COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	**))))**	**CASE NO. 2021-00393**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY TO
THE COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION
DATED MARCH 3, 2022

FILED: MARCH 25, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)

COUNTY OF JEFFERSON)

The undersigned, **Christopher D. Balmer**, being duly sworn, deposes and says that he is Director – Transmission Strategy and Planning for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Chr D Balmer

Christopher D. Balmer

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

J K Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 22nd day of March 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 1

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-1. Refer to LG&E/KU's response to Commission Staff's First Request for Information (Staff's First Request), Item 9.

a. Provide current industry estimates of carbon prices.

b. Assuming a carbon tax is implemented as the vehicle to limit carbon emitted into the atmosphere and using a $15 per ton and a $25 per ton carbon price, provide an update to the sensitivity of the preferred generation portfolio with carbon taxed at each of those prices and explain how, if at all, the preferred generation mix changes.

A-1.

a. The two largest CO_2 markets in the U.S. are the Regional Greenhouse Gas Initiative ("RGGI") and the California carbon market. Each has their own unique market structures and objectives. Recent prices for an allowance in RGGI have been approximately $13/ton and in California they have been in the mid-$20/ton range.

b. The table below shows a comparison of the optimal generation portfolios in the Base Load, Base Fuel scenario for the specified CO_2 prices. All portfolios were developed to serve energy requirements in 2035. NGCC is assumed to require CCS in the first set of portfolios; CCS is not required in the second set of portfolios. The Companies' CO_2 emissions in 2021 were approximately 29.8 million short tons. With no changes in the generation portfolio or dispatch, a $15/ton and $25/ton CO_2 price would increase costs to customers by $447 and $746 million per year, respectively. Therefore, in addition to the assumed unit retirements in Table 5-4 on page 5-18 of Volume I, the analysis evaluated other coal retirements as a means of lowering costs. Additional coal retirements do not lower costs in the scenarios with no CO_2 price.

In the scenario where NGCC requires CCS and there is no CO_2 price, SCCTs are added as replacement capacity for the assumed unit retirements, solar at $28.05/MWh is added to serve a portion of energy requirements during the day, and existing coal and NGCC units serve nighttime and the remaining daytime energy requirements. Introducing a CO_2 price of $15/ton to $25/ton results in significantly more solar and wind generation, additional coal retirements, and a shift from SCCTs to battery storage. With a $15/ton CO_2 price, battery storage is added for capacity throughout the year and to deliver renewable energy to load primarily at night in the summer and shoulder months. With a $25/ton CO_2 price, the high cost of NGCC with CCS is warranted for additional CO_2 reductions throughout the day.

Optimal Portfolios by Carbon Price (Base Load, Base Fuel Prices)

	NGCC Requires CCS			**NGCC Does Not Require CCS**		
CO_2 Price ($/short ton)	**$0**	**$15**	**$25**	**$0**	**$15**	**$25**
Additional Coal Retirements[1]	None	MC3	MC3; GH3-4	None	MC3-4; GH3-4	MC3-4; GH3-4
NGCC w/o CCS MW	N/A	N/A	N/A	1,539	3,078	3,078
NGCC w/ CCS MW	0	0	513	0	0	0
SCCT MW	1,320	0	440	0	0	0
Solar MW	2,100	4,100	3,900	0	2,900	3,600
Wind MW	0	1,200	1,900	0	0	0
Battery Storage MW	200	1,700	1,400	100	300	300

In the scenario where NGCC does not require CCS and there is no CO_2 price, NGCC is added without solar to replace the capacity and energy from the assumed unit retirements.[2] With a $3.60/mmBtu natural gas price, the cost of energy from a NGCC unit is approximately $23/MWh and lower than the assumed cost of solar. Introducing a CO_2 price of $15/ton to $25/ton results in the replacement of more coal with NGCC and the addition of solar. With these CO_2 and fuel prices, NGCC is lower cost than renewables and battery storage for serving nighttime energy requirements. Solar is added with these CO_2 prices to help serve daytime energy requirements.

The table below compares total CO_2 emissions and revenue requirements in 2035 for these cases. Revenue requirements reflect capital costs for constructing new units as well as variable and fixed costs for new and existing units. With no CO_2 price, 2035 revenue requirements in the scenario where NGCC requires CCS are not materially different than in the scenario where CCS is not required. However, CO_2 emissions are approximately 7% lower when CCS is not required (20.1 million short tons versus 21.5 million short tons); in the base fuel price scenario, NGCC units serve nighttime energy requirements that would otherwise be served by existing coal units with higher CO_2 emissions.

[1] All cases include the assumed unit retirements in Table 5-4 on page 5-18 of Volume I.
[2] A small amount of battery storage is added by the model to meet reserve margin constraints.

CO_2 Emissions and Revenue Requirements (Base Load, Base Fuel Price)

	NGCC Requires CCS			NGCC Does Not Require CCS		
CO_2 Price ($/short ton)	**$0**	**$15**	**$25**	**$0**	**$15**	**$25**
CO_2 Emissions (million short tons)	21.5	14.0	8.8	20.1	8.7	8.0
Revenue Requirements ($M)	1,499	1,831	2,058	1,496	1,749	1,835

A CO_2 price adds significant costs to customers. But perhaps counterintuitively, the impact of a CO_2 price on revenue requirements is smaller and total CO_2 emissions are lower when CCS is *not* required for NGCC. With a 60% lower CO_2 emissions rate than coal, NGCC without CCS is a cost-effective resource for reducing CO_2 emissions, particularly at night. In the scenario where CCS is required and the CO_2 price is $15/ton, serving a significant portion of nighttime energy requirements with coal continues to be least-cost due to the high cost of serving nighttime energy requirements with renewables and battery storage. When CCS is not required, 2035 revenue requirements are $252 million to $339 million higher. When CCS is required, 2035 revenue requirements are $332 million to $559 million higher.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 2

Responding Witness: Stuart A. Wilson

Q-2. Refer to LG&E/KU's response to Staff's First Request, Item 26e.

a. Confirm that the inclusion of Carbon Capture and Sequestration (CCS) for Natural Gas Combined Cycle (NGCC) units necessarily assumes that there will be a cost to emitting carbon or a mandate to limit carbon emissions because it would not be economical to include CCS for NGCC units if there is no cost or mandate and if LG&E/KU are not able to confirm, explain why they are not able to confirm.

b. If it is plausible to assume that CCS will be applied to NGCC units, explain why Simple Cycle Combustion Turbine (SCCT) units should not have been modeled with CCS for consistent application of assumptions.

c. Provide an update to the table provided in the response to Staff's First Request, Item 26h showing SCCT with CCS.

A-2.

a. The assumption regarding CCS for NGCC units relates only to new units. All new generation units are subject to New Source Performance Standards for selected emissions including CO_2. There has been discussion in the industry that the EPA is considering tightening CO_2 emission limits for new NGCCs that would have the effect of requiring CCS. This is the same approach that the EPA used to set NSPS CO_2 emissions standards for new coal-fired generation. Such an approach would not require a "cost or mandate" for emitting or reducing CO_2 emissions generally.

b. See the response to part a. The Companies assumed the NSPS would pertain only to NGCC units. This assumption is consistent with the lack of costs for a SCCT with CCS in NREL's 2021 ATB.[3]

[3] National Renewable Energy Laboratory, *2021 Annual Technology Baseline*, https://atb.nrel.gov/electricity/2021/fossil_energy_technologies

c. See the response to part b. The Companies do not have any information concerning the costs of CCS for SCCT.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 3

Responding Witness: Stuart A. Wilson

Q-3. Refer LG&E/KU's response to Staff's First Request, Item 26h indicating that NGCC without CCS is significantly less expensive per kW than either SCCT without CCS or NGCC with CCS. Refer also to the Integrated Resource Plan (IRP), Volume I, Section 5, Plan Summary, page 43, Table 5-19. Provide an update to Table 5-19 that includes NGCC without CCS as a potential generation resource and explain the resulting changes in the least cost portfolios.

A-3. See the updated table below.

Table 0-1:
New Generation in Least-Cost Resource Plan Summary, With NGCC without CCS

Years	Load Scenario	Fuel Price Scenario	Gas*	Solar	Wind	Batteries
2026-2030	Base	Base	1 NGCC	0 MW	0 MW	0 MW
		High	1 NGCC	1,000 MW	0 MW	0 MW
		Low	1 NGCC	0 MW	0 MW	0 MW
	High	Base	3 NGCC	0 MW	0 MW	0 MW
		High	3 NGCC	1,500 MW	0 MW	0 MW
		Low	3 NGCC	0 MW	0 MW	0 MW
	Low	Base	0	0 MW	0 MW	0 MW
		High	0	1,000 MW	0 MW	0 MW
		Low	0	0 MW	0 MW	0 MW
2031-2036	Base	Base	2 NGCC	0 MW	0 MW	100 MW
		High	1 SCCT	2,300 MW	0 MW	900 MW
		Low	2 NGCC	0 MW	0 MW	100 MW
	High	Base	2 NGCC	0 MW	100 MW	1,400 MW
		High	0	2,800 MW	0 MW	2,500 MW
		Low	5 NGCC	0 MW	0 MW	0 MW
	Low	Base	2 NGCC	0 MW	100 MW	100 MW
		High	1 NGCC	1,300 MW	200 MW	600 MW
		Low	2 NGCC	0 MW	100 MW	100 MW

* 1 NGCC unit = 513 MW. 1 SCCT = 220 MW.

When CCS is not required for NGCC, the least-cost portfolio in the reference case (base load, base fuel price) includes one NGCC unit in 2028, two NGCC units in 2034, and 100 MW of batteries in 2036.[4] Across the scenarios, NGCC units are generally chosen instead of SCCTs. As noted in the response to Question No. 1b, the energy cost for an NGCC is lower than the cost of solar in the base fuel price scenario. But this is not the case in the high fuel price scenario, which continues to include significant amounts of solar to lower energy costs. Wind continues to be included in the 2031-2036 period in some scenarios. Batteries are included only in the 2031-2036 period but in generally smaller amounts compared to the results when NGCC without CCS is not allowed.

It is important to note that the IRP is not a commitment to pursue a particular capacity addition approach; rather, it is a forward-looking analysis based on numerous assumptions that attempts to minimize the cost of serving projected load under various scenarios. In practice, the Companies will continue to seek to safely and reliably serve their customers at the lowest reasonable cost, including adding renewable capacity to the extent it results in safe, reliable, and economical service.

[4] The original reference case included 6 SCCTs, 2,100 MW of solar, and 200 MW of batteries.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 4

Responding Witness: Christopher D. Balmer / Stuart A. Wilson

Q-4. Refer to the IRP, RTO Membership Analysis, Introduction, pages 8–9 and the IRP, Volume I, Section 5, page 43, Table 5-19. LG&E/KU state in the Introduction that they "do not recommend RTO membership at this time," however they also later state in part "[a]t the same time, being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology, as RTO membership may support higher levels of renewable penetration with lower integration costs."

a. Explain this statement more fully and provide more detail, including specifically the timeline referred to, the actual penetration levels of renewable resources at which LG&E/KU see potential benefits from Regional Transmission Organization (RTO) membership, and the percentage of intermittent resources assumed in both the companies and the nation's future generation resource mix.

b. Table 5-19 indicates significantly higher levels of renewable resources are the least-cost resource under many of the scenarios modeled. Explain potential benefits from RTO membership in light of this forecast.

c. State whether LG&E/KU agrees that current federal policy, other state renewable portfolio standards or mandates, and corporate sustainability goals generally point toward the nation's future generation including more intermittent renewable technology, and explain the basis for LG&E/KU's response.

A-4.

a. RTO membership may be beneficial if the level of intermittent resources is such that intra-hour balancing in a larger RTO footprint is needed to reliably integrate the intermittent resources. According to 2019 study by Wood Mackenzie, at annual renewable energy penetrations greater than 25 percent, operational and cost complexities progressively multiply, in large part due to the intermittent nature of renewables.[5] Four IRP cases contain renewable penetrations greater than 25 percent, but not until late in the IRP analysis period. The table below contains the percentage of intermittent resources in each of the IRP cases. The IRP does not contemplate the level of intermittent resources in the nation's generation resource mix.

IRP Case		**Intermittent Energy (% of Total Energy)**
Load Scenario	**Fuel Price Scenario**	
Base	Base	19%
	High	31%
	Low	6%
High	Base	28%
	High	39%
	Low	10%
Low	Base	15%
	High	26%
	Low	4%

b. See the response to part a.

c. Statements and actions of the Biden Administration indicate a policy that would require increasing volumes of non-CO_2 emitting generation. Currently, wind and solar generation (which are intermittent) are the dominant non-CO_2 emitting generation technologies.

[5] http://www.decarbonisation.think.woodmac.com/.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 5

Responding Witness: Stuart A. Wilson

Q-5. Refer to the IRP, Volume I, Section 8, Resource Assessment and Acquisition Plan, page 1, Table 8-1 showing that LG&E/KU's expected reserve margin for summer peak demand for 2034 to 2036 ranges from 44.9 to 47.8 percent. Refer also to LG&E/KU's response to Louisville/Jefferson County Metro Government's First Request for Information, Item 10 in which LG&E explains that this is due to the addition of significant solar generation and the need to maintain minimum generation during the winter where the expected reserve margins for the same period are much lower. Refer also to the IRP, Volume III, 2021 IRP Reserve Margin Analysis (RMA), pages 27-35.

a. Explain whether LG&E/KU's RTO analysis specifically takes into account that PJM Interconnection LLC (PJM) is summer peaking and LG&E/KU can be a winter peaking utility, including LG&E/KU's ability to sell excess summer capacity into wholesale markets to offset costs if LG&E/KU have a winter peak.

b. Explain how LG&E/KU factored the ability to sell excess capacity and energy/ancillary services, especially during the summer, into the respective wholesale markets into their RTO analysis and ultimate recommendation not to seek RTO membership.

c. Refer to the IRP, Volume I, Section 8, page 18, Table 8-11, which shows LG&E/KU's projected capacity purchases from non-utility sources.

(1) Explain whether LG&E/KU currently attempts to sell excess capacity into wholesale markets, or may do so in the future even if not an RTO member.

(2) Explain why it would not be beneficial to be an RTO member when LG&E/KU predicts they will become a net purchaser of capacity after 2028.

A-5.

a. Yes. As noted in Section 8.1.2 of the *2021 RTO Membership Analysis*, the analysis of the Companies' capacity position in PJM's capacity market included an adjustment for the expected peak load diversity between the Companies and PJM, as specified by PJM. But it is uncertain how the relationship between the Companies' and PJM's peaks may change over time. The analysis resulted in the PJM capacity market benefits shown in the tables in Appendix B, pp. 48-49, of the study. Note that the stated summer reserve margins assume 79% of the nameplate solar capacity will be available throughout the peak hour. As discussed in the response to Louisville Metro 1-10, this assumption is uncertain.

b. Capacity is an annual product. If the Companies join an RTO, they will seek to sell all available capacity and energy into the capacity market to maximize the benefit to customers. See Sections 8.1 and 8.2 of the *2021 RTO Membership Analysis*. The analysis resulted in the energy and capacity market benefits shown in the tables in Appendix B of the study. These tables demonstrate, when accounting for all the expected costs and benefits of joining an RTO, the potential capacity and energy market benefits are not enough to outweigh the potential costs for the Companies to recommend RTO membership at this time.

   But it is important to note that if the Companies joined an RTO, their generating fleet would change over time to adapt to the RTO's market and its rules, which also are likely to change over time. Therefore, it is unlikely that any revenues from selling "excess" capacity and energy into an RTO market would persist; rather, they should diminish and ideally decline to zero over time.

   Moreover, strictly speaking, the concept of "excess" capacity and energy becomes practically meaningless in an RTO. If the Companies joined an RTO, their overarching objective would not change—i.e., they would continue to seek to serve customers safely and reliably at the lowest reasonable cost—but the means by which the Companies would meet that objective would fundamentally change. The Companies would serve load by paying RTO market prices at their load node(s), and they would seek to maximize RTO market returns on their generating assets to offset costs to serve load. Thus, for all practical purposes, the size and composition of a load-serving RTO member's generating fleet relative to its native load customers' demand and energy usage has no meaning or import; "excess" capacity and energy become meaningless concepts for all practical purposes. Also, as noted above, the longer a load-serving entity is an RTO member, the more disconnected its generating fleet is likely to become relative to its native load customers' demand and energy usage precisely because the overall RTO, not the load-serving entity, supplies customers' needs, and the goal of a load-serving entity's generation planning in an RTO is maximizing market returns, not directly serving customers.

c.

(1) The Companies do not currently sell capacity into wholesale markets and do not currently have plans to do so. FERC rules require the Companies to un-designate the network transmission service for capacity currently serving native load if that capacity is sold into an RTO market. Therefore, the capacity would no longer be available to serve the Companies' customers, which is a significant downside to selling capacity into an RTO market.

(2) The Companies have not concluded that RTO membership would or would not be beneficial after 2028. Section 10 of the *2021 RTO Membership Analysis* discusses the long-term considerations the Companies will need to evaluate in a future decision regarding RTO membership.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 6

Responding Witness: Stuart A. Wilson

Q-6. Refer to the IRP, Volume III, RTO Membership Analysis, page 9, which states: "But as the industry transitions to cleaner energy resources, RTO membership may present the best path for integrating high levels of renewable penetration if necessary changes are achieved by the RTOs to address potential shortfalls in capacity and energy adequacy and reliability." Explain the necessary changes LG&E/KU are referring to for both Midcontinent Independent System Operator (MISO) and PJM

A-6. MISO, in its 2021 *Renewable Integration Impact Assessment*,[6] said it is preparing for an unprecedented pace of change to accommodate increased penetration of renewables. The market rules and tariffs for accomplishing the following changes are yet to be determined.

- A combination of existing and emerging transmission technologies and operational and market changes are needed to maintain grid stability with higher penetration of renewables.
- Increased flexibility and innovation in transmission planning are needed to accommodate a shift in periods of high transmission system stress from peak load times to peak renewable resource times.
- Improved mechanisms to identify localized resource adequacy issues and the availability and transmissibility of energy from traditional resources to respond are needed to address a trend of shifting times of peak power demand to periods when renewable resources are often less available (summer evenings and winter mornings).
- Flexible resources need to be incentivized more to accommodate system ramping needs and intermittent generation resulting from renewable resource patterns.
- Additional transmission is needed to deliver renewable energy to load centers.

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[6] *MISO's Renewable Integration Impact Assessment (RIAA),* February 2021. See https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

PJM, in its 2021 *Energy Transition in PJM: Frameworks for Analysis*,[7] came to similar conclusions, noting the need for

- improvements to evaluating the capacity contribution of renewables,
- new market incentives for resource flexibility,
- thermal generators to support reliability,
- transmission expansion and grid-enhancing technologies, and
- improved reliability standards, especially for distributed energy resources.

[7] See the attachment provided in response to SREA 1-18(j).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 7

Responding Witness: Stuart A. Wilson

Q-7. Refer to the IRP, RTO Membership Analysis, page 14, which states: "However, as more companies lean on the RTOs to integrate increasing levels of renewables and replace dispatchable generation, reliably meeting customers' energy needs at every moment has the potential to become unsustainable. Furthermore, the RTOs themselves have considered ways to reduce CO2, including carbon pricing, in the absence of national CO2 regulations. Achieving CO2 reductions with new renewables, especially wind resources, will likely require significant transmission investments to move the power from areas with high generation resources to load centers. Depending on these and other variables, it could be more cost-effective for the Companies to be on their own transition path rather than that of the RTOs."

a. Explain whether LG&E/KU has begun planning an independent transition path to renewables in order to compare the net benefit of remaining independent against the cost of RTO membership.

b. Explain whether LG&E/KU have used a carbon price in any of their analyses in order to compare the net benefit of remaining independent against the cost of RTO membership.

A-7.

a. The Companies are continually contemplating the replacement of their existing generating units as they retire, including the potential addition of renewables as well as gas-fired resources, all of which are options for transitioning to lower CO_2 emissions. This planning will continue to occur in parallel with evaluating the potential for RTO membership to be part of the lowest reasonable cost long-term plan to provide safe and reliable power to customers.

b. The Companies did not use a carbon price in the RTO analysis. Assuming the carbon price was applicable both inside and outside an RTO, the Companies do not anticipate that it would have a meaningful impact on the overall analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 8

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-8. Refer to the IRP, Volume III, RTO Membership Analysis, page 21. Explain why LG&E/KU used forecasts for market energy prices at the companies' interfaces with MISO and PJM instead of using generator-specific or load zone-specific Locational Marginal Pricing models.

A-8. The RTO study was a high-level screening analysis to determine if it was warranted for the Companies to pursue RTO membership at this time. It is important to remember that Locational Marginal Prices will be equal across an RTO footprint absent transmission congestion. Because the Companies' transmission system is designed and built to enable energy to flow from its own generators to its own load, there are very few congestion events that require redispatch of the Companies' generation units.[8] Thus, from an analytical perspective, representing PJM and MISO wholesale energy prices as an external market to the Companies' system should not result in a materially different conclusion from a full-blown RTO detailed model regarding the energy market implications of operating inside or outside an RTO.

Finally, the cost-benefit approach in the RTO Membership Analysis, particularly the energy market modelling methodology, is consistent with that used by the Companies in Case No. 2003-00266 (MISO membership investigation). In that case, the Commission stated, "Based on a review of the cost-benefit analysis and their underlying assumptions, the Commission finds the LG&E and KU analysis to be based on assumptions and inputs that are more reasonable than those incorporated by MISO's analysis."[9] The Commission further stated that "the LG&E and KU analysis is more credible and it provides a more reasonable indication of the likely outcome of exiting MISO and pursuing the TORC option."[10]

[8] Note that transmission system congestion management in an RTO is generally accomplished through changing Locational Marginal Prices (non-zero congestion component) rather than through re-dispatch.
[9] Commission order in Case No. 2003-00266, page 16, May 31, 2006.
[10] Ibid, page 17.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 9

Responding Witness: David S. Sinclair

Q-9. Refer to the IRP, Volume III, RTO Membership Analysis, pages 21–22.

a. Explain why the analysis does not incorporate any optimization of a hedging strategy against market energy and capacity risk of RTO membership relative to the LG&E/KU's assumed capacity need beginning in 2028.

b. Explain whether the ability to sufficiently mitigate the market energy and capacity risk to customers is an essential component in the LG&E/KU's determination of whether joining an RTO is net beneficial.

A-9.

a. The development of an optimal capacity and energy market hedging strategy will depend heavily on two factors: future price volatility and future market rules and tariffs of the RTO. Given the screening nature of the Companies' RTO analysis and the inherent uncertainty about future price and market rules and tariffs so far into the future, it was not deemed feasible to prepare a credible hedging plan.

b. Consistent with past RTO cost-benefit analysis, a significant component will focus on forecasted capacity and energy costs inside and outside the RTO. The approaches and methods to procure the necessary capacity and energy to serve customers is different inside and outside an RTO. Outside an RTO, the focus is on physical assets to serve load in real time while the focus inside an RTO is more on market rule and tariff compliance and LMP risk management, which can include physical assets as well as financial instruments. The Companies anticipate that the Commission would expect them to attempt to manage RTO market risks consistent with the practices currently employed by other jurisdictional utilities.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information

Dated March 3, 2022

Case No. 2021-00393

Question No. 10

Responding Witness: Christopher D. Balmer / Stuart A. Wilson

Q-10. Refer to the IRP, Volume III, RTO Membership Analysis, pages 32–35.

a. Explain how LG&E/KU would conduct an analysis using a complete RTO-wide regional market model to determine expected energy market benefits and cost which they explained would be advisable prior to deciding whether to join an RTO rather than their own models.

b. Explain whether LG&E/KU considered conducting an RTO-wide regional market model as part of this RTO analysis, and why it decided not to do so.

c. Explain when and under what circumstances LG&E/KU would seek to conduct this analysis, and state whether they would only do so when they are seriously considering joining an RTO.

d. Explain how LG&E/KU could know definitively whether joining an RTO would be net beneficial without having conducted this analysis.

A-10.

a. Important outputs of any dispatch-related analysis of a market region are prices and generator volumes that result from that system meeting a specific load in an hour. For the Companies' own "market region," they have a detailed representation of each generating unit and transmission constraints and use the software products PROSYM and Plexos to determine the generator volumes necessary to serve their load. Because market prices in an RTO are generally the cost of the highest unit that cleared to serve load (assuming units offer into the market at cost, which is what is generally the optimal market participant behavior), these same models can be used to determine the market price inside the Companies' market region. In the Companies' RTO analysis, they engaged a third party to provide electricity price forecasts for the RTOs adjacent to LG&E and KU. The third-party models have a more detailed representation of generation and load in those RTOs, which they use to calculate forecasts of electricity prices. These forecasts of RTO electricity prices are then inputs to the Companies' dispatch models to be used to determine off-system sales and purchases. As long as the potential transmission volume between the Companies' "market region" and the RTO "market region" are reasonably represented inside and outside an RTO, there should be no material difference in the Companies' generation volumes and energy market prices using a single RTO model or the regional dual market approach used in the Companies' RTO study.

That notwithstanding, if the Companies' screening analysis indicated that RTO membership appeared to be favorable for customers and greater clarity existed regarding future RTO rules and tariffs, the Companies would consider the pros and cons of developing or engaging a consultant to develop a detailed RTO-wide regional market model, including the addition of the Companies' generation and transmission systems into that RTO.

b. Given the uncertainty regarding future RTO rules and tariffs, the Companies did not consider an RTO-wide study to be cost-effective or necessary at the time. See the response to Question No. 6 and part (a).

c. See the responses to parts (a) and (b).

d. Regardless of the models used, the Companies cannot definitively know whether joining an RTO would be beneficial due to the significant uncertainties involved. Given the large number of market design issues that RTOs are trying to address as part of the clean energy transition, a decision today to join an RTO would likely be based on a preference for operating in an RTO versus serving load in real-time (see the response to Question No. 9) as a standalone utility.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information

Dated March 3, 2022

Case No. 2021-00393

Question No. 11

Responding Witness: Stuart A. Wilson

Q-11. Refer to the IRP, Volume I, Section 8, page 12, Table 8-3. Confirm that the dates in the column titled "Upgrades, Derates, Retirements" on the far right of the table all correspond to planned retirement dates for the specified generation resources. If they are not all retirements, identify and describe the upgrades or derates accordingly.

A-11. Confirmed. See the response to JI 1-25(a).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILTIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 12

Responding Witness: Stuart A. Wilson / John K. Wolfe

Q-12. Refer to the IRP, Volume I, Section 8, pages 9-8, wherein discussing distributed energy resources, LG&E/KU state: "The contribution of all connected load and distributed energy resources are currently included in load forecasts at the distribution substation transformer level. These forecasts, along with other key system information, are used to develop a joint ten-year plan for major capacity enhancements necessary to address load growth and improve system performance."

a. Explain whether this joint ten-year plan for major capacity enhancements is included in this IRP and if so identify where. If not, provide such a plan.

b. Quantify the current total amount of distributed energy resources (DER) within the LG&E/KU service areas.

c. Describe the projected timeline of the DER interconnection portal and projected cost savings.

d. Discuss the relative benefits or detriments of being part of an RTO in regards to the imminent proliferation of DER aggregations and the management of the processes which will be necessary to interface with aggregators, DERs, and the Commission versus staying independent and managing these processes in house.

A-12.

a. A 10-year non-coincidental forecast is used to develop a 5 year business plan for EDO major capacity enhancements. This 10-year forecast is based on recent peak loads and does include any DER that is connected to the distribution system. The 2021 EDO business plan can be found in attachment (PSC DR2 LGE KU Attach 1 to Q12 – 2021 BP.xls). Additionally, copies of the 10 year non-coincidental load forecast for LG&E and KU are included in attachments (PSC DR2 LGE KU Attach 2 to Q12 – LGE Forecast.xls) and (PSC DR2 LGE KU Attach 3 to Q12 – KU Forecast.xls), respectively.

b. As of March 8, 2022 the Companies have 2,153 customers with 25.74 MW (AC) of total distributed generation capacity connected system-wide. Of this total, LG&E has 949 customers with 9.75 MW and KU/ODP has 1,204 customers with 15.99 MW. There is also 0.98 MW of connected distributed energy storage assets on the electric distribution system. These totals do not include the Companies' own facilities (10 MW solar at E.W. Brown, 2 MW solar at Simpsonville Solar Share, and 1 MW battery energy storage at E.W. Brown).

c. The online DER interconnection portal is planned for implementation in 2023. The Companies have not performed a formal cost/benefit analysis. However, based on current and projected trends in DER interconnection applications, the online interconnection portal is expected to drive cost savings by process automation and expedited handling of smaller, simple interconnections. A financial business case is planned prior to portal implementation.

d. It is not clear that DER aggregation is "imminent," particularly in the Companies' service territories. The relevant FERC order, Order No. 2222, applies only to RTOs, not the Companies, and requires them to establish tariff provisions and procedures to allow aggregated DERs to participate in their markets.[11] It appears that it will take RTOs time to comply. For example, PJM has asked FERC to allow PJM's proposed tariff and other changes to accommodate DER aggregation to become effective on February 2, 2026;[12] MISO has not yet made its filing to ask for an integration date for DER aggregations. With regard to the Companies' service territories, the Companies' current retail tariff provisions regarding distributed generators make it unlikely most customers eligible for such service would find it economically advantageous to become part of a DER aggregation even if one were available. Thus, the Companies do not believe DER aggregation is imminent in their service territories.

   That aside and all other things being equal, being in an RTO would tend to increase the likelihood of increased DER aggregation in the Companies' service territories because it would reduce the transmission cost associated with aggregated DERs' transactions in RTO markets. To be clear, that does

[11] Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, FERC Docket No. RM18-9-000, Order No. 2222 (FERC Sept. 17, 2020). *See also* https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.
[12] *PJM Interconnection, L.L.C.*, FERC Docket No. ER22-962-000, Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C. Motion for Extended Comment Period at 2 (Feb. 1, 2022) ("PJM respectfully requests that the Commission grant an effective date of February 2, 2026 for the Tariff, Operating Agreement, and RAA revisions proposed herein.") available at https://www.pjm.com/directory/etariff/FercDockets/6522/20220201-er22-962-000.pdf.

not mean being in an RTO would make DER aggregation likely; rather, it would marginally increase the likelihood. Whether an individual customer would choose to participate in an aggregation would depend on the DER customer's risk tolerance, the retail rate provisions that would otherwise apply (e.g., NMS-1 or NMS-2), the customer's view of the relevant RTO market, and the terms offered by aggregators.

With regard to the management of the processes necessary to interface with aggregators, DERs, and the Commission, it is too early in the development of DER aggregations and their potential participation in RTO markets—the rules for which are still very much under development at the federal level and within RTOs—for the Companies to develop a non-speculative view concerning whether being in an RTO would help or hamper managing such processes versus handling them in-house. The Companies' primary concerns would be to ensure they are able to review and approve interconnections, as well as to ensure that there is metering and information sharing sufficient to ensure that aggregated DER customers receive credit or compensation only once for each kWh they export.

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

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 13

Responding Witness: Christopher D. Balmer / Stuart A. Wilson

Q-13. Refer to the IRP, Volume I, Section 8, pages 9-10. Both MISO and PJM have longstanding delays in their respective generator interconnection queues, with only a small percentage of the projects in each queue likely to be built for various reasons.

a. With the possibility that PJM may implement a two-year pause on accepting new generation projects into its generator interconnection queue, explain whether LG&E/KU have seen or expect to see any substantial change to the number of interconnection requests to its transmission system or costs for network upgrades.

b. Explain whether the possibility for a higher than average number of interconnection requests to LG&E/KU's transmission system was contemplated or specifically modeled in the IRP.

c. Describe the interconnection process to LG&E/KU's transmission system generally, and whether there have been any changes to the process since the last IRP in 2018.

d. Discuss the relative benefits or detriments of being part of an RTO in regards to the generator interconnection queue versus staying independent and managing LG&E/KU's own interconnection queue.

A-13.

a. The Companies, to date, have not seen a substantial change in the number of generator interconnection requests, nor costs for network upgrades, since the PJM announcement of a possible two-year pause on accepting new generator projects into its generator interconnection queue. It is possible that PJM's announcement could lead to additional requests in the Companies' Generator Interconnection (GI) queue.

b. The number of interconnection requests was not contemplated in the IRP.

c. The Companies' interconnection process follows the FERC pro-forma interconnection process (Attachments M and N of the Companies' Open Access Transmission Tariff) and is administered by the Companies' Independent Transmission Organization (ITO). Generally, the sequence of events is the Customer's submission of a GI request, followed by a series of studies performed by the ITO to determine the impact of the requested GI on the LG&E/KU transmission system, and the identification of any interconnection facilities and network upgrades. If the Customer elects to proceed, a Generator Interconnection Agreement is executed. All GI requests are studied in a serial manner. There have been no changes to this process since the last IRP in 2018.

d. From a GI queue perspective, the Companies see neither benefit nor detriment to whether they are in an RTO. The Companies have an ITO that performs administrative duties and required studies similar to an RTO.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information

Dated March 3, 2022

Case No. 2021-00393

Question No. 14

Responding Witness: Stuart A. Wilson

Q-14. Refer to LG&E/KU's Response to Staff's First Request, Item 23. Explain whether limiting battery storage resources and solar and wind resources to 100 MW increments deters the acceptance of any renewable or non-renewable supply resource.

A-14. Particularly for solar and wind, the 100 MW size was assumed as indicative of cost-competitive increments for long-term modeling. The Companies also assumed indicative sizes for SCCT (220 MW) and NGCC (513 MW). Because PLEXOS was used to develop optimal generation portfolios for the end of IRP period and considered all assumed unit retirements in total, smaller battery, solar, or wind capacities would not have materially changed the amount of these resources selected. The actual technology choices will be made on demonstrated need and RFP results presented to the Commission in a CPCN filing.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Commission Staff's Second Request for Information
Dated March 3, 2022

Case No. 2021-00393

Question No. 15

Responding Witness: Christopher D. Balmer / Stuart A. Wilson

Q-15. Refer to the IRP, Volume III, RTO Membership Analysis, page 40, where it states "[f]or RTO membership to be favorable, the expected benefits of joining the RTO should outweigh the expected range of fixed costs consistently over time and in a clear and convincing manner *because it is highly uncertain whether the Companies would be able to exit an RTO a second time*." (Emphasis added). Fully explain the emphasized portion of this statement.

A-15. To the best of the Companies' knowledge, in the almost 20 years since the Commission initiated the investigation into the Companies' MISO membership that ultimately resulted in the Companies' exiting MISO, no other vertically integrated utility has completely exited an operating RTO and returned to operating outside an RTO. It is therefore reasonable to characterize such an event as historically rare.

Moreover, the Companies' exit from MISO required years of litigation and effort at the state and federal levels. Achieving that outcome was not a foregone conclusion.

Therefore, based on the Companies' own experience and the historically rare nature of RTO exits, it is indeed highly uncertain whether the Companies would be able to exit an RTO a second time. It is thus important to ensure there is a high degree of certainty across a range of possible futures that customers would benefit from RTO membership before the Companies again become transmission-owning RTO members.