a marginal cost associated with a change in each of the four independent variables. In mathematics, a change in a function due to a change in one of several independent variables is called a *partial derivative*, which for a function *f* and a variable *x* is represented mathematically as $\frac{\partial f}{\partial x}$. Therefore, we have four marginal costs, with each representing a change in COST due to a change in each of the four variables. Thus, we have (1) marginal cost (MC_e), which is a change in COST due to a change in energy, (2) marginal cost (MC_{cp}), which is a change in COST due to a change in coincident peak demand, (3) marginal cost

(MC_{ncp}), which is a change in COST due to a change in non-coincident peak demand, and (4) marginal cost (MC_c) which is a change in cost due to a change in the number of customers served.[4] Each of these marginal costs can be defined in terms of partial derivatives as follows:

Marginal Energy Cost

(1) $$MC_e = \frac{\partial COST}{\partial q_e}$$

Marginal Coincident Peak Demand Cost

(2) $$MC_{cp} = \frac{\partial COST}{\partial q_{cp}}$$

Marginal Non-Coincident Peak Demand Cost

(2) $$MC_{ncp} = \frac{\partial COST}{\partial q_{ncp}}$$

Marginal Customer Cost

(4) $$MC_c = \frac{\partial COST}{\partial q_c}$$

Q. Which of these four types of marginal costs does Mr. Watkins concentrate on?

[4] The industry literature on calculating marginal costs will often identify marginal demand and energy costs for the generation function, marginal transmission demand costs, marginal distribution demand costs, and marginal distribution customer costs. For example, see "Marginal Cost Analysis in Evolving Power Markets: The Foundation of Innovative Pricing, Energy Efficiency Programs, and Net Metering," *Emerging Current Topics in Energy Markets and Regulation*, 2010, at p. 2:

> A marginal cost analysis will assess the incremental cost of an additional kilowatt of demand or a kilowatt of energy, or to serve an additional customer at a particular time and place.

A. Mr. Watkins focuses on Marginal Energy Costs but ignores Marginal Coincident Peak Demand Costs, Marginal Non-Coincident Peak Demand Costs and Marginal Customer Costs. In terms of economically efficient pricing structures, the Marginal Energy Costs cannot be emphasized to the exclusion of these other three important marginal costs. The first type of marginal cost, Marginal Energy Cost, is a short-run cost that corresponds to variable energy costs, namely, fuel and variable O&M expenses. A change in energy usage by a customer results directly in a change in fuel expenses and variable O&M expenses incurred by the Company. As I demonstrated earlier, fuel and variable O&M expenses only represent about 36% of the Companies' total cost of service. But the Companies' costs also change due to changes in the other three variables. In the long run, the Companies will require additional generation capacity due to increases in peak system demands, and the Company will require additional distribution capacity due to increases in non-coincident peak demands. Therefore, MC_{cp} and MC_{ncp} are considered long-run marginal costs. But when new customers are added, the Companies also incur additional distribution costs, metering costs, and customer service costs. Whenever the Companies add new customers – regardless of their size – poles must be installed or underground trenches need to be dug, overhead or underground cable must be installed, transformers must be installed, services installed, meters installed, additional meters read, and additional bills rendered. Mr. Watkins ignores these costs.

Q. Is recovering fixed costs through the energy charge economically efficient?

A. No. Mr. Watkins' proposal to load up the Companies' energy charges with fixed costs is highly inefficient. His proposal would send a pricing signal to customers that a change in energy usage will automatically result in a change in KU and LG&E's fixed costs, which will not happen. After a utility invests in distribution infrastructure, a change in customers' kWh usage does not affect the fixed costs associated with the infrastructure. If fixed distribution costs are recovered through the energy charge then when a customer reduces its energy usage there is no reduction in the Companies' fixed distribution cost. All that is accomplished is that the fixed cost incurred to serve the customer is inappropriately shifted to other customers. Therefore, Mr. Watkins' proposal is not only economically inefficient but it is also inherently unfair. In his zeal to promote energy conservation, Mr. Watkins has tossed economic efficiency and inter-class equity out the window.

Q. Are there examples in competitive industries where fixed costs are recovered through fixed monthly or daily charges?

A. There are a number of examples. Cable television service providers and cell phone companies such as Sprint, AT&T, and T-Mobile price their service as monthly fixed charges that typically do not vary by the amount of time that their customers watch cable television or use their cell phones for domestic calls. Another example is car rental companies such Hertz and Avis, which typically rent automobiles based on daily rates without a limit on the number of miles driven. The reason that these competitive industries have moved to fixed daily or monthly pricing structures is that most of their costs consist of fixed costs, much like an electric or gas utility. It is now somewhat unusual for companies operating in these competitive industries to recover their fixed costs based a pricing structure other than a monthly or daily fixed charge.

Q. In terms of *efficient pricing*, what type of rate structure do these four types of marginal cost suggest?

A. The analysis of both marginal and embedded costs suggest that the most efficient pricing structure would be a four-part rate consisting of: (i) a Basic Service Charge (i.e., a customer charge), (ii) an Energy Charge, (iii) a system peak Demand Charge, and (iii) a non-coincident peak Demand Charge. This is precisely the type of rate design that the Companies utilize for their large customer rates – TODS, TODP, RTS, and FLS. These rates have relatively large customer charges and two types of demand charges – a Base Demand Charge that is applied to the customers' maximum demands whenever they occur and Peak Demand Charge that is applied to the customers' demand during the Companies' peak hours. It is noteworthy that Mr. Watkins does not object to the four-part rate design used in the Companies' large customer rates. But more significantly, Mr. Watkins does not object to the Basic Service Charges for the large customer rates, which are significantly higher than the proposed Basic Service Charges for the residential rates.

Q. In opposing the adoption of a daily Basic Service Charges, does Mr. Watkins identify any problems with using a daily customer charge?

A. No. He fails to identify specific problems with the use of a daily Basic Service Charge. He simply states that a monthly charge is "accepted industry practice which virtually all public utility ratepayers are used to." The Company is proposing a daily charge because it more accurately reflects service for the actual number of days in a billing cycle, because it is easier for customers to understand than a pro-rated charge for a partial month of service, and because it will create future optionality for new programs, such as prepaid metering. Mr. Watkins failed to counter any of these justifications for the Companies' proposal. Indisputably, because a daily Basic Service Charge reflects the actual number of days in a billing month, a daily charge will more accurately reflect the actual cost of service. Furthermore, as I explained in the response to Question No. 12 of Sierra Club's Supplemental Data Requests:

> [I]t is easier for someone with basic skills in mathematics to understand the following billing of a Basic Service for a service period of 13 days during a month:
>
> 13 days x $0.53 per day = $6.89
>
> than for a customer to understand a pro-rated billing for a month with billing-cycle consisting of 30 days:
>
> $$\frac{13\ days}{30\ days}\ x\ \$16.13\ per\ month =\ 0.4333\ x\ \$16.13\ per\ month = \$6.90$$
>
> Another problem with customers understanding a prorated Basic Service Charge is that the number of days in a monthly billing cycle will in some cases differ from the number of days in a calendar month, thus creating the potential for additional confusion on the part of customers. For example, in the pro-rated example shown above, the number of days in the monthly billing cycle is 30 days but the number of days during the calendar month could be 31 days, creating additional reasons for customers not being able to understand the mathematics involved in the pro-ration.

Thus, as this response shows, a daily charge will be easier for customers to understand than a monthly charge. Furthermore, Mr. Watkins does not deny that a daily charge would facilitate pre-paid metering or other services should the Companies choose to offer them. He simply argues that the Companies should not try to be proactive by taking steps to create greater optionality but should just cross that bridge when we come to it, while disregarding other benefits of daily charges.

Q. What is your recommendation regarding the Basic Service Charges?

A. It is my recommendation that the Commission approve the Basic Service Charges proposed by the Companies. Even if the Commission approves lower revenue requirements than are proposed by the Companies, it is still my recommendation that the Commission approve the levels of the Basic Service Charges proposed by KU and LG&E. The proposed Basic Service Charges are significantly below the actual cost of service and should be approved as filed.

Q. Does Mr. Watkins offer legitimate reasons for opposing separating out the energy charge into fixed and variable cost components for informational purposes?

A. No. Mr. Watkins claims that customers “could care less [sic] about the cost structure for ratemaking purposes within the energy charges.” Obviously, Mr. Watkins has no way of knowing whether KU and LG&E’s customers care about this issue or not. But based on my own experience, I frequently get questions from utility customers both informally and at public meetings about what costs are included in a utility’s charges. Furthermore, when I was an employee of LG&E, I was frequently asked very specific questions from residential customers about what costs are recovered through the energy charge and customer charge. But regardless of my personal experiences, I fail to understand why the AG’s witness is opposed to providing additional cost information to customers. LG&E's gas rates have been separated into fixed and variable cost components for decades. In fact, it was the Commission that directed the Company to break out its charges per Mcf of throughput into a Gas Supply Cost Component and a Distribution Charge, and to show this breakdown in each rate schedule. When LG&E first implemented its Gas Supply Clause in Case No. 9133, the Company proposed that the MCF charge would continue to include both fixed and variable costs, but in its Order in Case No. 9133 the Commission directed the Company to break out the Gas Supply Cost Component and the Distribution Charge in its next rate case:

> LG&E proposed to retain the total rate per 100 cubic feet authorized in its last rate case, which includes 35.720 cent as gas costs, rather than putting all gas costs in the GSCA determined in the quarterly filing. To avoid customer confusion at the present time, the Commission will allow such practice. *However, with LG&E's next rate case all gas costs will be included in the GSCA and all other costs will be set out as the distribution cost.* (*Order in Case No. 9133*, dated January 7, 1985, at p. 2. Emphasis added.)

Obviously, the Commission concluded that Customers are concerned about such matters.

However, the Companies are not proposing this change just to inform and educate customers. The change is also intended to inform and educate the Companies' employees and other stakeholders, including intervenors in the Companies' rate cases, various government agencies and organizations providing assistance to customers. It is important for employees and stakeholders to understand that the energy charge recovers both fixed and variable costs.

Q. Another reason that Mr. Watkins gives for proposing this change is that in his experience working in the industry he claims that has never seen a utility break out its fixed and variable costs. How do you respond to this observation?

A. Well, Mr. Watkins must not have looked at LG&E's gas rates too closely, because its gas rates have been separated into fixed and variable cost components for about three decades. Also, my consulting firm has worked with electric utilities across the United States that have unbundled their rates into fixed and variable cost components for informational purposes, some operating in states with retail competition and others not. For example, the energy charge for most utilities in Michigan are unbundled into a large number of cost components, including fixed and variable generation costs, fixed transmission costs, and fixed distribution costs. But whether Mr. Watkins is or is not aware of a utility that unbundles its rates for informational purposes is not a valid reason to keep information from customers. I am actually surprised that the AG's witness would recommend that customers should be prevented from receiving information about the cost components that make up the Companies' energy charges. Mr. Watkins' position strikes me as a bit paternalistic. What he seems to be suggesting is that customers cannot be trusted with information concerning the cost components that make up the Companies' rates. Personally, I reject the proposition that cost information should be shielded from customers.

Q. What is your recommendation for separating out the Companies' energy charges into fixed and variable components for informational purposes?

A. It is my recommendation that the Commission approve the Companies' proposal to break out the energy charges into a Variable Energy Charge component and an Infrastructure Energy Charge.

V. LARGE CUSTOMER RATES – TODS, TODP, RTS, RTS

Q. The Companies are proposing to modify the demand charge for TODS so that it is applied as a KVA charge. Did any of the intervenor witness oppose this change?

A. No.

Q. As part of your direct testimony, you sponsored a study concerning the impact of 100% base demand ratchets for Rate TODS. Did any of the intervenor witnesses comment on the study?

A. No. The study was included as Exhibit WSS-3 of my direct testimony.

VI. KSBA'S SPECIAL SCHOOL RATE PROPOSAL

Q. Were pilot rates for schools implemented in the Companies' rate cases as a result of the settlement agreement?

A. In the Stipulation and Recommendation ("Stipulation") in the Companies' previous rate cases, the parties agreed to implement two optional pilot rates for schools – School Power Service (Rate SPS) and School Time-of-Day Service (Rate STOD).

Q. Did the Commission approve the pilot rates?

A. Yes, but with the following requirements: (1) the Stipulation was to be modified to include non-public schools not covered by KRS 160.325; (2) the pilot rates would be available to new participants until the total projected revenue reduction reaches $750,000 annually for each utility, compared to the projected annual revenues for the participating schools under the rates which the schools would otherwise be served; (3) a limit was placed on the amount of time the pilot rates would be in effect of three years, or until the Utilities file their next rate case; and (4) beginning six months from the date of the Commission's rate case order, the Utilities were required to file a report with the Commission to provide details concerning monthly load information, individually and in the aggregate, and preliminary findings regarding the schools' load characteristics. Regarding the time limit for the pilot rate, the Commission stated that it "will place a limit on the amount of time the pilot tariff will be in effect and finds that the pilot tariffs should be effective for three years, or until KU [or LG&E] files its next rate cases, whichever is earlier." (Orders in Case Nos. 2016-00370 and 2016-00371, dated June 22, 2017, at p. 20.) Effective with the filing of the application in the current rate cases, the Companies terminated Rates SPS and STOD on September 28, 2018, and moved all schools that were taking service under those rates to the appropriate rate schedules – Rates PS, TODS, or TODP.

Q. Did the Companies file reports with the Commission that set out details concerning the effectiveness of the pilot school rates?

A. Yes. The Companies filed three reports with the Commission assessing whether the pilot school rates were effective. The first report was filed with the Commission on December 21, 2017; the second report was filed with the Commission on June 22, 2018; and the third report was filed with the Commission on December 21, 2018. The third report was based on an analysis of load data for a full 12-month period. The final report is included as Rebuttal Exhibit WSS-2.

Q. What was the conclusion of the final report on the pilot school rates that was filed on December 21, 2018?

A. It concluded as follows:

> There is no evidence that creating a separate rate for schools would result in an improvement in fairness or equity of the rates for the schools or of the rates for the remaining non-school customers. Furthermore, given their similar load characteristics as non-school customers, the results of this analysis suggest that the schools have not likely modified their loads in response to taking service under the Pilot Rates. (*School Pilot Tariffs Report No. 3*, December 21, 2018, at p. 6.)

The report compared the load characteristics for the schools served under the pilot rates to customers served under the standard rate schedules. This comparison demonstrated that the load characteristics for the schools were not materially different from the load characteristics of non-school customers, certainly not sufficiently different to warrant the creation of a separate rate schedule for the schools that were served under the pilot rates. The report states as follows:

> The class statistics for LG&E and KU indicate that the load characteristics that would create significant cost differences in those rate classes are simply not present between schools and non-school customers in the PS and TOD rates. (*Id.*, at p. 7.)

Q. Were the pilot school rates that were implemented in the last rate cases based on cost of service?

A. No. They were the result of a stipulation agreement that were developed as part of settlement discussions.

Q. Did KSBA submit a cost of service study in the current rate case proceedings that would support implementing special school rates?

A. No. KSBA did not submit a cost of service study in these proceedings showing schools broken out into separate rate classes. KSBA's witness Willhite recommends reinstating the pilot rates for schools but doesn't calculate unit costs that support those rates. The data presented in the reports evaluating the effectiveness of the pilot school rates show that the load characteristics of the schools do not support the deeply discounted rates that were implemented as part of the Stipulation.

Q. Are there particular statistics reported in *School Pilot Tariffs Report No. 3* that concern you about offering a special rate for schools?

A. Yes. The coincident-peak and non-coincident load factors for the schools are lower than the non-school customers. Load factor is the ratio of average demand to maximum demand. The *coincident-peak load factor* ("CP load factor") is therefore the ratio of the rate class's average demand to the class demand at the time of the Companies' peak. The *non-coincident-peak load factor* ("NCP load factor") is the ratio of the sum of the customers' maximum demand to average demand. The low CP load factor for schools indicates that schools are more likely to have a high demand at the time of the Companies' system peak relative to their average demands than non-school customers. This means that the Companies must install more generation capacity for schools than for non-school customers, relative to their average demand.

The low NCP load factor for schools indicates that schools are more likely to have high maximum individual demands than non-schools relative to their average demands. This means that the Companies must install more distribution capacity for schools than for non-school customers, relative to their average demand. The following tables show comparisons between the CP and NCP load factors for schools versus non-schools based on load research data for a full year (November 2017 through October 2018):

TABLE 5

Kentucky Utilities Company

	Customers Taking Service Under the Pilot Rates for Schools	Sample of Customers Taking Service Under Standard Rates
Average Coincidence Factor	0.674012	0.707894
Average CP Load Factor	0.680610	0.744180
Average NCP Load Factor	0.458739	0.526757

TABLE 6

Louisville Gas and Electric Company

	Customers Taking Service Under the Pilot Rates for Schools	Sample of Customers Taking Service Under Standard Rates
Average Coincidence Factor	0.681444	0.733917
Average CP Load Factor	0.609078	0.663990
Average NCP Load Factor	0.415053	0.487314

As can be seen from these tables, for both KU and LG&E, the CP and the NCP load factors are lower for schools than non-schools.

Q. KSBA's witness Willhite claims that the coincidence factor is the most significant. Is he correct?

A. No. The higher coincident factors for the non-schools are purely the consequences of the higher CP load factors for the non-school customers. Mathematically, as CP load factors approach 100%, coincident factors also approach 100%. Therefore, higher load factor customers also exhibit higher coincidence factors. Mr. Willhite's claim that coincidence factor is the more important statistic is incorrect. (*Id.*, Testimony of Ronald L. Willhite, Case Nos. 2018-00294 and 2018-00295, at p. 4.) Coincidence factors do not come into play in the Companies' cost of service studies. CP and NCP load factors, on the other hand, are major drivers in the Companies' cost of service studies. CP and NCP load factors are the primary statistics for explaining differences in cost of service between customer classes. Both of these key statistics suggest that, if anything, the rates for schools should be higher than for non-schools.

Q. Do you believe that it is appropriate to offer a special rate for schools, regardless of whether the CP and NCP load factors are higher or lower?

A. No. The electric utility industry has been moving away from offering special rates tailored to special customer groups. Beginning around the time of the Public Utilities Regulatory Policies Act (PURPA), electric utilities began collapsing the plethora of special rates into more streamlined sets of cost-based rates that tend to reflect the size of customer kW demands rather than end-uses. A major problem with special rates that differentiate between types of end-use customers is where to stop with tailored rates for specific type end-use customers. It would be possible to have school rates, church rates, water heater rates, space heating rates, public authority rates, mining rates, chemical manufacturing rates, cement manufacturing rates, steel mill rates, aluminum smelter rates, hotel and resort rates, grain drying rates, water pumping rates, gas pipeline compressor rates, radio tower rates, elevator rates, and so on *ad infinitum*. Most likely, any of these customers would argue that their unique circumstances and load characteristics warrant a special rate. However, working with utilities across the country, I have seen distinct rates for most all of these special groups being eliminated in favor of cost-based rates suitable for most any type of end-use customer. In fact, KU and LG&E have eliminated a number of these special rates over the years. A sound rate design will generally operate effectively with any type of customer. For a number of years, it has been the Companies' objective to develop rates designs that accurately reflect costs for a wide range of customers within each rate class. The Companies' Power Service rates and TOD rates are both designed to reflect cost of service. The Companies' large customer rates (TODS, TODP, RTS, and FLS) are particularly well designed to reflect differences in cost of service among customers within each rate class. TODS, TODP, RTS, and FLS are multi-part rates consisting of a Basic Service Charge, Energy Charge, Base Demand Charge, Intermediate Demand Charge, and Peak Demand Charge. This multi-part rate design is extremely effective in terms of reflecting cost of service and can be viewed as the "gold standard" for rate design. However, an impediment to implementing multi-part rates on a wider scale is the traditionally higher cost of the metering equipment that is required to measure the time-differentiated demands necessary to bill multi-part rates. But, as advanced metering solutions are adopted in the industry, we can expect to see a broader adoption of multi-part demand rates. Already, electric utilities across the country which have invested in automatic metering infrastructure are adopting multi-part rates for general service and residential customers.

VII. SUBSTITUTE GAS SALES SERVICE ("SGSS")

Q. Please provide a description of LG&E's Substitute Gas Sales Service (SGSS).

A. Rate SGSS provides substitute gas sales service for any customer who desires to receive firm sales service from LG&E in addition to gas received from other sources with which the customer is physically connected. This rate applies to customers who normally purchase gas supply directly from a pipeline, from another local distribution company, or from a local producer but desire to rely on LG&E as an alternative or substitute supplier of natural gas. In its role as a substitute supplier, LG&E maintains sufficient storage and distribution delivery capacity on its system to provide firm service to a customer under Rate SGSS, just as it would any other commercial or industrial sales customer. Rate SGSS is structured as a three-part rate consisting of (i) a Basic Service Charge, which is a fixed customer charge to be billed monthly; (ii) a Distribution Charge, which will be applied to monthly volumetric deliveries; and (iii) a Demand Charge, which will be applied to the customer's Monthly Billing Demand. The demand charge helps ensure that other customers are not subsidizing those customers who take substitution or backup service from LG&E. For Rate SGSS, LG&E is proposing to include a 100% demand ratchet, which is the same ratchet provision that is used to determine the billing demand for the Base Demand Charge in KU and LG&E's large customer electric rate schedules – TODS, TODP, RTS, and FLS. SGSS currently includes a 70% ratchet provision, which was the result of a settlement in LG&E's last rate case.

Q. Do any of the intervenor witnesses address Rate SGSS?

A. Yes. DOD witness Selecky addressed Rate SGSS in his direct testimony. Specifically, Mr. Selecky proposes to change the ratchet provision of Rate SGSS, as follows:

> The Commission should not eliminate the 70% demand ratchet provision. A 100% ratchet is punitive and does not reflect the usage diversity for gas customers that utilize the system. The cost components that are used to develop the monthly demand charge include transmission demand costs. Typically, the transmission system is designed to meet the system peak and not the non-coincident peaks or the total of all customers' maximum demands. A 70% ratchet factor reflects the diversity in individual customer demands at the time of the system peak. (*Op. cit.*, at p. 22, lines 3-9.)

Q. Is Mr. Selecky's proposal consistent with the demand ratchet provision of TODS, TODP, RTS, and FLS?

A. No. Rates TODS, TODP, RTS, and FLS include three demand charge components – Peak Demand Charge, Intermediate Demand Charge, and Base Demand Charge. The Peak and Intermediate Demand Charges are designed to recover fixed production costs, and the Base Demand Charge is designed to recover transmission and distribution delivery costs. The Demand Charge for Rate SGSS is essentially equivalent to the Base Demand Charge for electric.[5] Under LG&E's current electric tariff, the Base Demand Charge recovers transmission and distribution costs and currently incorporates a 100% ratchet, which is the same ratchet provision that LG&E is proposing for the SGSS demand charge. Mr. Selecky does not challenge the current 100% Base Demand ratchet provision for TODP. Mr. Selecky states that the "Companies' proposed method of cost recovery for TODP from the Base, Intermediate and Peak demand charges should be adopted by the Commission." (*Op. cit.*, at p. 19, lines 13-14.) To be consistent with TODP, whose Base Demand ratchet provision Mr. Selecky does not challenge, the ratchet provision of Rate SGSS should be 100%.

Q. Why is it appropriate to utilize a 100% ratchet for gas delivery service?

A. As with the electric system, LG&E's gas delivery system is sized to meet the maximum volumes of gas used by customers at any time. On LG&E's gas system, mains, regulators, and other equipment are sized to meet the maximum demands that individual customers place on the system. Therefore, it is appropriate to apply a demand charge to the maximum demand established by the customer. It is particularly important to have a 100% demand ratchet for Rate SGSS, because gas suppled under that rate is intermittent. This kind of customer only falls back on LG&E when the

[5] For gas service, the analogue for the production fixed costs recovered through the Peak and Intermediate Demand Charges are the purchased gas demand costs recovered through the Company's Gas Supply Component (GSC).

customer fails to secure adequate gas supply.

Q. Mr. Selecky claims that the demand ratchet provision of Rate SGSS does not reflect any type of usage diversity. Does demand diversity matter for the portions of the distribution system providing service to individual customers?

A. No. The distribution system is sized to deliver gas to individual customers. For the DOD customer represented by Mr. Selecky, LG&E installed two 8-inch parallel pipelines directly from one of its storage facilities to provide service to the DOD customer. Each of these parallel pipelines spans 3 to 4 miles. The Company installed two large gas regulator stations at its storage facilities that serve the DOD customer. The regulator stations include overpressure protection equipment, two gas regulator runs, piping, valves and electronic monitoring equipment. The Company has also installed two large metering stations, consisting of two six-inch orifice meters, one four-inch orifice meter, one rotary meter, regulation equipment, and electronic monitoring and control equipment. These facilities have been refurbished within the last ten years. The DOD customer is one of only two natural gas customers served by LG&E whose natural gas service is provided from costly orifice metering stations. These facilities are sized solely to meet the DOD customer's historical maximum demands *and no other customer*. In fact, the facilities were designed to serve a historical demand that is several times larger than the customer's recent peak demand. Therefore, with respect to the distribution facilities installed to serve the DOD, usage diversity is irrelevant, because there can be no diversity with respect to facilities that have been installed to serve a single customer.

Furthermore, there is little or no diversity between the DOD customer's usage and LG&E's system peak demand. Like most customers on LG&E's gas system, the DOD customer's usage requirements are driven by cold temperatures (high heating degree days). For example, during the last three winter peak seasons (Dec 2016 – Feb 2017, Dec 2017 – Feb 2018, Dec 2018 – Jan 2019), LG&E's maximum demand day occurred on January 30, 2019. This was during the so-called "polar vortex" that gripped the Midwest United States, when it was widely reported in the news media that temperatures in Chicago and Minnesota were falling below minus 30° F. (See Rebuttal Exhibit WSS-3.) LG&E's maximum daily demand on January 30, 2019, was about 490,000 Mcf. The DOD customer's maximum demand day during January 2019 also occurred on January 30, 2019. This indicates that on the peak day that occurred during the last three winter seasons, there was zero diversity between LG&E's system demand and the DOD customer's usage. Both LG&E and the DOD customer experienced a peak on January 30, 2019, when the average of the 24-hourly temperature observations on that gas day was about 7° F, which was not only the coldest temperature during January 2019 but also the coldest gas day during the last three winter heating seasons.

Q. What is your recommendation regarding LG&E's proposed ratchet provisions for Rate SGSS?

A. It is my recommendation that the Commission approve the 100% ratchet provisions for Rate SGSS. The provision is reasonable for gas sales service to customers whose purchases from LG&E are intermittent and who normally purchase natural gas from another provider but want to rely on LG&E as an alternative or substitute supplier of gas.

VIII. LEAD-LAG STUDIES

Q. Did the Companies submit lead-lag studies in the current rate case proceedings?

A. Yes. In the settlement agreement filed in their last rate cases, LG&E and KU "committed to file a lead-lag study in their next base-rate cases." (*Stipulation and Recommendation*, Case Nos. 2016-00370 and 2016-00370, Section 5.4, at p. 17.) Lead-lag studies for KU and LG&E were included as part of the Companies' Application in the current proceedings.

Q. What is a lead-lag study used for?

A. A lead-lag study is a statistical study that estimates the Cash Working Capital required by a utility for its operations. Cash Working Capital is the amount cash *invested* by the utility to fund its operations.[6] A lead-lag study is an analysis that measures the difference between the revenue lags and expense leads, where *revenue lags* represent the number of days between a company supplying service to customers and receiving cash payment for the service and where *expense leads* represent the number of days between the company incurring the expense and paying for those cash expenses.

[6] It should be noted by AG's witness Mullinax uses a slightly different definition of Cash Working Capital. She states that Cash Working Capital "represents the cash a utility needs to have on hand to fund its day-to-day operations." (*Direct Testimony of Donna H. Mullinax*, at p. 19, lines 10-11) As a point of fact, a utility will not have the *cash on hand*. Cash Working Capital is not a cash balance that sits on the Companies' balance sheet, but an amount of cash *invested* by the utility that reflects the difference between revenue lag and expense leads. Capital working capital thus represents the cash invested by the utility to fund these differences.

Q. Are AG's witness Mullinax and you in agreement with what a lead-lag study is supposed to measure?

A. Yes. Ms. Mullinax states that a "lead-lag study is an in-depth analysis that measures the difference between a company's revenue lag (the lapsed days between a company supplying service and being paid for service) and the expense lead (the lapsed days between the company incurring costs and having to pay for those costs.)." I could quibble over the word "cost"[7] in her definition, but essentially, I agree with her definition.

Q. Please explain the terms "revenue lags" and "expense lags" and how they relate to Cash Working Capital.

A. As I mentioned earlier, revenue lags represent the number of days between a company supplying service to customers and receiving cash payment for the service. Therefore, if there are 45 days from the middle of a service month and the day when customers pay their bills then there is a revenue lag of 45 days. This delay in receiving payment of the service provided by the utility creates a cash need associated with the revenues of 45 days. Therefore, if the utility's annual revenue is $100 million, the revenue lag creates a cash need of $12.3 million ([$100,000,000 ÷ 365 days] x 45 days = $12,328,767). Thus, the Cash Working Capital corresponding to the revenue lag is $12.3 million. But the cash requirements created by the revenue lag can be offset or

7 The word "cost" is too broad, in my opinion because a lead-lag study only measures the expenses lags for cash *expenses* and not *non-cash accruals* such as depreciation and amortization expenses. As will be discussed later in my testimony, expense lags for depreciation are fully captured by including net utility plant in rate base.

reduced by the time delay between incurring and paying expenses, i.e., by the expense leads. Again, expense leads represent the number of days between the company incurring the expense and paying for those cash expenses. If a utility incurs an expense during a month – for example, it buys diesel fuel for service vehicles -- but pays the expense at the end of the following month then, assuming 30 days in the month, there is a expense lead of 45 days for the transaction represented by the difference in the number of days from the middle of the month when the fuel was purchased and the end of the following month (15 days + 30 days = 45 days). Therefore, expense leads result in a reduction in requirements for Cash Working Capital and a reduction in rate base.

However, if the payment for an expense *precedes* the service period for the expense, then the transaction results in negative lead days (or, equivalently, lag days), resulting in an *increase* in Cash Working Capital and thus an *increase* in rate base. Depreciation expense is an example of an expense item for which the payment of the expense *precedes* the service period for the expense. When a utility makes a plant investment it is effectively making an upfront payment of the depreciation expenses for service from the plant over the life of the property. In the case of utility property, net plant costs are included in rate base instead of capturing the prepaid expenses in Cash Working Capital with a lead-lag study based on *negative* lead days. Including net plant (i.e., gross plant less net depreciation) in rate base is mathematically equivalent to calculating Cash Working Capital associated with the payment leads on depreciation expenses determined ratably over the life of the property. *Therefore,* *including net plant in rate base is identical to calculating the **negative expense leads** (i.e., **lags**) for depreciation expenses.* (See Rebuttal Exhibit WSS-4 for a mathematical proof of this.)

Q. Ms. Mullinax claims that the Companies' lead-lag studies double count depreciation expenses and other non-cash expenses. Is she correct?

A. Absolutely not. Because the payment of assets precedes the use of those assets and the recording of depreciation expense, the lag between payment for those assets and the recording of depreciation expense (i.e. the negative lead days) is recognized by including net plant in service in rate base. Therefore, by including net plant in rate base, the negative leads associated with depreciation expenses have been fully captured. Because net plant is included in rate base, thereby capturing the fact that payment of capital assets precedes the use of the plant and the recording of depreciation expenses, it is necessary to assume zero lead days for depreciation expenses in the lead-lag study, otherwise there would indeed be double counting. Thus, on the expense side, the negative leads associated with depreciation expenses have been captured just like any other expense. But with respect to the revenue side of the lead-lag study, what costs are recovered through revenues have nothing whatsoever to do with the calculation of revenue lags. Revenue lags are simply the timing difference between when service is provided to customers and when payments are received from customers. These lags apply to all revenues. In a lead-lag study, expenses are expenses and revenues are revenues. Ms. Mullinax is confusing the two. Ms. Mullinax is proposing to remove large chunks of revenue lags merely because she seems not to recognize that including net plant in service and other non-cash expenses in rate base have fully captured the lags (i.e., negative leads) related to the payment of these expenses. Removing the revenue requirements for depreciation and other non-cash expenses from revenue lags would deny KU and LG&E the ability to recover its costs using a return-on-rate-base approach for determining revenue requirement.

Q. Is Ms. Mullinax's proposal to remove depreciation expenses and other non-cash expenses from revenues consistent with her own definition of lead-lag analysis?

A. No. At the beginning of her discussion of Cash Working Capital she defines a lead-lag study as "an analysis that measures the difference between a company's revenue lag (the lapsed days between a company supplying service and being paid for service) and the expense lead (the lapsed days between the company incurring costs and having to pay of those costs)." (Id., at pp. 19-20.) While she describes the lag portion of the analysis as the *revenue lag* she proposes to remove large portions of revenues from the analysis. According to her own definition, revenue lag reflects the timing difference (number of days) between when service is provided and when revenues are recovered from customers. Therefore, according to her own definition of a lead-lag study, the revenue collected from customers is not just a portion of revenue, but the entire revenue, including revenue collected from the rate mechanisms and any other costs included in the amount of revenue paid by customers. For purposes of calculating Cash Working Capital, revenue lags should correspond to *<u>total revenue</u>* because the cash that a utility must invest to cover the time delay in receiving its revenue requirements relates to the *<u>total revenue</u>* not portions thereof.

Q. Is the Companies' treatment of depreciation and other non-cash expenses in the lead-lag studies consistent with the methodology that was approved by Virginia State Corporation Commission (VA SCC) for Old Dominion Power Company (KU-ODP)?

A. Yes. The cash working capital methodology that the Companies are proposing in the cases before the Kentucky Commission is the same methodology that was approved by the VA SCC for KU-ODP, which is the name under which KU operates in Virginia.[8]

Q. Is the Companies' treatment of depreciation and other non-cash expenses in the lead-lag studies consistent with lead-lag studies that have been approved by the Commission for other utilities.

A. Yes. In the lead-lag study that was submitted by Kentucky-American Water Company in Case No. 2012-00520, zero lead days were applied to depreciation expenses and other non-cash accrual items, but no adjustment was made to reduce revenue lags for these expenses. See response to Question 20 of the Commission Staff's Second Request of Information, dated November 13, 2018, which is attached as Rebuttal Exhibit WSS-5.

Q. Does Ms. Mullinax recommend any changes to the expense leads in the Companies' lead-lag studies?

A. Ms. Mullinax is recommending two adjustments to the Companies' proposed Cash

[8] *Kentucky Utilities Company d/b/a Old Dominion Power Company For an Adjustment of Electric Base Rates*, Case No. PUR-2017-00106, Testimony of Justin M. Morgan (VSCC Feb. 28, 2018).

Working Capital amounts. She makes an adjustment to the lag days for Other O&M Expenses that assumes that lead days for all entries in the Companies' sample of Other O&M transactions that do not indicate a service period would arbitrarily be 30 days.

Q. Do you agree with this adjustment?

A. No. Ms. Mullinax arbitrarily assumes lead days of 30 for any transaction in the Companies' Other O&M transactions for which the transaction detail did not specify a service period. Ms. Mullinax did not perform any type of empirical analysis to support her 30-day assumption. In calculating the lead days for Other O&M expenses, KU and LG&E used the invoice date for any transaction that did not indicate a specific service data for the expense. This is a standard approach in performing lead-lag studies. It is inappropriate to simply assume an arbitrary value that was not developed based on empirical data.

Q. Ms. Mullinax proposes to remove prepayments from rate base. Is this adjustment appropriate?

A. No. Ms. Mullinax claims that prepayments are double counted in the lead-lag study. This is incorrect. The Companies did not include prepaid expenses in the lead-lag study. Ms. Mullinax does not point to specific instances in which the Companies calculated expense leads for prepaid expenses included in Prepayments included in the Companies' rate base. She relied on two responses to data requests submitted by the Companies – KU's and LG&E's responses to the Question No. 59 of the AG's initial data request. After reviewing these responses, which are attached as Exhibits HHM-58 and DHM-59 to Ms. Mullinax, the Company unintentionally indicated that expenses included for Rate Base Prepayments included were also included in the lead-lag study. (On February 21, the Companies filed corrected responses to Question No. 59 of the AG's first data request. These revised responses are attached as Rebuttal Exhibit WSS-6.) In response to the AG's data requests, the Companies should have stated that fuel expenses, gas supply expenses, and charges to materials and supplies were included in the lead-lag study but not the expense items included in Rate Base Prepayments.

Q. Does Ms. Mullinax identify transactions included in the lead-lag study that were also included in Rate Base Prepayments?

A. No.

IX. REVENUES FROM POLE ATTACHMENT AUDITS

Q. The Companies propose that parties that attach to KU and LG&E's poles pursuant to Rate PSA be required to reimburse the Companies for the cost of any audit of pole attachments. Is this a reasonable requirement?

A. Yes. As discussed in Mr. Conroy's rebuttal testimony, audits are necessary to ensure that attachment customers are accurately billed for the services that they receive and that attachment customers are observing the application and permitting procedures contained in Rate PSA. These audit costs would not be incurred in the absence of Rate PSA customers attaching to the Companies' poles. Therefore, it is reasonable that attachment customers cover the cost of these audits, thereby ensuring that other customers are not burdened with these costs. However, it has come to our attention that the fees associated with planned audits were not included in miscellaneous revenues in KU's Schedule M-2.3 and LG&E's Schedule M-2.3-E. Forecasted costs in the amount of $96,565 were included in KU's test-year revenue requirements, and forecasted costs in the amount of $66,167 were included in LG&E's test-year revenue requirements for the pole attachment audits. However, there were no off-setting revenues included in other miscellaneous revenues to reflect the reimbursement of these costs from attachment customers. Accordingly, the *increase* in other miscellaneous electric revenues shown on page 2 of Schedule M-2.3 for KU (i.e. the column labeled "increase") should be adjusted upwards by an additional $96,565 and the *increase* in other miscellaneous electric revenues shown on page 2 Schedule M-2.3-E for LG&E should be adjusted upwards by an additional $66,167.

Q. What effect do these adjustments to miscellaneous revenues have on the rates to the Companies' other customers?

A. These adjustments have the effect of lowering the revenue requirements applicable to the Companies' electric customers from what was originally proposed in these proceedings. Making these upward adjustments to the increase in other miscellaneous revenues ensures that there is no double recovery of revenues related to the pole attachment audits.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

W. Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15th day of February 2019.

Judy Schooler (SEAL)
Notary Public

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

Rebuttal Exhibit WSS-1

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY
Percentage of Variable Expenses to Total Cost of Service

Utility	Fuel & Variable O&M	Total Cost of Service	Ratio of Fuel to Total Cost of Service
LG&E	$ 378,981,730	$ 1,048,700,447	36.14%
KU	$ 551,982,042	$ 1,560,311,053	35.38%

Rebuttal Exhibit WSS-2

The Prime Group LLC

School Pilot Tariffs Report No. 3

Report on the Load Characteristics for the Optional Pilot Rates for Schools

Kentucky Utilities Company
Louisville Gas and Electric Company

December 21, 2018

Load Characteristics of the Optional Pilot Rates for Schools

Background

The parties in Kentucky Utilities Company's ("KU's") and Louisville Gas and Electric Company's ("LG&E's") (collectively "Utilities" or "each Utility" when referenced individually) last rate case, filed in Case Nos. 2016-00370 and 2016-00371, submitted a Stipulation and Recommendation ("Stipulation Agreement") agreeing to the implementation of Optional Pilot Rates for Schools. In the Stipulation Agreement, these discounted Optional Pilot Rates were available to participants until the total projected revenue impact (reduction in revenues) for each Utility reaches $750,000.

The Stipulation Agreement provided for the creation of two Optional Pilot Rates for Schools for KU and LG&E: (1) School Power Service ("Rate SPS") and (2) School Time-of-Day Service ("Rate STOD"). Rate SPS is a multi-part rate consisting of a Basic Service Charge, Energy Charge and seasonally differentiated Demand Charge. Rate SPS was modelled after the Power Service ("Rate PS"), except Rate SPS offers discounted charges to schools taking service under the rate. Schools taking service under Rate SPS would be transferred from Rate PS. Rate STOD is a multi-part rate consisting of a Basic Service Charge, Energy Charge and time-differentiated Demand Charge. Rate STOD was modeled after Time of Day Secondary ("Rate TODS") and Time of Day Primary ("Rate TODP"), except Rate STOD offers discounted charges to schools in comparison to the Rates TODS and TODP. Schools taking service under STOD would be transferred from Rate TODS or TODP.

After a hearing concerning the Stipulation Agreement, in its Orders in Case Nos. 2016-00370 and 2016-00371, dated June 22, 2017, the Commission approved the Optional Pilot Rates for Schools, with the following requirements: (1) the Stipulation was to be modified to include non-public schools not covered by KRS 160.325; (2) the pilot rates would be available to new participants until the total projected revenue reduction reaches $750,000 annually for each utility, compared to the projected annual revenues for the participating schools under the rates which the schools would otherwise be served; (3) a limit was placed on the amount of time the pilot rates would be in effect of three years, or until the Utilities file their next rate case;[1] and (4) beginning six months from the date of the Commission's rate case order, the Utilities were required to file a report with the Commission which set out details

[1] The Commission's Orders in Case Nos. 2016-00370 and 2016-00371 also provided as follows:

> In the event that new base rates are not in effect by July 1, 2020, schools participating in the pilot tariffs should be returned to the tariffs under which they were formerly served. In addition, the Commission finds that KU should create a regulatory liability to record the difference between what the schools served under the pilot tariffs would have been billed under the pilot tariffs subsequent to July 1, 2020, and the amounts they are billed under the tariffs to which they are returned. The regulatory liability will be addressed in [the Utility's] next base rate proceeding.

Id. at p. 20.

concerning monthly load information, individually and in the aggregate, and indicating preliminary findings as conclusion regarding the schools' load characteristics are reached.

This report represents the third report filed with the Commission regarding the load characteristics for the schools taking service under the Optional Pilot Rates. The first report was submitted to Commission on December 21, 2017. However, because each school's transition to the School Pilot Rates took place in September and October 2017, no meaningful load data was available at that time. The second report looked at load data for each of the schools under the Pilot Rate from December 2017 through March 2018.

Description of Load Data

As summarized below, there are currently 233 public and private schools taking service under the Optional Pilot Rates for Schools:

Pilot School Rate Count				
Utility	**Rate**	**Public**	**Private**	**Total**
KU	School Power Service	69	8	77
	School Time of Day Service	76	0	76
	KU Total	145	8	153
LG&E	School Power Service	68	8	76
	School Time of Day Service	4	0	4
	LG&E Total	72	8	80
System	**System Total**	**217**	**16**	**233**

The Utilities have collected hourly load data for these customers. When this report was being prepared, complete hourly load data for all customers were available for the twelvemonth period of November 2017 through October 2018.

Appendix A of this report shows the average monthly energy usage, average monthly coincident peak (CP) demand, average monthly non-coincident (NCP) demand, coincident factor, CP load factor, and NCP load factor for each school taking service under KU's Optional Pilot Rates for Schools. Appendix B shows the same information for each school taking service under LG&E's Optional Pilot Rates for Schools. Each row of these reports corresponds to data for a single school taking service under the Optional Pilot Rates for Schools. The names of the individual school have been omitted from these reports.

The CP demands are important because they represent each school's demand during the hour of KU and LG&E's combined monthly system peak. Because KU and LG&E must install or purchase sufficient generation capacity to meet their combined system peak demands, CP demands are important determinants of the Utilities' cost of providing service, particularly production demand-related costs. NCP demands represent the maximum monthly demand of each customer. NCP demands are important because KU and LG&E must install delivery capacity (transmission and distribution capacity) to serve each customer's maximum demand. Both CP and NCP demands are utilized to allocate costs in KU and LG&E's

class cost of service studies. *Coincidence factor* represents the ratio of the customer's CP demand to its NCP demand and, therefore, provides a measure of whether a maximum demand occurs at the time of KU and LG&E's combined system peak. In other words, coincidence factor provides information about the portion of a customer's total demand that occurs at the time of the utility's peak load. *Load factor* represents the ratio of a customer's average kWh energy usage to its demand. In Appendix A and B, both CP and NCP load factors are shown. *CP load factor* represents the ratio of the customer's average demand to the customer's CP demand, and *NCP load factor* represents the ratio of the customer's average demand to the customer's NCP demand. Coincidence factors and load factors provide an indication of how cost of service might differ from one customer to another. For example, with everything else being equal, it would cost more to serve a customer with a high coincidence factor. Likewise, it costs more *ceteris paribus* to serve a customer with a low load factor than one with a high load factor.

Load Factor and Coincident Factor Analysis

The following table compares the average coincidence factors, CP load factors, and NCP load factors for the customers served under the Optional Rates for Schools to a random sample of customers taking service under KU's standard rate schedules (Rate PS, Rate TODS, and Rate TODP).

Kentucky Utilities Company		
	Customers Taking Service Under the Pilot Rates for Schools	**Sample of Customers Taking Service Under Standard Rates**
Average Coincidence Factor	0.674012	0.707894
Average CP Load Factor	0.680610	0.744180
Average NCP Load Factor	0.458739	0.526757

As can be seen from the above table, the average coincidence factor for the customers taking service under the Pilot Rates for Schools is slight lower than the coincidence factor for the random sample of non-school customers taking service under KU's standard rate schedule. The average CP and NCP load factors for the customers taking service under the Pilot Rates for Schools are also slightly lower than KU's non-school customers.

Louisville Gas and Electric Company		
	Customers Taking Service Under the Pilot Rates for Schools	**Sample of Customers Taking Service Under Standard Rates**
Average Coincidence Factor	0.681444	0.733917
Average CP Load Factor	0.609078	0.663990
Average NCP Load Factor	0.415053	0.487314

As can be seen from the above table, the average coincidence factor for the customers taking service under the Pilot Rates for Schools is slightly lower than the coincidence factor for the random sample of non-school customers taking service under LG&E's standard rate schedule. The average CP and NCP load factors for the customers taking service under the Pilot Rates for Schools are also somewhat lower than LG&E's non-school customers.

Based on this data, there is not a significant difference between the coincidence factors and NCP load factors of customers taking service under the Pilot Rates for Schools and non-school customers taking service under Rates PS, TODS, and TODP. The Coincidence factors, NCP and CP load factors for the schools are lower than for the non-school customers. These results suggest that the schools have not likely modified their load patterns in response to taking service under the Pilot Rates.

LOLP Analysis

In addition to the results discussed in the previous section, the Utilities also evaluated the Loss of Load Probability ("LOLP") for customers taking service under the Pilot Rates for School's compared to that of the non-school customer group. The LOLP methodology mirrors the allocation method which was used in the Utilities' latest Cost of Service Study for allocation of Production-related demand costs. LOLP is a key measure used by KU and LG&E for planning generation resources. LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. For each customer group, the LOLP was calculated as the hourly load-weighted LOLP for the customer group. LOLP, therefore, takes into consideration the magnitude of the load, installed generation capacity, forced outage rates, maintenance schedules, and ramp-up rates of generating units. LOLP can be calculated for any period – an hour, a day, a week, etc. Specifically, it is used to evaluate the level of reserve margins the Utilities target. Thus, LOLP can be a useful measure of determining whether a class of customers is likely contributing to KU and LG&E's need for additional generating capacity.

LOLP was calculated for each hour of the twelve-month period from November 2017 through October 2018 based on the hourly loads for that period and the characteristics of the Utilities' generating facilities, including capacity, forced outage rates, and maintenance schedules. Hourly loads for the customers taking service under the Pilot Rates for Schools and the non-school customer group were then weighted by the LOLP for each hour to determine LOLP weighted hourly load for each group of customers for both LG&E and KU.

The LOLP is not a directly comparable number from one class to another. To create a measure of LOLP that can be compared across classes of service we calculated two LOLP statistics; 1) LOLP per CP kW, and 2) LOLP per customer. These statistics will allow us to compare effect of LOLP between classes. We calculated the LOLP per CP kW for customers taking service under both Rate SPS and Rate STOD and compared them to the same calculations for non-school customers taking service under the PS and TOD rate schedules for each hour of the evaluation period. We also calculated the total LOLP per customer for each of the rate categories.

	Kentucky Utilities LOLP per CP kW Summary	
	Power Service	**TOD Service**
Schools	0.003482	0.003575
Non - Schools	0.003630	0.003646

As can be seen from the table above, both the school and non-school sets of customers have similar LOLP per Coincident peak demand on KU's system. The data suggests that from the perspective of production cost allocation, there would be little difference in the production cost allocated to each group and no reason to separate the schools into a different rate category.

	Louisville Gas & Electric LOLP per CP kW Summary	
	Power Service	**TOD Service**
Schools	0.004007	0.004019
Non - Schools	0.003885	0.004371

The LOLP per CP kW for LG&E's customers also show very similar results, indicating that it would be of little value to create separate rate categories for schools.

	Kentucky Utilities	Louisville Gas & Electric
	Total LOLP per Customer	**Total LOLP per Customer**
Schools	7.51	7.20
Non - Schools	7.64	7.06

Finally, as can be seen from the table above, the LOLPs per customer for customers taking service under the Pilot Rate for Schools are not materially different from those that take service under the Standard rate schedules. This would lend additional support for there being no meaningful difference between those customers taking service under the Pilot Rate for Schools and customers under the Standard rate schedule for both PS and TOD.

Conclusion

The purpose of creating separate rate classes for groups of customers is to construct a class of customers that have similar load characteristics, and therefore, similar costs of providing service. The characteristics that drive the cost of providing service in a cost of service study are load factor, coincidence factor, and loss of load probability. When rate classes do not contain customers with similar load characteristics, the rate structure does not accurately reflect the cost of providing service to those customers who are dissimilar to the other members of the class. Therefore, it is important that utility rate classes contain reasonably similar customers, so the rates are fair and reasonable for all customers in the class. Conversely, if similar customers are charged different rates so that one group is advantaged over another, those rates are discriminatory because they are not based on the cost of providing service.

Examining the comparative load factors, coincidence factors, LOLP per CP kW, and LOLP per customer leads to the conclusion that the schools have very similar load characteristics, and therefore, very similar cost of service, as the other customers in the PS and TOD rate schedules. There is no evidence that creating a separate rate for schools would result in an improvement in fairness or equity of the rates for the schools or of the rates for the remaining non-school customers. Furthermore, given their similar load characteristics as non-school customers, the results of this analysis suggest that the schools have not likely modified their loads in response to taking service under the Pilot Rates.

In contrast to the similarities between the schools and other members of the PS and TOD rates, the same statistics show significant differences when comparing different classes to each other. The table below shows the LOLP per customer, LOLP per CP kW, NCP Load Factor, and 12 CP Load Factor for each class on LG&E's system. It is important to note the significant variability in many of these statistics from class to class compared with the variability in the same statistics between schools and non-schools in the PS and TOD classes. Significant variation in some, or all, of these statistics indicate the necessity for a separate rate schedule. The same variability is not present when comparing the schools to other customers served under Rates PS and TOD.

Louisville Gas and Electric Company					
		LOLP Per	LOLP Per	NCP	12 CP
Rate Class		**Customer**	**CP kW**	**Load Factor**	**Load Factor**
Residential Rate RS		0.228	0.008046	14.5%	53.3%
General Service Rate GS		0.445	0.007336	25.1%	63.0%
Power Service Primary		19.766	0.006800	32.0%	79.7%
Power Service Secondary		7.792	0.006446	37.0%	68.1%
TOD Primary		168.684	0.007026	40.3%	90.8%
TOD Secondary		33.915	0.006649	39.5%	73.5%
Retail Transmission Service		712.112	0.006005	47.9%	93.9%
Special Contract		252.352	0.005826	32.8%	90.1%
Street Lighting Rate (RLS & LS)		0.001	0.001462	42.4%	281.8%
Lighting Energy Rate LE		0.017	0.001415	40.2%	272.7%
Traffic Energy Rate TLE		0.028	0.005724	85.5%	95.3%
Outdoor School Lighting		0.113	0.005412	2.7%	157.9%

As can be seen from the above table, there are significant differences in the LOLP and load-factor statistics from one class to another. These differences do not exists between the customers served under School Power Service and Power Service, and between School Time-of-Day Service and Time-of-Day Service.

Below are the same statistics for the rate classes on KU's system:

Kentucky Utilities					
Rate Class		**LOLP Per Customer**	**LOLP Per CP kW**	**NCP Load Factor**	**12 CP Load Factor**
Residential Rate RS		0.220	0.006051	16.3%	51.5%
General Service Rate GS		0.258	0.006777	18.1%	74.2%
All Electric Schools Rate AES		2.637	0.004442	23.0%	54.7%
Power Service Secondary Rate PSS		5.394	0.006578	29.6%	67.6%
Power Service Primary Rate PSP		8.083	0.005870	41.0%	69.7%
TOD Secondary Rate TODS		30.386	0.006136	43.3%	68.7%
TOD Primary Rate TODP		169.396	0.006088	45.2%	76.5%
Retail Transmission Service Rate RTS		575.438	0.006022	58.6%	84.4%
Fluctuating Load Service Rate FLS		6067.113	0.006014	45.5%	84.5%
Street Lighting Rate (RLS, LS)		0.001	0.001464	40.3%	279.7%
Lighting Energy Rate LE		0.032	0.001630	36.9%	295.0%
Traffic Energy Rate TE		0.016	0.005239	79.2%	93.2%
Outdoor Sports Lighting Rate OSL		0.340	0.003357	4.7%	84.6%

Again, this table indicates significant differences in the LOLP and load-factor statistics from one class to another. These same differences do not exist between the customers served under School Power Service and Power Service, and between School Time-of-Day Service and Time-of-Day Service.

The class statistics for LG&E and KU indicate that the load characteristics that would create significant cost differences in those rate classes are simply not present between schools and non-school customers in the PS and TOD rates. The data suggests that the PS and TOD rate classes are the appropriate classes under which the schools should be served.

APPENDIX A

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
KU	School Power Service	Public	59,337	124.9	228.7	0.545874	0.651358	0.355560
KU	School Power Service	Public	60,396	155.6	199.7	0.779067	0.532166	0.414594
KU	School Power Service	Public	62,378	152.2	192.0	0.792458	0.561865	0.445254
KU	School Power Service	Public	47,873	126.1	203.1	0.621028	0.520284	0.323111
KU	School Power Service	Public	48,654	84.8	142.3	0.596062	0.785945	0.468472
KU	School Power Service	Public	25,344	55.4	78.7	0.703313	0.627566	0.441375
KU	School Power Service	Public	97,050	178.7	214.8	0.831593	0.744570	0.619179
KU	School Power Service	Public	26,592	39.5	56.5	0.699569	0.922046	0.645035
KU	School Power Service	Public	33,155	83.3	127.1	0.655330	0.545693	0.357609
KU	School Power Service	Public	37,895	92.3	158.4	0.582808	0.562450	0.327800
KU	School Power Service	Public	79,713	131.5	210.0	0.626168	0.830841	0.520246
KU	School Power Service	Public	30,904	66.2	154.3	0.429051	0.639910	0.274554
KU	School Power Service	Public	50,261	128.2	214.7	0.596868	0.537474	0.320801
KU	School Power Service	Public	62,166	123.9	171.7	0.721454	0.687861	0.496260
KU	School Power Service	Public	58,838	120.2	179.2	0.671131	0.670717	0.450139
KU	School Power Service	Public	66,366	113.1	181.9	0.621982	0.804124	0.500151
KU	School Power Service	Public	41,446	116.2	178.0	0.653007	0.488661	0.319099
KU	School Power Service	Public	48,944	123.7	223.7	0.552717	0.542495	0.299846
KU	School Power Service	Public	43,719	96.2	163.5	0.587915	0.623196	0.366386
KU	School Power Service	Public	16,784	33.0	52.6	0.626418	0.697612	0.436997
KU	School Power Service	Public	8,659	15.8	27.5	0.575360	0.749176	0.431046
KU	School Power Service	Public	71,645	157.6	186.1	0.847126	0.622959	0.527725
KU	School Power Service	Public	32,920	86.0	156.8	0.548228	0.524861	0.287744
KU	School Power Service	Private	56,099	126.2	196.8	0.641351	0.609182	0.390699
KU	School Power Service	Public	47,940	73.1	124.4	0.587322	0.899140	0.528084
KU	School Power Service	Public	43,862	97.0	175.7	0.551880	0.619894	0.342107
KU	School Power Service	Public	43,047	109.2	156.8	0.696567	0.540344	0.376385
KU	School Power Service	Private	8,602	17.9	24.0	0.743411	0.659998	0.490649
KU	School Power Service	Public	47,711	113.3	192.1	0.589816	0.577108	0.340387
KU	School Power Service	Public	54,489	109.2	159.0	0.686814	0.683740	0.469603
KU	School Power Service	Public	60,321	179.5	241.6	0.743069	0.460546	0.342218
KU	School Power Service	Public	52,135	104.7	154.3	0.678450	0.682629	0.463130

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
KU	School Power Service	Public	117,814	228.4	289.2	0.789761	0.707036	0.558390
KU	School Power Service	Public	47,463	103.9	165.6	0.627225	0.626272	0.392813
KU	School Power Service	Public	44,008	107.7	180.5	0.596868	0.559821	0.334139
KU	School Power Service	Public	49,821	114.9	130.2	0.882727	0.594359	0.524656
KU	School Power Service	Private	26,421	51.8	62.5	0.829064	0.699018	0.579531
KU	School Power Service	Public	58,184	106.5	150.2	0.708787	0.748882	0.530798
KU	School Power Service	Public	66,310	141.0	224.7	0.627291	0.644791	0.404472
KU	School Power Service	Public	48,327	104.9	147.2	0.712899	0.631273	0.450034
KU	School Power Service	Public	58,433	116.3	208.9	0.556390	0.688922	0.383309
KU	School Power Service	Public	47,537	137.8	213.4	0.645927	0.472775	0.305378
KU	School Power Service	Public	36,078	67.6	99.9	0.677117	0.731158	0.495079
KU	School Power Service	Public	31,811	80.3	126.9	0.632994	0.542744	0.343554
KU	School Power Service	Public	40,597	74.9	98.3	0.762061	0.743176	0.566346
KU	School Power Service	Public	26,640	63.1	82.5	0.765140	0.578236	0.442431
KU	School Power Service	Public	63,070	112.2	157.3	0.713354	0.770353	0.549535
KU	School Power Service	Public	81,575	144.1	206.5	0.697805	0.775955	0.541465
KU	School Power Service	Public	41,096	86.0	135.5	0.634789	0.654732	0.415617
KU	School Power Service	Public	45,488	92.2	149.0	0.618900	0.676165	0.418479
KU	School Power Service	Public	42,063	84.8	132.3	0.640843	0.680126	0.435854
KU	School Power Service	Public	13,940	48.9	54.7	0.894247	0.390557	0.349255
KU	School Power Service	Public	50,736	117.6	171.3	0.686297	0.591509	0.405951
KU	School Power Service	Public	22,316	56.6	93.9	0.602857	0.540109	0.325609
KU	School Power Service	Public	39,123	76.8	123.0	0.624414	0.698285	0.436019
KU	School Power Service	Public	53,585	122.1	229.4	0.532203	0.601451	0.320094
KU	School Power Service	Public	40,021	60.0	117.5	0.510876	0.913586	0.466729
KU	School Power Service	Public	79,343	134.8	177.9	0.757973	0.806661	0.611427
KU	School Power Service	Public	13,655	39.8	48.7	0.818227	0.469732	0.384348
KU	School Power Service	Public	43,037	86.0	129.9	0.661506	0.686273	0.453974
KU	School Power Service	Public	42,932	88.0	160.3	0.548875	0.668718	0.367043
KU	School Power Service	Public	77,240	156.4	205.6	0.760630	0.676806	0.514799
KU	School Power Service	Private	46,595	101.9	131.9	0.772367	0.626712	0.484052
KU	School Power Service	Public	41,993	84.4	124.9	0.676251	0.681579	0.460919

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
KU	School Power Service	Public	54,239	141.2	208.2	0.678020	0.526524	0.356994
KU	School Power Service	Public	74,524	146.5	212.6	0.689366	0.697062	0.480531
KU	School Power Service	Private	12,438	28.0	41.9	0.668776	0.608283	0.406805
KU	School Power Service	Private	57,107	124.2	172.0	0.722150	0.630256	0.455139
KU	School Power Service	Private	9,499	13.4	54.8	0.244526	0.971595	0.237580
KU	School Power Service	Public	46,805	125.2	187.3	0.668606	0.512207	0.342465
KU	School Power Service	Public	46,874	101.7	194.6	0.522567	0.631624	0.330066
KU	School Power Service	Public	72,824	174.3	234.2	0.744217	0.572636	0.426165
KU	School Power Service	Public	42,111	108.3	208.3	0.519787	0.533192	0.277147
KU	School Power Service	Public	45,713	94.8	189.9	0.499338	0.660871	0.329998
KU	School Power Service	Private	41,771	107.4	138.4	0.775777	0.533073	0.413546
KU	School Time-of-Day Service	Public	139,584	291.0	423.2	0.687711	0.657391	0.452095
KU	School Time-of-Day Service	Public	177,162	289.6	437.9	0.661302	0.838419	0.554448
KU	School Time-of-Day Service	Public	97,712	207.9	275.5	0.754634	0.644076	0.486041
KU	School Time-of-Day Service	Public	130,704	247.2	360.4	0.685921	0.724768	0.497133
KU	School Time-of-Day Service	Public	294,546	469.7	729.9	0.643474	0.859527	0.553083
KU	School Time-of-Day Service	Public	168,053	284.3	448.6	0.633831	0.810164	0.513507
KU	School Time-of-Day Service	Public	57,602	117.7	196.3	0.599750	0.670544	0.402159
KU	School Time-of-Day Service	Public	22,107	42.2	66.6	0.632958	0.718527	0.454797
KU	School Time-of-Day Service	Public	57,479	120.9	210.5	0.574491	0.651616	0.374348
KU	School Time-of-Day Service	Public	102,436	201.5	322.4	0.624964	0.696883	0.435527
KU	School Time-of-Day Service	Public	173,365	350.9	570.0	0.615545	0.677191	0.416841
KU	School Time-of-Day Service	Public	100,972	254.3	326.2	0.779399	0.544299	0.424226
KU	School Time-of-Day Service	Public	120,392	283.2	472.3	0.599637	0.582639	0.349372
KU	School Time-of-Day Service	Public	121,690	295.7	399.5	0.740282	0.564026	0.417538
KU	School Time-of-Day Service	Public	95,987	152.9	251.8	0.607082	0.860632	0.522474
KU	School Time-of-Day Service	Public	254,802	573.5	749.2	0.765550	0.608924	0.466162
KU	School Time-of-Day Service	Public	78,742	198.1	288.2	0.687476	0.544695	0.374465
KU	School Time-of-Day Service	Public	88,067	152.3	249.8	0.609548	0.792771	0.483232
KU	School Time-of-Day Service	Public	99,746	208.7	381.0	0.547907	0.654936	0.358844
KU	School Time-of-Day Service	Public	254,270	527.5	636.6	0.828613	0.660652	0.547425
KU	School Time-of-Day Service	Public	250,104	408.9	512.6	0.797710	0.838338	0.668750

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
KU	School Time-of-Day Service	Public	101,966	255.6	317.7	0.804302	0.546875	0.439853
KU	School Time-of-Day Service	Public	102,071	202.7	365.5	0.554614	0.690151	0.382767
KU	School Time-of-Day Service	Public	223,704	491.2	623.8	0.787335	0.624241	0.491487
KU	School Time-of-Day Service	Public	87,270	207.4	281.2	0.737609	0.576660	0.425350
KU	School Time-of-Day Service	Public	90,084	207.6	328.5	0.632143	0.594629	0.375891
KU	School Time-of-Day Service	Public	75,807	174.5	331.9	0.525803	0.595401	0.313064
KU	School Time-of-Day Service	Public	90,757	197.2	293.2	0.672451	0.630910	0.424256
KU	School Time-of-Day Service	Public	154,664	332.2	495.0	0.671079	0.638201	0.428284
KU	School Time-of-Day Service	Public	366,976	528.6	846.8	0.624292	0.951468	0.593994
KU	School Time-of-Day Service	Public	124,030	210.4	317.8	0.661916	0.808048	0.534860
KU	School Time-of-Day Service	Public	65,747	175.7	228.3	0.769649	0.512786	0.394665
KU	School Time-of-Day Service	Public	123,603	315.4	469.1	0.672346	0.537152	0.361152
KU	School Time-of-Day Service	Public	77,929	156.8	246.2	0.636936	0.681026	0.433770
KU	School Time-of-Day Service	Public	65,021	117.0	234.3	0.499624	0.761428	0.380428
KU	School Time-of-Day Service	Public	501,637	735.3	1,116.0	0.658819	0.935125	0.616078
KU	School Time-of-Day Service	Public	164,737	395.6	463.2	0.854132	0.570739	0.487487
KU	School Time-of-Day Service	Public	138,434	307.4	449.4	0.683956	0.617301	0.422207
KU	School Time-of-Day Service	Public	106,972	187.9	270.1	0.695481	0.780416	0.542764
KU	School Time-of-Day Service	Public	175,443	258.3	458.4	0.563411	0.931098	0.524590
KU	School Time-of-Day Service	Public	114,721	196.8	330.4	0.595776	0.798811	0.475912
KU	School Time-of-Day Service	Public	105,328	204.1	322.1	0.633737	0.707153	0.448149
KU	School Time-of-Day Service	Public	119,028	253.8	370.3	0.685343	0.642824	0.440555
KU	School Time-of-Day Service	Public	83,108	180.6	281.1	0.642538	0.630582	0.405173
KU	School Time-of-Day Service	Public	101,677	171.0	246.2	0.694492	0.815151	0.566116
KU	School Time-of-Day Service	Public	198,406	352.9	513.2	0.687602	0.770587	0.529857
KU	School Time-of-Day Service	Public	85,590	164.2	256.9	0.639114	0.714554	0.456682
KU	School Time-of-Day Service	Public	181,645	256.5	382.7	0.670391	0.970453	0.650583
KU	School Time-of-Day Service	Public	192,934	378.4	550.9	0.686968	0.698787	0.480045
KU	School Time-of-Day Service	Public	101,321	226.3	300.8	0.752471	0.613543	0.461674
KU	School Time-of-Day Service	Public	163,311	257.8	363.5	0.709276	0.868105	0.615726
KU	School Time-of-Day Service	Public	127,958	209.6	305.8	0.685566	0.836566	0.573521
KU	School Time-of-Day Service	Public	178,443	273.7	449.6	0.608655	0.893665	0.543934

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
KU	School Time-of-Day Service	Public	100,621	232.7	336.7	0.690954	0.592751	0.409564
KU	School Time-of-Day Service	Public	103,850	212.5	342.2	0.621048	0.669690	0.415910
KU	School Time-of-Day Service	Public	75,031	161.6	236.1	0.684677	0.636305	0.435664
KU	School Time-of-Day Service	Public	114,474	211.0	297.6	0.709198	0.743526	0.527307
KU	School Time-of-Day Service	Public	96,638	168.4	296.9	0.567094	0.786724	0.446146
KU	School Time-of-Day Service	Public	100,517	168.9	271.6	0.621851	0.815736	0.507266
KU	School Time-of-Day Service	Public	82,636	165.6	233.7	0.708696	0.683902	0.484678
KU	School Time-of-Day Service	Public	141,770	274.1	399.5	0.686132	0.708943	0.486429
KU	School Time-of-Day Service	Public	109,982	207.6	277.5	0.748240	0.726090	0.543289
KU	School Time-of-Day Service	Public	116,593	192.4	280.8	0.685361	0.830481	0.569179
KU	School Time-of-Day Service	Public	147,553	292.6	365.5	0.800423	0.691193	0.553246
KU	School Time-of-Day Service	Public	82,542	219.3	312.5	0.701669	0.515949	0.362026
KU	School Time-of-Day Service	Public	203,443	376.7	623.1	0.604570	0.740158	0.447477
KU	School Time-of-Day Service	Public	96,075	277.3	331.8	0.835775	0.474871	0.396886
KU	School Time-of-Day Service	Public	66,806	131.6	303.4	0.433740	0.695828	0.301809
KU	School Time-of-Day Service	Public	93,912	233.0	332.5	0.700645	0.552492	0.387101
KU	School Time-of-Day Service	Public	80,792	216.3	300.5	0.719809	0.512001	0.368543
KU	School Time-of-Day Service	Public	59,319	156.8	208.9	0.750619	0.518512	0.389205
KU	School Time-of-Day Service	Public	121,596	226.2	300.5	0.752496	0.736936	0.554541
KU	School Time-of-Day Service	Public	100,990	250.3	333.5	0.750463	0.553057	0.415049
KU	School Time-of-Day Service	Public	96,192	204.7	279.6	0.732334	0.643990	0.471616
KU	School Time-of-Day Service	Public	150,626	423.3	498.0	0.850008	0.487688	0.414538
Average KU Pilot Rate for Schools			**88,059**	**177**	**263**	**0.674012**	**0.680610**	**0.458739**

APPENDIX B

Louisville Gas Electric Company

Summary of Load Data for Customers Served under the Pilot Rates for Schools

November 2017 through October 2018

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
LG&E	School Power Service	Public	44,697	99.4	161.6	0.614790	0.616637	0.379102
LG&E	School Power Service	Public	55,937	118.7	150.1	0.790834	0.645794	0.510716
LG&E	School Power Service	Public	54,071	138.6	203.9	0.679912	0.534708	0.363554
LG&E	School Power Service	Public	43,816	89.5	141.3	0.633451	0.671188	0.425165
LG&E	School Power Service	Public	44,334	110.9	156.9	0.706932	0.547924	0.387345
LG&E	School Power Service	Public	50,981	147.0	260.0	0.565418	0.475274	0.268729
LG&E	School Power Service	Private	45,667	89.0	133.9	0.664758	0.703274	0.467507
LG&E	School Power Service	Public	66,405	170.8	235.1	0.726267	0.533001	0.387101
LG&E	School Power Service	Public	47,592	112.7	195.8	0.575407	0.578895	0.333100
LG&E	School Power Service	Private	32,514	66.0	110.9	0.594741	0.675559	0.401782
LG&E	School Power Service	Public	60,282	122.8	176.9	0.694134	0.673053	0.467189
LG&E	School Power Service	Public	47,653	120.7	222.5	0.542540	0.540979	0.293503
LG&E	School Power Service	Public	28,636	90.6	129.3	0.700387	0.433295	0.303474
LG&E	School Power Service	Public	42,959	102.1	163.3	0.625478	0.576554	0.360622
LG&E	School Power Service	Public	43,484	89.9	126.5	0.710425	0.663314	0.471235
LG&E	School Power Service	Public	35,167	87.5	134.5	0.650312	0.550992	0.358317
LG&E	School Power Service	Public	117,684	284.2	457.5	0.621202	0.567558	0.352568
LG&E	School Power Service	Public	35,975	107.9	183.6	0.587873	0.456936	0.268620
LG&E	School Power Service	Public	41,931	116.9	186.5	0.626988	0.491482	0.308154
LG&E	School Power Service	Public	46,293	96.3	179.2	0.537351	0.658925	0.354074
LG&E	School Power Service	Public	60,814	147.0	198.0	0.742457	0.567071	0.421026
LG&E	School Power Service	Public	2,064	3.2	4.2	0.743172	0.897611	0.667079
LG&E	School Power Service	Public	53,221	134.9	170.7	0.790090	0.540732	0.427227
LG&E	School Power Service	Public	45,228	71.9	139.8	0.514304	0.861875	0.443265
LG&E	School Power Service	Public	205,036	348.0	448.9	0.775097	0.807621	0.625985
LG&E	School Power Service	Public	47,250	114.1	163.0	0.699739	0.567710	0.397249
LG&E	School Power Service	Public	53,355	134.2	215.5	0.622434	0.545130	0.339307
LG&E	School Power Service	Public	65,819	144.7	211.3	0.684808	0.623441	0.426938
LG&E	School Power Service	Public	61,029	161.9	214.4	0.755395	0.516513	0.390171
LG&E	School Power Service	Public	48,068	127.0	175.1	0.725417	0.518816	0.376358
LG&E	School Power Service	Public	43,794	100.6	170.9	0.588648	0.596666	0.351226
LG&E	School Power Service	Public	50,508	104.7	167.0	0.627034	0.661305	0.414661

Louisville Gas Electric Company

Summary of Load Data for Customers Served under the Pilot Rates for Schools

November 2017 through October 2018

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
LG&E	School Power Service	Public	42,923	99.1	153.1	0.646963	0.593949	0.384263
LG&E	School Power Service	Public	40,447	85.7	131.3	0.652803	0.646877	0.422284
LG&E	School Power Service	Private	46,857	106.0	137.3	0.771723	0.605976	0.467646
LG&E	School Power Service	Public	41,187	95.3	136.5	0.698413	0.592155	0.413569
LG&E	School Power Service	Public	43,054	118.6	159.1	0.745234	0.497700	0.370903
LG&E	School Power Service	Public	30,043	42.8	61.9	0.691707	0.961700	0.665215
LG&E	School Power Service	Public	162,662	318.8	431.5	0.738761	0.699330	0.516638
LG&E	School Power Service	Public	198,963	451.1	612.5	0.736479	0.604560	0.445246
LG&E	School Power Service	Public	61,530	160.0	209.6	0.763265	0.527222	0.402410
LG&E	School Power Service	Public	40,153	83.2	144.4	0.576475	0.661305	0.381226
LG&E	School Power Service	Public	39,712	86.9	146.0	0.595580	0.626019	0.372844
LG&E	School Power Service	Public	44,466	115.2	158.3	0.728096	0.528885	0.385079
LG&E	School Power Service	Public	25,804	35.8	51.9	0.688604	0.989284	0.681224
LG&E	School Power Service	Public	14,852	42.7	53.7	0.794528	0.476828	0.378853
LG&E	School Power Service	Public	50,861	114.2	141.1	0.809429	0.610280	0.493978
LG&E	School Power Service	Public	38,093	105.4	132.0	0.798434	0.495515	0.395636
LG&E	School Power Service	Private	210,962	552.0	703.5	0.784696	0.523785	0.411012
LG&E	School Power Service	Public	287,456	612.6	826.8	0.740859	0.643181	0.476506
LG&E	School Power Service	Public	46,710	114.1	187.2	0.609578	0.560931	0.341931
LG&E	School Power Service	Public	50,279	113.1	184.2	0.613664	0.609568	0.374070
LG&E	School Power Service	Public	85,580	128.0	195.9	0.653283	0.916383	0.598658
LG&E	School Power Service	Public	144,105	229.0	344.0	0.665620	0.862652	0.574198
LG&E	School Power Service	Public	63,865	169.1	224.0	0.754881	0.517670	0.390779
LG&E	School Power Service	Public	39,570	97.4	157.4	0.618740	0.556827	0.344531
LG&E	School Power Service	Public	38,142	107.6	149.0	0.722027	0.485851	0.350797
LG&E	School Power Service	Private	87,280	223.1	336.2	0.663758	0.536122	0.355855
LG&E	School Power Service	Public	37,586	100.0	120.4	0.830945	0.515026	0.427958
LG&E	School Power Service	Public	193,333	428.8	689.3	0.622002	0.618016	0.384407
LG&E	School Power Service	Public	65,552	195.1	380.0	0.513466	0.460514	0.236458
LG&E	School Power Service	Public	75,261	159.4	212.1	0.751808	0.646999	0.486419
LG&E	School Power Service	Public	89,185	174.5	227.9	0.765959	0.700321	0.536417
LG&E	School Power Service	Public	47,109	103.4	169.3	0.611067	0.624249	0.381458

Louisville Gas Electric Company

Summary of Load Data for Customers Served under the Pilot Rates for Schools

November 2017 through October 2018

Utility	Rate Schedule	Public/Private	Average kWh	Average CP	Average NCP	Coicidence Factor	CP Load Factor	NCP Load Factor
LG&E	School Power Service	Public	54,570	151.1	181.2	0.833615	0.495085	0.412710
LG&E	School Power Service	Private	44,469	117.2	167.1	0.701137	0.520229	0.364752
LG&E	School Power Service	Public	44,161	112.2	154.3	0.727528	0.539298	0.392354
LG&E	School Power Service	Public	36,101	106.3	133.1	0.798227	0.465657	0.371700
LG&E	School Power Service	Public	15,032	34.8	41.6	0.835301	0.592339	0.494782
LG&E	School Power Service	Public	54,954	103.8	237.1	0.437753	0.725631	0.317647
LG&E	School Power Service	Private	26,121	59.1	78.1	0.756143	0.605994	0.458218
LG&E	School Power Service	Private	18,627	43.1	60.9	0.707877	0.591893	0.418988
LG&E	School Power Service	Public	41,130	98.1	143.2	0.685509	0.574376	0.393740
LG&E	School Power Service	Public	15,558	38.2	73.4	0.519608	0.558816	0.290365
LG&E	School Time-of-Day Service	Public	214,045	437.6	661.7	0.661301	0.670490	0.443396
LG&E	School Time-of-Day Service	Public	78,856	154.3	258.7	0.596656	0.700345	0.417865
LG&E	School Time-of-Day Service	Public	169,564	353.4	487.5	0.724855	0.657692	0.476731
LG&E	School Time-of-Day Service	Public	57,484	116.0	261.4	0.443807	0.679211	0.301438
Average LG&E Pilot Rate for Schools			**66,573**	**150**	**220**	**0.681444**	**0.609078**	**0.415053**

Rebuttal Exhibit WSS-3

Next Article
Here's What to Watch for in February's Weather

USA NATIONAL FORECAST

Polar Vortex Triggers Coldest Arctic Outbreak in at Least Two Decades in Parts of the Midwest

By weather.com meteorologists · January 31 2019 07:00 PM EDT · weather.com

01:11

Deadly Cold Kills at Least 11 People, Shuts Down Cities

The deadly polar vortex-triggered arctic temperatures are over, but the temperatures left shutdown cities, power outages, flight cancelations and several deaths in their wake.

At a Glance

- Extreme cold in the Midwest broke numerous daily records and a few all-time records.
- For some in the upper Midwest, it was the coldest outbreak since the 1990s.
- A preliminary all-time state record low may have been set in Illinois.
- While not as cold, some bitterly cold air also filtered into the Northeast.

The arctic cold outbreak of January 2019 will go down as the coldest in parts of the upper Midwest since the 1990s, shattering numerous daily records and even topping a few all-time cold records, while creating wind chills as cold as the 60s below zero.

(**NEWS: Impacts From the Cold Outbreak**)

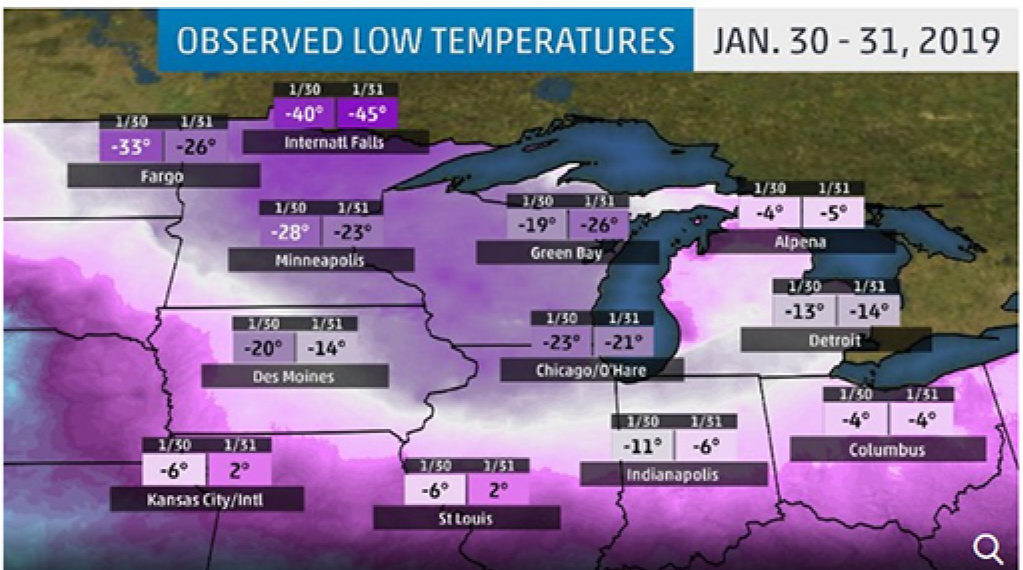
Mount Carroll, Illinois, may have set a new all-time record low for the state of Illinois Thursday morning, Jan. 31, with a temperature of minus 38 degrees.

An ad hoc state climate extremes committee will examine the data and determine whether it will officially be accepted as a new state record, which would beat the current all-time Illinois cold record of minus 36 degrees set Jan. 5, 1999, in Congerville. A second location, Morrison, preliminarily tied the all-time record of minus 36 degrees.

At least four locations tied or set all-time record lows:

- **Minus 43 degrees** northwest of Mather, Wisconsin, on Wednesday, Jan. 30, tied the all-time low at that location in records dating to 1903.
- **Minus 33 degrees** Thursday morning, Jan. 31, in Moline, Illinois, shattered the all-time record low of minus 28 degrees from Feb. 3, 1996.
- **Minus 31 degrees** in Rockford, Illinois, Thursday morning, Jan. 31, topped its previous record of minus 27 degrees from Jan. 10, 1982.
- **Minus 30 degrees** in Cedar Rapids, Iowa, Thursday morning, Jan. 31, beat the previous all-time record of minus 29 degrees.

At least 340 daily cold records were broken or tied in the Midwest alone from Jan. 30 through Jan. 31, according to the Midwest Regional Climate Center.



A sampling of low temperatures across the Midwest Jan. 30-31, 2019.

Among the daily record lows set on Jan. 31 were Grand Forks, North Dakota (minus 32 degrees), Detroit (minus 14 degrees), La Crosse, Wisconsin (minus 33 degrees), Pittsburgh (minus 5 degrees) and several other locations.

The coldest temperature early Jan. 31 was minus 56 degrees in Cotton, Minnesota. That was just a few degrees short of the state's all-time record low of minus 60 degrees set in Tower on Feb. 2, 1996. NWS-Duluth meteorologist Joe Moore told The Wall Street Journal that only some morning fog limited how far the temperature plunged at the observation site in Cotton.

One instigator for this outbreak of cold air was a displacement of a lobe of the polar vortex to a position over the Great Lakes, according to a wunderground.com blog entry from Jeff Masters and Bob Henson.

(**MORE: Satellite Imagery Made the Cold Resemble a Giant, Oozing Cloud**)

Other Late-January Cold Plunge Notables

Here are some other notables about this cold outbreak:

- **Minus 23 degrees** Wednesday, Jan. 30, at Chicago's O'Hare Airport was its coldest temperature in 34 years, when its all-time record low of minus 27 degrees was set.
- Chicago O'Hare was below zero for 52 straight hours, the fourth longest streak on record, there, according to the National Weather Service.
- **Minus-60s wind chills** were recorded in parts of Minnesota, North Dakota and northeastern Iowa Tuesday night, Jan. 29, into Wednesday, Jan. 30. Minus 66 degrees was the coldest wind chill observed in this arctic outbreak in Ponsford, Minnesota, Tuesday evening, Jan. 29.
- **Minus-50s wind chills** were observed Wednesday morning, Jan. 30, as far south as central Illinois and northwestern Indiana, including much of Chicagoland and the Milwaukee metro area.
- Numerous daily record lows for Jan. 30 were set from the Midwest into parts of the Northeast.
- **Minus 49 degrees** was reported west of Rugby, North Dakota, Wednesday morning, Jan. 30. Lake Metigoshe State Park plunged to minus 46 degrees.
- **Minus 20 degrees** in Des Moines, Iowa, Wednesday, Jan. 30, was its first temperature in the minus 20s since Feb. 4, 1996.
- **Minus 26 degrees** Monday morning, Jan. 28, at the National Weather Service office outside of Marquette, Michigan, smashed a daily record low set in 2014.
- **A minus-82-degree wind chill** was observed Monday, Jan. 28, in northern Manitoba and southern Nunavut, Canada, according to the National Weather Service.
- **Minus 46 degrees** Sunday morning, Jan. 27, in International Falls, Minnesota, set a daily record low. This also tied as the fifth-coldest temperature on record there for any day of the year.
- **Minus 23 degrees** in Madison, Wisconsin, Saturday, Jan. 26, was the coldest morning there since Feb. 3, 1996. Madison was even colder Wednesday, Jan. 27, and Thursday, Jan. 28, when the low fell to minus 26 degrees.

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Ice flows fill the Merrimack River as it heads towards the Atlantic Ocean in Newburyport, Massachusetts during the extreme cold temperatures caused by the Polar Vortex, bringing temperatures below freezing, on Jan. 31, 2019. (Joseph Prezioso/AFP/Getty Images)

The Weather Company's primary journalistic mission is to report on breaking weather news, the environment and the importance of science to our lives. This story does not necessarily represent the position of our parent company, IBM.

Rebuttal Exhibit WSS-4

Mathematical Equivalency Between

Net Cost Rate Base and Lead-Lag Results

The following shows the mathematical equivalency between (i) the net book value of an asset included in rate base and (ii) an equivalent cash-working capital related to capital expenditures related to the asset using lead-lags. This proof assumes that the average service life (ASL) of the property is equal to the depreciable life of the asset. The proof also assumes a net salvage value of zero. A proof could also be constructed using a survivor curve (i.e., probability dispersion function such as an Iowa Curve) for the property, but the results would be the same; however, advanced calculus or numerical integration techniques would be required to integrate the survivor curve over the remaining life of the asset. The following example demonstrates the equivalency net book value amount and the equivalent cash working capital amount for an asset using simple algebra rather than calculus.

Let:

NBV represents the net book value included in rate base

OC represents the up-front capital expenditure (of Original Cost) of some utility property;

SL represents the average service life (ASL) and depreciable life of the property

CY represents the current year

ECWC represents the equivalent cash working cash working capital amount using lead-lag

Net Book Value Included in Rate Base

For a current year (***CY***), the net book value (***NBV***) for utility property is determined as follows:

$$NBV = OC - CY\ x\ \left(\frac{OC}{SL}\right)$$

$$= OC\ \left(1 - \frac{CY}{SL}\right)$$

Equivalent cash working capital

ECWC related to the capital expenditures for the utility property is calculated using expense lags (i.e. negative expense leads) as follows. In developing the following formula, it is assumed that a calendar year consists of 365 days (i.e., leap years are ignored). ECWC is determined as follows by multiplying (1) the up-front expenditures incurred for the asset (i.e., the OC of the asset) per day over the service life of the asset by (2) the lag days for depreciation for the remaining service life of the asset:

$$ECWC = \frac{OC}{365\ x\ SL}(SL\ x\ 365 - 365\ x\ CY)$$

By cancelling out the number of days during the year (i.e. 365) and rearranging terms (i.e., bringing SL inside the parenthesis) we have:

$$ECWC = \frac{OC}{SL}(SL\ - CY)$$

$$= OC\ \left(1\ - \frac{CY}{SL}\right)$$

Conclusion

As shown above, the equivalent cash working capital amount (ECWC) calculated for the capital expenditures of an asset equals the net book value of the asset. Therefore, by including net utility plant in rate base, the cash working capital for depreciation has been fully accounted. Because net utility plant accounts for the expense lags via depreciation expense, it is appropriate to assume zero days for the expense lags in the lead-lag study. But assuming zero expense lags in the lead-lag study does not mean that expense lags for depreciation expense are not accounted. Expense lags for depreciation expenses are simply captured another way – viz., by including net plant in rate base. Therefore, because depreciation and pension expense lags are captured just like any other expense, it is appropriate to include revenue lags for these accruals.

Rebuttal Exhibit WSS-5

KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information Dated November 13, 2018

Case No. 2018-00294

Question No. 20

Responding Witness: William Steven Seelye

Q-20. Refer to the Seelye Testimony, pages 102-103. Here, Mr. Seelye explains that the cash working capital methodology proposed by KU, in this case, is the same Lead/Lag methodology approved by the Virginia State Corporation Commission.

a. Provide a comparative analysis between the Lead/Lag methodology proposed by KU in this proceeding to the methodology proposed by Atmos in Case No. 2015-00343.[1] Include in this analysis detailed explanations for any differences between the two methodologies.

b. Provide a comparative analysis between the Lead/Lag methodology proposed by KU in this proceeding to the methodology proposed by Kentucky-American Water and accepted by the Commission in Case No. 2012-00520.[2] Include in this analysis detailed explanations for any differences between the two methodologies.

A-20.

a. Based on a review of the testimony and workpapers filed by Atmos in Case No. 2015-00343, it does not appear that a lead-lag study was submitted in that proceeding. Attachment 1 of Atmos's Filing Requirement (FR_16(8)(b), Attachment 1) indicates that the 1/8th O&M Method for Cash Working Capital was utilized. The Companies reviewed workpapers and responses to data requests submitted by Atmos in Case No. 2015-00343 and could not find where Atmos had submitted a lead-lag study.

In his testimony filed in Case No. 2015-00343, Atmos's witness Gregory K. Waller states: "The components of rate base are: net plant in service, construction work in progress, cash working capital calculated using the 1/8 O&M expense method, plus an allowance for other working capital items consisting of materials and supplies, gas stored underground, and prepayments,

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[1] Case No. 2015-00343, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC Aug. 4, 2016).
[2] Case No. 2012-00520, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Oct. 25, 2013).

less customer advances for construction and deferred income taxes." (Testimony of Gregory K. Waller, at p. 7.)

b. The Companies reviewed the testimony, exhibits and responses to data requests filed by Kentucky-American Water Company ("KY-Amer") in Case No. 2012-00520 supporting its lead-lag study. Based on the information that was filed by KY-Amer, the Companies could only perform a high-level review of KY-Amer's lead-lag study. However, the methodology for calculating expense lead days, as supported by Exhibit 37, Schedule B-5.2 of KY-Amer's Filing Requirement, and as described in the Direct Testimony submitted by Linda C. Bridwell, generally appears to be the same as used by the Company. Specifically, Schedule B-5.2 breaks out the expense categories similarly to KU and LG&E. Also, similar to LG&E and KU, KY-Amer assumed zero lead days for accrual items such as depreciation expenses, amortization expenses, and deferred income taxes. The methodology for calculating revenue lag days also appears to be similar. Differences the Companies observed are potential lead-lag day differences for pension and OPEB, uncollectibles, and net income. The Companies included working capital for pension and OPEB as a balance sheet item in rate base (see Schedule B-5.2 filed with the Companies' Application). The Companies included uncollectibles expense in the determination of lead-lag results but did not include net income in the determination of lead-lag results. Also, the Companies included pass-through items, (i.e., school tax, sales tax, and franchise fees) in their lead-lag studies; however, KY-Amer did not appear to include these pass-through items in its lead-lag study.

Rebuttal Exhibit WSS-6

KENTUCKY UTILITIES COMPANY

February 21, 2019 Supplemental Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00294

Question No. 59

Responding Witness: William Steven Seelye

Q-59. Schedule B-5.1 reports the inclusion of Fuel Stock, Gas Stored Underground, Materials and Supplies, and Prepayments under Other Working Capital Allowances on Schedule B-1. Have the test period operating expenses associated with these items been removed from cash working capital determined under the lead-lag method on Schedule B-5.2?

a. If the response is in the affirmative, explain why there are lagged expenses related to Fuel, Non-Fuel Commodities, Purchased Power, and Purchased Gas in cash working capital, as computed under the lead-lag method.

b. If the response is in the negative,

i. Explain why not removing the related expense from cash working capital under the lead-lag method does not lead to double counting in rate base?

ii. Provide the related expense reflected in each lagged item on Schedule B-5.2 for the forecast test year.

A-59. **Original Response:**
No.

a. Not applicable.

b.

i. Removing these expense items from the analysis of expense leads would increase cash working capital. For example, for coal expenditures the expense lead was determined as the difference between the time the coal is recorded in inventory and when the payment for the coal clears the Company's bank account. This difference results in positive expense lead days, which reduces cash working capital. Schedule B-5.1 includes inventory and prepayment amounts for which the Company incurs carrying costs until expensed in connection with providing service to customers. Therefore, there is no double counting in rate base because the cash working capital determined from the expense lead calculation in the lead/lag study and the prepayment or inventory items included in rate base measure two different and off-setting timing differences.

ii. Fuel and gas expenses are separately identified on Schedule B-5.2. Information is not readily available to determine the expense amounts attributable to Prepayments and Materials and Supplies.

February 21, 2019 Supplemental Response:

No, except for prepayments. Rate base prepayments were not included in the determination of expense lead days in the lead-lag study.

a. Not applicable.

b.

i. Removing these expense items from the analysis of expense leads would increase cash working capital. For example, for coal expenditures the expense lead was determined as the difference between the time the coal is recorded in inventory and when the payment for the coal clears the Company's bank account. This difference results in positive expense lead days, which reduces cash working capital. Schedule B-5.1 includes inventory and prepayment amounts for which the Company incurs carrying costs until expensed in connection with providing service to customers. Therefore, there is no double counting in rate base because the cash working capital determined from the expense lead calculation in the lead/lag study and the prepayment or inventory items included in rate base measure two different and off-setting timing differences.

ii. Fuel and gas expenses are separately identified on Schedule B-5.2. Information is not readily available to determine the expense amounts attributable to Prepayments and Materials and Supplies.