A Review of Louisville Gas & Electric and Kentucky Utilities’ 2024 Integrated Resource Plan

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On behalf of Sierra Club

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1. SUMMARY

1.1 INTRODUCTION

Energy Futures Group ("EFG") was asked by Sierra Club to perform a review of Louisville Gas and Electric Company and Kentucky Utilities Company's ("KU/LG&E" or the "Companies") 2024 IRP. The review and these comments were prepared by Chelsea Hotaling, Senior Consultant and Anna Sommer, Principal, with technical assistance from Dr. Ryan Quint and Kyle Thomas of Elevate Energy Consulting and from Ranajit Sahu. EFG is a clean energy consulting company focused on integrated resource planning as well as design, implementation, and evaluation of programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. EFG has performed IRP modeling and critically reviewed IRPs in over a dozen states, provinces, and territories. Our IRP and related work is conducted in the states shown in Figure 1.

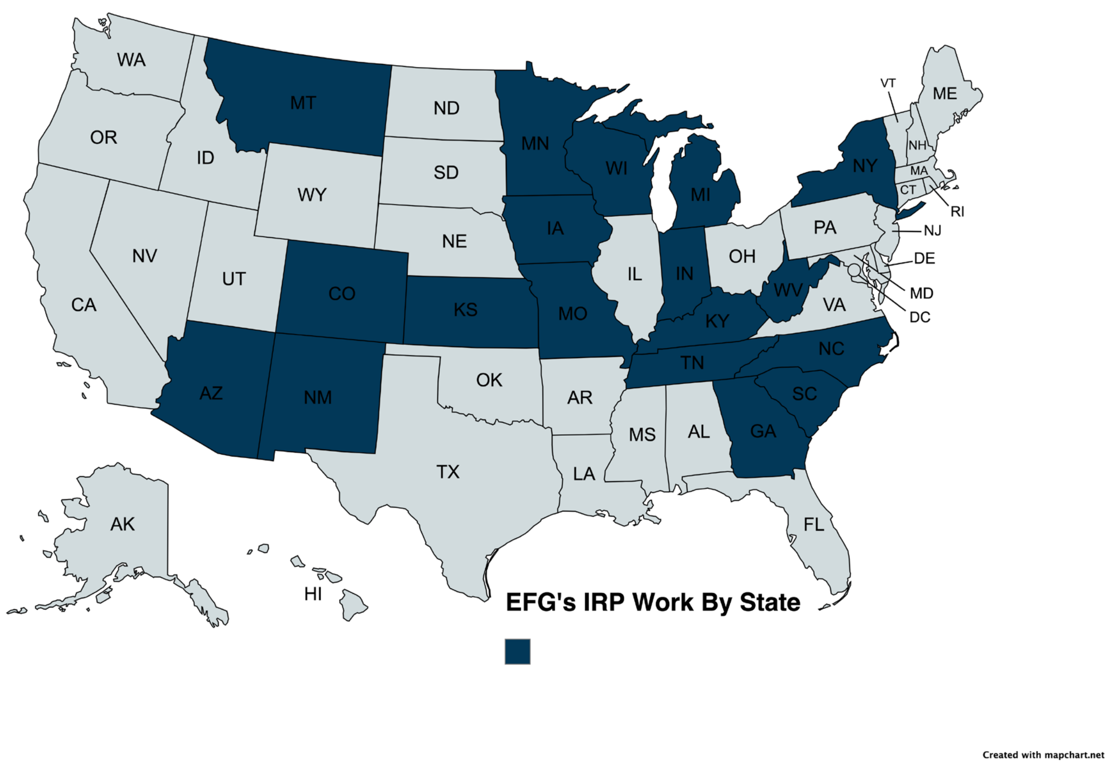

Figure 1. States in Which EFG Conducts IRP and Related Work

Our work in these jurisdictions involves either conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms including PLEXOS and the Strategic Evaluation and Risk Model ("SERVM"), both of which were utilized by KU/LG&E to prepare the 2024 Integrated Resource Plan ("IRP").

KU/LG&E's 2024 IRP is a significant improvement over the 2021 IRP. EFG also conducted a review of the 2021 IRP and some of the concerns identified by EFG related to modeling methodology, access to modeling files, and the use of the Equivalent Load Duration Curve Model ("ELDCM") have been partially addressed. The 2024 IRP contained significant improvements including using PLEXOS to perform capacity expansion modeling over the planning period rather than for just a single year. In addition, KU/LG&E provided workpapers to intervenors that included modeling input and output files.

KU/LG&E also helped Sierra Club secure access to a project-based PLEXOS license. We appreciate that KU/LG&E allowed Sierra Club to be able to access PLEXOS. Ensuring intervening parties can have access to the same software package that the Companies utilized for their IRP modeling is an important step for ensuring transparency in IRPs.

The first section of this report outlines important aspects of the Companies' 2024 IRP and the second section discusses alternative modeling we performed to evaluate different assumptions around load growth and resource options.

1.2 RECOMMENDATIONS

While the 2024 IRP includes significant improvements from the 2021 IRP, we have identified several recommendations for further improvement. Based on our review of the Companies' IRP and their responses to discovery questions, we offer the following recommendations:

1. The Commission should not approve the construction of new resources that are intended to serve large customers without establishing protections for existing ratepayers that would guarantee costs caused by these new loads are paid by the new load and prevent early exit from said large load agreements without a stranded cost allocation to those large loads.
2. KU/LG&E's operational decisions regarding Mill Creek 3 and 4 are primarily what cause the need for a second NGCC under the Mid Load scenario. But the Companies' plan to advance the second NGCC to 2031 is not adequately justified by the Companies as it is based on speculative load growth. While the Companies characterize this as a "no regrets" decision because of load growth inquiries, it puts unnecessary risk on existing ratepayers to build a new power plant for need that may never materialize.
3. The Companies should have evaluated whether it was a lower-cost alternative to convert Ghent 2 to run on natural gas compared to its proposed retrofit with an SCR. Former coal-fired power plants that were converted to run on gas achieve NOx emissions rates at or below the targeted emission rate that the Companies hope to achieve at Ghent 2 during ozone season with an SCR, so the Companies should have considered conversion as an alternative. We modeled such a scenario and found that it was a lower PVRR cost than the retrofit alternative. Moreover, it had a significantly cheaper PVRR when a reasonable, less speculative amount of load growth is assumed.
4. The Companies' interconnection process for new load does not appear to shield existing customers from serious risks to the operational security and reliability of the grid that large loads may introduce and urgently needs to be reformed before new customers are interconnected.
5. The Companies should provide an analysis around the costs and benefits of securing ATC access with neighboring regions.

2. LOAD FORECAST

2.1 ECONOMIC DEVELOPMENT AND DATA CENTER LOAD

Similar to other utilities across the country, KU/LG&E had to address in its IRP how to handle unprecedented load growth in its service territory, the scale of which is still uncertain and speculative. This unique aspect of today's load growth has led to new and varied approaches to planning for new large loads in demand forecasts. Utilities' approaches span the gamut from only including new loads that have a signed service agreement to attempting to assign probabilities to various characteristics influencing the likelihood of customer interconnection. For this IRP, the Companies have reported that the load forecast includes generic assumptions around data center load growth. As the Companies stated:

> *For purposes of the IRP, the Companies modeled generic data center load rather than customer-specific loads. However, the Companies used total size and ramping schedule assumptions that were based on information provided by higher-probability prospective data-center customers while also ensuring that this information was aligned with the most recent national information available. Given prospective customers and available sales tax incentives in Jefferson County, LG&E's service territory was deemed to be the most reasonable location for data centers in the Mid load forecast. Thus, the Companies modeled 1,050 MW of data center load in the LG&E service territory in the Mid load forecast. The Companies assumed 70 MW tranches of load being spaced out every 6 months starting January 2027 and continuing through January 2029 and then growing to 140 MW tranches every 6 months from July 2029 through July 2031.*[1]

While we don't doubt that the Companies are receiving the noted inquiries from potential customers, the Companies' approach to handling this speculative possible load growth raises a myriad of concerns. Specifically, with respect to the load forecast, the Companies have no means to know whether inquiries from customers are duplicative of inquiries made by those same customers at other load serving entities. One should expect that data center developers are in conversations with multiple utilities across a number of states and thus the possible load growth will be reflected in numerous utility load forecasts. Indeed, since the Companies appear to lack any barriers to entry to their load interconnection queue,[2] it's possible that inquiries are coming from customers who have no intention of constructing data center themselves and are merely attempting to hold a place in line. This also raises the question of how to plan for these large loads when there is a high degree of uncertainty around which service territory they will ultimately decide to locate in, the first year they are expected to take service, and their projected load ramp.[3] All of these different factors result in a high degree of uncertainty around data centers. As

[1] Companies' Discovery Response to Commission Staff 21.
[2] Companies' Discovery Response to Joint Intervenors 16.
[3] Load ramp is the level of demand requested by the data center. For example, the customer might report that initial demand will be 100 MW in the first year, 200 MW in the second year, and 300 MW in the third year.

the Companies stated in the IRP, "Due to the magnitude of data center loads, economic development is a key uncertainty in this load forecast."[4]

While the Companies have developed two additional load scenarios in addition to the base forecast, which includes the assumption of 1,050 MW of data center load, the Companies were dismissive of the probability that their low load scenario would manifest.[5] In the high load scenario, the Companies assumed 1,750 MW of data center load in addition to the second phase of the Blue Oval SK electric vehicle battery production facility.[6] The Companies' low load scenario does not include any data centers and includes assumptions around some large customers leaving the service territory later in the 2030s.[7] As stated in the IRP, "Based on current economic development activity, including data centers, the Companies assign a low likelihood to the Low forecast. The 2024 IRP therefore focuses primarily on the Mid and High load forecasts, though the analysis considers all three forecasts."[8]

We do not oppose the use of varying levels of new customers in load forecasts for IRP planning. Given the uncertainty, a wide band of assumptions is appropriate. However, it is important not to dismiss forecasts that assume lower levels of growth or no growth at all because of the potential for the load to not materialize and the impact this has for the potential of overbuilding capacity. Additionally, this information helps clarify what precipitates resource plan changes, which is essential for appropriate allocation of costs. As the Companies reported, "There have not been any projects that have made formal announcements to date, including an announced load or ramp schedule."[9] Table 1 below shows a breakdown of the data center projects the Companies reported as of November 25, 2024. The different phases represent different levels of engagement ranging from the inquiry phase which means high level information requests have been made, to the announced phase, which means the project has made a formal announcement to locate in the service territory.

Table 1. Prospective Data Center Customers as of November 25, 2024[10]

Phase	Phase Description[11]	Project MW
Inquiry	Indicates a request for high level information, may involve a few meetings, and is generally in the early stages of evaluation.	1,700
Suspect	Indicates that there is a likelihood of, or evidence of, continued follow up. The project is likely engaged in	1,787

[4] KU/LG&E 2024 IRP, Volume 1 at 7-13.
[5] Companies' Discovery Response to Sierra Club 1-13(a).
[6] KU/LG&E 2024 IRP, Volume 1 at 5-16.
[7] KU/LG&E 2024 IRP, Volume 1 at 5-17.
[8] KU/LG&E 2024 IRP, Volume 1 at 5-15.
[9] Companies' Discovery Response to Sierra Club 1-12(f).
[10] Companies' Discovery Response to Joint Intervenors 1-64, Attachment 1 at 79.
[11] Companies' Discovery Response to Joint Intervenors 1.16(c).

	continued information exchange and is on the verge of more formal processes and information exchange.	
Prospect	Indicates very regular exchange of information, more detailed evaluation of a site and site characteristics that likely include detailed evaluation of infrastructure capabilities and capacities, costs of doing business, in person site visits, and incentive negotiation.	2,215
Imminent	Indicates a high probability for the project to announce and locate in the Companies' service territory. An imminent project likely has all the information necessary from the Companies and the state and local communities to make a decision and may only be finalizing its own business plan or internal processes before proceeding.	544
Announced	The project has made a formal public decision that it will locate in the Companies' service territory and proceed with all actions determined through the process of evaluation in the phases above.	0

The Companies provided an update on the status of potential data center customers as of January 20, 2025, which is shown in Table 2.

Table 2. Prospective Data Center Customers as of January 20, 2025[12]

Phase	Project MW
Inquiry	2,500
Suspect	800
Prospect	2,500
Imminent	400
Announced	0

The Companies' base load scenario does not include all prospective data center customers. However, it is important to point out that there are no announced projects, either as of the report from November 2024 or from the most recent report as of January 2025. This means that a wide band of uncertainty including no additional data center load is a reasonable set of bookends for analysis.

We are now in a very different planning paradigm than that in which the Companies found themselves in the 2021 IRP. The links between generation planning, transmission and interconnection studies, and ratemaking are closer than ever. The choice of load growth in the IRP has interactive effects with the need for transmission and interconnection studies as well as rate setting. For example, the resource plan selected in the IRP should include

[12] Companies' Discovery Response to Sierra Club 2-13.

information on transmission planning, both of which inform rates and lead to more information about how potential customers perceive their chances of interconnecting and the attendant costs if they do so. However, when an intervenor asked how the Companies intended to protect existing ratepayers from stranded asset risk and whether such risk was addressed in the IRP the Companies said, "The Companies object to this request as irrelevant to an IRP review proceeding; the Commission's IRP regulation neither requires addressing nor mentions cost recovery or ratemaking."[13] While it may be the Companies' belief that the IRP does not have to address cost recovery or ratemaking, the IRP process does have implications for the financial impact to ratepayers, especially if the load does not materialize. And it is even more important when trying to make assumptions around new customer load that has not made any firm commitments to locate in the Companies' service territories. With the level of potential load growth forecasted by the Companies, and with no firm commitments in hand, it is crucial for the Companies to have a plan to avoid stranded asset risks and overbuilding if these customers fail to materialize or fail to materialize at the levels modeled by the Companies.

Table 3 shows the reserve margin projections for the Companies across the three different load scenarios contemplated for this IRP. The Companies are planning for a summer reserve margin of 23% and a winter reserve margin at 29%. Positive values in the "Capacity Need" line of the table reflect the capacity needed to meet the reserve margin and negative values reflect a surplus capacity position, or the Companies being above their winter or summer planning reserve margins ("PRM"). Under the low load scenario, the Companies will be well above the winter and summer planning reserve margins. However, under the mid load scenario, the Companies will be short starting in the winter and summer of 2030.

These capacity projections reflect the risks around the level of load that the Companies project to materialize and have significant implications for the amount of new resources the Companies would need to meet their planning reserve margins under the mid and high load forecast scenarios.

[13] Companies' Discovery Response to The Kentucky Coal Association, Inc. ("KCA") 2-5.

Table 3. Load Scenario Reserve Margin[14]

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Winter									
Low Load									
Total Reserve Margin	28.1%	40.3%	41.5%	42.2%	43.0%	43.6%	45.4%	45.6%	45.8%
Capacity Need	55	-678	-742	-780	-825	-860	-951	-962	-974
Mid Load									
Total Reserve Margin	26.7%	32.5%	30.1%	25.1%	20.4%	18.3%	18.8%	18.8%	18.9%
Capacity Need	143	-219	-73	264	602	764	728	726	722
High Load									
Total Reserve Margin	25.5%	27.4%	19.3%	11.5%	5.6%	3.7%	3.9%	3.8%	3.8%
Capacity Need	216	108	687	1,319	1,868	2,062	2,047	2,054	2,051
Summer									
Low Load									
Total Reserve Margin	22.8%	38.0%	39.4%	40.5%	41.7%	42.9%	46.1%	47.0%	48.0%
Capacity Need	12	-904	-977	-1,038	-1,101	-1,163	-1,323	-1,368	-1,416
Mid Load									
Total Reserve Margin	21.5%	28.4%	24.6%	20.2%	15.6%	16.0%	16.7%	17.0%	17.4%
Capacity Need	94	-349	-105	192	533	505	450	428	404
High Load									
Total Reserve Margin	20.4%	20.2%	11.9%	6.4%	1.5%	1.6%	1.9%	1.7%	1.7%
Capacity Need	166	191	822	1,302	1,772	1,756	1,734	1,758	1,756

3. LARGE LOAD INTERCONNECTION PROCESS

The Companies' interconnection process does not appear to place obligations on potential customers that might dissuade speculative entry to their interconnection queue. For example, when asked to detail their policies and procedures with respect to large load interconnection, the Companies referred to their Open Access Transmission Tariff ("OATT") as well as other documents posted on the OASIS site. Those documents do not appear to require a deposit to cover study costs on behalf of new customers, do not appear to require site control by the customer before requesting study, and do not appear to have milestones by which customers would need to commit to paying network upgrades or other costs or forfeit their place in the interconnection queue. Given how little experience most jurisdictions tend to have with data center interconnection, this is to be expected. But the Companies need to institute reforms to their interconnection process to ensure that the Companies are spending their time studying load that has the best chance of interconnecting and that study costs are not absorbed by existing ratepayers.

Interconnecting and serving data center customers pose unique challenges to reliable system operations given the scale and speed to energization. For many utility systems there is a significant gap between current system

[14]KU/LG&E 2024 IRP Volume III, Resource Assessment at 23.

capabilities and these customers' energy demands. We are just starting to understand the challenges posed by this new paradigm. Pockets of data center growth such as in the Dallas area or in Virginia have cropped up already, and with those load additions the electric industry is starting to gain visibility into some of the potential challenges. For example, a normally cleared fault on a 230-kv line in the Eastern Interconnection led to the simultaneous loss of 1,500 MW of data center load.[15] While the event did not lead to cascading effects on the rest of the grid, the grid operator did have to take measures to reduce voltage to within normal operating levels. NERC stated that the event highlights potential reliability risks for the bulk power system ("BPS") "with respect to the voltage ride-through characteristics of large data center loads." It also made several recommendations, including that transmission planners should:

1. *Require dynamic response models of large loads in their facility interconnection requirements,*
2. *Study the impact that these large load losses would have on the system, and*
3. *Ensure that operating agreements with large loads include ramp rates when connecting/reconnecting large loads to the system.*[16]

In ERCOT, which has added several thousand MWs of data center and cryptomining demand, operational concerns have pushed ERCOT to propose voltage ride-through standards and ramping limits on large loads.[17] ERCOT has experienced "great load forecast error on extreme or unusual operating days when an accurate forecast is most critical", "multiple events . . . where a significant amount of Large Load unexpectedly disconnected from the grid," and that "Large Load can change their MW consumption rapidly enough to exhaust available [r]egulation service."[18] In addition, in the summer of 2024, a data center in ERCOT's footprint began oscillating at 23 Hz. Though this did not lead to damage to generators, ERCOT concluded, in part, that the following were key lessons learned and issues to resolve to help prevent such situations from happening in the future:[19]

- *High resolution data (PMU/DFR) is essential to identify oscillations and determine oscillation magnitudes and frequency modes,*
- *ERCOT, TO, and load owners/operators need to have good understanding and maybe requirements of actual Load performance (steady state and dynamic) to ensure reliable integration,*
- *Lack of industry standard to define the large load performance needed for electric grid reliability and equipment security, and*
- *Lack of the accurate models to properly represent these large loads need to be addressed.*

[15] NERC Incident Review, "Considering Simultaneous Voltage-Sensitive Load Reductions". January 8, 2025. Available at: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.
[16] Ibid.
[17] ERCOT. "Large Loads – Impact on Grid Reliability and Overview of Revision Request Package." August 16, 2023
[18] Ibid.
[19] Available at: https://www.ercot.com/files/docs/2025/02/28/LL-Oscillation_LFLTF_Mar2025_Final.pptx.

While it does not appear to us that the Companies explicitly require dynamic load models from potential data center customers as recommended by NERC, they do require:[20]

Details of various properties of the end-user Facility, including but not limited to:

a. Voltage level at the point of interconnection,

b. Capacity factor,

c. Power factor,

d. Maximum ramp rate.

2. Ten-year forecast of summer and winter load, beginning the first year after service is scheduled to start.

3. Identification of any portion of load that is interruptible, and description of:

a. The conditions under which an interruption can be implemented,

b. Limitations on the amount and frequency of interruptions.

4. Load characteristics that may impact power quality, system stability, or otherwise result in system reliability concerns.

This is not entirely unexpected, because, as stated previously, these are largely new grid reliability concerns and there's little precedent to follow. However, it's been our observation that when customers are expected to self-identify dynamic behaviors such as "load characteristics that may impact power quality, system stability, or otherwise result in system stability concerns," those behaviors tend not to identified. This is not necessarily a result of omission but rather that the customer also has limited information about the operation of the planned facility.

When asked about the conditions under which the Companies would perform some of the studies for which dynamic data would be used, e.g. transient stability and electromagnetic transient ("EMT") studies,[21] the Companies responded that "LG&E/KU has performed transient stability studies but no EMT studies for large loads. As part of LG&E/KU's ad hoc evaluation, transient stability studies were performed when it was determined that system reliability may be impacted by either 1) frequency or voltage excursions in the event the load was lost during a fault or 2) large amounts of load switching on and off could impact power quality, such as for an arc furnace." It's not clear whether the Companies consider these risks to be inherent in both arc furnaces *and* data centers. And, importantly, they are not the only risks to operational security of the BPS that these loads may trigger.

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[20] "Facility Interconnection Modeling Requirements" available at https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/facility-interconnection-modeling-requirements.pdf.

[21] A transient stability study examines the operation of an electric system after a significant disturbance such as loss of a generator or a large load. An EMT study looks at power system operations during very brief fluctuations on the grid that might occur during periods even shorter than those examined in transient stability studies.

The Companies' Facilities Interconnection Requirements do require new loads to minimize disturbances on the Companies' transmission system and to "mitigate any power quality violations."[22] But this language doesn't address the subsynchronous concerns posed by data centers.

Finally, cost allocation and rate design will be a key concern for existing ratepayers.[23] The Companies have not indicated whether data centers are likely to take service under an economic development rider or through the Retail Transmission Service rate[24] – either way rates should be designed such that existing ratepayers do not subsidize the costs of serving these new customers.

As the Commission and Commission staff consider requests to approve service contracts for new customers and/or requests to approve the acquisition of new generators, here are some important questions to ask the Kentucky utilities:[25]

Protecting Existing Customers:

- What measures are being taken to ensure that costs and risks associated with potential large new loads are not being passed onto existing customers?
- What financial safeguards are in place to ensure that debts or financial obligations do not adversely impact ratepayers?
- Will existing customers be subsidizing infrastructure investments or operational costs in any way? Why or why not? How is this guaranteed?
- What is the plan for dealing with stranded assets if large load customers do not materialize or leave the queue?
- What contingency plans are in place to ensure that demand from large load customers that does not materialize does not adversely affect existing customers?
- How is the utility assuring that large load customers will remain in the region long term? Will they pay exit fees to ensure that assets built to serve them do not become stranded costs passed to other ratepayers?
- Are existing customers adequately represented and educated on the benefits and risks presented by large load customers? Is the Commission ensuring that ratepayers and stakeholders have opportunities for informed input into current and future decisions?
- How are existing customers and ratepayers being protected from higher energy costs, given the large increase in demand?
- What are the projected economic benefits (e.g., job creation, tax revenue) of approving this request? Are they focused in specific counties, or are they spread evenly across areas served by the utility?

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[22] Available at https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/FAC-001_Facility_Interconnection_Requirements_Procedure_2024-01-01.pdf.

[23] EFG recently released a paper on safeguards for ratepayers in large load tariffs: https://energyfuturesgroup.com/wp-content/uploads/2025/01/Review-of-Large-Load-Tariffs-to-Identify-Safeguards-and-Protections-for-Existing-Ratepayers-Report-Final.pdf.

[24] Companies' Discovery Response to Sierra Club 2-25.

[25] A version of these questions was published in Elevate Energy Consulting (March 2025). Practical Guidance and Considerations for Large Load Interconnections. [Draft Working Paper]. Available at: https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/.

Jurisdictional and/or Legal Issues:

- Are there proposals or plans for large load interconnection seeking to modify the existing regulatory process? What are the primary drivers or reasons for such change?
- What specific regulatory requirements are being avoided with such changes and what measures are in place for oversight, where applicable?
- Does the proposed approach align with other utilities and states? If not, would the petition or proposal establish new precedents for avoiding any specific jurisdictional obligations?
- What impacts would this have on existing ratepayers?
- Does the petition or request align with broader state-level resource goals?

Large Load Application Process:

- What information is required for the initial large load interconnection request, and is it adequate to assess the credibility, certainty, and readiness of the interconnection customer to seek transmission service?
- How does the transmission provider assess the adequacy and completeness of the information provided at the time of the interconnection request to ensure that all technical requirements are met by the proposed facility?
- What financial commitments (i.e., deposits) are required for large load interconnection requests? Do those financial commitments escalate throughout the interconnection process?
- What site control requirements exist for large load interconnection requests, and are these considered as part of a "readiness" assessment?
- If site control is not required, are there deposit requirements to cover the cost of the load interconnection study?
- What technical and financial capabilities are required for an interconnection customer to be deemed a credible applicant? Are those criteria made public?

Large Load Interconnection Requirements:

- Are the large load interconnection requests intended to connect to the distribution system or transmission system? Who is the interconnecting entity? Are these customers distribution-connected and seeking interconnection service or are they directly transmission-connected?
- How are the distribution and transmission providers coordinating interconnection requirements to ensure alignment of transmission and distribution system reliability needs?
- Has the distribution and/or transmission provider established clear, effective, and consistent interconnection requirements for large loads?
- Do those requirements include data sharing, modeling, operational performance limitations (e.g., ramp rate limits), oscillations, ride-through performance, monitoring data, and event analysis support?

Large Load Queue Management:

- Does the utility have a dedicated queue process for large load interconnection requests?
- Is this queue process administered by the transmission or distribution organization (or department), and how are these organizations and departments collaborating with each other through the process?

- What type of queue process is used – serial, cluster, other? What is the reasoning for the type of queue process used?
- If using a serial queue process, what checks and balances are in place to ensure that load interconnection requests are processed in a timely manner and that speculative interconnection requests are removed from the queue without causing unnecessary backlogs or delays for other legitimate requests?
- Are there defined timelines for how long a large load interconnection request can remain in the queue before being removed?
- Are clear, explicit queue milestones and timelines established that hold the large load customer accountable to move the queue process along?

Large Load Operational and Performance Considerations:

- Does the transmission provider require the large load customer to provide some form of narrative or other data that explains how the large load facility will operate when connected to the bulk power system?
- Is the large load customer required to provide the following information to the transmission provider/transmission planner?
    - Facility electrical topology and single line diagram
    - Protection and control systems throughout the facility and their associated settings
    - Load voltage and frequency ride-through curves (threshold and duration)
    - Load variation narrative and explanation (frequency and magnitude of variations)
    - Expected ramp rates
    - Restoration settings
    - UPS protection and control settings
    - Load composition information
    - Auxiliary equipment capabilities, ratings, and protection settings
    - Explanation and technical details related to fast ramping and oscillatory behavior
    - Power quality impacts
    - Short-circuit levels
    - Backup generation and grid-paralleled generation information
    - Transformer and other equipment ratings, documentation, etc.

Load Forecasting:

- Is there a defined or formalized methodology for determining when large load interconnection requests enter system demand forecasts and are subsequently included in integrated resource planning and other long-term transmission or resource procurement activities?
- What specific interconnection milestones (site control, financial, technical, etc.) must be met for considering large loads in models and studies?
- How are large loads differentiated from other demand growth projections? If speculative large loads are included, what factors are being considered to inform the probability of interconnection? Do these factors include forecasts of market trends specific to each industry (e.g., data centers) and potential limitations to the total capacity growth (e.g., available water resources or fiber optic cable capacity)?

Large Load Modeling:

- Have large load modeling requirements been established by the transmission provider or transmission planner? Do they include production cost, steady-state powerflow, dynamic stability, EMT, and short-circuit models?
- Are these models required as part of the large load interconnection application? Or are they required at later stages throughout the interconnection study process? Are these milestones established and enforced?
- How are these models verified to be accurate representations of the equipment proposed?
- Are there any post-event data collection procedures in place at the large load points of interconnection?

Large Load Interconnection Studies:

- What is the process and what are the milestones for initiating large load interconnection studies?
- Are any types of cursory or high-level analyses done prior to conducting a more comprehensive interconnection study? Why or why not?
- What type of large load studies are conducted for each interconnection request (see study-specific questions below)?
- What specific criteria are used to determine whether each type of study is conducted (e.g., interconnection request size)? Is this codified and made available publicly?
- What are the average costs of conducting large load interconnection studies?
- Is there a staffing and training plan in place to address the forecasted increase in large load interconnection requests?
- What mechanisms exist for recovering transmission system costs from large load interconnection customer requests? Are large load customers paying for studies performed by the transmission provider, whether qualitative or quantitative? If not, how are these costs covered by the utility?

- **Production Cost Analysis Studies:**
    - Are 8760-hour studies being conducted to ensure that large loads can be met at all hours of the day, given the projected resource mix proposed by the utility?
    - Are large load demand profiles (daily, seasonal, price-sensitive, and other variabilities) documented, well-understood by the utility, and modeled appropriately?

- **Powerflow and Contingency Analysis Studies:**
    - Which powerflow base cases are used to conduct steady-state thermal and voltage violation analysis? More specifically, which seasons and dispatch conditions are modeled and why?
    - What contingencies are tested in these studies?
    - Are N-1-1 operating conditions considered?

- **Dynamic Stability Studies:**
    - What method is used to reduce the list of contingencies to study in dynamic simulations? How many contingencies are studied for each load interconnection in this domain?
    - Are electromechanical oscillations considered in dynamic studies?
    - Are the resonant effects of data center AI load ramping/variability considered in these studies (i.e., a form of forced oscillation)?
    - How are the stability impacts on nearby generators considered in these studies?

- Are motor restart studies conducted?

- **Short-Circuit Studies:**
  - Are breaker duty studies conducted?
  - Are short circuit studies (e.g., ASPEN, CAPE, etc.) conducted for large load interconnections or are these studies only conducted in positive sequence simulation platforms?
  - How are impacts to protection systems analyzed for large load interconnections?
  - What protection system modifications are commonly required for these large loads?
  - What long-term effects are large loads having on short-circuit levels across the system? Are these effects positive or negative?

- **Electromagnetic Transient ("EMT") Studies:**
  - Are EMT studies being conducted for large load interconnections? If not, why not?
  - Are fast-ramping and oscillatory behaviors of data centers, particularly AI data centers, studied by the utility in the EMT domain? How is the utility studying potential electromagnetic transients (e.g., capacitor switching)?
  - How are subsynchronous oscillations, subsynchronous control interactions, and/or subsynchronous torsional interactions being studied to ensure large loads do not cause serious adverse impacts or damage with existing power electronic controllers or synchronous generators?

Transmission Network Upgrades:

- How is the utility coordinating with stakeholders to address transmission network performance deficiencies and assess potential network upgrades required for large load interconnections?
- What alternative solutions are considered as part of network upgrades beyond transmission infrastructure investments?
- What advanced technologies are included in these assessments? Examples include grid forming ("GFM") inverter technology, FACTS devices, high voltage DC ("HVDC") technologies, powerflow control, etc.

Cost Allocation for Network Upgrades:

- Are the large load customers' direct connection facilities allocated the full costs of network upgrades?
- Is this consistent across transmission and distribution connections? Are existing load service requirements for typical residential, commercial, and smaller industrial facilities used for large load interconnections? Do practices need to adapt for large load customers, even if dispersed across multiple distribution load points?
- Is the large load customer entitled to any refund or discount of contributions made to direct connection costs?
- How are broader network upgrade costs allocated to large load customers?
- For any costs not fully accounted for by the large load customer, what cost allocation methodology is used for allocating the broader upgrades to large load customers versus being considered "network benefits"?
- How does the cost allocation methodology compare with utilities in different states or regions, and why?

- How are the full suite of network impacts considered in the cost allocation considerations? Examples include increased congestion levels, voltage issues, degradations in stability, reduced operational maintenance windows, etc.

Resource Portfolio:

- What types of generation facilities will be built (e.g., natural gas, renewable, batteries, hybrid) to serve these large load customers and how do they align with the directive to make just and reasonable investments?
- Are energy and capacity considerations adequately assessed, including ensuring energy availability across 8760 hours, energy security and resource availability, and resilience to extreme weather conditions?

4. ENVIRONMENTAL REGULATION SCENARIOS EVALUATED

For this IRP, the Companies evaluated four different assumptions around environmental regulations, which are centered around the Good Neighbor Plan ("GNP"), which concerns the ozone National Ambient Air Quality Standards ("NAAQS"), the 2024 Effluent Limits Guidelines ("ELG"), and the recent Clean Air Act ("CAA") Greenhouse Gas ("GHG") rules set out at CAA Sections 111(b) and 111(d). While the Companies evaluated these four different scenarios, they report in the IRP that "the Companies believe the Ozone NAAQS + ELG scenario is the most likely environmental scenario."[26] These four scenarios are outlined in
Table 4 below:

Table 4. Environmental Regulation Scenarios

Scenario	Description
No New Regulations[27]	No new regulations take effect over the planning period and no investments are needed for environmental compliance
Ozone NAAQS[28]	Assumes selective catalytic reduction ("SCR") is a Reasonably Achievable Control Technology SCR needed to operate Ghent 2 in the ozone season beyond 2030
Ozone NAAQS + ELG[29]	Builds on the Ozone NAAQS scenario Modifications on landfill constraints needed for all coal stations except E.W. Brown
Ozone NAAQS + ELG + GHG Rules[30]	40% capacity limit applied to NGCC resources starting in 2032 Existing coal compliance:

[26] KU/LG&E 2024 IRP, Volume 1 at 5-11.
[27] KU/LG&E 2024 IRP, Volume 1 at 5-11.
[28] KU/LG&E 2024 IRP, Volume 1 at 5-11.
[29] KU/LG&E 2024 IRP, Volume 1 at 5-11; KU/LG&E 2024 IRP Volume III, Resource Assessment at 34.
[30] KU/LG&E 2024 IRP, Volume 1 at 5-11; KU/LG&E 2024 IRP Volume III, Resource Assessment at 39.

	• Co-firing with 40% natural gas by 2030 and retire by 2039 • Convert to burn 100% natural gas by 2030 with no retirement obligation • Retire unit by 2032

The Ozone NAAQS scenario has implications around the decision options to pursue an SCR for Ghent 2 since that is the only existing resource impacted under this environmental regulation scenario. The Companies evaluated the three option decisions in PLEXOS, which the Companies reported included adding the SCR to allow for year-round operation, not installing the SCR and allowing Ghent 2 to operate only during the non-ozone season (October through April), or to retire Ghent 2.[31] The Companies did not evaluate a conversion of Ghent 2 to run on natural gas as an alternative. The Companies assumed the capital cost of the SCR is $137.8 million. [32]

The Ozone NAAQS + ELG scenario includes the options for Ghent 2 to comply with the GNP and also considers the impact of ELG on the coal stations, with the exception of E.W. Brown. The 2024 ELG regulation scenario considers the modifications that are needed to the capture, handling, and disposal of coal combustion residuals for the purposes of meeting zero liquid discharge. This environmental regulation scenario has implications for decision options for the Mill Creek station because the required modifications needed to meet the requirements will increase the need for landfill storage capacity. The Companies report that if they comply with the 2024 ELG at Mill Creek through zero liquid discharge, then the units could only operate until 2037 because of the landfill storage capacity constraints.[33] Under the Ozone NAAQS + ELG scenario, the Companies evaluate options for the Ghent, Trimble, and Mill Creek units, which include complying through zero liquid discharge by 2029, retiring by the end of 2034, or converting to burn 100% gas by the end of 2034.[34] Due to landfill storage constraints, Brown would not be able to operate on coal past 2035 and Mill Creek would not be able to operate past 2037.[35]

The Ozone NAAQS + ELG + GHG Rules option evaluates a scenario where all three environmental regulations are in place and the Companies will need to comply with the additional restrictions around the operation of thermal generating resources under the GHG rules. In this scenario, NGCC resources comply with the GHG rules through a 40% capacity factor limit starting in 2032 and coal units have three options for compliance, which include co-firing with 40% natural gas by 2030 and retiring by 2039, converting to burn 100% natural gas by 2030 with no retirement obligation, or retiring by 2032. The Companies indicated they assign a low likelihood to this scenario due to the level of replacement capacity required for compliance.[36]

[31] KU/LG&E 2024 IRP Volume III, Resource Assessment at 54.
[32] KU/LG&E 2024 IRP Volume III, Resource Assessment at 31.
[33] KU/LG&E 2024 IRP Volume III, Resource Assessment at 34.
[34] KU/LG&E 2024 IRP Volume III, Resource Assessment at 34.
[35] KU/LG&E 2024 IRP Volume III, Resource Assessment, Table 35 at 57.
[36] KU/LG&E 2024 IRP Volume 1 at 5-11.

5. RESOURCE PLANS

For this IRP, the Companies developed capacity expansion plans for each combination of load (three scenarios) and environmental regulation (four scenarios) across the five different fuel prices evaluated.[37] After evaluating all of the plans developed for this IRP, the Companies indicated that they started with the least-cost resource plan in the Mid Load and Ozone NAAQS + ELG scenario and made modifications to support the potential for additional economic development load growth and CO_2 regulations.[38]

Given the Companies' view that the Ozone NAAQS + ELG scenario is the most likely environmental scenario, we have focused our review of the Companies' modeling on this scenario. Table 5 shows the Least-Cost and Recommended Resource Plans developed under the Ozone NAAQS + ELG scenario for the mid and high load scenarios. It is important to note that this table reflects the solar cost sensitivity, which the Companies assumed would include a different forecast for solar prices. This has implications for the decision on Ghent 2, as the modeling without modifying the solar prices results in the decision to not add SCR to Ghent 2. The Companies said this result is "predicated upon the availability of almost 2,000 MW of solar at costs more than 30 percent lower than today, which is inconsistent with the Companies' recent market experience and potentially not possible to execute."[39]

The Least-Cost Resource Plans under the mid and high load scenarios retire Brown 3 and 4 in 2030 and 2031, respectively, and add 1 NGCC in 2030. The mid load scenario includes 100 MW of four-hour battery storage in 2030 and 400 MW in 2031, while the high load scenario includes 700 MW of four-hour battery storage in 2029, a second NGCC in 2031, and 200 MW of four-hour battery storage in 2031. Both load forecast scenarios add 200 MW of four-hour battery storage in 2032. In 2035, both load scenarios include the retirement of Mill Creek 3 and 4. The mid load scenario adds a second NGCC and 200 MW of four-hour battery storage and the high load scenario adds a third NGCC and a SCCT in 2035.

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[37] KU/LG&E 2024 IRP Volume III, Resource Assessment at 28-29.
[38] KU/LG&E 2024 IRP Volume III, Resource Assessment at 6.
[39] KU/LG&E 2024 IRP, Volume 1, Footnote 32 at 5-26.

Table 5. Least-Cost and Recommended Resource Plans[40]

Year	Least-Cost Resource Plans Ozone NAAQS + ELG: Mid Load, Solar Cost Sensitivity	Least-Cost Resource Plans Ozone NAAQS + ELG: High Load	Recommended Resource Plan Ozone NAAQS + ELG Mid Load	Enhanced Solar Resource Plan Ozone NAAQS + ELG Mid Load
2028	+Disp DSM	+Disp DSM; +300 MW 4hr BESS	+Disp DSM +400 MW 4hr BESS; Add GH2 SCR	+Disp DSM +400 MW 4hr BESS; Add GH2 SCR +200 MW Solar
2029		+700 MW 4hr BESS		
2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC; ELG @ GH, TC	+1 NGCC; ELG @ GH, TC	+1 NGCC; ELG @ GH, TC +200 MW Solar
2031	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+600 MW Solar
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; Retire BR3; +500 MW 4hr BESS; 500 MW Solar	Retire MC3-4; Retire BR3; +500 MW 4hr BESS

5.1 THE COMPANIES' RECOMMENDED RESOURCE PLAN

The Companies developed the Recommended Resource Plan by making different assumptions around the timing of resource decisions on the basis of supporting the potential for high economic development load growth and CO_2 regulations (Table 5 above).[41] The Recommended Plan accelerates the SCR on Ghent 2 and 400 MW of battery storage resources to 2028. The Recommended Plan also accelerates the second NGCC to 2031 and defers the retirement of Brown 3 to 2035.

Regarding pushing up the addition of SCR to Ghent 2 in 2028, the Companies report that adding the SCR to Ghent 2 in 2028 "provides assurance the unit will be available to support economic development load growth."[42] The Companies also report that the earlier timing is needed because NOx emission limits for the ozone season begin in 2028 and that SCR might be needed to comply with this limit under the addition of economic development load.[43]

The Companies describe the Recommended Resource Plan as a "no regrets" plan "because the accelerated resources are needed by 2035 if high economic load growth or CO_2 regulations do not come to fruition."[44] As discussed in Section 2.1 of these comments, the Companies do not have firm commitments from any new

[40] KU/LG&E 2024 IRP, Volume 1, Table 5-4 at 5-27.
[41] KU/LG&E 2024 IRP, Volume 1 at 5-27.
[42] KU/LG&E 2024 IRP Volume III, Resource Assessment at 8.
[43] KU/LG&E 2024 IRP Volume III, Resource Assessment at 31.
[44] KU/LG&E 2024 IRP, Volume 1 at 5-27.

customers and the resource decisions the Companies made for the Recommended Resource Plan depend on the unprecedented and speculative level of potential load from new customers.

6. SUPPLY SIDE RESOURCES

6.1 ACCREDITATION FOR THERMAL RESOURCES

The Companies perform their modeling in PLEXOS on an installed capacity ("ICAP") basis for meeting the minimum capacity reserve requirement, but do reflect an unforced capacity ("UCAP") basis for modeling dispatch ratings for NGCC and SCCT resources, while all other resources were modeled on an ICAP basis.[45] This means that the capacity contribution for dispatchable resources are modeled at 100%, or their full nameplate value.[46]

For example, under an ICAP approach for accrediting resources, if there is a 400 MW unit with a 10% forced outage rate, this means that the resource will be accredited at 400 MW, but the planning reserve margin will be increased by approximately 40 MW to reflect the forced outage rate. An ICAP approach means that thermal outage risk is socialized to load because thermal outage risk is accounted for by increasing the planning reserve margin, which leads to a less optimal selection of resources in the capacity expansion modeling. The UCAP approach, takes a different approach because it assigns the resource with a lower accredited value based on the forced outage rate. The UCAP approach will also impact the reserve margin since the outage risk is now accounted for in the resource accreditation instead of the reserve margin.

Modeling performance adjustments to accreditation for solar and battery storage without also modeling those changes for new thermal resources would inappropriately bias the expansion plans towards thermal resources. For this IRP, the Companies modeled the solar winter and summer capacity contributions at 0% and 83.7%, respectively.[47] The accreditation for four-hour battery storage resources was modeled at 85% and 93% for eight-hour battery storage resources.[48] We recommend that KU/LG&E begin using a planning reserve margin and thermal accreditation that is, at a minimum, based on UCAP but an even more appropriate approach would be to use the portfolio verification approach described in our 2021 IRP report on behalf of the Joint Intervenors. That report explains how SERVM can be used as a check on reliability, lessening the importance of accreditation and planning reserve margin assumptions that are very difficult to dynamically model. As Astrapé noted in a report on thermal accreditation, simply decrementing thermal capacity by its forced outage rate still results in "capacity accreditation of conventional resources [that] is often overstated".[49] Astrapé further noted that "[f]ailure to

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[45] Companies' Discovery Response to Sierra Club 1-5.
[46] Companies' Discovery Response to Southern Renewable Energy Association ("SREA") 11(a).
[47] KU/LG&E 2024 IRP, Volume III Technology Update at 21.
[48] KU/LG&E 2024 IRP, Volume III Technology Update at 21.
[49] Dison, Joel, Alex Dombrowsky, and Kevin Carden, "Accrediting Resource Adequacy Value to Thermal Generation," March 30, 2022. https://www.astrape.com/wp-content/uploads/2024/01/Accrediting-Resource-Adequacy-Value-to-Thermal-Generation-1.pdf.

incorporate these adjustments [other than the equivalent forced outage rate ("EFOR")] could potentially create a disparity in the relative treatment between traditional resources and renewable and BESS resources. As demonstrated in these analyses, EFOR alone falls short as a metric to use for establishing capacity accreditation for thermal generation."[50]

6.2 RENEWABLE CONSTRAINT

For the new solar and wind resource options modeled in PLEXOS, the Companies applied a constraint that limits the maximum renewable penetration over the study period. The Companies implemented this constraint by preventing solar generation from being greater than 20% of total energy requirements and the total amount of solar and wind generation from being greater than 25% of total energy requirements. [51] The Companies reported that these generation limits are consistent with the results from a Kentucky regional case study [52] and that "[t]hese limits were set to allow for the maximum penetration of renewables that can be integrated into the existing generation and transmission system without significant reliability impacts or renewable energy production curtailments."[53]

Upon review of the Kentucky regional case study cited by the Companies, the study acknowledges that there are methods for handling overgeneration from renewable resources, which could include regional energy trading and power flow, energy storage, and curtailment.[54] The capacity expansion modeling performed by the Companies allows the model to optimize the existing and new resource mix. This means the model is considering the risks of periods where there may be overgeneration or undergeneration from renewable generating resources and can optimize around that for new resource additions, which include battery storage resources.

The study cited by the Companies also depends on the assumptions regarding the existing system and the composition of coal and natural gas resources. As stated in the study, "At low values of overgeneration, under two example levels of 0.1 and 1 TWh, respectively, natural gas dominant cases can effectively use approximately double the amount of renewables without significant curtailment compared to coal-dominant generation."[55]

Another approach to modeling limits on new resource builds is to assign either an annual or cumulative build limit. It is not atypical to model annual build limits on resources in capacity expansion modeling. However, those limits merit scrutiny when they become binding, meaning that the model selects the maximum amount of a resource

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[50] Ibid.

[51] KU/LG&E 2024 IRP, Volume III Resource Assessment at 18.

[52] KU/LG&E 2024 IRP, Volume III Resource Assessment, Footnote 27 at 18.

[53] Companies' Discovery Response to Commission Staff 14(a).

[54] Lewis, D. D., Patrick, A., Jones, E. S., Alden, R. E., Hadi, A. A., McCulloch, M. D., & Ionel, D. M. (2023). Decarbonization analysis for thermal generation and regionally integrated large-scale renewables based on minutely optimal dispatch with a Kentucky case study. *Energies*, *16*(4), 1999. See page 12.

[55] Lewis, D. D., Patrick, A., Jones, E. S., Alden, R. E., Hadi, A. A., McCulloch, M. D., & Ionel, D. M. (2023). Decarbonization analysis for thermal generation and regionally integrated large-scale renewables based on minutely optimal dispatch with a Kentucky case study. *Energies*, *16*(4), 1999. See page 12.

available in any given year. This tends to mean that if those limits are relaxed that the model may want an even higher amount of that particular resource because it finds it cost-effective to add more of the resource sooner rather than deferring building the resource or adding a less cost-effective option. We recommend that the Companies utilize this approach for modeling renewable resource additions. The Companies can utilize an iterative approach to evaluate different levels of build limits to evaluate the impact that they have on resource additions, and as highlighted earlier, any limits that may be binding should be considered for further testing on the limits modeled.

6.3 PUMPED STORAGE

In the Companies' 2022 Certificate of Public Convenience and Necessity ("CPCN"), Witness Sinclair discussed a pumped storage project that submitted a bid to the Companies' Request for Proposals ("RFP"). At that time, Witness Sinclair reported that "the proposal was viewed as not far enough along in its development to be a viable resource to address the timing of the Companies' current energy and capacity needs."[56] Through discovery in this case, Commission Staff asked the Companies if they were aware of any updates regarding the development of this project. In response the Companies said:

> *The Companies are aware of the Lewis Ridge Pumped Storage project. Pumped storage is a potential energy storage resource, and the Companies are currently working with Rye Development to evaluate the feasibility of the project and its cost relative to other technology such as lithium-ion batteries.*[57]

While the Companies did not include pumped storage as a new supply side resource option in PLEXOS for the capacity expansion modeling, the Companies could evaluate this project as a sensitivity to see if it is selected. We understand that additional consideration will be made around this particular project, such as project timing and cost. However, the Companies could evaluate the project with the information that is available today.

6.4 TRANSMISSION SYSTEM UPGRADE COSTS

As part of the costs modeled for the supply side resources, the Companies did not include any assumptions around potential transmission system upgrade costs that may be needed. As the Companies said:

> *The Resource Assessment does not explicitly consider transmission system upgrade costs. These costs are typically low when replacing resources at existing stations and uncertain in scenarios that involve new generation sites. Because transmission system upgrade studies are time consuming*

[56] Direct Testimony of Witness Sinclair at 28-30. Case No. 2022-00402.
[57] Companies' Discovery Response to Commission Staff 15.

and focused on specific generation scenarios, a detailed transmission system upgrade study is completed only for CPCN filings.[58]

In the Companies' 2022 CPCN filing, the Companies evaluated retirements for Mill Creek 2, Ghent 2, and Brown 3. As part of the resources contemplated as part of the 2022 CPCN case, the Companies evaluated potential retirements and capacity replacements for a handful of the proposals they received as part of the Request for Proposals.[59] Table 6 shows the transmission system upgrade costs the Companies determined would be needed for retirement and replacement scenarios for NGCC and SCCT sites.

Table 6. Transmission System Upgrade Costs[60]

Scenario	Cost (2022 Dollars)
Retirements: Mill Creek 1-2, Brown 3 Additions: SCCTs at Mill Creek	46,034,824
Retirements: Mill Creek 1-2, Brown 3 Additions: NGCC at Mill Creek	35,035,000
Retirements: Mill Creek 1-2, Brown 3, Ghent 2 Additions: NGCC or SCCTs at Mill Creek and Brown	3,420,000

The costs given in Table 6 suggest that replacing retiring coal generation with new gas would help avoid transmission upgrade costs – an intuitive outcome. However, with the Companies now considering the extension of existing coal units to support new loads, these transmission costs should be revisited. They are an important and nontrivial capital cost that is likely to effect resource selection.

7. DEMAND SIDE MANAGEMENT ("DSM")

In addition to the Companies' three load forecast scenarios including different assumptions around data center load, there are also different assumptions around the level of distributed generation and energy efficiency in the three forecasts. Table 7 shows the difference in the level of distributed generation (MW) and energy efficiency and other energy reductions (GWh) for 2032.

Table 7. Differences in Load Forecast Scenarios[61]

Load Scenario	Data Centers in 2032 (MW)	Distributed Generation in 2032 (MW)	Energy Efficiency, CVR, AMI, and Other Reductions in 2032 (GWh)
Low	0	275	2,150
Mid	1,050	150	1,500
High	1,750	125	700

[58] KU/LG&E 2024 IRP, Volume III Resource Assessment at 58.
[59] 2022 CPCN Case. Docket No. 2022-00402. Exhibit SAW-1 at 55.
[60] 2022 CPCN Case. Docket No. 2022-00402. Exhibit SAW-1, Table 35 at 55.
[61] KU/LG&E 2024 IRP, Volume 1, Table 5-2 at 5-13.

The different forecasts for distributed generation in the load forecasts reflect varying assumptions around net metering, as the Low Load scenario assumes that net metering continues indefinitely, while the High and Mid Load scenarios assume that net metering capacity is capped at the Companies' annual peak load in 2025.[62] However, it's important to recognize that the 1% threshold is not, in fact, a cap that limits the utilities' ability to offer net metering. The relevant Kentucky statute says, "If the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year, the supplier shall have no further obligation to offer net metering to any new customer-generator at any subsequent time [emphasis added]."[63] In other words, utilities have the option to continue offering net metering beyond the 1% threshold.

It is not just typical practice, but good practice, to evaluate the economics of additional DSM programs in IRPs. The IRP should consider a wide range of potential savings and costs in comparison to supply-side investments and retirements. While the Companies did include different assumptions around accelerating or decelerating energy efficiency savings in the load forecast scenarios, we recommend that the Companies explicitly model different levels of savings with a cost for those savings included for the evaluation. These savings should be consistent with a coherent program or portfolio design and reflect the reduction in program costs for monetizable benefits such as avoided transmission and distribution ("T&D"). [64]

Our recommendation is to move the Companies to an approach that directly evaluates additional DSM programs, as this is in fact supported by Kentucky's IRP rules, by the Staff's encouragement to "LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time," and by the existence of a DSM Advisory Group. Moreover, considering additional DSM in IRPs is typical practice amongst peer utilities; this is on top of the importance of these programs to resiliency, customer affordability, and reliability.

8. TRANSMISSION

As part of the IRP, the Companies included a Long-Term Transfer Analysis that evaluated transmission system upgrades that would be required for imports and exports to surrounding systems for long-term firm transfers. For imports from neighboring systems, the Long-Term Transfer Analysis found:

> *The Companies' Long-Term Transfer Analysis shows that the Companies would not require any upgrades on the LG&E/KU transmission system for long-term winter-season imports of up to 500 MW and only a minor upgrade ($3.1 million) to accommodate up to 1,000 MW. The Companies*

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[62] KU/LG&E 2024 IRP, Volume 1 at 5-20.

[63] KRS 278.466.

[64] IRP models cannot typically explicitly model all the benefits of DSM, for example, avoided transmission and distribution expenses. However, those avoided costs can be calculated outside of an IRP model and decremented from DSM costs so that they are included in the optimization.

> *similarly would not require transmission upgrades to accommodate long-term firm transfers to the Companies during the summer of up to 300 MW from PJM or MISO and up to 100 MW from TVA. Relatively small investments would be required to increase that import capacity to 500 MW for all three surrounding systems and to 1,000 MW for imports from MISO, but a fairly significant investment (almost $55 million) would be required to increase the capacity to 1,000 MW from TVA and PJM.*[65]

The Companies noted that investing in the transmission upgrades would not guarantee that generation would be available, as they referenced their experience during Winter Storm Elliott.[66]

Table 8 shows the different scenarios evaluated for imports and exports into and out of LG&E. The results indicate that an investment of around $6.5 million would be needed for 1,000 MW of imports from MISO. The cost of upgrades for 500 MW of import capability from PJM and 500 MW from TVA would be around $3.1 million for each system.

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[65] KU/LG&E 2024 IRP, Volume III, Resource Adequacy Analysis at 16.
[66] KU/LG&E 2024 IRP, Volume I at 5-27 to 5-28.

Table 8. Transfer Study Results[67]

Export Area	Import Area	Transfer MW	Violations - Flow	Violations - Volt	Network Upgrade Costs
LGEE	MISO	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	PJM	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	TVA	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
MISO	LGEE	100	0	0	$0
		300	0	0	$0
		500	1	0	$2,812,500
		1000	4	0	$6,498,000
PJM		100	0	0	$0
		300	0	0	$0
		500	2	0	$3,090,000
		1000	9	0	$54,792,500
TVA		100	0	0	$0
		300	1	0	$2,812,500
		500	2	0	$3,090,000
		1000	9	0	$54,792,500

As part of the modeling performed in SERVM to determine the planning reserve margin required to meet the Loss of Load Expectation of 1 day in 10 years, the Companies performed a sensitivity analysis on the assumption around import capability from neighboring systems. Results of these sensitivities are shown in Table 9 below. As part of the base case, the Companies assumed imports were based on historical available transmission capacity ("ATC") data for winter and summer weekdays from 2022 – 2024, which indicated that ATC is available 55% of the time. [68] Since imports are limited in the base case, when the Companies evaluated a sensitivity where access to neighbors was not allowed, it increased the LOLE, slightly. When the Companies evaluated the High ATC case, which looked at 700 MW of availability from neighbors, there was a significant decrease in the LOLE. The Companies caveated this case around the assumptions that are made with respect to the resource adequacy of neighboring systems, but it is still an important result and in combination with the results of the Long-Term Transfer Analysis, strongly suggests that the Companies should further investigate making modest investments in the transmission system to allow for more transfer capability.

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[67] KU/LG&E 2024 IRP, Volume III, Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System at 2.

[68] KU/LG&E 2024 IRP, Volume III, Resource Adequacy Analysis at 27.

Table 9. Loss of Load Expectation ("LOLE") Results[69]

	Summer	Winter	Annual
Base Case	0.68	0.32	1.00
No Access to Neighbors	0.76	0.32	1.10
High ATC (700 MW minimum)	0.02	0.13	0.15

When asked in discovery about pursuing the transmission investments modeled as part of the High ATC case, the Companies said they did not intend to do so because the "[t]he purchase of firm transmission does not ensure that generation will be available in neighboring markets when needed, as experienced during Winter Storm Elliott."[70] The Companies also indicated there would be a cost for securing access to the import capability.[71] That's fine, all resources have some costs, but there appears to be strong evidence that adding more transfer capability would be low cost and provide meaningful benefits to ratepayers absent additional analysis from the Companies.

Given the results of the Long-Term Transfer Analysis and the High ATC evaluated in SERVM as part of the planning reserve margin analysis, it would be helpful to understand if the Companies are going to conduct any further evaluation of the costs of securing firm import capability from either MISO, TVA, or PJM. It would be helpful to understand the full cost of the transmission investments and firm service access.

9. ALTERNATIVE MODELING

9.1 METHODOLOGY

9.1.1 CAPACITY EXPANSION AND PRODUCTION COST MODELING

The Companies' modeling methodology involves the use of three different models, which include the Strategic Energy and Risk Valuation Model ("SERVM"), PLEXOS, and PROSYM. For this IRP, the Companies helped us gain access to a license for PLEXOS and EFG is a license holder of the SERVM model.

The Companies used SERVM to develop the planning reserve margin and the capacity contribution for battery storage and DSM resources. Both of these are inputs into the capacity expansion modeling. The Companies used PLEXOS to perform their capacity expansion modeling. Portfolios of resources are created for the different scenarios evaluated by the Companies in this IRP. Capacity expansion modeling involves utilizing an optimization engine to minimize system costs given the costs of new and existing resources including a simplified[72] projection of

[69] KU/LG&E 2024 IRP, Volume III, Resource Adequacy Analysis, Table 9 at 17.
[70] Companies' Discovery Response to Sierra Club 1-29.
[71] KU/LG&E 2024 IRP, Volume III, Resource Adequacy Analysis at 16.
[72] In order for the model to reach a solution the "problem size" has to be manageable, a common way to limit problem size is to simulate only a handful of hours, such as two "typical" days per month in the capacity expansion step.

unit commitment and dispatch.[73] One of the inputs into the capacity expansion model is the PRM. When the model is choosing the least cost portfolio, it will seek to minimize the cost of a plan that meets peak load plus the PRM. The Companies then moved to their next step, production cost modeling using a third optimization software called PROSYM. A portfolio must be fixed for this modeling, the model does not optimize the resources within each plan. Instead, the purpose is to simulate the operation of the portfolio on an 8,760 hour per year, chronological basis in each year of the planning period. The results from the production cost modeling are then combined with the capital and other fixed costs in the capacity expansion modeling to develop the total costs of the portfolios evaluated.

PLEXOS is a very powerful, customizable tool for this purpose. There are dozens of utilities who license PLEXOS for dispatch simulation reasons such as power marketing, fuel budgeting, maintenance scheduling, etc. In contrast, PROSYM is no longer supported by its vendor and lacks many of the capabilities of contemporary modeling tools such as the ability to properly optimize battery storage, the ability to pair solar with battery storage, etc. In the IRP the Companies stated that "PLEXOS and PROSYM use the same inputs (e.g., they use the same natural gas and coal prices), but the Companies used PROSYM rather than PLEXOS for detailed production cost modeling because they have used and configured PROSYM over a number of years to do such modeling relatively quickly."[74]

PLEXOS is capable of performing both capacity expansion and production cost modeling. In the last IRP, EFG recommended that the Companies use the same model to perform capacity expansion and production cost modeling, which would mean utilizing PLEXOS, since PROSYM is not capable of performing capacity expansion modeling. We again make that recommendation. One of the other reasons for recommending the switch to a single model is because there is a concern about how PROSYM can handle the dispatch of resources like battery storage. A review of the PROSYM output files for the Recommended Resource Plan indicate unrealistically low capacity factors or periods where it is not dispatched.[75] While no model is perfect, a switch away from PROSYM to another platform to conduct both capacity expansion and production cost modeling will simplify the modeling approach, enhance transparency, and shift planning to a model with more modern capabilities.

For this IRP, the Companies did abandon use of the ELDCM model and are only using SERVM because "it is less capable of modeling limited-duration resources".[76] We support and appreciate this development.

9.2 MODELING INPUT CHANGES

The alternative modeling we performed focused on the Ozone NAAQS + ELG environmental scenario under the mid coal and mid gas prices. We chose to focus on these given the Companies' statements around this scenario being the most likely environmental regulation scenario.[77]

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[73] The model can also optimize for any external market interactions.
[74] KU/LG&E 2024 IRP, Volume III Resource Assessment at 28.
[75] The Companies' workpaper named "CONFIDENTIAL_out_unityr" for the Recommended Resource Plan.
[76] KU/LG&E 2024 IRP, Volume III Resource Adequacy Analysis, Footnote 8 at 8.
[77] KU/LG&E 2024 IRP Volume III, Resource Assessment at 25.

We used the Companies' PLEXOS database to perform the capacity expansion and production cost modeling. We made several changes to modeling input assumptions, which are outlined in the following subsections.

9.2.1 FUTURE OPERATIONS AT GHENT 2

Under the Ozone NAAQS + ELG environmental scenario, there is a requirement made for the future operation of Ghent 2 given the requirements of the GNP. Under this scenario, the Companies had three compliance pathways for Ghent 2, which include: install SCR by 2030, retire by 2030, or operate only in the non-ozone seasons (October through April) starting in 2030.[78] However, the Companies did consider a pathway where Ghent 2 is converted to operate 100% on natural gas, without the need for an SCR. As the Companies said, "[t]he Companies assume the Ghent 2 unit, converted to operate on gas but without an SCR, would emit an amount of NOx in excess of limitations stipulated in the proposed Good Neighbor Plan regulations."[79]

We evaluated a resource plan where Ghent 2 is allowed to convert without the need for an SCR. The Companies are proposing to install SCR in order to reduce NOx emissions from the coal-fired Ghent 2. However, the Companies strangely assume that, even with gas conversion, "SCRs are assumed to remain in service and maintain existing emissions levels…" [80] However, formerly coal-fired units that are converted to gas are able to achieve the NOx emission level without the installation of an SCR. The Companies have stated that their post-SCR installation NOx emissions target for Ghent 2 is 0.04 lb/MMBtu during the ozone season (May – September) and 0.09 lb/MMBtu (rest of the year, from October – April). Based on NOx emissions achieved by many previously coal-fired tangential units like Ghent 2, it is possible to achieve the target NOx levels of 0.04 and 0.09 lb/MMBtu, without SCR. A review of EPA's Clean Air Markets database shows that: IPL Harding Street Station (previously E.W. Stout) Units 50 and 60; North Omaha Station Unit 3; Sabine Unit 3; Danskammer Unit 4; and Gulf Clean Energy Units 4 and 5 have all achieved NOx levels of 0.04 lb/MMBtu on a daily average basis. These and additional tangential-fired units like Ghent 2 achieve the 0.09 lb/MMBtu level on a daily average basis including: Cherokee Unit 4; Jim Bridger Unit 71; McMeekin Units 1 and 2; Muskogee Unit 4; Naughton Unit 3; and Yates Units 6 and 7. Thus, the Companies should have considered whether it was lower-cost to convert the unit to natural gas without installing the SCR as an alternative.

9.2.2 COAL RETIREMENT AND REPLACEMENT

The Companies also included a constraint in PLEXOS to represent that if any of the existing coal units retire, then the capacity would need to be replaced over the planning period by dispatchable resources, which the Companies

[78] Companies' Discovery Response to Joint Intervenors 1-35.
[79] Companies' Discovery Response to Sierra Club 2-7.
[80] KU/LG&E 2024 IRP Volume III, Resource Assessment at 55.

model as NGCC, SCCT, and Small Modular Reactor nuclear resources.[81] In response to a discovery question related to evaluating coal retirements prior to 2030, the Companies said,

> *Kentucky law requires replacing retiring coal units with "dispatchable" resources that have "the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service."*[82]

The alternative modeling we performed removed this constraint within PLEXOS and allowed the model to select the optimal mix of resources without being limited to only NGCC, SCCT, or nuclear resource options.

9.2.3 LOAD FORECAST MODELED

The Companies' load forecast included generic assumptions around different levels of growth for new customers, with a particular focus on levels of growth from data centers locating in the Companies' service territory. Since these assumptions did not reflect any specific customer, we modified the load forecast to only include the load related to one of the prospective data center customers. We focused on this particular customer because the Companies indicated they have an executed Engineering, Procurement, and Construction contract with developers of the data center project to be built at Camp Ground Road.[83]

In order to develop this load forecast, we took the Companies' Mid Load scenario and removed all of the data center load assumed for that case.[84] We then developed an hourly forecast for the Campground customer based on the projected load ramp[85] and developed hourly values based on the shape the Companies assumed for new data center load.[86] The total amount of new data center load included in this forecast is 400 MW.

9.2.4 ENERGY EFFICIENCY

Table 10 below shows the differences in the level of energy efficiency included in the Companies three load forecast scenarios.

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[81] Companies' Discovery Response to Sierra Club 1-38.
[82] Companies' Discovery Response to Joint Intervenors 2.44.
[83] Companies' Discovery Response to Sierra Club 1-12(c)(i).
[84] Companies' Discovery Response to Sierra Club 2-16 confirmed that hourly data center load was provided in workpaper "Data_Center_1_Phase_2_Included_MA_Shaping".
[85] Companies' Discovery response to Sierra Club 1-12 (c)(i).
[86] Companies' Discovery Response to Sierra Club 2-16 confirmed that hourly data center load was provided in workpaper "Data_Center_1_Phase_2_Included_MA_Shaping".

Table 10. Differences in Load Forecast Scenarios[87]

Load Scenario	Energy Efficiency, CVR, AMI, and Other Reductions in 2032 (GWh)
Low	2,150
Mid	1,500
High	700

We looked at an alternative forecast that looked at the energy efficiency savings that were included in the Low Load scenario. We looked at including this incremental level of energy efficiency savings as a reduction to the Companies' Mid load scenario.

The Companies' assumption around the additional savings from energy efficiency seem to include customer-initiated energy efficiency improvements and the Companies' programs.[88] However, the Companies did not include any specific costs of energy efficiency in the Mid, Low, or High scenario. [89] In order to incorporate costs for additional levels of energy efficiency above what was included in the Companies' base load forecast, we developed a levelized cost of $38.25/MWh from the Companies' reported costs and savings of the current programs.[90]

9.2.5 RENEWABLE RESOURCE BUILD LIMIT

The Companies implemented a limit in PLEXOS on solar and wind resources that constrained the annual generation to a certain percentage of the annual energy requirements. We removed this constraint applied by the Companies and instead applied an annual build limit. For solar, the build limit started at 600 MW per year in 2028 and then increased to 800 MW per year in 2032, and then reached 1,000 MW per year in 2033. These were applied as annual build limits and no cumulative build limits were applied.

9.3 ALTERNATIVE RESOURCE PLAN

Given the results of the Companies' modeling for this IRP, and the constraint on Brown 3, Mill Creek 3, and Mill Creek 4 needing to retire on or before a certain date because of the landfill storage constraints,[91] our alternative modeling focused on the resource decisions at Ghent 2 and Brown 3 and maintained the Mill Creek 3 and 4 retirement date of 2035 that the Companies assumed in the Recommended Resource Plan.

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[87] KU/LG&E 2024 IRP, Volume 1, Table 5-2 at 5-2.
[88] Companies' Discovery Response to Joint Intervenors 1.60.
[89] Companies' Discovery Response to Sierra Club 2-12(a).
[90] KU/LG&E 2024 IRP, Volume I, Table 8-13, 8-14, and 8-17. The levelized calculation assumed an average measure life of 10 years for the energy efficiency savings.
[91] Companies' Discovery Response to Joint Intervenors 1-34.

The least cost plans across the low, mid, and high load forecasts under the different environmental regulation scenarios found that Brown 3 retired in either 2030 or 2031 or converted in 2035.[92, 93, 94] Given these results, and the Companies' Recommended Plan delaying the retirement of Brown 3 to 2035, our alternative modeling focused on evaluating a retirement of Brown 3 in 2031.

We also evaluated the decision on Ghent 2. The Companies' Recommended Resource Plan pursues the addition of SCR on Ghent 2 in 2028. Our alternative modeling looked at converting Ghent 2 by 2030. We assumed that a conversion to 100% gas would not require the installation of an SCR.

9.4 PRODUCTION COST MODELING CHANGES

In addition to the changes made to perform the capacity expansion modeling, we also made two changes that applied to the production cost modeling we performed in PLEXOS. First, we applied a cycle limit on all battery storage resources to limit them to 365 cycles per year. Second, we relaxed the constraint that the Companies placed on CT resources that limited their capacity factor. We relaxed this assumption given some of the capacity factors we saw for CT resources in the PROSYM modeling output files being higher than the limit applied in PLEXOS.

9.4.1 ALTERNATIVE PLAN

As discussed above, we looked at developing an alternative resource plan with different decisions around Ghent 2 and Brown 3 from the Companies' Recommended Plan. Our alternative plan looked at converting Ghent 2 in 2030 and retiring Brown 3 in 2031 under two different load forecast assumptions. The first load forecast assumed the Companies' Mid Load scenario with the adjustment to include the higher level of energy efficiency savings that the Companies included in their Low Load scenario. The second load forecast looked at only including 400 MW from a new customer in the load forecast. Table 11 shows the capacity expansion result for a plan that converts Ghent 2 in 2030 and retires Brown 3 in 2031 under the Mid Load scenario, with the inclusion of the higher level of energy efficiency savings.

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[92] KU/LG&E 2024 IRP Volume III, Resource Assessment, Table 25 at 44.
[93] KU/LG&E 2024 IRP Volume III, Resource Assessment, Table 26 at 45.
[94] KU/LG&E 2024 IRP Volume III, Resource Assessment, Table 27 at 47.

Table 11. Expansion Plans Under Companies Mid Load Scenario with Higher Energy Efficiency Savings

Year	Ghent 2 Convert and Brown 3 Retire
2030	Convert Ghent 2 200 MW 4-Hour Storage
2031	Retire Brown 3 1 NGCC 100 MW 4-Hour Storage
2032	200 MW 4-Hour Storage
2035	Retire Mill Creek 3-4 300 MW 4-Hour Storage 1 NGCC 600 MW Solar
2036	1,000 MW Solar

We also looked at this plan under our modified load forecast which took the Companies' Mid Load scenario, removed all of the generic data center load the Companies assumed, and then added the 400 MW from the new customer that the Companies have signed an EPC agreement with.

Table 12. Expansion Plan Under Alternative Load Scenario

Year	Ghent 2 Convert and Brown 3 Retire
2030	Convert Ghent 2
2031	Retire Brown 3 500 MW 4-Hour Storage
2035	Retire Mill Creek 3-4 200 MW 4-Hour Storage 1 NGCC 500 MW Solar
2036	1,000 MW Solar

The results of the two different load scenarios indicate the importance of the load assumption on whether the model selects one or two NGCC resources over the planning period. Under the assumption that only includes the load from the 400 MW of new customer load, and allowing the model to optimize without the SB constraint, the model does not select a NGCC resource until 2035 when Mill Creek 3 and 4 are retired. The NGCC that is selected in 2035 could also be delayed or not needed if Mill Creek 3 or 4 are converted to operate on natural gas instead of retiring.

9.4.2 PRESENT VALUE OF REVENUE REQUIREMENT ("PVRR") OF ALTERNATIVE RESOURCE PLANS

The Companies use their own financial model developed in Excel to calculate the PVRR values of resource plans. This model includes the system operational costs from the production cost modeling, including variable operations and maintenance ("O&M") and fuel costs. The financial model also includes assumptions around the ongoing capital and maintenance for existing and new units, capital and O&M for new resources in the capacity expansion plan, and additional capital expenditures like the addition of SCR for Ghent 2 or the conversion of a unit. We assumed the stay open and environmental costs for the existing resources that the Companies modeled for the Ozone NAAQS + ELG environmental scenario. Our modeling utilized the same modeling period as the Companies did for its Recommended Resource Plan in PROSYM, which was from 2024 to 2039.[95] This means that the production costs included in the financial model are only for that period of time, while there are other costs, such as stay open or new capital investment costs, that are in the model through 2050.

We modified the Companies' financial model assumptions regarding the Production Tax Credit ("PTC") for renewable resources. In their model, the Companies assumed a flat value for the PTC over the planning period. We modified this assumption to start the PTC at the 2024 rate of $29/MWH and then added in the additional bonus for projects being located within an Energy Community and grossed up the value to account for the Companies' tax rate. Once that value is determined, it should escalate by an inflation rate, which is consistent with how the PTC value is calculated under federal law, and which we assumed to be 2.3%, so that projects coming online throughout the planning period have the PTC adjusted for inflation.

Table 13 shows the PVRR results for our alternative plan under the Mid Load scenario that includes the higher level of energy efficiency savings in comparison to our rerun of the Companies' Recommended Plan. We included the new resource additions through 2035 that the Companies reported for their Recommended Plan and put this through PLEXOS to develop the production costs to include in the financial model.

There are three different PVRR periods reflected in Table 13. The first period, which is 2023 – 2039, reflects the period that was modeled for the production costs. The second period, which is 2023 – 2050, reflects the additional costs post 2039 for the stay open costs for existing units and the capital for new resources. The third period, which is "2023 – 2050 and Terminal Value" reflects the costs out to 2050 and then the inclusion of a terminal value that considers costs past 2050.

[95] Companies' Discovery Response to Sierra Club 2-10.

Table 13. PVRR Results for Mid Load Scenario (Millions $)

	Ghent 2 Convert Brown 3 Retire Higher EE	Rerun Companies' Recommended Plan
2024 – 2039	$23,094	$23,786
2024 – 2050	$26,470	$26,965
2024 – 2050 and Terminal Value	$31,310	$31,255

This alternative plan is materially lower cost than our rerun of the Companies' Recommended Plan for the 2024 – 2039 and 2024 – 2050 PVRR periods. While our rerun of the Companies' Recommended Plan does become slightly lower in cost for the "2024 – 2050 and Terminal Value" PVRR, we would not recommend comparing portfolios based on this PVRR. In our experience, we typically do not see utilities develop a PVRR for portfolio modeling for periods that extend beyond 2050. The level of uncertainty in planning increases with time and to conclude that a resource plan would be lower cost on the basis of calculations more than 25 years down the road is imprudently speculative. Table 14 shows the PVRR results for the alternative plan when optimized under the alternative load forecast, which only includes 400 MW of new customer load.

Table 14. PVRR Results for Alternative Load Forecast (Millions $)

	Ghent 2 Convert Brown 3 Retire
2024 – 2039	$21,792
2024 – 2050	$24,670
2024 – 2050 and Term	$28,925

The PVRR results for the alternative plans indicate the cost differences that arise from the different load forecasts and the risk associated around the uncertainty of any new data center load materializing. As the Companies stated in the IRP, "Due to the magnitude of data center loads, economic development is a key uncertainty in this load forecast."[96] And from the time when the Companies provided responses to discovery questions in this proceeding, the Companies indicated that there have not been any projects that have made formal announcements that they will locate in the Companies' service territories.[97]

10. SUMMARY OF RECOMMENDATIONS

Based on our review of the Companies' IRP and the alterative modeling we performed, we offer the following recommendations:

[96] KU/LG&E 2024 IRP, Volume 1 at 7-13.
[97] Companies' Discovery Response to Sierra Club 1-12(f).

1. The Commission should not approve the construction of new resources that are intended to serve large customers without establishing protections for existing ratepayers that would guarantee costs caused by these new loads are paid by the new load and prevent early exit from said large load agreements without a stranded cost allocation to those large loads.
2. KU/LG&E's operational decisions regarding Mill Creek 3 and 4 are primarily what cause the need for a second NGCC under the Mid Load scenario. But the Companies' plan to advance the second NGCC to 2031 is not adequately justified as it is based on speculative load growth. While the Companies characterize this as a "no regrets" decision because of load growth inquiries, it puts unnecessary risk on existing ratepayers to build a new power plant for need that may never materialize.
3. The Companies should have evaluated whether it was a lower-cost alternative to convert Ghent 2 to run on natural gas compared to their proposed retrofit of Ghent 2 with an SCR. Former coal-fired power plants that were converted to run on gas achieve NOx emissions rates at or below the emission rate that the Companies hope to achieve at Ghent 2 during ozone season with an SCR, so the Companies should have considered conversion as an alternative. We modeled such a scenario and found that it was a lower PVRR cost than the retrofit alternative. Moreover, it had a significantly cheaper PVRR when a reasonable, less speculative amount of load growth is assumed.
4. The Companies' interconnection process for new load does not appear to shield existing customers from serious risks to the operational security and reliability of the grid that large loads may introduce and urgently needs to be reformed before these new customers are interconnected.
5. The Companies should provide an analysis around the costs and benefits of securing ATC access with neighboring regions.