COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES	))))))	**Case No. 2025-00045**

DIRECT TESTIMONY OF CHELSEA HOTALING
ON BEHALF OF SIERRA CLUB

June 16, 2025

DIRECT TESTIMONY OF CHELSEA HOTALING
ON BEHALF OF SIERRA CLUB
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2025-00045

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Chelsea Hotaling, and my business address is 91 Main Street, Canton, NY 13617.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Senior Consultant at Energy Futures Group ("EFG").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Sierra Club.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I have worked for nine years in electric utility regulation and related fields. I have reviewed dozens of integrated resource plans ("IRPs") and related filings by utilities in Arizona, Colorado, Georgia, Kansas, Kentucky, Iowa, Indiana, Michigan, Missouri, Montana, Minnesota, New Mexico, Nova Scotia, Puerto Rico, Wisconsin, and South Carolina. I have performed my own capacity expansion, production cost, and reliability modeling in numerous cases using multiple models, including EnCompass, AURORA, PLEXOS, and the Strategic Energy & Risk Valuation Model ("SERVM").

I received a Bachelor's Degree in Accounting and Economics from Elmira College in 2011. I also received a Master of Business Administration Degree in 2012, a Master's Degree in Environmental Policy in 2019, and a Master's Degree in Data Analytics in 2020, all from Clarkson University. My resume is attached as Exhibit CH-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS OR ANY COMMISSION?

A. Yes, I filed expert witness testimony in Case No. 2024-00152, Case No. 2022-00371, and Case No. 2022-00387. I have also filed testimony before regulatory commissions in Colorado, Georgia, Iowa, Michigan, Montana, South Carolina, West Virginia, and Wisconsin.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to Kentucky Utilities Company ("KU") and Louisville gas and Electric Company's ("LG&E") (collectively, "KU-LG&E" or the "Companies") request for approval of new supply side resources and to install Selective Catalytic Reduction ("SCR") on Ghent 2. I also respond to the Companies' assumptions for new large load customers that are included in the 2025 Certificate of Public Convenience and Necessity ("CPCN") Load Forecast presented in this proceeding.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE KENTUCKY PUBLIC SERVICE COMMISSION.

A. My recommendations include:

- The Commission should deny approval of the new supply side resources requested in this proceeding until the Companies can provide evidence that the customers needed to justify the proposed resource additions have committed to taking service under agreements that require a financial commitment to the Companies. If the Commission does approve the resources requested by the Companies in this proceeding, the Commission should also direct the Companies to evaluate their existing units for retirement to determine the resources that would be most economic to retire in the event that the new customer load does not materialize by 2031, and/or the Commission should disallow recovery of costs for units that are not used and useful. The CC and battery storage resources requested in this proceeding represent 1,660 MW of winter firm capacity and the Companies should be directed to evaluate up to that level of existing resource firm capacity for retirement.

- The Commission should deny approval of the SCR for Ghent 2 since the Good Neighbor Plan does not currently apply in Kentucky, and SCR is not necessary to comply with any other currently-applicable environmental compliance requirement.
- If the Companies enter into reservation agreements to secure new generation resources, and if the purpose of securing that new generation resource is to serve an incremental load addition, the cost of that reservation agreement should be borne by the new large load customer(s) and should not be passed on to existing ratepayers.
- The Companies should be required to submit quarterly reports to the Commission to provide updates on the status of new prospective customers. This information should include:

    1. Customer or Project name;
    2. Project address;
    3. Announced Project Load (MW);
    4. Projected load ramp including load (MW) and timing;
    5. Changes in project status since the last report to include:
        a. Updates to announced load;
        b. Updates to load ramp;

c. Project Stage (new project, existing project and undergoing the transmission service request ("TSR") process, contract status – EPC or service agreement)

6. Reason for project loss if known (selected alternative state/ project cancelled/ project delayed indefinitely)

7. Additional information including: site control, construction progress, permit status, whether or not data center developers have a tenant in place for the site, and the number of projects the developer has experience with.

Q. PLEASE SUMMARIZE THE KEY FACTS SUPPORTING THE RECOMMENDATION TO DENY THE COMPANIES' PETITION.

A. The key facts include:

1. No potential customer in the Company's load queue has made a material financial commitment towards taking service from the Companies.

2. One of the biggest projects included in the Company's load forecast calculations is seeking a new site after community pushback led it to abandon its original plans.

3. It does not appear that there has been any material change in the drivers of new load since the production of the 2024 IRP and this filing, e.g., no signed service contracts. Despite this, the Companies have increased their large load projections by 700 MW.

4. Before they start construction of transmission facilities necessary to interconnect a new, large customer, the Companies require a financial commitment that will ensure recovery of transmission costs in the event the customer does not take service. The

Companies have no similar threshold before spending billions of dollars on new generation.

5. According to the Companies, "No internal documentation exists that the Companies use to assign the stage of economic development projects."[1] However, the assigned stage influences the level of large load in the Companies' load forecast.

6. The data center furthest along in development within the Companies' service territory is a tenant-based developer with no tenant yet announced.

7. The Companies have very few barriers to entry into their load queue and therefore would have difficulty distinguishing speculative requests from those that are more serious.

III. THE COMPANIES' REQUEST FOR NEW RESOURCES

Q. WHAT RESOURCES ARE BEING REQUESTED BY THE COMPANIES IN THIS PROCEEDING?

A. The Companies are requesting approval for the following resources:

- Two 1x1 Combined Cycle ("CC" or "NGCC") resources at 645 MW each. The Brown 12 CC is proposed to be located at the Brown site and in service by 2030. The Mill Creek 6 CC is proposed to be located at the Mill Creek site and in service by 2031.
- A 400 MW four-hour battery energy storage system to be built at the Cane Run Generating Station to be in service in 2028.

[1] KU/LG&E response to AG-KIUC 2-20(b).

- A selective catalytic reduction ("SCR") for Ghent 2 to be in service by 2028.

Q. WHAT IS THE TOTAL CAPITAL COST FOR THE RESOURCES REQUESTED IN THIS PROCEEDING?

A. The total projected capital costs for the resources requested are approximately $3.7 billion. Table 1 shows the capital cost for each of the resources requested by the Companies. This includes the capital cost of the resources only and not additional costs for ongoing capital expenditures, variable costs, fixed operations and maintenance ("O&M"), and firm fuel transportation costs.

Table 1. Proposed Resource Capital Cost[2]

Proposed Resource	Capital Cost
Brown 12	$1,383,000,000
Mill Creek 6	$1,415,000,000
Cane Run BESS	$775,000,000
Ghent 2 SCR	$152,000,000
Total	**$3,725,000,000**

Q. WHAT HAS LED TO THE COMPANIES TO REQUEST APPROVAL FOR THESE RESOURCES?

A. Witness Bevington testified that the Companies have over 8,000 MW of economic development load potential, with 6,000 MW related to data centers and the remaining 2,000 MW for industrial customers.[3] Figure 1 shows the comparison between the winter and summer peak forecast with and without the economic development load.

[2] Joint Application at 12. For Brown and Mill Creek, costs include projected capital cost and related gas and electric transmission work.
[3] Direct Testimony of Witness Bevington at 5.

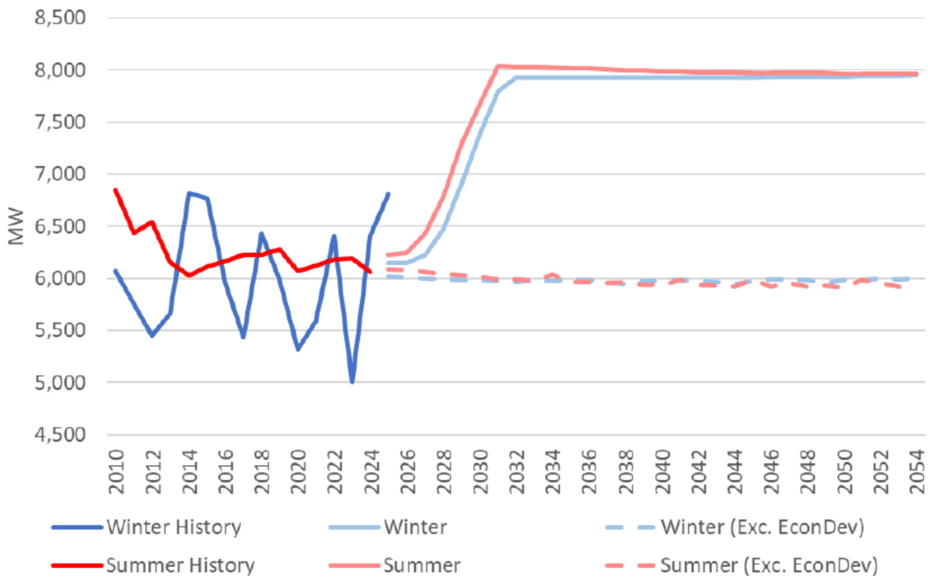

Figure 1. Winter and Summer Peak Forecast (MW)[4]

Q. WHAT IS DRIVING THE PROJECTED NEW LOAD IN THE COMPANIES LOAD FORECAST?

A. The majority of the projected new load growth is from data centers. Many of the prospective data center customers in the Companies' load queue average 344 MW and are up to 600 MW in size.[5] It is important to note that this is a substantial difference in customer makeup from the Companies' current experience as the Companies currently have just four customers with demand greater than 50 MW.[6]

Q. WHAT LEVEL OF NEW LOAD DID THE COMPANIES ASSUME IN THE 2025 CPCN LOAD FORECAST?

A. The 2025 CPCN Load Forecast is the High Scenario evaluated in the 2024 Integrated Resource Plan ("IRP"). The 2025 CPCN Load Forecast includes an assumption of 1,750 MW

---

[4] Exhibit SAW-1, Figure 2 at 11.
[5] KU/LG&E response to Attorney General and Kentucky Industrial Utility Customers' ("AG-KIUC") 1-33(a) Attachment.
[6] KU/LG&E response to Joint Intervenors 1-140(i).

of data center demand in addition to the 120 MW Phase 2 for the BlueOval SK Battery Park ("BOSK").[7] The 2025 CPCN Load Forecast also includes 20 MW from an economic development prospect and 19.4 MW from an existing customer's expansion.[8]

Q. WHAT IS THE PROJECTED CAPACITY POSITION FOR THE COMPANIES?

A. Table 2 shows the winter capacity position for the Companies under the 2025 CPCN Load Forecast. Under this forecast, the Companies will fall below the winter reserve margin requirement of 29% starting in 2029.[9] As Witness Wilson outlined in his testimony, the Companies can accommodate 402 MW from the Camp Ground data center, the 20 MW customer expansion, and BOSK Phase One, but if Phase Two of BOSK is added, then the Companies will not be able to meet their target winter reserve margin without resource additions.[10]

[7] KU/LG&E response to AG-KIUC 1-26(b).
[8] Direct Testimony of Witness Jones at 21.
[9] Exhibit SAW-1 at 34.
[10] Direct Testimony of Witness Wilson at 4-5.

Table 2. Winter Capacity Position Under 2025 CPCN Forecast[11]

	2028	2029	2030	2031	2032
Peak Load	6,481	6,918	7,386	7,795	7,930
Dispatchable Resources					
Existing Resources	7,977	7,977	7,977	7,977	7,977
Retirement/Additions					
Coal	-597	-597	-597	-597	-597
SCCTs	-55	-55	-55	-55	-55
Mill Creek 5	660	660	660	660	660
Total	7,985	7,985	7,985	7,985	7,985
Reserve Margin	23%	15%	8%	2%	1%
Renewable/Limited-Duration					
Existing Resources	72	72	72	72	72
Existing CSR	111	111	111	111	111
Existing Dispatchable DSM	110	124	125	135	145
Retirements/Additions					
Solar	0	0	0	0	0
Battery Storage	125	125	125	125	125
Total	418	432	433	443	453
Total Supply	**8,403**	**8,417**	**8,418**	**8,428**	**8,438**
Total Reserve Margin	**29.7%**	**21.7%**	**14.0%**	**8.1%**	**6.4%**
Capacity Need (Excess)	**-43**	**507**	**1,110**	**1,628**	**1,792**

Q. ARE THE RESOURCES REQUESTED IN THIS PROCEEDING BEING ADDED TO MEET THE COMPANIES' PROJECTION FOR LOAD GROWTH?

A. Yes. Table 3 shows the Companies' projected capacity position if economic development load is removed from the forecast.[12] Without this load, the Companies have excess capacity and are above the winter reserve margin requirement of 29%.

[11] Exhibit SAW-1, Table 7 at 23.
[12] Winter peak values are taken from the Companies workpaper named "AWJ_JDL_Charts.xlsx". In response to AG-KIUC 3-1(a), the Companies confirmed that column C in worksheet "Peak_Chart_2" "excludes all economic development, including the projects identified in the Companies' application (Data Centers, BOSK, Auto, etc.)."

Table 3. Winter Capacity Position Under 2025 CPCN Forecast and No New Load

	2028	2029	2030	2031	2032
Peak Load	5,997	5,988	5,982	5,975	5,970
Dispatchable Resources					
Existing Resources	7,977	7,977	7,977	7,977	7,977
Retirement/Additions					
Coal	-597	-597	-597	-597	-597
SCCTs	-55	-55	-55	-55	-55
Mill Creek 5	660	660	660	660	660
Total	7,985	7,985	7,985	7,985	7,985
Reserve Margin	30%	30%	30%	30%	30%
Renewable/Limited-Duration					
Existing Resources	72	72	72	72	72
Existing CSR	111	111	111	111	111
Existing Dispatchable DSM	110	124	125	135	145
Retirements/Additions					
Solar	0	0	0	0	0
Battery Storage	125	125	125	125	125
Total	418	432	433	443	453
Total Supply	**8,403**	**8,417**	**8,418**	**8,428**	**8,438**
Total Reserve Margin	**40.1%**	**40.6%**	**40.7%**	**41.1%**	**41.3%**
Capacity Need (Excess)	**-667**	**-693**	**-701**	**-720**	**-736**

Q. HOW IS THE SCR PROPOSED AT GHENT 2 DRIVEN BY THE ADDITION OF NEW CUSTOMERS IF THIS IS NOT A NEW RESOURCE ADDITION?

A. The Companies' position is that an SCR is needed at Ghent to comply with the 2015 National Ambient Air Quality Standard for ozone ("2015 Ozone NAAQS") and to be able to operate the unit to serve new customer loads.[13]

[13] The Companies said, "A Ghent 2 SCR in 2028 will drive self-compliance to NOx reductions that support Kentucky's obligations to 2015 Ozone NAAQS attainment and provides assurance the unit will be available to support economic development load growth." 2024 IRP Volume III, 2024 IRP Resource Assessment at 8.

IV. NEW LARGE LOAD ASSUMPTIONS

Q. IS THE 2025 CPCN LOAD FORECAST BASED ON SPECIFIC CUSTOMERS THAT HAVE MADE A COMMITMENT TO LOCATE WITHIN THE COMPANIES' SERVICE TERRITORY?

A. No, the 2025 CPCN Load Forecast for 1,750 MW of data center load is not based on specific prospective data center customers. The Companies stated the 1,750 MW is an estimate:

> The 1,750 MW of data center load included in the 2025 CPCN Load Forecast does not consist of specific data center projects; rather, it is a reasonable estimate of how much of the more than 6,000 MW of potential data center load in the Companies' current queue will come to fruition in the near term.[14]

Q. DOES THE 2025 CPCN LOAD FORECAST INCLUDE THE SECOND PHASE OF BLUE OVAL ("BOSK")?

A. Yes. The contract that the Companies have with BOSK includes the Phase Two load of 120 MW.[15] While the Companies have a contract to include Phase Two, some of the language presented by the Company makes it unclear how fast BOSK might ramp up to the full level of load that includes Phase Two. Witness Jones said, "It is my understanding that all of the electrical facilities necessary for BOSK to take service at the second building are in place, meaning that BOSK could relatively quickly begin taking service for the building at up to 120 MW <u>if it decides to proceed</u>."[16] In a discovery response, the Companies also said, "The building for phase two has already been constructed. The phase two load ultimately will result from growth in consumer demand for EVs."[17] Based on the Companies responses, there is uncertainty about whether BOSK will ramp up to the full level of load, and if it does,

[14] KU/LG&E response to Staff 1-17.
[15] Direct Testimony of Witness Jones at 20.
[16] Direct Testimony of Witness Jones at 20 (emphasis added).
[17] KU/LG&E response to Sierra Club 2-1(c).

at what time the ramp will happen.

Q. THE COMPANIES HAVE REFERRED TO THE 1,750 MW DATA CENTER LOAD ASSUMPTION AS "REASONABLE".[18] WHAT LED THE COMPANIES TO DETERMINE THAT 1,750 MW OF DATA CENTER LOAD IS REASONABLE?

A. Company witnesses testified on several items to support the level of data center load included in the Companies' 2025 CPCN Load Forecast. For example, Witness Jones cited national load growth, Kentucky's efforts to attract data center customers, and the level of prospective customers in the Companies' load queue.[19]

Q. WHAT SUPPORT HAVE THE COMPANIES PROVIDED FOR THE DERIVATION OF THE 1,750 MW OF DATA CENTER LOAD?

A. The Companies' support for the 1,750 MW assumption relies on two reported calculations. The first calculation is an expected value approach that weights the project sizes by assigned probabilities.[20] Table 4 shows the breakout of the Companies' load queue with the reported probabilities assigned to each phase prior to the "Announced" phase. The Companies have assigned higher probabilities to the phases that are closer to the "Announced" phase.

---

[18] KU/LG&E response to AG-KIUC 2-18(a) states "The Companies did not evaluate a larger range of data center load because they believe 1,750 MW is a reasonable estimate for economic development load growth."
[19] Direct Testimony of Witness Jones at 18.
[20] KU/LG&E response to Staff 2-14(a).

Table 4. Companies Phase Description with Probabilities[21]

Phase	Description	Load	Probability[22]
Inquiry	Early stage of evaluation	1,630	10%
Suspect	Project engaged in information exchange	1,785	20%
Prospect	Regular exchange of information and detailed evaluation of a site	2,200	50%
Imminent	Project has information necessary to make a decision	402	80%
Announced	Signed Contract	0	-

According to the Companies, when the probability weights are assigned, the 1,750 MW of data center load falls above the low probability expected value of 1,040 MW and below the mid-probability expected value of 1,905 MW.[23] The second calculation reported by the Companies assumed that the Camp Ground and Project Lincoln[24] data centers come to fruition at approximately 1,000 MW. Though, as noted above, neither has taken service from the Companies and indeed Project Lincoln is now scouting a new location after abandoning its prior location over community pushback.[25] The Companies then determined the average size of projects in the Suspect, Prospect, and Imminent phases to be 350 MW, and when assigning two additional 350 MW data centers to the KU and LG&E service territories, this resulted in approximately 1,750 MW of data center load.[26] The Companies' justification for this second calculation is that "Adding two such data centers was and is reasonable given the queue of more than 5,000 MW of data center potential after removing the Camp Ground and

[21] KU/LG&E response to Staff 1-18.
[22] KU/LG&E response to Sierra Club 2-9.
[23] KU/LG&E response to Staff 2-14(a).
[24] Also known as Project Meridian.
[25] https://www.courier-journal.com/story/news/local/2025/06/02/new-location-proposed-for-6-billion-data-center-in-oldham-county/83997706007/
[26] KU/LG&E response to Staff 2-14(a).

Project Lincoln data centers."[27]

Q. IS THE ASSUMPTION FOR 1,750 MW OF DATA CENTER LOAD GROWTH DIFFERENT FROM WHAT WAS MODELED AS THE BASE CASE, OR MID LOAD FORECAST, IN THE 2024 IRP?

A. Yes, it is different. The 2024 IRP Mid load forecast assumed 1,050 MW of data center load by 2032.[28] The 1,750 MW assumption is from the 2024 IRP High load forecast.

Q. DO YOU KNOW WHY THE COMPANIES USED THE HIGH CASE FROM THE 2024 IRP FOR THE DATA CENTER LOAD INCLUDED IN THE 2025 CPCN LOAD FORECAST?

A. Company witnesses have pointed to the overall level of the load queue, efforts in Kentucky to advance data center development, and announcements from prospective customers.[29] However, it is not clear what has materially changed since the 2024 IRP as it relates to the customers in the Companies' load queue. In terms of contracts, the number of prospective customers that have signed service contracts remains the same as it was during the IRP, i.e., zero.

Q. HOW DO YOU RESPOND TO THE COMPANIES POSITION THAT THE 1,750 MW PROJECTION OF DATA CENTER LOAD INCLUDED IN THE 2025 CPCN LOAD FORECAST IS REASONABLE?

A. I have concerns with the Companies' position around the 1,750 MW of data center load included in the 2025 CPCN forecast. My concerns are highlighted below, and I will discuss each one in more detail in my testimony:

---

[27] KU/LG&E response to Staff 2-14(a).
[28] Direct Testimony of Witness Jones at 8.
[29] Direct Testimony of Witness Bevington at 2-10. Direct Testimony of Witness Jones at 14 – 16.

1. The Companies do not have a signed electric service agreement ("ESA") with any customers in the load queue. The Companies do have one signed engineering, procurement and special equipment and construction ("EPC") agreement with the Camp Ground project, but that is currently being negotiated since the original EPC agreement did not have a financial security provision.[30]
2. A limited number of prospective customers have completed or are in process of a Transmission Service Request ("TSR").
3. The Companies do not appear to have sufficient information to evaluate the full extent of risks associated with the largest projects in their load queue.

When these concerns are taken in totality, the Companies do not have financial commitments from prospective customers to utilize the 1,750 MW of projected data center load to support the need for the resources requested in this proceeding.

Q. ARE YOU SAYING THAT THE COMPANIES WILL NEVER HAVE A DATA CENTER LOCATE IN THEIR TERRITORY?

A. My position is that relying on 1,750 MW of data center load growth to support committing customers to approximately $3.7 billion in new generation is not reasonable when the Companies do not have financial commitments from prospective customers. I am not taking a position on whether or not data center load will *ever* materialize within the Companies' service territories. My concern with the 1,750 MW assumption relates to the investment of billions of dollars in new generation resources that have no guarantee of cost recovery from these new customers and which would significantly raise costs for existing ratepayers if the load that will contribute to the costs of these resources does not materialize or does not reach

[30] KU/LG&E response to Sierra Club 3-18(b).

the Companies' full load projections.

Q. THE COMPANIES HAVE REPORTED THERE ARE 6,000 MWs OF DATA CENTER LOAD IN THEIR LOAD QUEUE.[31] ARE ANY OF THESE PROJECTS IN THE "ANNOUNCED" PHASE, OR HAVE A SIGNED ELECTRIC SERVICE AGREEMENT WITH THE COMPANIES?

A. The Companies do not have any signed Electric Service Agreements ("ESA") with any of the prospective data center customers in the load queue.[32] At the time of this filing, the only agreement the Companies have signed is an agreement for engineering, procurement and special equipment and construction ("EPC") to interconnect the proposed 402 MW Camp Ground data center.[33]

Q. DO THE COMPANIES REQUIRE A FINANCIAL COMMITMENT UNDER AN EPC AGREEMENT?

A. A signed EPC agreement with a prospective customer would indicate a greater level of commitment to taking service from the Companies as this agreement precedes the construction of the transmission facilities identified in the Facilities Study and should guarantee reimbursement of those costs if the customer does not ultimately take service. Under the EPC process there is some level of financial security required of the prospective customer as it relates to transmission costs:

> The Companies require the developer to execute an Engineering, Procurement and Construction Agreement prior to the Company incurring any costs on upgrades or modifications to the transmission system to accommodate the load. While no money is collected, the agreement requires the developer to provide security, in a form acceptable to the

[31] Direct Testimony of Witness Bevington at 5.
[32] KU/LG&E response to Staff 1-18 and KU/LG&E response to AG-KIIUC 1-35(c).
[33] KU/LG&E response to JI 1-7(a). Please also see KU/LG&E response to Sierra Club 1-12(c)(i) in Case No. 2024-00326.

Company[34], that will protect the Company in the event the load does not come to fruition. Specifically, the developer will be liable for all costs incurred by the Company until electric service is taken under an executed contract for the provision of electric service.[35]

Q. DID THE CAMP GROUND EPC INCLUDE A SECURITY PROVISION?

A. The Camp Ground EPC agreement provided by the Companies did not include a security provision.[36] The Companies indicated that their EPC agreements have changed over time and although the November 8, 2024 EPC agreement with Camp Ground does not have a security provision, "the Companies are currently negotiating a new amended agreement that does contain creditworthiness and security provisions appropriate to the increased potential financial commitment."[37]

Q. DO THE COMPANIES HAVE A FINANCIAL COMMITMENT FOR THE CAMP GROUND PROJECT?

A. Since the original EPC agreement did not have a security provision, the Companies do not have a financial commitment for the Camp Ground project at this time. The Companies indicated they are in negotiations for an amended agreement that will include security provisions. However, it is not clear what aspects of the agreement are under negotiation[38] and whether the Camp Ground project will move forward with an amended EPC agreement.

Q. THE COMPANIES REQUIRE AN AGREEMENT ENSURING RECOVERY OF A CUSTOMER'S INTERCONNECTION COST BEFORE STARTING

---

[34] In response to Sierra Club 3-18(a), the Companies clarified that acceptable forms of security include "cash deposits, guarantees, and letters of credit."
[35] KU/LG&E response to Southern Renewable Energy Association ("SREA") 2-3(c).
[36] KU/LG&E provided the EPC agreement in response to Sierra Club 1-12(c)(i) in Case No. 2024-00326.
[37] KU/LG&E response to Sierra Club 3-18(b).
[38] In response to Staff 2-14, KU/LG&E reported that an additional TSR for 123 MW has been submitted for the Camp Ground project.

CONSTRUCTION OF TRANSMISSION FACILITIES. DO THE COMPANIES HAVE A SIMILAR REQUIREMENT FOR THE GENERATION NEEDED TO SERVE THESE CUSTOMERS?

A. No. The Companies seem to have a different threshold for when to start making investments in transmission versus generation. On one hand, the Companies enter into EPC agreements with prospective customers before investments in transmission facilities are made. However, the Companies do not have a similar threshold before they start making investments in generation resources as evidenced by the fact that the Companies are requesting resources in this CPCN before any contracts with prospective customers are in place. It is not clear why the Companies would have a different threshold of requiring a financial commitment from prospective customers when there is an even greater amount of capital at stake for the supply side generation.

Q. WHY DOES IT MATTER IF PROSPECTIVE CUSTOMERS HAVE MADE A COMMITMENT TO THE COMPANIES?

A. The level of load growth assumed by the Companies determines the amount of new resource capacity the Companies need to procure to meet the demand of those new customers. In this proceeding, the Companies are requesting resources that amount to $3.7 billion dollars of capital investment. Assuming more growth than what might materialize risks the Companies overbuilding capacity and passing these costs onto the existing customer base.

Additionally, a financial commitment is an indication of seriousness on the part of the customer. Mr. Bevington testified to this point in the hearing in Case No. 2024-00326, saying that "the EPC agreement [when] you ask them to post collateral or you put up some financial mechanism or you tell them that they're going to be on the hook for what we're getting ready to do, you know seeing their reactions to those kinds of things is indicative of whether they're serious or not."[39]

Q. ARE OTHER UTILITIES DEVELOPING LOAD FORECASTS USING ASSUMPTIONS AROUND COMMITMENTS FROM PROSPECTIVE CUSTOMERS?

A. Yes. While not an exhaustive list of utilities across North America, Table 5 shows several utilities within the PJM footprint that require different levels of commitments from prospective customers in order for those customers to be included in the load forecast. One important note for these examples is that PPL, which like KU/LG&E, is also part of the PPL Corporation. Based on the information that PPL provided to PJM about how it incorporates data center load projections into the load forecast, there is a higher threshold than KU/LG&E is using for its forecasting. PPL reported that only data centers with a Signed Agreement are included in the load forecast. PPL's Signed Agreement appears to be similar to the EPC agreement that KU/LG&E enters into with new customers prior to the construction of transmission facilities. Therefore, it is not clear why KU/LG&E has a lower threshold for data center projections included in the load forecast than other subsidiaries of PPL Corporation.

[39] https://www.youtube.com/live/cU0_E6gp_r8?si=dQCeJPPre62G3XwH&t=18958.

Table 5. Electric Utilities in PJM with Commitment Requirements

Electric Utility	Requirement for Inclusion in Forecast
American Electric Power ("AEP")[40]	• Near-term additions based on contracts in place at the time the forecast is submitted • Project must have a signed Letter of Agreement ("LOA")[41] and an Electric Service Agreement ("ESA") in progress
Dominion Energy Virginia[42]	• Signed firm contracts are used to validate forecast • Firm contracts include a Construction Letter of Authorization[43] and an Electric Service Agreement
Exelon (BGE, ComEd, PECO)[44]	• Customers with signed engineering agreements with financial deposits
PPL[45]	• Only include data center projects with a Signed Agreement[46]

[40] AEP Load Adjustment Request Detail provided to PJM. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/aep-documentation.pdf

[41] In the documentation provided to PJM, AEP states "*Both an LOA and ESA are legally binding contracts that include financial commitments from the customer. However, an ESA generally takes the form of a take-or-pay contract in which a customer is required to purchase a minimum amount of energy over several years. An LOA only covers the customer interconnect, including any engineering or infrastructure costs associated with connecting the customer to the system*." Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/aep-documentation.pdf

[42] Dominion Energy Virginia Load Adjustment Request Detail provided to PJM. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/dominion-documentation.pdf

[43] In the documentation provided to PJM, Dominion Energy Virginia states that a Construction Letter of Authorization is "*a contract that authorizes the Company to construct transmission and distribution facilities to serve a customer request. This contract obligates the customer to: 1) reimburse the Company for any investments made if the project is canceled and 2) execute an Electric Service Agreement within a fixed period of time after the facilities are in place*." Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/dominion-documentation.pdf.

[44] Exelon Load Adjustment Request Detail Provided to PJM. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/exelon-documentation.pdf.

[45] PPL Load Adjustment Request Detail Provided to PJM. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/ppl-documentation.pdf.

[46] In the documentation provided to PJM, Exelon said under a Signed Agreement, "*PPL proceeds with detailed engineering analysis, offering developers precise estimates for cost, timeline, and preliminary engineering requirements*." Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/ppl-documentation.pdf.

While each utility has some differences in the threshold requirements, the common denominator between them is that some level of a signed agreement and financial commitment has been made by the prospective customer before those customers are included in the load forecast. This is in contrast to the approach that the Companies have taken, where the 2025 CPCN Load Forecast is based on a portion of projects in the Companies' load queue, with no requirement for those prospective customers to have demonstrated that they have made a financial commitment to the Companies.

Q. WHAT IS A TRANSMISSION SERVICE REQUEST ("TSR") AND WHY IS THE TSR IMPORTANT?

A. The TSR is an important step because it develops the costs for network upgrades and interconnection costs for prospective customers. The TSR is submitted by the Companies to the Independent Transmission Organization ("ITO"), known as TranServ. The TSR process includes a system impact phase where TranServ evaluates the impact of the requested load on the transmission system, in addition to performing a facilities study which determines the upgrades or modifications necessary to accommodate the load request.[47] In order to pursue a TSR, the prospective customer does have to cover the cost of the studies, which the Companies have estimated to be approximately $50,000.[48] While there is a cost to perform the TSR studies, these are relatively minor financial commitments for customers who may spend billions of dollars constructing their projects.

Q. HOW MANY OF THE PROJECTS IN THE COMPANIES' LOAD QUEUE HAVE STARTED THE TRANSMISSION SERVICE REQUEST ("TSR") PROCESS?

[47] Direct Testimony of Witness Bevington at 13.
[48] Direct Testimony of Witness Bevington at 13.

A. Table 6 shows the number of projects per the Companies' defined phases that have begun the TSR process. The Companies reported 6,017 MW of data center load in the Companies' load queue, and out of those projects, five TSRs have been submitted for 1,252 MW, or approximately 21% of the pipeline.[49] The Companies have said that there is no specific phase at which it becomes appropriate for a customer to ask that a TSR be submitted.[50] It is important to note that 750 MW of the 2,200 MW TSR in the Prospect phase represents one customer (Meridian) that was considering 100 MW at one site and 650 MW at another site.[51] Since this filing, Project Meridian is no longer pursuing the 650 MW site due to community pushback and is reverting to the 100 MW site, although that TSR has lapsed.[52] If that 750 MW is removed, then the Companies have TSRs that amount to 502 MW.

Table 6. MW of Load with a TSR per Phase of the Interconnection Process[53]

Phase	Description	Load (MW)	TSR	TSR (MW)[54]
Inquiry	Early stage of evaluation	1,630	None	-
Suspect	Project engaged in information exchange	1,785	None	-
Prospect	Regular exchange of information and detailed evaluation of a site	2,200	3 projects[55]	850
Imminent	Project has information necessary to make a decision	402	2 requests for one project[56]	402
Announced	Signed Contract	0	-	-

Q. DO THE COMPANIES HAVE DATA ON THE LEVEL OF TRANSMISSION INVESTMENT NEEDED TO INTERCONNECT PROSPECTIVE CUSTOMERS IN

49 KU/LG&E response to Staff 1-18(a).
50 LG&E/KU technical conference held on June 10, 2025.
51 KU/LG&E response to SREA 2-3(a).
52 KU/LG&E response to Sierra Club 3-11.
53 KU/LG&E response to Staff 1-18.
54 KU/LG&E response to AG-KIUC 35(a)(b)(f).
55 In response to Staff 1-18 the Companies indicated there are six projects in this stage and three TSRs have been submitted for two customers.
56 In response to Staff 1-18, the Companies indicated there are TSRs for the project in the Imminent phase.

THE LOAD QUEUE?

A. Yes. Based on information provided by the Companies, five Facilities Studies have been completed for prospective customers. Table 7 shows the network upgrades and network interconnection costs for each of the studies along with the timeline needed to develop the interconnection facilities and network upgrades. The total interconnection facilities cost is $217,606,955.

Table 7. Information from Facilities Study[57]

TSR Study	MW	Interconnection Facilities Cost	Interconnection Facilities Timeline	Network Upgrades Cost	Network Upgrades Timeline
2024-001	335	$29,113,536	36 months	$1,151,329	30 months
2024-011	67	$0	NA	$330,765	37 months
2024-012	100	$21,923,756	30 months	$790,800	36 months
2024-013	650	$47,801,757	70 months	$399,239	24 months
2024-014	100	$118,767,906	64 months	$0	NA

Q. HAVE THE COMPANIES PROVIDED INFORMATION RELATED TO TRANSMISSION COSTS FOR CUSTOMERS THAT HAVE NOT COMPLETED THE TSR PROCESS?

A. Yes, in discovery the Companies provided an internal document that provides transmission cost estimates for prospective customers.[58] The Companies' estimates are based on the level of requested load and site location for the prospective customers. Upon reviewing this document, there are two important takeaways. First, some of the interconnection costs for prospective customers will be influenced by the location of other prospective customers. For example, [redacted] was evaluated with two other customers ([redacted]

[57] KU/LG&E response to AG-KIUC 3-4(a).
[58] KU/LG&E response to Sierra Club 1-41(b) Attachment.

[redacted]), with estimated transmission costs of $[redacted], while the cost with [redacted] and without [redacted] was estimated at $[redacted].[59] This was also the case for another project, [redacted], and whether or not a specific prospective customer was included (identified as [redacted]). Regardless of the other customer, the transmission cost estimate was $[redacted], but without the other customer, the transmission cost estimate was $[redacted].[60] Second, the review of the estimates provided by the Companies also showed increasing transmission costs at certain sites when higher levels of load were evaluated. For example, one prospective project was evaluated at three different tiers of load levels ([redacted] MW, [redacted] MW, and [redacted] MW), and the corresponding transmission cost estimates were $[redacted], $[redacted], and $[redacted].[61] Another prospective customer was evaluated at [redacted] MW and [redacted] MW, and the transmission cost estimate increased from $[redacted] to $[redacted].[62]

Q. HOW ARE THESE TRANSMISSION COSTS ALLOCATED?

A. My understanding is that the transmission costs will be recovered, but it is not clear if the new customer bears the responsibility for the interconnection facilities and network upgrades are recovered from all customers. It will be helpful for the Companies to clarify in their rebuttal testimony how the transmission costs would be allocated. The Companies' transmission allocation policy says that "Network Facilities" are charged to rates while "End-User Facilities" are assigned to the new customer. Those terms are not used in the System Impact Study and Facilities study, instead those studies include the terms "Network Interconnection Facilities" and "Network Upgrades". None of the discovery responses by the

[59] KU/LG&E response to Sierra Club 1-41(b) Attachment.
[60] KU/LG&E response to Sierra Club 1-41(b) Attachment.
[61] KU/LG&E response to Sierra Club 1-41(b) Attachment.
[62] KU/LG&E response to Sierra Club 1-41(b) Attachment.

Companies clarify how these terms relate to each other so ambiguity about the recovery of these costs remains. Any cost not allocated directly to a large customer are likely to be recovered in rates from all customers.

Q. WHAT INFORMATION HAVE THE COMPANIES GATHERED ON THE PROSPECTIVE CUSTOMERS IN THEIR LOAD QUEUE?

A. The Companies appear to be basing the evaluation of prospective customers on ongoing conversations the Companies have with those customers and collecting a handful of data points on the prospective customers. The Companies said they "project the likelihood that a project will locate in the service territories based on conversations, meetings, research on their history (if the actual company is known), and most often work alongside the state and local communities as a project continues to evaluate the client as interactions intensify."[63] On the other hand, the Companies also stated that "No internal documentation exists that the Companies use to assign the stage of economic development projects."[64] Even if the Companies are tracking some information[65] related to the prospective projects in the load queue, there seems to be a significant gap in the information the Companies should be tracking to help assess the risks of the prospective customers and the information the Companies do have. For instance, the Companies reported they have not assessed the creditworthiness of new load customers;[66] do not know how many customers have applied for construction, water use, or air quality permits;[67] and do not know if projects are

[63] KU/LG&E response to AG-KIUC 1-36(b).
[64] KU/LG&E response to AG-KIUC 2-20(b).
[65] KU/LG&E response to AG-KIUC 1-36(b) indicates the Companies do ask questions about site control and zoning.
[66] KU/LG&E response to AG-KIUC 2-29(b).
[67] KU/LG&E response to Joint Intervenors 2-7 (c).

considering multiple jurisdictions.[68]

Q. WHY IS IT IMPORTANT FOR THE COMPANIES TO GATHER MORE INFORMATION ON PROSPECTIVE CUSTOMERS?

A. It is crucial that the Companies gather as much information as possible to be able to appropriately assess the risks of each prospective customer in the load queue. For instance, the Northern Virginia Electric Cooperative ("NOVEC") has a process for identifying risks related to data centers in its load queue:

> NOVEC staff thoroughly vet each individual project in NOVEC's data center development queue to identify any projects that are at a high risk of failure. High risk factors can include outstanding zoning issues, lack of firm site plan from the customer, technical issues related to electric service, among others. Any project that is deemed as a high-risk project by NOVEC staff is excluded from NOVEC's load forecast and can only be added to the load forecast after all outstanding issues have been resolved. NOVEC staff also ensure that customers have not submitted duplicate requests for the same project at multiple locations and that multiple customers have not submitted requests to develop projects on the same tract of land, eliminating the risk of double counting.[69]

Q. ARE PROJECTS IN THE COMPANIES' LOAD QUEUE IMMUNE TO RISKS RELATED TO WHETHER OR NOT THE PROJECT WILL MATERIALIZE?

A. No. And one of the prospective projects, referred to as Project Lincoln or Project Meridian, wanted to locate at a site that was not zoned for a data center. Kentucky LLC or WHP, the developer of the project, filed plans for a hyperscale data center on land zoned for agricultural and conservation use.[70] In addition to concerns around zoning, this project also faced pushback from residents that have expressed concern about the data center being

[68] KU/LG&E response to Joint Intervenors 2-7(d).
[69] NOVEC Load Adjustment Request Detail Provided to PJM. Retrieved from https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/novec-documentation.pdf
[70] Retrieved from https://www.wdrb.com/in-depth/oldham-county-looks-to-pause-data-center-deals-amid-pushback-over-6b-project/article_d51c7f32-ff65-4e5e-a982-ddd9eae91e47.html

located in a rural location.[71] There also could be some risks around developer experience for this project. In an interview given by a WHP representative, it is not clear whether this developer has actually successfully constructed a datacenter either in Kentucky or elsewhere. In the interview, the WHP representative reported involvement in a proposed data center in Illinois and another project "in a very well-established data center market" in the northeast, and when asked for more information and the response was that the "group is under 'layers of NDAs'".[72]

Q. HAVE THERE BEEN ANY RECENT UPDATES FOR PROJECT MERIDIAN/PROJECT LINCOLN?

A. Yes. In response to a discovery question, the Companies indicated that because of the pushback from concerned citizens, Project Meridian is no longer moving forward with plans to locate at the site identified in the TSR request for 650 MW and will be pursuing the first site identified where a TSR was performed for 100 MW.[73] It is not clear if the TSR for 100 MW will be resubmitted or if a TSR for a higher load request will be made for that site.[74] Based on information provided by the Companies, the TSR study process typically takes six to seven months to complete.[75] It is unclear at this time what the potential transmission cost impacts might be at the first site for a load request increasing from 100 MW to 650 MW.

---

[71] Retrieved from https://www.wdrb.com/in-depth/oldham-county-looks-to-pause-data-center-deals-amid-pushback-over-6b-project/article_d51c7f32-ff65-4e5e-a982-ddd9eae91e47.html

[72] Retrieved from https://www.wdrb.com/in-depth/data-center-developer-chose-very-suitable-oldham-county-site-after-talks-with-lg-e/article_faafa110-3ef7-44c4-8dd7-9d2736df3fa2.html

[73] KU/LG&E response to Sierra Club 3-11. Also see https://www.courier-journal.com/story/news/local/2025/06/02/new-location-proposed-for-6-billion-data-center-in-oldham-county/83997706007/

[74] KU/LG&E response to Sierra Club 3-11 indicates the Project Meridian 1 TSR for 100 MW has "lapsed and dropped out of the queue."

[75] KU/LG&E response to AG-KIUC 2-38(a).

Q. YOU HAVE MENTIONED THAT THE COMPANIES SHOULD GATHER INFORMATION ON DIFFERENT RISK ITEMS FROM THEIR PROSPECTIVE CUSTOMERS. IF THE COMPANIES HAVE INFORMATION ON WHETHER OR NOT THE PROSPECTIVE CUSTOMER HAS SITE CONTROL, IS THAT SUFFICIENT TO GAUGE THE LEVEL OF RISK FOR THE CUSTOMER?

A. No, only having information on site control is not sufficient. While it is an important data point for the Companies to be aware of, it is not the only risk factor for the prospective customers. For instance, in discovery, the Companies reported that one of the five projects in the "Prospect" stage had let the land control option expire, but reported that customer "has expressed interest in continuing evaluation pending the outcome of other projects in the economic development queue."[76] Knowing whether a customer has site control must be supplemented by information about the nature of that control and whether the customer has permission to use the site from the relevant permitting authorities.

Q. ARE THERE OTHER RISK ITEMS RELATED TO THE PROSPECTIVE DATA CENTER CUSTOMERS IN THE COMPANIES' LOAD QUEUE?

A. Yes, in particular as it relates to the type of data center customers in the queue. Prospective data center customers might include the likes of major companies like Microsoft, Meta, Amazon, and Google, or they might be data center developers. Data center developers look to develop a site and then find a tenant that the site can be leased to. The data center developers pose an additional risk because they need to find tenants to lease space, otherwise the facility will remain unutilized or underutilized. For example, the Companies reported that

[76] KU/LG&E response to Joint Intervenors 2-7(a).

a tenant for the Camp Ground data center (also referred to as "Poe" or "PowerHouse"[77]) had not been determined as of the date of the Companies' response to the first set of discovery questions, but that the "Companies currently anticipate a tenant will be announced during the pendency of this proceeding.[78] In another response, the Companies said "To the best of the Companies' knowledge, there are no announced tenants or users for the projects that have been announced at this point."[79] Having information on whether or not data center developers do have a tenant is important information for the Companies to track and utilize to evaluate the risk for that prospective customer.

Q. WHEN CUSTOMERS HAVE NOT MADE A COMMITMENT TO THE COMPANIES AND THEY ARE IN THE LOAD QUEUE, IS THERE A RISK THAT THOSE CUSTOMERS ARE ALSO IN ANOTHER ELECTRIC UTILITY'S LOAD QUEUE, AND POTENTIALLY, ANOTHER UTILITY'S LOAD FORECAST?

A. Yes. When customers have not made a commitment to take service, the risk exists that those customers are also pursuing alternative locations in other utility service jurisdictions. The Companies acknowledged that is it common for projects to "evaluate multiple communities and states as they work to find the most suitable location for operations."[80] When there are low barriers for entry into a utility's load queue, i.e. no costs or time limits for how long the customer can be in the queue, that tips the balance towards a likelihood that the prospective customer will enter multiple queues. When there is no or relatively little cost for customers to be in numerous load queues, the likelihood of those customers entering numerous queues at the same time is high since they bear relatively little risk and potentially significant benefit in

[77] KU/LG&E response to Staff 2-15.
[78] KU/LG&E response to AG-KIUC 1-44 and KU/LG&E response to LMG-LFUCG-1-32.
[79] KU/LG&E response to Staff 1-28(a).
[80] KU/LG&E response to Joint Intervenors 1-5(f).

holding that queue position. On the transmission side, the $50,000 cost of a TSR study is a relatively minor financial commitment for customers who may spend billions of dollars constructing their project.

The cost risk is solely on the utility and the weight the utility gives to the prospective customers in the queue and whether or not they are counted in the utility's load forecast.

Q. HOW MIGHT THE COMPANIES IMPROVE THEIR PROCESS FOR TRACKING PROSPECTIVE CUSTOMERS?

A. There are several steps the Companies can take to make improvements. First, the Companies should collect additional information on prospective customers to help identify and assess risks for those customers. Second, the Companies should implement processes to raise the barrier for entry into the load interconnection queue.[81] I will discuss each of these recommendations in more detail below.

Q. HOW MIGHT THE COMPANIES IMPROVE HOW RISKS ARE ASSESSED FOR PROSPECTIVE CUSTOMERS?

A. In addition to the information I have recommended the Companies to collect, I think there are some useful parallels to the evaluation of responses to an all-source request for proposals ("RFP"). Not all responding projects nor all loads will materialize and there are many non-cost factors that can impact the likelihood of project success. For example, when utilities issue an RFP, it is not uncommon for the responding bids to be evaluated based on certain criteria, not just project cost, but also development status or deliverability of a project. This information is commonly used to determine which bids should rise to the top or advance to a

[81] References to a load interconnection queue mean all of the prospective customers that the Companies are tracking and not just those customers that are undergoing and have completed the TSR process.

"short list", for further consideration. Table 8 shows some of the evaluation criteria used by AES Indiana for its 2024 RFP. Projects were evaluated based on development status and developer experience, with established criteria set points, such as achievement of site control or completion of a System Impact Study for the development status, and whether or not the developer has established other assets in locations within a certain proximity or achieved required permits for the project. All of these criteria could be applied to new, large loads as well in the Kentucky context.

Table 8. AES RFP Evaluation[82]

Development Status	Developer Experience
Executed a Pro-Forma MISO Facility Service Agreement ("FSA")	Developer has established in-service asset(s) in the same county as proposed capacity asset(s)
Achieved site control under MISO queue requirements	Developer has established in-service asset(s) in a comparable county or permitting jurisdiction to that of the proposed capacity asset(s)
Completed a MISO System Impact Study	Developer has not established assets in the same county as proposed capacity asset, but county has favorable permitting ordinance(s) in place
Completed a MISO Facilities Study	Developer and proposed capacity asset have not achieved all required permits and do not meet any of the three items above
Completed all environmental studies/permits	
Awarded an EPC Contract	

[82] Retrieved from https://aesindianarfp.com/Portals/0/Documents/RFPDocuments/AES_Indiana_2024_RFP_Evaluation_Criteria.pdf

Q. IF THE COMPANIES HAVE AN OBLIGATION TO SERVE NEW CUSTOMERS, WHY ARE YOU DRAWING A PARALLEL BETWEEN THE INFORMATION GATHERED AND USED IN EVALUATING BIDS FOR A GENERATION RFP AND THE INFORMATION THE COMPANIES GATHER FOR PROSPECTIVE NEW LARGE LOAD CUSTOMERS?

A. I am making this comparison to highlight the differences in how risk for proposed generation projects is evaluated as compared to the risks with prospective new load customers. Forecasting the level of new large load customer growth when significant financial commitments from those customers have not been made presents a significant risk of overbuilding capacity and burdening existing ratepayers with the costs of that capacity. With rising costs for CCs and CTs, the error of planning for a customer that is 650 MW and assumed to be served by a CC, represents approximately $1.4 billion dollars of capital investment, without considering the ongoing fuel and maintenance expenses over the lifetime of that unit.[83] Significant investments are needed to meet prospective new load growth, especially as it relates to data centers. Given the level of capital needed to serve these customers, there should be a high level of scrutiny for the requests submitted to the Companies in order to protect the existing ratepayers. My point is that there is a discrepancy between the rigor and caution applied to supply side resources compared to requests from large loads.

Q. WHAT DOES IT MEAN IF THERE IS A LOW BARRIER TO ENTRY FOR A LOAD INTERCONNECTION QUEUE[84]?

[83] Witness Bellar discusses the cost increases from the Mill Creek 5 CC to the proposed Brown 12 and Mill Creek 6 CC at page 10 of his testimony.
[84] References to a load interconnection queue mean all of the prospective customers that the Companies are tracking and not just those customers that are undergoing and have completed the TSR process.

A. A low barrier to entry refers to a load interconnection queue that has limited, or no requirements for a prospective customer to be included in the queue. In the instance of a low barrier to entry, it is possible that a prospective customer could contact the utility to express interest in locating in the service territory, and that would be the only requirement for that prospective customer to be included in the load queue.

Q. WHAT IS THE IMPACT OF HAVING A LOW BARRIER TO ENTRY FOR A LOAD INTERCONNECTION QUEUE?

A. Figure 2 provides an example of two different load interconnection queues: one that has a low barrier to entry and one that has a high barrier to entry. For the low barrier to entry, Figure 2 reflects a larger volume of speculative projects (represented by the red circles), whereas the high barrier to entry represents a lower number of speculative projects and a larger number of credible customers in the queue. Under a low barrier to entry, there is an increase in the likelihood of more speculative requests, i.e., customers being in many different utility load interconnection queues, since there are no costs the customer faces for being in those different queues.

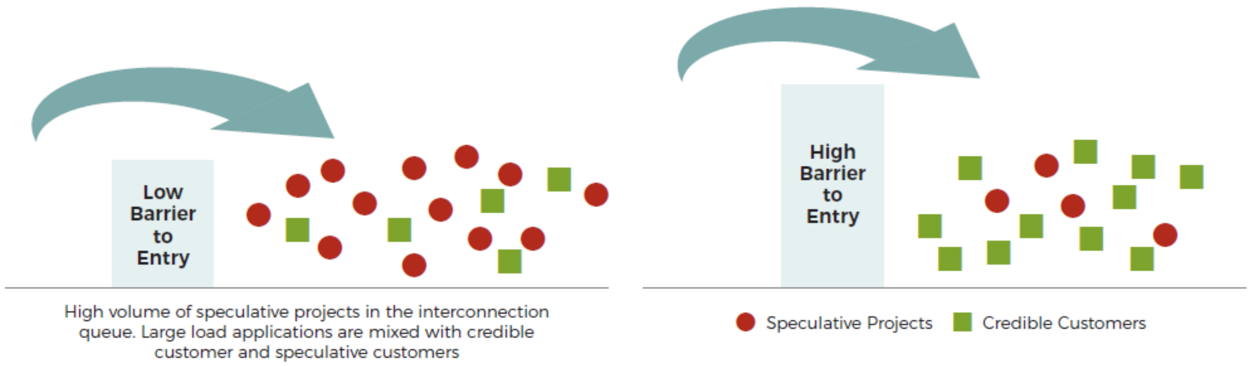

Figure 2. Barrier to Entry Example[85]

Q. ARE THERE IMPROVEMENTS THE COMPANIES CAN MAKE TO THEIR LOAD INTERCONNECTION QUEUE?

A. Yes, improvements in the load interconnection queue go hand in hand with improvements in the data the Companies track for prospective customers. Table 9 provides examples of recommendations from a recent paper published by Elevate Energy Consulting and GridLab, which includes several factors the Companies could implement. These improvements cover four different categories. The first is financial commitments, which could include non-refundable fees and deposits, higher study fees, mile-stone based payment schedules, pre-payment for network upgrades, or withdrawal penalties. The second category is site control and this includes signed agreements or contracts, proof of zoning compatibility, and permits. The third category is financial credibility and this includes providing examples of financial strength such as credit ratings or audited financial statements. The last category includes avoiding duplicative requests, which includes having evidence of agreements between third-party developers and their customers.

[85] Elevate Energy Consulting and Gridlab (May 2025). Practical Guidance and Considerations for Large Load Interconnections, Figure 3.2 at 26. Retrieved from https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/

Table 9. Recommendations to Improve Interconnection Requirements[86]

	Recommendations
Higher Financial Commitments	• Significantly higher non-refundable application fees and deposits, sometimes based on $/MW demand capacity. • Higher study fees • Milestone-based payment schedules • Pre-payment for network upgrades • Withdrawal penalties
Site Control	• Signed purchase agreement, long-term lease, or option contract • Proof of zoning compatibility • Air quality, water use, stormwater, and wetland permits
Financial Credibility	• Example of financial strength such as credit rating • Audited financial statements
Avoiding duplicative requests	• Agreements between third-party developers and end-use customers • Contract, letter of intent, or binding agreement between developers and end-use consumers

Q: BECAUSE THE COMPANIES HAVE PROPOSED A LARGE LOAD TARIFF[87] IN THE RATE CASE, DOES THAT ADDRESS THE CONCERNS YOU HAVE RAISED ABOUT THE 2025 CPCN LOAD FORECAST AND RISKS OF OVERBUILDING?

A: No, it does not. While I understand the Companies have proposed a new large load tariff, ultimately, the prospective customers still need to sign a contract with the Companies to be responsible for the costs that would be assigned to them under the proposed tariff. At this time, the Companies do not have signed electric service agreements with any of the prospective customers. The barometer for whether load will materialize is dependent on

[86] Elevate Energy Consulting and Gridlab (May 2025). Practical Guidance and Considerations for Large Load Interconnections, Figure 3.2 at 32. Retrieved from https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/
[87] Referred to as Extremely High Load Factor.

whether prospective customers accept service under the proposed tariff.

Q. ARE THERE OTHER RISKS TO BE AWARE OF RELATED TO NEW LARGE LOAD CUSTOMERS?

A. Yes, experience from other jurisdictions suggests risks associated with changes to ramp rates, modifications to announced load levels, projects dropping out of the load queue, and a difference in the level of load that materializes once a project is online compared to the level of load announced by the customer.

Q. DO YOU HAVE EXAMPLES OF SOME OF THESE DATA POINTS FROM OTHER JURISDICTIONS?

A Yes, some examples that are worthy to note are Georgia Power and the Electric Reliability Council of Texas ("ERCOT").

Q. WHAT INFORMATION DOES GEORGIA POWER REPORT TO THE GEORGIA PUBLIC SERVICE COMMISSION?

A. Georgia Power provides the following data points to the Georgia Commission[88] on a quarterly basis:

1. Customer or Project name;
2. Project address;
3. Announced Project Load (MW);
4. Projected load ramp including load (MW) and timing;
5. Changes in project status since the last report to include:
    a. Updates to announced load;
    b. Updates to load ramp;

[88] Attachment A in the Order Adopting Stipulation in Georgia Power's Amended 2023 Integrated Resource Plan Update. Docket No. 55378.

c. Project Stage (new project, existing project and undergoing the transmission service request ("TSR") process, contract status – EPC or service agreement)

6. Reason for project loss if known (selected alternative state/ project cancelled/ project delayed indefinitely)

Q. WHAT HAS THE DATA COLLECTED BY GEORGIA POWER SHOWN AS IT RELATES TO NEW LARGE LOAD CUSTOMERS?

A. Table 10 and Table 11 show some of the data points that Georgia Power reports across the quarterly load reports that are submitted to the Georgia Commission. Some of the information Georgia Power includes in the quarterly reports are the level of load that has left the queue, the reasons for the customer leaving the queue (if known), projected changes to announced load, and changes to load ramp rates. Table 10 provides information on how much the existing load levels have changed as it relates to the customer's initial announced level of load and the ramp rate. For the "Projected Load Change" column, this reflects adjustments customers have made to the level of load that was initially reported to Georgia Power and is shown as a net basis for all customers in the queue. For each quarterly report, with the exception of the change between quarter two and quarter three, there was an overall downward adjustment in the projected load from customers. The column labeled as "Average Change in Ramp" shows the average amount of load that was modified due to the customer modifying the ramp rate for the project. Ramp rate refers to the projection for how the customer's load will grow, or ramp, over time. It is typical for a new customer, especially a data center, not to have all of the load show up overnight. Instead, the load usually has a projection in how it will ramp up over time. For instance, a prospective customer might announce an intended load level of 300 MW by 2031, but that will occur in incremental additions of 100 MW leading up to 2031. The customer might start at 100 MW in 2029, grow to 200 MW in 2030, and then reach the full announced load of 300 MW in 2031. The data collected by Georgia Power indicates that the customers that have remained in the load queue have made downward adjustments to their announced levels of load and the ramp rates.

Table 10. Georgia Power Load Reports

	Projected Load Change (MW)[89]	Average Change in Ramp (MW)
2023 IRP and Q1[90]	-204 MW	-429 MW
Q1 and Q2[91]	-581 MW	-472 MW
Q2 and Q3[92]	134 MW	-165 MW
Q3 and Q4[93]	-1,000 MW	-847 MW

Table 11 shows the number of projects that have left Georgia Power's load queue and the reason for the project leaving the queue. Tracking information around why projects have left the queue can help load forecasts become more accurate and give the Companies an idea around the risk of projects dropping out of their queue. The information from Georgia Power's queue indicates there is some risk with projects being canceled or delayed indefinitely, whether for financial or other reasons. Projects selecting alternative states also touches on the risk I highlighted earlier in my testimony as it relates to prospective customers being in multiple utility load queues at the same time as the customer evaluates which utility jurisdiction it might select.

[89] A negative number represents the customers in Georgia Power's queue making a downward adjustment to the announced load levels.
[90] Workbook named "PD Large Load Economic Development Report Q1 2024". Docket No. 55378.
[91] Georgia Power Company's Large Load Economic Development Report Q2 2024 at 2. Docket No. 55378.
[92] Georgia Power Company's Large Load Economic Development Report Q3 2024 at 2. Docket No. 55378.
[93] Georgia Power Company's Large Load Economic Development Report Q4 2024 at 2. Docket No. 55378.

Table 11. Georgia Power Load Reports: Reasons Projects Left Queue

	Canceled	Delayed Indefinitely	Selected Alternative State
Q1 and Q2[94]	5	3	1
Q2 and Q3[95]	5	0	3
Q3 and Q4[96]	2	0	2

Q. WHAT DATA DOES ERCOT INCOROPORATE INTO ITS LOAD FORECAST?

A. For its 2025 Forecast, ERCOT made two changes in how it incorporates data center load into the load forecast. First, ERCOT evaluated the requested MWs compared to the peak consumption for data centers with in-service dates in 2022 through 2024 and found the average peak consumption per site to be 49.8% of the requested MWs from those data centers.[97] Second, ERCOT evaluated the percentage of projects with in-service dates in 2024 that have energized and found that to be 55.4%.[98] With those two data points, ERCOT adjusted its forecast downward to reflect the 49.8% and 55.4% calculations.

Q. HOW SHOULD THE COMPANY IMPROVE THE DATA IT TRACKS FOR PROSPECTIVE CUSTOMERS?

A. The Companies should be required to file quarterly reports for submission to the Commission that are similar to the information Georgia Power submits. In addition, the Companies should also be directed to track and report on information including site control, construction progress, permit status, whether or not data center developers have a tenant in place for the site, and the number of projects the developer has experience with. I make this

[94] Workbook named "PD Large Load Economic Development Report Q2 2024". Docket No. 55378.
[95] Workbook named "PD Large Load Economic Development Report Q3 2024". Docket No. 55378.
[96] Workbook named "PD Large Load Economic Development Report Q4 2024". Docket No. 55378.
[97] 2025 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast (April 8, 2025) at 9. Retrieved from https://www.ercot.com/files/docs/2025/04/08/ERCOT-2025-Long-Term-Load-Forecast-Report.pdf
[98] 2025 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast (April 8, 2025) at 10. Retrieved from https://www.ercot.com/files/docs/2025/04/08/ERCOT-2025-Long-Term-Load-Forecast-Report.pdf

recommendation because the Companies have indicated there is an internal tracking process, but implementing a reporting mechanism on the data points I have recommended will allow for the Companies to reflect their ongoing conversations with prospective customers in these quarterly reports in a transparent manner that is available for all stakeholders to review.

V. THE RISK OF OVERBUILDING

Q. THE COMPANIES HAVE STATED THAT THE 2025 CPCN LOAD FORECAST IS REASONABLE, BUT HAVE ALSO MADE CLAIMS THAT THE RESOURCES REQUESTED IN THIS PROCEEDING WILL CONTINUE TO BE PRUDENTLY EVALUATED. HOW DO YOU RECONCILE THOSE TWO STATEMENTS?

A. The testimony presented in this proceeding from the Companies sets the tone for a sense of urgency for making resource decisions to serve prospective new customer load. Witness Tummonds said:

> *The Companies are requesting CPCNs at this time so they can ensure the timely execution of their cost-effective plans, position themselves to meet their obligation to reliably serve customers in the years ahead, and avoid future increases in NGCC pricing given the tightening NGCC market.*[99]

As I have outlined in my testimony, the Companies do not have firm commitments for the level of load that has been included in the 2025 CPCN forecast, which is 1,750 MW. Planning to add new resources for new customer load growth that has not made firm commitments to the Companies introduces the risk that the Companies may be in a position of significantly overbuilding their system. In response to several discovery questions on the potential for the Companies to be in a position of excess capacity if the load does not materialize, the Companies said:

[99] Direct Testimony of Witness Tummonds at 9.

> *But it is also important to bear in mind that receiving a CPCN for a particular resource does not mean the Companies will proceed with it irrespective of changed circumstances. […] Thus, the Companies will act on any CPCN authority granted in this proceeding only insofar as it is reasonable and prudent to do so.*[100]

> *The Companies will continue to prudently evaluate the proposed investments and would not move forward if the proposed generation resources do not align with the load.*[101]

With this response, the Companies seem to be indicating there is still time even after the current docket concludes to decide whether the proposed resources will be procured and constructed, assuming approval for the CPCN is granted by the Commission. However, it is unclear what the timeframe is for making that decision. Table 12 shows dates for some of the key milestones for the Cane Run battery storage project and the Brown 12 CC. The information provided by the Companies indicates some significant milestones after which the Companies would likely be obligated to additional contractual costs, like the Limited Notice to Proceed ("LTNP") for Brown 12 and purchasing equipment for the Cane Run battery project, are happening before the end of 2025. When asked about at what point in the project timeline it would be too late for the Companies to make a decision to not move forward with constructing the resources requested in this proceeding, the Companies referenced the execution of the EPC contracts in mid-2026 as a point when the Companies "will have expended appreciable cost."[102] In addition, the Companies have not articulated any factors that would lead to a change in decision to build these projects. When asked about what circumstances the Companies would consider for not moving forward with a project, the Companies indicated they "do not have a predetermined list of circumstances to consider."[103]

---

[100] KU/LG&E response to Staff 2-14(b).
[101] KU/LG&E response to AG-KIUC 2-22(f).
[102] KU/LG&E response to Sierra Club 3-13(e).
[103] KU/LG&E response to Sierra Club 4-3(a).

The commitment to reassess their decision comes with no accompanying explanation of what would lead the Companies to reverse course.

Table 12. Cane Run and Brown 12 Project Timelines[104]

Project	Milestone	Date Start	Date End
Cane Run BESS	Purchase equipment	11/2025	11/2025
Cane Run BESS	Execute EPC Agreement	1/27/2026	1/27/2026
Cane Run BESS	Construction starts	8/25/2026	
Brown 12	End date for reservation agreement	-	6/30/2026
Brown 12	Execute Limited Notice to Proceed	8/26/2025	8/26/2025
Brown 12	Execute Final Notice to Proceed	5/23/2026	5/23/2026
Brown 12	Construction starts	6/22/2026	

Q. AS PART OF THE COMPANIES' PLANS TO SERVE NEW LOAD CUSTOMERS, HAVE THE COMPANIES ENTERED INTO A RESERVATION AGREEMENT FOR ANY OF THE RESOURCES PROPOSED IN THIS PROCEEDING?

A. Yes, the Companies executed a Unit Reservation Agreement with GE for the proposed Brown 12 CC.[105] The Companies agreed to pay $25 million to GE to ensure the equipment will be manufactured and delivered for commercial operation in 2030 and to lock in firm pricing. Based on the timeline shown in Table 12, the end date for this reservation agreement is June 30, 2026.

Q. WHAT HAPPENS TO THE RESERVATION AGREEMENT FOR BROWN 12 IF THE COMPANIES DO NOT MOVE FORWARD WITH THE CONTRACT?

A. Based on the information provided by the Companies, my understanding is that if the [redacted]

[104] Brown 12 information provided in KU/LG&E response to AG-KIUC 1-28(a) Attachment 2. Cane Run BESS information provided in KU/LG&E response to AG-KIUC 1-29 Attachment.
[105] Direct Testimony of Witness Bellar at 11.

[redacted].[106]

Q. HOW COULD THIS RISK BE MITIGATED TO ENSURE THAT EXISTING CUSTOMERS ARE NOT HELD RESPONSIBLE FOR COSTS INCURRED FOR RESOURCES NEEDED TO SERVE NEW PROSPECTIVE CUSTOMERS?

A. The Companies appear to have taken the position that data centers can be built faster than new generation can so that is why the Companies need to start now before service agreements have been signed. It is not clear where the Companies are in the process with prospective customers in terms of the prospective customers being close to signing an electric service contract. Making significant investments in generation without any financial commitments from prospective customers places the risk on existing ratepayers. If the Companies want to enter into agreements to secure new resources that are not supported by firm commitments from new prospective customers, then any costs associated with that agreement should be assigned to the prospective customer(s) and/or borne by the Companies. Existing customers should not be held responsible for these costs.

Q. YOU HAVE STATED IN YOUR TESTIMONY THAT THERE IS A RISK THAT THE COMPANIES MIGHT OVERBUILD TO MEET NEW CUSTOMER LOAD THAT HAS NOT MADE A COMMITMENT TO THE COMPANY. HAVE THE COMPANIES STATED HOW THEY WOULD RESPOND TO BEING IN A POSITION OF HAVING EXCESS CAPACITY IF THE RESOURCES PROPOSED IN THIS CPCN ARE APPROVED AND THE PROJECTED LOAD DOES NOT MATERIALIZE?

[106] KU/LG&E response to Staff 1-34(a).

A. In response to a question from the AG-KIUC, the Companies stated that if in a position of overcapacity, the Companies could pursue capacity sales:

> *That aside, if the Companies were in an over-capacity situation, they would expect to find counterparties interested in purchasing capacity and energy given the anticipated capacity shortages in multiple surrounding systems and the projected national doubling of data center demand and other anticipated load growth.*[107]

However, in a follow up discovery response, the Companies then clarified that a capacity sale is not expected, but that it could be an option:

> *Please note the Companies are not in an RTO. Thus, a capacity sale or other firm power sale would require undesignating the applicable unit(s) from their status as Designated Network Resources ("DNRs") that enables their Network Integrated Transmission Service ("NITS") to serve native load. Undesignated units would no longer be available to serve native load. Therefore, the Companies do not expect to make capacity sales; rather, they were simply noting that it could be an option in an over-capacity situation.*[108]

Based on the first response from the Companies, it appears that the pathway for addressing a position of overcapacity if the projected load does not materialize would be to pursue capacity sales. In the follow up response, the Companies seemed to clarify that if that option was pursued then the Companies would need to undesignate that unit to be able to enter into a capacity sale, which would mean that resource would no longer be available to serve native load. From what the Companies have said, this appears to mean that in order to recoup revenue associated with the capacity sale, the resource could no longer be used to serve the Companies' load. And, importantly, there is no guarantee that a capacity sale would occur at a price that would recoup the investment in the projects.

Q. IF THE COMPANIES RECEIVE APPROVAL AND BUILD THE RESOURCES

[107] KU/LG&E response to AG-KIUC 1-42(c).
[108] KU/LG&E response to AG-KIUC 2-9.

REQUESTED IN THIS PROCEEDING, AND THE LOAD DOES NOT MATERIALIZE, IS THERE ANOTHER COURSE OF ACTION?

A. Yes, the alternative option is that if the Companies are in a position of overcapacity, or having excess resources above and beyond the winter reserve margin, then resources can be retired.

Q. HAVE THE COMPANIES IDENTIFIED EXISTING RESOURCES THAT MIGHT BE SUBJECT TO RETIREMENT?

A. Yes. As Witness Wilson mentions in his testimony, Brown 3, Mill Creek 3, and Mill Creek 4, will face landfill storage capacity limits in the future.[109]

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE COMPANIES ASK FOR APPROVAL OF THE RESOURCES REQUESTED IN THIS PROCEEDING?

A. Based on the information the Companies have presented to date, there is not sufficient evidence of firm customer commitments to the Companies to support the level of resources requested in this proceeding. I offer these recommendations:

- The Commission should deny approval of the new supply side resources requested in this proceeding until the Companies can provide evidence that the customers needed to justify the proposed resource additions have committed to taking service under agreements that will cover appropriate costs. If the Commission does approve the resources requested by the Companies in this proceeding, the Commission should also direct the Companies to evaluate their existing units for retirement to determine the resources that would be most economic to retire in the event that the new customer load does not materialize by 2031, and/or the Commission should disallow

[109] Direct Testimony of Witness Wilson at 18.

recovery of costs for units that are not used and useful. The CC and battery storage resources requested in this proceeding represent 1,660 MW[110] of winter firm capacity and the Companies should be directed to evaluate up to that level of existing resource firm capacity for retirement.

- If the Companies enter into reservation agreements to secure new generation resources, and if the purpose of securing that new generation resource is to serve an incremental load addition, the cost of that reservation agreement should be borne by the new large load customer(s) and should not be passed on to existing ratepayers.

VI. GHENT 2

Q. THE COMPANIES HAVE STATED AN SCR IS NEEDED AT GHENT 2 FOR ENVIRONMENTAL COMPLIANCE. WHAT COMPLIANCE ARE THE COMPANIES REFERRING TO?

A. The Companies have reported that an SCR is needed for Ghent 2 in order to comply with the 2015 Ozone NAAQS.[111] Under the Clean Air Act ("CAA"), the Environmental Protection Agency ("EPA") has the authority to set National Ambient Air Quality Standards ("NAAQS") for several criteria pollutants, including ground-level ozone (also known as smog), which is caused, in part, by emissions of nitrogen oxides ("NOx") from large power plants.

Q. WHAT TOOL IS USED TO ATTAIN AND MAINTAIN COMPLIANCE WITH NAAQS?

A. At a high level, EPA is responsible for setting the NAAQS at a level requisite to protect

[110] Winter capacity of each CC at 660 MW and Cane Run battery at 340 MW.
[111] Direct Testimony of Witness Imber at 2.

public health, and then designating every area of the country (typically at the county level) as either being in attainment (i.e., meeting), nonattainment (i.e., failing to meet), or unclassifiable (i.e., unable to determine compliance). Each state then has a responsibility for developing and implementing a State Implementation Plan ("SIP"), which outlines how a state will implement, maintain, and enforce NAAQS. If an area is designated as being in nonattainment, the state must generally require pollution reductions from sources within the area to ensure compliance with the NAAQS. States are required to submit a SIP and if the EPA disapproves a SIP or if a state does not submit a SIP, then the EPA must issue a federal implementation plan ("FIP").

Q. WHAT IS THE GOOD NEIGHBOR PROVISION OF THE CLEAN AIR ACT?

A. The good neighbor provision of the Clean Air Act aims to address interstate pollution, which is when pollution from upwind emission sources impact the air quality in a different state downwind.[112] In general, each SIP (or if the state fails to develop a lawful plan, each FIP) must include provisions ensuring that pollution from within the state does not contribute significantly to nonattainment in any other state.

Q. WHAT IS THE GOOD NEIGHBOR PLAN?

A. The EPA released the Good Neighbor Plan on June 5, 2023, after the EPA disapproved of several SIPs, including Kentucky's plan, for failing to curb emissions that contribute to nonattainment in downwind states. At a very high level, EPA's 2023 plan would have required existing large sources of NOx, including coal-burning power plants, in Kentucky to meet a NOx emission rate commensurate with the installation and operation of selective catalytic reduction technology during the ozone season ozone (approximately May through

[112] https://www.epa.gov/Cross-State-Air-Pollution/what-cross-state-air-pollution

September). Alternatively, an affected power plant could reduce operations during ozone season, or purchase NOx allowances from other sources.

Q. HAS THE GOOD NEIGHBOR PLAN FACED LEGAL CHALLENGES?

A. Yes, the Good Neighbor Plan has faced legal challenges. As Witness Imber discussed in his testimony, several events have taken place. First, following the EPA's disapproval of Kentucky's SIP, Kentucky filed a lawsuit challenging EPA's underlying SIP disapproval, and in December 2024, the Sixth Circuit Court of Appeals vacated EPA's SIP disapproval for Kentucky. As a result, EPA's Good Neighbor Plan does not apply to Kentucky.[113] Separately, in June 2024, the U.S. Supreme Court stayed the effectiveness of the Good Neighbor Plan pending the completion of litigation. In March 2025, the EPA announced an intention to reconsider the Good Neighbor Plan altogether.

Q. DOES THE GOOD NEIGHBOR PLAN APPLY TO KENTUCKY?

A. My understanding is that the Good Neighbor Plan does not apply to Kentucky at this time, and will not apply to Kentucky unless and until EPA reconsiders and disapproves Kentucky's SIP in light of the Sixth Circuit's decision. Even if EPA disapproved the SIP again, the Good Neighbor Plan will not be effective until various challenges to the rule itself are resolved, likely by the Supreme Court.

Q. IF THE GOOD NEIGHBOR PLAN DOES NOT CURRENTLY APPLY TO KENTUCKY, WHY ARE THE COMPANIES ASKING FOR APPROVAL TO ADD THE SCR TO GHENT 2?

A. The Companies assert that the proposed SCR at Ghent 2 is needed in the event that the EPA once again disapproves Kentucky's SIP on remand from the Sixth Circuit, and in the event

[113] Direct Testimony of Witness Imber at 5.

that the Good Neighbor Plan itself is ultimately upheld.[114] Witness Imber also provides other reasons for pursuing the SCR, which include the possibility that downwind states might someday petition EPA to require upwind states to reduce emissions under a separate provision of the Clean Air Act, and the possibility that EPA could someday adopt a more-stringent ozone standard that might require further emission reductions. [115] Neither of those hypothetical future possibilities justifies spending $152 million to install SCR at Ghent 2. Mr. Imber also asserts that relaxing the 2015 Ozone NAAQS does not appear to be a priority of the Trump Administration, but it is not clear why this is relevant because, as noted, under the current NAAQS, Ghent 2 has no obligation to install or operate SCR.[116]

Q. HAVE THE COMPANIES ALSO ASSERTED A NEED FOR THE SCR BECAUSE OF LOAD GROWTH?

A. Yes. In addition to the Company's position on environmental compliance, the Companies assert that an SCR for Ghent 2 is needed for load growth.[117] As I have discussed in my testimony, however, the Companies do not currently have signed electric service agreements with any prospective customers and there is not enough information on the Companies projection for 1,750 MW of new load. In any case, regardless of load growth, there are currently no final and effective environmental compliance obligations that would require the Companies to install SCR at Ghent 2.

Q. DO THE COMPANIES HAVE AN ALTERNATIVE TO ADDING AN SCR TO GHENT 2 IF THE EPA DOES APPROVE KENTUCKY'S SIP?

---

[114] Direct Testimony of Witness Imber at 8.
[115] Direct Testimony of Witness Imber at 8.
[116] Direct Testimony of Witness Imber at 9.
[117] 2024 IRP Volume III, 2024 IRP Resource Assessment at 8.

A. Yes. In the 2024 IRP and this CPCN docket, the Companies modeled an alternative pathway for Ghent 2 where the unit would only operate during the non-ozone months (October – April) and would be unavailable during the ozone season (May – September).

Q. WHAT IS YOUR RECOMMENDATION FOR THE SCR THE COMPANIES ARE REQUESTING FOR GHENT 2?

A. Since the Good Neighbor Plan does not currently apply to Kentucky at this time, other requirements for nitrogen oxides reductions at the Companies' coal units are speculative, and the Companies do not have firm contracts in place with prospective large load customers, the Commission should not approve the SCR for Ghent 2 at this time.

VII. CONCLUSION

Q. OVERALL, WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION IN THIS PROCEEDING?

A. My recommendations include:

- The Commission should deny approval of the new supply side resources requested resources requested in this proceeding until the Companies can provide evidence that the customers needed to justify the proposed resource additions have committed to taking service under agreements that require a financial commitment to the Companies. If the Commission does approve the resources requested by the Companies in this proceeding, the Commission should also direct the Companies to evaluate their existing units for retirement to determine the resources that would be most economic to retire in the event that the new customer load does not materialize by 2031, and/or the Commission should disallow recovery of costs for units that are not used and useful. The CC and battery storage resources requested in this proceeding represent 1,660 MW of winter firm capacity and the Companies should be directed to evaluate up to that level of existing resource firm capacity for retirement.

- The Commission should deny approval of the SCR for Ghent 2 since the Good Neighbor Plan does not currently apply in Kentucky.
- If the Companies enter into reservation agreements to secure new generation resources, and if the purpose of securing that new generation resource is to serve an incremental load addition, the cost of that reservation agreement should be borne by the new large load customer(s) and should not be passed on to existing ratepayers.
- The Companies should be required to submit quarterly reports to the Commission to provide updates on the status of new prospective customers. This information should include:

    1. Customer or Project name;
    2. Project address;
    3. Announced Project Load (MW);
    4. Projected load ramp including load (MW) and timing;
    5. Changes in project status since the last report to include:
        a. Updates to announced load;
        b. Updates to load ramp;
        c. Project Stage (new project, existing project and undergoing the transmission service request ("TSR") process, contract status – EPC or service agreement)
    6. Reason for project loss if known (selected alternative state/selected alternative supplier/Project cancelled/project delayed indefinitely)

7. Additional information including: site control, construction progress, permit status, whether or not data center developers have a tenant in place for the site, and the number of projects the developer has experience with.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES	))))))	**Case No. 2025-00045**

AFFIDAVIT OF CHELSEA HOTALING
IN SUPPORT OF DIRECT TESTIMONY ON BEHALF OF SIERRA CLUB

State of Florida)
County of St Lucie)

Chelsea Hotaling
Chelsea Hotaling

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Chelsea Hotaling this 16 day of June 2025.

NOTARY PUBLIC
STATE OF FLORIDA
Antoinette Robinson
Notary Public – State of Florida
Comm. Expires 09-07-2028
Commission # HH526405

Notarized Online with NotaryLive.com

Antoinette Robinson
Antoinette Robinson, Notary Public
Notary Public

Notary ID No.: HH526405

My Commission expires: 09/07/2028

Sworn to (or affirmed) and subscribed before me by means of ___Physical Present, or X Online Notarization, this16th day of JUN, 2025 by CHELSEA HOTALING who provided identification of NY DL

ENERGY FUTURES GROUP

Chelsea Hotaling

Senior Consultant

PROFESSIONAL SUMMARY

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such an IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the EnCompass, Aurora, PLEXOS, and SERVM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

EXPERIENCE

2025-present: Senior Consultant, Energy Futures Group, Hinesburg, VT
2021-2024: Consultant, Energy Futures Group, Hinesburg, VT
2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT
2019-2020: Analyst, Energy Futures Group, Hinesburg, VT
2018-2019: Intern, Sommer Energy, Canton, NY
2016-2019: Research Assistant, Clarkson University, Potsdam, NY

EDUCATION

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

SELECTED PROJECTS

- **Clean Wisconsin.** *Performed capacity expansion and production cost modeling within PLEXOS to evaluate alternative resource portfolios to the plan put forward by Wisconsin Electric Power Company. (2024 – 2025)*

- **West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.** *Reviewed the commitment and operation of the Amos, Mitchell, and Mountaineer generating units during the 2023-2024 review period. (2024) Reviewed the commitment and operation of the Harrison and Fort Martin generating units during the 2022-2023 review period. (2023)*
- **The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.** *Evaluated Santee Cooper's 2024 Annual Integrated Resource Plan Update. (2023-2024) Evaluated Dominion Energy South Carolina's 2024 Annual Integrated Resource Plan Update. (2023-2024) Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Santee Cooper 2023 IRP. (2023) Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP. (2023) Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)*
- **The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.** *Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)*
- **GridLab.** *Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)*
- **Sierra Club.** *Evaluated Louisville Gas & Electric and Kentucky Utilities 2024 Integrated Resource Plan and performed capacity expansion and production cost modeling within PLEXOS in support of those comments. (2024-2025). Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)*
- **Minnesota Center for Environmental Advocacy.** *Evaluated Xcel Energy's 2024 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation (2024). Evaluated Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to 2024) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)*
- **Citizens Action Coalition of Indiana.** *Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource*

plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019).

- **Natural Resources Defense Council.** *Reviewed and provided comments on Ameren Missouri's 2023 Integrated Resource Plan. (2023)*
- **Kentucky Resources Council and Kentuckians for the Commonwealth.** *Reviewed and provided comments on Big Rivers Electric 2023 Integrated Resource Plan. (2023)*
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.** *Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)*
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association.** *Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)*
- **The Council for the New Energy Economics.** *Reviewed and submitted comments on Evergy's IRP filing in Kansas and Missouri (2020 – 2024) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).*
- **The Department of Attorney General and Sierra Club.** *Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)*
- **The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar.** *Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)*
- **Colorado Office of the Utility Consumer Advocate.** *Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)*
- **EfficiencyOne.** *Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)*
- **Washington Electric Cooperative.** *Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)*
- **Coalition for Clean Affordable Energy.** *Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)*

SELECTED PUBLICATIONS

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.

EXPERT TESTIMONY

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-317. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-316. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Montana, Docket No. 2024.05.053. *NorthWestern Energy's Application to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Service Schedules, Cost Allocation, and Rate Design*. On behalf of Montana Environmental Information Center, Human Resource Council District XI, Natural Resources Defense Council, and NW Energy Coalition ("Joint Parties").

Before the Public Service Commission of West Virginia, Case No. 24-0413-E-ENEC. *Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the Georgia Public Service Commission, Docket No. 55378. *Georgia Power Company's 2023 Integrated Resource Plan Update.* On behalf of Georgia Interfaith Power & Light.

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and General Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024.* On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief,* on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC, on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC, on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. Application for a Determination of Ratemaking Principle, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief,* on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.