COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	))))))))))	**CASE NO. 2022-00402**

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

Filed: August 9, 2023

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Section 1 – Introduction and Overview

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Do you have any overarching concerns and observations concerning the intervenors' positions in this proceeding?

A. Yes. My primary concern is best captured in a single sentence from the counsel for the Joint Intervenors in a response to one of the Companies' data requests: "*Recommending denial of a requested CPCN is not the equivalent of recommending a specific alternative.*"[1]

I could not agree more. But that is also my primary concern with the criticisms and recommendations of the intervenors: with only one exception (Lane Kollen testifying for KIUC),[2] *none* of the intervenors has presented "a specific alternative" that could safely and reliably serve the Companies' customers while satisfying applicable environmental constraints and the requirements of Senate Bill 4, much less at the lowest reasonable cost (Mr. Kollen's proposed portfolio falters on this last point). And none has provided any rigorous modeling or analysis to support their

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[1] Joint Intervenors' Response to Companies DR 1-53 (emphasis added). The Joint Intervenors are Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.

[2] KIUC is the Kentucky Industrial Utility Customers, Inc.

recommendations. Customers require and deserve safe and reliable service at the lowest reasonable cost. The Companies' proposals accomplish this essential objective.

I would further observe that the adage, "Hope is not a strategy," is certainly true when it comes to providing electric service. Yet hope is the primary underpinning of nearly all the intervenors' recommendations:[3]

- Hope that environmental requirements will simply vanish or be delayed indefinitely (Emily Medine for the Kentucky Coal Association);
- Hope that neighboring systems will have adequate generation and transmission to allow the Companies to retire seven fossil fuel-fired generating units with no replacement capacity or only renewables and batteries (Sierra Club, Louisville Metro, LFUCG, and the Joint Intervenors);
- Hope that customers will install vast amounts of distributed solar and battery resources (Andrew McDonald for the Joint Intervenors); and
- Hope that customers will participate en masse in unspecified DSM-EE programs, which still would not obviate the need for replacement resources for the Companies' retiring units (Jim Grevatt and Anna Sommer for the Joint Intervenors).

Hope for what *might* happen cannot reliably serve customers. The Companies must have real resources to provide service in real time, and they must plan their system accordingly. That is what the Companies have done and presented in this proceeding; with the sole exception of Mr. Kollen, that is not what the intervenors have done.

[3] Again with the notable exception of Mr. Kollen.

Moreover, there is a stark contrast between the hope certain intervenors place in being served by the Companies' neighboring systems, renewable resources, and batteries—to the exclusion of adding thermal resources to the Companies' portfolio to replace retiring thermal units—and the frank remarks PJM Vice President for State and Member Services Asim Haque made just a few days ago to the Kentucky General Assembly's Interim Joint Committee on Natural Resources and Energy:

- "We are concerned about being in a supply crunch by the end of this decade."[4]
- "We will need thermal resources until those resources can be replaced at scale. And we don't see that technology being integrated into the system, certainly not tomorrow. And so we will continue to need our thermal resources."[5]
- "We are going to need thermal resources in order to preserve reliability until replacement tech exists to deploy at scale."[6]
- "Our queue consists of primarily, again, solar wind and battery resources. … But, you know, a variable that we're not sure about right now is how much actual renewable generation is going to leave our queue and construct. … [W]e talked about our concern about 40 gigs [GW] retiring by the end of this decade and currently we have 48 gigs [GW] that have found their way through all things PJM and are waiting to construct, but we are not seeing steel in the ground. … [A] variable that we just don't know enough about yet is how much of this generation that is in the queue and finds their way through the queue, how much of this generation is actually going to get built? And we don't have that answer right now. Last year, it's a pretty pitiful two gigs. And 1,300 of it was a natural gas plant in Ohio. 700 of it was renewable."[7]
- "There are a lot of watts in the queue that are some combination of solar, wind, battery resource, and we hope they get built because we need the watts. But as we sit here today, they're not getting built."[8]

In short, PJM's Vice President for State and Member Services sounded an alarm: PJM is worried about its own problem of thermal retirements without adequate thermal

[4] Interim Joint Committee on Natural Resources and Energy Hearing August 3, 2023, YouTube video at 13:25-13:33, available at https://www.youtube.com/watch?v=Bja3IDPFPMs (accessed August 4, 2023).
[5] *Id.* at 1:12:10-1:12:36.
[6] *Id.* at 1:26:53-1:27:00.
[7] *Id.* at 1:19:57-1:22:14.
[8] *Id.* at 1:36:35-1:36:51.

replacements, and renewable and battery resources, though valuable, are not the sole answer to the concern about a "supply crunch by the end of this decade." Notably, not once in Mr. Haque's testimony before the Interim Joint Committee did he suggest that distributed resources, including DSM-EE, could avoid the approaching "supply crunch" that rightly has PJM so concerned.

The Companies do not believe their customers should be satisfied with a looming "supply crunch" and no plan to meet it. Only one of the intervenors has put forward an actual plan to meet customers' needs that is built on more than belief, though even that plan is significantly costlier than the Companies' proposed portfolio. Therefore, none of the intervenors' proposals in this proceeding is superior to the Companies' proposed portfolio, and all but one would be insufficient to meet customers' needs. Finally, as I explain below, none has shown any material concern to justify denying necessary approvals for the Companies' proposed portfolio.

Q. Do any of your comments mean the Companies would not consider joining PJM?

A. Not at all. The Companies have studied and will continue to study possible RTO membership, including PJM membership. To date, the Companies' analyses have indicated RTO membership would not be in customers' interest, but circumstances could change. Importantly, contrary to the false dichotomy Mr. Levitt's testimony appears to create between approving the Companies' CPCN requests for their two proposed NGCC units on one hand and PJM membership on the other, as I explain at length later in my testimony, *there is nothing mutually exclusive about the Companies' proposed resource portfolio and PJM membership*. Indeed, as I show below and consistent with the Companies' most recent RTO study, adding NGCC capacity could be quite beneficial if the Companies were to join PJM. Therefore, I want to be clear from the outset that approving the Companies' requested resource portfolio in this case does not preclude them from later joining PJM; rather, adding the two proposed NGCCs would result in "no regrets" if the Companies later became PJM members.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony consists of five substantive sections and a conclusion:

The first substantive section (Section 2) addresses the failure of intervenors to adequately and appropriately model the implications to system reliability and costs of their recommended generation resources.

Section 3 discusses the shortcomings and incompleteness of Mr. Levitt's analysis on behalf of the Sierra Club, Lexington-Fayette Urban County Government and Louisville/Jefferson County Metro Government of the Companies joining PJM.

Section 4 addresses the misleading and incomplete analysis of coal and natural gas markets and solar purchase power agreements ("PPAs") by Ms. Medine on behalf of the Kentucky Coal Association ("KCA").

Section 5 discusses how Ms. Medine's analysis of EPA's proposed Clean Air Act Section 111(b) and 111(d) regulations concerning greenhouse gas emissions is incorrect and how the proposed rules would not alter the Companies' recommended supply-side generation portfolio (Section 5).

The fifth and final substantive section, Section 6, explains how concerns expressed by various intervenors regarding the Companies' modeling, analysis, and decision-making are misplaced and incorrect. I will demonstrate that the Companies have appropriately, thoroughly, and adequately addressed material risks such that the recommended generation portfolio creates a "no regrets" outcome.

I conclude my testimony by confirming my previous recommendation for the Commission to approve the Companies' proposed resource portfolio.

Q. Are you sponsoring any exhibits to your testimony?

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

Rebuttal Exhibit DSS-1	Selected KIUC Member Scope 2 and Renewable Energy Goals
Rebuttal Exhibit DSS-2	Companies' Modeling of Intervenor Recommended Portfolios
Rebuttal Exhibit DSS-3	Ensuring a Reliable Energy Transition - PJM
Rebuttal Exhibit DSS-4	Available Import Transmission Capacity
Rebuttal Exhibit DSS-5	"Emergence of Climate Impact Drivers" Table 12.12 from IPCC AR-6
Rebuttal Exhibit DSS-6	David S. Sinclair Rebuttal Testimony Workpapers

Note that Rebuttal Exhibit DSS-6 consists of electronic workpapers and is being provided separately.

Section 2 – The Intervenors Failed to Holistically Evaluate their Recommended Generation Portfolios and Made Numerous Errors in Evaluating the Companies' Proposals

Q. Please summarize your understanding of the generation portfolios recommended by witnesses for each of the intervenors.

A. The following intervenors had witnesses (in some cases multiple witnesses) who testified on their behalf in this case: KIUC, KCA, Sierra Club ("SC"), the Joint Intervenors ("JI"),[9] and Lexington-Fayette Urban County Government and

[9] The Joint Intervenors are Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.

Louisville/Jefferson County Metro Government (collectively "Cities").[10] The following is my understanding of the recommended generation portfolios of these intervenors:

- KIUC witness Mr. Kollen:
  - Coal Units - retire Mill Creek Units 1&2, and Brown Unit 3; keep Ghent Unit 2 operational[11]
  - Small CTs – retire Haefling Units 1 & 2 and Paddy's Run 12
  - New NGCCs – construct Mill Creek Unit 5 and Brown Unit 12
  - Solar PPAs – deny all four PPAs
  - Owned solar – approve CPCN for Marion and Mercer County projects
  - Brown battery electric storage system ("BESS") – deny CPCN

- KCA witness Ms. Medine:
  - Do not make any changes to the Companies' existing generation portfolio

- Sierra Club witness Mr. Goggin and Sierra Club, Louisville Metro, and LFUCG witness Mr. Levitt:[12]
  - Coal Units - retire Mill Creek Units 1&2, Brown Unit 3, and Ghent Unit 2
  - Small CTs – retire Haefling Units 1 & 2 and Paddy's Run 12
  - New NGCCs – deny CPCNs for Mill Creek Unit 5 and Brown Unit 12
  - Solar PPAs – supports all four PPAs
  - Owned solar – approve CPCN for Marion and Mercer County projects
  - Brown BESS – approve CPCN

- JI witnesses Mr. McDonald, Mr. J. Wilson, and Ms. Sommer:
  - Same generation portfolio as proposed by the Sierra Club witnesses

Q. Did any of the witnesses for the intervenors attempt to model their recommended generation portfolios?

A. No. While all of the intervenors had numerous criticisms of alleged deficiencies in the Companies' generation modeling and financial analysis, none attempted to holistically

[10] Note that the Attorney General and Walmart did not have any witness testimony and the witness for Mercer County Fiscal Court did not testify on a recommended generation portfolio.
[11] Mr. Kollen does not explicitly state his position concerning the retirement of Mill Creek Unit 1; I infer that he does not oppose its retirement because he clearly states his opposition to retiring Ghent Unit 2.
[12] Mr. Levitt recommends that the Companies take these generation actions and also join PJM.

quantify the revenue requirement implications, financial risks, and reliability implications of their recommendations. This serious omission calls into question the reasonableness of their recommendations. It is also interesting that the only intervenor whose witness conducted any modeling at all, namely Joint Intervenors witness Ms. Sommer, did not recommend either of the generation portfolios she modeled, but presented them as illustrations of her concerns with the Companies modeling.

Q. Did the Companies attempt to model the intervenors' recommended generation portfolios?

A. Yes. To make an informed decision regarding the reasonableness of any generation portfolio, it is necessary to use the appropriate modeling tools to evaluate the ability of a particular generation portfolio to reliably and cost-effectively meet customers' energy needs throughout the year and over time under a broad range of possible futures. Therefore, the Companies used the PROSYM model to evaluate the recommendations of each of these intervenors.[13] Rebuttal Exhibit DSS-2 describes in detail the assumptions and results of the Companies' analysis.

Q. Do you have any general observations regarding the results of the Companies' modeling of the intervenors' recommended generation portfolios?

A. Yes. My general observations are:

- Mr. Kollen's (KIUC) recommended portfolio would reliably serve load without depending on real-time energy from third parties (via bilateral energy purchases or PJM RTO membership) and would meet the requirements of Senate Bill 4 ("SB4") for fossil fuel unit retirements. But his contention to remove the four

[13] It was not necessary to utilize the portfolio optimization capabilities of PLEXOS because each intervenor recommends a specific set of generation resource actions.

solar PPAs and to continue the operation of Ghent Unit 2 in the non-ozone season would increase costs to customers.[14]

- Ms. Medine's (KCA) recommendation to "do nothing" creates significant reliability and financial risks during the ozone season (May to September) beginning in 2027 that will continue until such time as the NO_x emission reductions required by the Good Neighbor Plan ("GNP") are addressed. Furthermore, as discussed by Mr. Imber in his rebuttal testimony, it is likely that the Companies will be required to reduce NO_x emissions at the Mill Creek site as soon as practicable and no later than 2026 to address the high likelihood that Greater Louisville will be out of compliance with federal ozone standards.[15] Following her recommendation would also unnecessarily cause the continued investment in and operation of the aging and higher cost Brown Unit 3 coal unit and deny customers access to lower cost and emitting energy from a new NGCC unit. Finally, as Mr. Bellar explains in his rebuttal testimony, doing nothing now will also likely make it more challenging and costly to address NO_x regulations and EPA's recently proposed greenhouse gas regulations for existing generators because the market for compliant replacement resources like NGCC is tightening and there is and will be increasing demand for firm gas transportation.

- The testimony on behalf of the Sierra Club (Mr. Goggin and Mr. Levitt), Joint Intervenors (Ms. Sommer, Mr. McDonald, and Mr. J. Wilson), and Cities (Mr.

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[14] I note that Mr. Kollen's recommendation is inconsistent with the Scope 2 emission reduction and renewable energy goals of some KIUC members served by the Companies. See Rebuttal Exhibit DSS-1 for those goals.

[15] Bullitt, Jefferson, and Oldham counties in Kentucky and Clark and Floyd counties in Indiana are "Greater Louisville" for these purposes.

Levitt) recommend a generation portfolio that would result in the Companies becoming extremely energy deficient, requiring the dependence on non-firm energy purchases using non-firm transmission from third-parties (if the Companies are not in an RTO) or generation from unknown third-parties in the PJM RTO at a time when PJM is clearly concerned about its future ability to reliably serve its existing members.[16] Also, these intervenors' "retire coal and buy energy from others" recommendation is not likely to meet the generation retirement requirements of Senate Bill 4. To address the Senate Bill 4 compliance uncertainty and the risk associated with purchasing so much energy from others, I will also discuss a previously modeled portfolio discussed in Stuart Wilson's Exhibit SAW-1 in which Brown Unit 3 is not retired and the non-SCR units Mill Creek Unit 2 and Ghent Unit 2 are retained to operate in the seven non-ozone season months.

<u>Section 2.1: Addressing Mr. Kollen's Proposals</u>

Q. Please summarize the modeling results for KIUC witness Mr. Kollen's recommended generation portfolio.

A. The complete modeling results for Mr. Kollen's recommendations are discussed in Rebuttal Exhibit DSS-2. The Companies' analysis created three incremental portfolios to illustrate the PVRR impact of each of Mr. Kollen's primary generation resource recommendations: (i) deny the CPCN for the Brown BESS, (ii) deny the four solar

[16] For example, see "Energy Transition in PJM: Resource Retirements, Replacements & Risks" at https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

PPAs, and (iii) keep Ghent Unit 2 in operation during non-ozone season months (October through April).[17]

Regarding the Brown BESS, consistent with the Companies' prior analysis discussed in Exhibit SAW-1, removing the Brown BESS project would reduce PVRR by between $78 million and $130 million, depending on the natural gas price scenario and the coal-to-gas ("CTG") ratio. My Direct Testimony explains the unquantified and reliability benefits of the Brown BESS project.[18] While there might be some short-term financial savings from not moving forward with the project now, waiting until battery technology is absolutely, positively needed to serve customers will undoubtedly create risk, and likely costs, that are not knowable today. This "savings" in PVRR implicitly assumes that a Brown BESS is never needed through the analysis horizon. However, as the Companies demonstrated in response to PSC 6-2, some amount of battery storage would likely be part of a compliance strategy for EPA's proposed 111(b) and 111(d) CO_2 emission rules.

Concerning the solar PPAs, also consistent with all of the analysis presented in Exhibit SAW-1, not moving forward with the four solar PPAs will increase PVRR unless the absolute price of natural gas is low. In all other natural gas price scenarios and CTG ratios, the PVRR will increase by between $69 million and $734 million without the solar PPAs.[19] The value of the solar PPAs could be enhanced further by the sale of Renewable Energy Certificates ("RECs"). For every $1/REC, customers

[17] Mr. Kollen did not perform any analysis on how long Ghent Unit 2 should operate in the non-ozone season only so it was assumed that it will retire in 2035 based on its current book depreciable life. The Companies have already demonstrated that Ghent Unit 2 non-ozone season operation is not economic over the entire study period. See Exhibit SAW-1 Table 13.

[18] Sinclair Direct Testimony, Section 6, pages 24-26.

[19] As with the Brown BESS, the value of the solar PPAs would higher under the EPA's proposed 111(b) and 111(d) rules.

would save approximately $1.5 million annually based on the anticipated annual capacity factor from these PPAs.[20] Removing the solar PPAs also increased CO_2 emissions by around 1.4 million tons annually.

With regard to Ghent Unit 2, the PVRR impact of operating the unit in just the non-ozone season through 2034 will always increase the PVRR, regardless of the fuel price scenario and CTG ratio. The increase in PVRR ranges from $17 million to $58 million. Note also that Table 5 in Rebuttal Exhibit DSS-2 shows that 53 percent of the energy produced by Ghent Unit 2 during the non-ozone season will, in the Mid-Gas, Mid CTG ratio scenario, primarily be used to offset generation from other coal units. Only 28 percent of its average annual output from 2028 through 2034 is used to reduce energy from higher cost simple cycle gas turbine peaking units ("SCCT"). In fact, its operation at times forces a reduction in lower cost energy from NGCC units due to minimum generation issues, offsetting some of the savings from displacing SCCT units and higher cost coal generation.

Q. What is Mr. Kollen's rationale for not supporting the solar PPAs?

A. His main argument for not supporting the solar PPAs is that the solar PPAs cannot be replacement capacity for retiring fossil units under Senate Bill 4.[21] The Companies agree,[22] but that is not a reason to oppose execution of the PPAs, which are not required to satisfy the Senate Bill 4 requirements for the proposed retirements and have clearly demonstrated long-term economic benefits for all customers.

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[20] While not a prediction of future REC prices, during 2023 the Companies have made REC sales from the Brown solar project in the range of $15 to $20 per REC.
[21] Kollen Direct Testimony, page 19 lines 15-19 and page 20 lines 1-2.
[22] *See, e.g.*, Case No. 2023-00122, Direct Testimony of Lonnie E. Bellar at 10-11 (May 10, 2023) ("Finally, the solar PPAs will provide valuable energy to the Companies' system, but the Companies will not have the right to control those facilities' output ranges, so they are not dispatchable for Senate Bill 4 purposes").

Q. What is your recommendation to the Commission regarding the recommended generation portfolio of the KIUC?

A. Mr. Kollen is the only witness who has recommended a portfolio that is workable. While Mr. Kollen argues for keeping Ghent Unit 2 operational during non-ozone season, creating that option clearly comes at a cost, so the Commission should be mindful that this option, like most options, is not free. His contention for outright rejection of the solar PPAs is not supported by the data in this case and should be rejected by the Commission. Finally, his argument for wanting to reject the Brown BESS is based solely on economics (unlike his recommendations for Ghent Unit 2 and the solar PPAs) while ignoring the reliability and option values described by the Companies (especially in light of EPA's recently proposed 111(b) and 111(d) greenhouse gas regulations) that are associated with this project.

Section 2.2: Addressing Mr. Medine's Proposals

Q. Please summarize the modeling results for KCA witness Ms. Medine's recommended generation portfolio.

A. As previously stated, Ms. Medine's recommendations would effectively result in no change to the Companies' existing generation assets, thus leaving no clear means to comply with both existing and pending environmental regulations. Therefore, the modeling of her recommendation reflects the reality that Mill Creek Unit 2 and Ghent Unit 2 coal units lack SCRs, which will impact their availability to serve load, and that incremental capital expenditures will be required to keep these units and Brown Unit 3 operating beyond the retirement dates the Companies are proposing in this proceeding. Key observations on her recommended actions are:

- The Commission has already agreed with the Companies' recommendation in Case Nos. 2020-00060 and 2020-00061 that it was not economically justified to install the necessary equipment for Mill Creek Unit 1 to meet the effluent limit guidelines ("ELG") beginning January 1, 2025. Because this unit cannot operate under existing regulations beginning with this date, it was not included in the modeling of her recommendation.
- Based on the Companies' understanding of their allocation of the Good Neighbor Plan-related NO_x emission allowances, they are expecting to be unable to operate Mill Creek Unit 2 and Ghent Unit 2 in the ozone season (May through September) beginning in 2027 without purchasing allowances from a third-party. Given the uncertainty about both the availability of allowances and their price (if they are available to purchase at any price), the Companies' analysis assumed these units could not operate in the ozone season beginning in 2027 in order to identify the *minimum* quantity of allowances that would be required by using unserved energy as a proxy.
- As Mr. Imber discusses in his rebuttal testimony, the Companies are likely facing the need to reduce NO_x emissions on Mill Creek Unit 2 as soon as practicable and no later than 2026 to meet Greater Louisville's ozone reduction requirements. Buying allowances would not be an option to meet the Companies' compliance requirements.
- The inability to operate in the summer ozone season without SCRs or allowances means that the Companies would face a capacity shortfall that would threaten system reliability on very hot days.

- Her opposition to the owned solar assets and the solar PPAs removes generation that would be useful to help mitigate the risks her recommendation creates in the summer ozone season.

The totality of the results of modeling Ms. Medine's recommendation are shown in Rebuttal Exhibit DSS-2. The highlights are:

- Taking no action now will virtually assure a two-year delay in the ability to address the Good Neighbor Plan and likely Greater Louisville ozone non-attainment issues, uneconomically extend the life of Brown Unit 3, and delay actions that would be beneficial if the proposed 111(d) greenhouse gas regulations on existing coal units become final in their proposed form. The likely delay from her recommendation to "do nothing" could be even longer. Yet absent a material change in circumstances, and therefore in the data and information used by the Companies to prepare the breadth of analysis that supports their recommended actions in this proceeding, the delay proposed by Ms. Medine would likely serve only to increase, not decrease, costs to customers as other utilities move forward to secure least-cost compliance options ahead of the Companies.
- The summer capacity shortfall results in unserved energy concentrated in the afternoons in July and August (see Table 7 in Rebuttal Exhibit DSS-2) when customers' load is likely to be at its highest (see Figure 1 in Rebuttal Exhibit DSS-2) even with the normal weather assumption that underlies the Companies' load forecast. This risk will increase in years with higher than normal summer temperatures.

- The continuing operation of Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 would require incremental capital expenditures that would otherwise be avoided (see Table 9 in Rebuttal Exhibit DSS-2). Of particular concern is the need to spend a combined $120.4 million in capital from 2026 through 2029 to keep all three units operational. The Companies were unable to model the revenue requirement implications of Ms. Medine's recommendation because she states that depreciation rates should be shortened near the end of a plant's depreciable life to reduce future stranded cost risk,[23] but she does not opine on the expected remaining lives of these units nor how they should be replaced and the cost of replacement. Given the risk that she assumes associated with the proposed 111(d) greenhouse gas regulations, it would be reasonable to assume for depreciation purposes that all of these assets would have to retire by the end of 2031 to reduce stranded cost risk, but this issue (along with replacement generation) would need to be resolved before any revenue requirement analysis could be performed.
- Because Ms. Medine does not propose a recommended portfolio if all of the uncertainties she discusses are resolved (even in favor of coal), there is no way to perform any holistic PVRR analysis to compare with the Companies' recommended portfolio. Nonetheless, based on the analysis above regarding Mr. Kollen's recommendations, the PVRR implications of extending the life of Ghent Unit 2 even in the non-ozone season would likely increase PVRR by

[23] Medine, page 14, lines 4-7.

between $17 and $58 million through 2034 compared to the Companies' recommendation.

- Ms. Medine's suggestion that the Brown BESS should be rejected due to its "high cost and limited capability"[24] in favor of SCCT technology is interesting because, as is discussed in Rebuttal Exhibit DSS-2, the source of energy for charging the Brown BESS would likely be night-time coal energy. That would seem to be in the interest of the Kentucky Coal Association, and it would help allay her concerns about the reliability of natural gas transportation and supply.

Q. What is your recommendation to the Commission regarding the generation portfolio proposed by Ms. Medine on behalf of the KCA?

A. The Commission should disregard Ms. Medine's recommendations regarding the Companies' future generation portfolio. The Companies' modeling results show that Ms. Medine's recommended portfolio would be costlier for customers. Beyond that, her "do nothing" approach is really "doing something," namely exposing customers to risks of unknown compliance capability and costs, putting customers at risk for summer blackouts, especially during high load hours when temperatures are likely highest, and forcing the Companies to spend significant capital on aging and non-compliant coal units that would likely be retired should EPA's proposed 111(d) greenhouse gas regulations on existing coal units become final.

<u>Section 2.3: Addressing Messrs. Goggin and Levitt's Proposals</u>

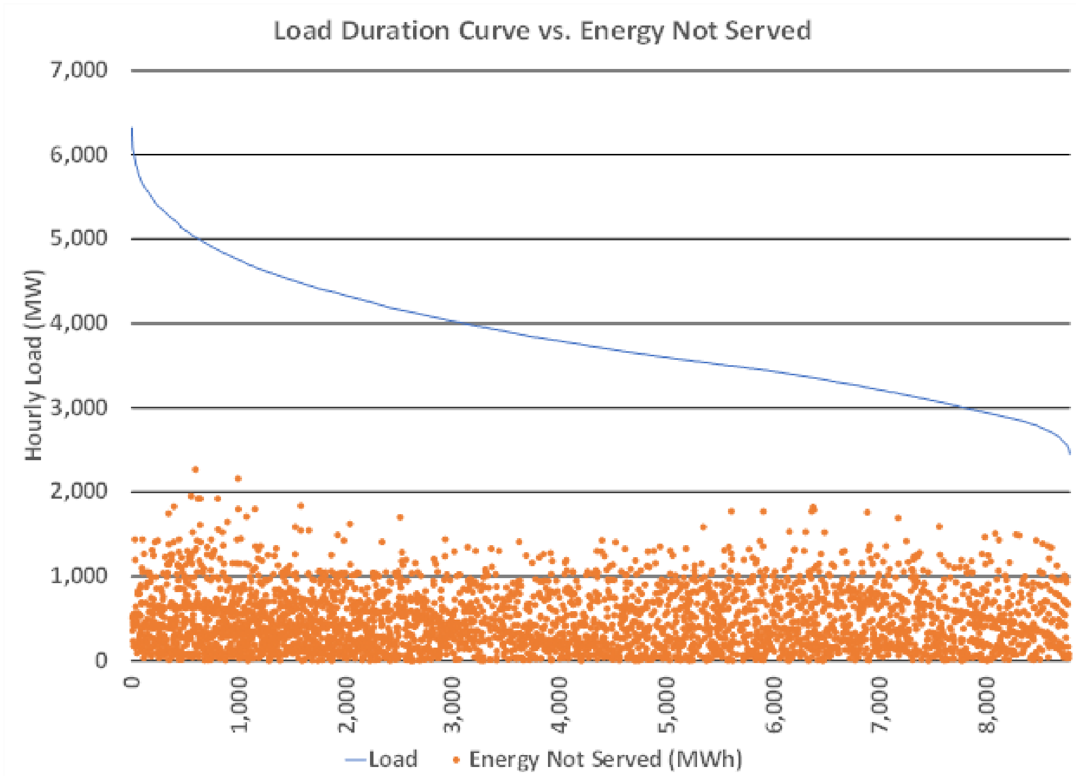
[24] Medine, page 11, lines 9-10.

Q. Please summarize the modeling results for Sierra Club witnesses Messrs. Goggin and Levitt's recommended generation portfolio.

A. Messrs. Goggin and Levitt both support the retirement of coal units and oppose the addition of both Mill Creek and Brown NGCC units. They support the addition only of solar (owned and PPAs) and the Brown BESS. The result of such a generation portfolio is that the Companies' customers would need to depend on large quantities of energy from third parties. In Mr. Goggin's view, this can be accomplished by purchasing energy (he does not say anything about capacity) and transmission from others when needed. On the other hand, Mr. Levitt proposes that the Companies join PJM to reduce the need for capacity and to supply the energy that they will no longer be able to supply from their own generation (because the coal units are retired and no NGCC units are built). Without adequate generation capacity, the PROSYM model will calculate "unserved energy" in an hour. "Unserved energy" is used as a proxy to estimate the minimum amount of energy that would need to be supplied by others. Figure 1 shows that the Companies would have large quantities of unserved energy in 2028, requiring the Companies to depend on others throughout the year to serve customers.[25]

[25] This is a copy of Figure 2 from Rebuttal Exhibit DSS-2.

Figure 1: Energy not served in 2028 with Sierra Club Witnesses' Portfolio



The volume of energy and the number of hours that the system would be energy deficient as recommended by Mr. Goggin and Mr. Levitt is unsurprising. Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 produced around 4.6 million MWh in 2021 and met 15 percent of the system's total energy requirements.[26] The proposed Mill Creek and Brown NGCC units could replace that amount of energy and more (likely up to over 8 million MWh), depending on the relationship of coal and natural gas prices. Removing that much low-cost energy generation from resources capable of producing energy around-the-clock (i.e., the proposed NGCC units) will require the remaining coal and SCCT units to run more. Despite the increased output from the Companies'

[26] Sinclair Direct at 4-5.

remaining generation, the system remains significantly energy deficient even with the addition of all the solar generation that the Companies are proposing.

Concerning the cost of Messrs. Goggin and Levitt's proposal, the Companies could not directly perform any revenue requirement analysis of their recommendations because one would at least need a forecast of electricity prices, transmission costs and availability, and possibly third-party capacity prices outside of the Companies' balancing area. Messrs. Goggin and Levitt provided no such assumptions.

That notwithstanding, given the massive capacity and energy deficit that would result from Messrs. Goggin and Levitt's recommendation, the Companies would not want to retire Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 even though the first two units would only be able to operate in the non-ozone season (October through April) because some capacity and energy is better than none. But this outcome would be highly uneconomical for customers. Portfolio 6 in Table 13 in Exhibit SAW-1 assumed that no NGCC units were built, Brown Unit 3 continued to operate, and Mill Creek Unit 2 and Ghent Unit 2 operated only in the non-ozone season – precisely the generation portfolio that would likely result from the recommendations of Messrs. Goggin and Levitt. The PVRR of Portfolio 6 was hundreds of millions of dollars to several billion dollars greater than the Portfolio 1 (the Companies' recommendation). This would be a truly unfortunate outcome for customers.

Finally, it is unclear that Messrs. Goggin and Levitt's proposal, which JI witness Mr. Wilson also seems to support regarding joining PJM, would satisfy the requirements of Senate Bill 4 regarding retiring seven fossil fuel-fired units. As Mr. Bellar states in his rebuttal testimony, it is unlikely that Senate Bill 4's language would allow utilities in RTOs to retire fossil fuel-fired resources with no definite plans for replacing them with "new electric generating capacity" that is dispatchable and meets all the rest of Senate Bill 4's requirements.

Q. Please explain why the Companies did not attempt to model their system in PJM as Mr. Levitt recommends.

A. I will holistically address Mr. Levitt's PJM recommendation in Section 3 of my Rebuttal Testimony. For purposes of illustrating the amount of energy that will be required to be served by others per Mr. Levitt's recommendation, the analysis discussed in Rebuttal Exhibit DSS-2 is a reasonable approximation – inside or outside an RTO. Also, the purpose of joining an RTO, as described by Mr. Levitt, is to explicitly utilize the generation assets of others. Thus, it is reasonable to expect the Companies' dependence on others to be greater in PJM than shown in this analysis. Lastly, as I will discuss in Section 3, the Companies' RTO study filed in this proceeding included an analysis by Guidehouse that did model the Companies as PJM members, so it was not necessary to repeat that analysis.

Q. In addition to the reliability and economic concerns with the Sierra Club's recommendation, do you have any other concerns with the testimony of Mr. Goggin?

A. Yes. Mr. Goggin's approach to generation planning in a standalone vertically integrated utility like the Companies seems to depend heavily on buying short-term energy from others when the Companies do not have enough generation and to simultaneously purchase transmission to get it to the Companies' load. He does not address having firm generating capacity, either inside or outside the Companies' balancing area, and associated firm transmission service to deliver energy to customers' load. Instead, Mr. Goggin believes it is reasonable to assume that the Companies can rely heavily on supply from others in evaluating loss of load expectations and target reserve margins by incorrectly assuming that is our normal practice during peak hours and by relying on something called capacity benefit margin ("CBM"). Second, he seems to believe that transmission service in large quantities is readily available throughout the year (both on the Companies' transmission system and on adjacent transmission systems). Third, despite repeated, publicly expressed concerns from RTOs like MISO and PJM regarding future generation retirements (mainly coal) and additions (almost all solar and wind), he asserts it is reasonable to expect that the Companies can and should depend on these markets rather than have adequate generation capability to supply customers' energy needs around-the-clock and in all weather conditions.

Q. What is CBM, and do the Companies hold significant amounts of it on their transmission system for use at peak times as asserted by Mr. Goggin?[27]

A. According to Attachment C of the Companies Open Access Transmission Tariff ("OATT"), capacity benefit margin is:

> [T]he amount of firm transmission transfer capability preserved for LSEs [Load Serving Entities] on the host transmission system where their LSE is located, to enable access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a LSE allows that entity to reduce its installed generating capacity below what may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity reserved as CBM *is intended to be used only by the LSE in times of emergency generation deficiencies* (emphasis added).

[27] Goggin at 8.

The Companies do not presently hold *any* CBM because it would be a poor substitute for generation assets located on our transmission system or firm point-to-point transmission service on an adjacent system to bring energy from a specific generation resource located outside our transmission system into our system (e.g., OVEC).[28] From a reliability perspective, the primary problem with CBM is that it would reserve transmission on only the Companies' system; it does *not* ensure transmission would be available on the other side of the interface (e.g., TVA, PJM, MISO) or that energy supply will be available—or that either or both would be available at a reasonable cost. CBM would, however, reduce available transmission capacity for the Companies to use on an economic, non-emergency basis. Finally, CBM would be available to use only if the Companies were in a NERC EEA Level 2 or higher emergency (something the Companies have only declared on only one day, namely December 23, 2022), which would mean the Companies were either expecting to be energy deficient or were in the process of shedding load. In short, CBM is a tool of last resort to keep the lights on, not a prudent generation planning tool.

Q. Do you agree with Mr. Goggin's statement that "the Companies have historically imported power during peak periods to meet generation needs"?[29]

A. No. Mr. Goggin is incorrect and makes a serious data error in the table on page 17 of his testimony that he uses to justify his statement. Mr. Goggin's analysis of imports is incorrect in that it confuses the imports of the overall Balancing Authority ("BA")

[28] There are other load serving entities ("LSEs") in the Companies' balancing area who may hold CBM, but due to FERC Standards of Conduct involving communications between marketing personnel like myself and transmission staff, I have no knowledge of possible CBM reservations by other LSEs. Therefore, it is possible that Mr. Goggin is correct that there are CBM reservations on the Companies' transmission system. However, such reservations were not made by the Companies LSE and such CBM reservations for others would not be for the benefit of serving our customers' load.
[29] Goggin at 15.

with the Companies' imports to serve their load.[30] (LG&E-KU's BA is the "LGEE BA.") The LGEE BA includes other Load Serving Entities ("LSEs"), not just the Companies. Those other LSEs import a significant amount of power to serve their load throughout the year because there is very little generation in the LGEE BA that is not owned by the Companies. The data cited by Mr. Goggin includes flows to serve the following entities in the LGEE BA: the Companies, East Kentucky Power Cooperative ("EKPC"), Big Rivers Electric Corporation ("BREC"), Tennessee Valley Authority ("TVA"), Kentucky Municipal Power Agency ("KMPA"), Kentucky Municipal Energy Agency ("KYMEA"), and Owensboro Municipal Utilities ("OMU"). Most of these entities have generation supply *outside* the BA that must be imported to serve their load.

Table 1 uses the peak hours in the same order cited by Mr. Goggin, but it corrects the "net imports" column to specifically identify the Companies' purchases from third parties, OVEC imports (using firm transmission service), and off-system sales. The remaining "net imports" reflects the activities of other entities in the BA. As the corrected data indicates, excluding nine hours on December 23, 2022, when the Companies experienced low gas pressure on an interstate pipeline that limited generation and forced the Companies to import non-firm power, the Companies did not import power (other than OVEC firm purchases) to serve load during *any* of the peak hours cited by Mr. Goggin. The last column shows that the quantity of imports related to other entities in the LGEE BA. As I have noted, most of those entities are known to have generation supply located outside of the BA, making their imports

[30] Mr. Goggin confirmed this in response to Companies data request to Sierra Club 1-3.

unsurprising.

Table 1: Corrected Version of Mr. Goggin's Table on Page 17

		Balancing Authority Data			LG&E/KU Data					
Date	Hour Ending	Demand	Net imports	Demand after net Imports	LG&E/KU Demand	Purchases from MISO, PJM and TVA	OVEC Imports *	Sales	Net imports	Non-LG&E/KU BA net imports
12/23/2022	18	7,544	1,437	6,107	6,407	400	88	0	488	949
12/23/2022	11	7,476	521	6,955	6,403	0	88	182	-94	615
12/23/2022	10	7,379	681	6,698	6,305	0	88	0	88	593
12/23/2022	12	7,373	866	6,507	6,297	400	88	218	270	596
12/23/2022	20	7,358	907	6,451	6,292	0	88	0	88	819
12/23/2022	19	7,346	1,014	6,332	6,223	0	88	0	88	926
12/23/2022	21	7,340	797	6,543	6,288	0	88	0	88	709
12/23/2022	13	7,339	796	6,543	6,246	266	88	243	111	685
12/23/2022	17	7,317	1,414	5,903	6,240	448	88	0	536	878
12/23/2022	22	7,283	943	6,340	6,239	100	88	0	188	755
12/23/2022	14	7,279	995	6,284	6,196	233	88	122	199	796
6/15/2022	15	7,236	345	6,891	6,163	0	149	0	149	196
12/23/2022	15	7,234	1,515	5,719	6,154	676	88	0	764	751
12/23/2022	16	7,232	1,481	5,751	6,141	592	88	0	680	801
12/23/2022	9	7,204	693	6,511	6,133	0	88	0	88	605
6/16/2022	17	7,202	463	6,739	6,156	0	150	0	150	313
6/16/2022	16	7,201	423	6,778	6,187	0	153	0	153	270
6/16/2022	15	7,194	460	6,734	6,164	0	153	0	153	307
6/15/2022	16	7,182	299	6,883	6,161	0	149	0	149	150
7/20/2022	17	7,178	479	6,699	6,104	0	85	0	85	394
12/23/2022	23	7,170	1,283	5,887	6,134	434	88	0	522	761
6/15/2022	17	7,168	278	6,890	6,173	0	147	0	147	131
6/16/2022	14	7,163	468	6,695	6,108	0	153	0	153	315
8/12/2021	16	7,153	472	6,681	6,117	0	170	0	170	302
8/12/2021	15	7,148	488	6,660	6,123	0	170	0	170	318
6/16/2022	18	7,146	482	6,664	6,079	0	150	0	150	332
6/14/2022	17	7,145	295	6,850	6,135	0	159	0	159	136
6/22/2022	15	7,143	363	6,780	6,171	0	140	0	140	223
7/6/2022	14	7,139	538	6,601	6,076	0	120	0	120	418
8/12/2021	17	7,135	366	6,769	6,097	0	170	100	70	296
6/14/2022	16	7,131	283	6,848	6,141	0	161	0	161	122
6/15/2022	14	7,120	299	6,821	6,096	0	149	0	149	150
6/14/2022	18	7,115	311	6,804	6,090	0	159	0	159	152
6/15/2022	18	7,110	303	6,807	6,060	0	149	0	149	154
8/11/2021	17	7,101	209	6,892	6,035	0	169	300	-131	340
12/23/2022	8	7,101	458	6,643	6,061	0	88	200	-112	570
6/14/2022	15	7,098	307	6,791	6,078	0	161	0	161	146
7/20/2022	18	7,089	396	6,693	6,046	0	85	0	85	311
7/20/2022	16	7,086	456	6,630	6,067	0	85	0	85	371
8/11/2021	15	7,080	216	6,864	6,038	0	169	300	-131	347

*OVEC imports via firm transmission service

Mr. Goggin's conflating of BA data with the Companies' data caused him to reach faulty conclusions about how the Companies plan and operate to serve the load of their customers, and it undermines all of his testimony that depends on this mistaken position.

Q. Do the Companies ever import energy from outside their balancing area to serve their load?

A. Yes. The Companies' trading personnel continuously monitor energy markets and attempt to purchase when it is economical to do so or to sell energy not needed to serve load when it would result in margins to benefit customers. Given the amount of capacity available from our low-cost cost of energy coal and existing NGCC units, the Companies tend to purchase very little energy and are much more likely to make off-system sales. Furthermore, because the Companies designed their system to have adequate generation and load control to serve peak demand plus a reserve margin, there would have to be large scale generation issues (as were experienced on December 23, 2022) for the Companies to be *required* to import energy from others at time of peak. If the system were in such a situation, the Companies would have to declare an "energy emergency" (an EEA event), which, to my knowledge, the Companies had never done prior to December 23, 2022.

Q. Have the Companies recently experienced any summer peak conditions that offered an opportunity to further illustrate the risk of relying on the availability of transmission import capability during hours of high load?

A. Yes. On July 28, 2023, temperatures reached 96 °F in Louisville. Non-firm hourly import transmission availability from PJM declined to zero during the hours between 3:00 p.m. and 6:00 p.m., which were the Companies' peak load hours that day as shown in Rebuttal Exhibit DSS-4.

Q. What is the current availability of transmission to import energy into the Companies system?

A. It is important to remember that to import energy onto the Companies' system, there must be available transmission on both our system and the other system (e.g., TVA, MISO, or PJM).[31] Available transmission capacity is constantly changing. Rebuttal Exhibit DSS-4 shows snapshots of available transmission capacity, including recent daily and future monthly firm transmission availability, on the Companies' system and on adjacent systems. Note that daily and monthly firm transmission availability indeed changes, at many times moving to zero, throughout the historical and forward periods. Longer term (one year and beyond) firm transmission availability must be assessed by the provider through use of the appropriate application and potentially requires a system impact study to determine availability. PJM requires an application at least 60 days in advance of the long-term period in which service begins. There is also a cost associated with all transmission products. For example, one year of firm point-to-point transmission of 100 MW from PJM, if available, would cost $6.7 million ($66,779/MW-Year).

Q. Given your discussion of CBM, the error made by Mr. Goggin, and recent real-world transmission availability, are the Companies overstating their capacity need by at least 600 MW as stated by Mr. Goggin?[32]

A. No. Mr. Goggin's analysis and conclusions are based on a combination of incorrect and imprudent assumptions and errors in the understanding of data. The Companies'

[31] One feature of the Southeast Energy Exchange System ("SEEM") is that its transaction matching software evaluates available transmission across multiple paths and systems to determine if an economic transaction is possible.

[32] Goggin at on page 16, lines 11-13.

assumptions regarding transmission that are used in SERVM are prudent, reasonable, and based on the proper application of real-world data.

Q. Mr. Goggin asserts that NERC's Long-Term Reliability Assessment ("LTRA") shows there is plenty of capacity both currently and on the horizon in the areas surrounding the Companies, upon which the Companies can rely to meet customers' future energy needs. Do you agree with his assertion?

A. No. Mr. Goggin misapplies the LTRA to the Companies and overlooks some important aspects of the report and how NERC assesses future generation retirements and additions. As it relates to PJM, the report contains the following:

- A table on page 61 projecting future PJM capacity assumes that by 2032 there will still be 42,989 MW of coal generation, a decrease of only 412 MW from the 2023 value of 43,401 MW. Coal represents 21 percent of PJM's projected 2032 capacity of 201,475 MW. If a large amount of this capacity retires, which would certainly be a risk should the proposed EPA 111(d) regulations come to fruition, PJM's capacity and energy situation would be markedly different than NERC's projection.
- Natural gas generating capacity is assumed to be 91,694 MW in 2032 compared to 87,312 MW in 2023. NERC assumes that there is no growth (or reduction) in PJM's natural gas capacity from 2026 through 2032.
- The LTRA assumes little growth in wind and solar capacity from 2023 through 2032. Solar is assumed to grow from 8,470 MW to 10,299 MW and wind is assumed to grow from 1,949 MW to 2,910 MW. It is also true PJM's interconnection queue has large amounts of requests for new solar, wind, and

battery storage projects. The NERC report states on page 63, "Wind, solar, and storage requests now total over 120,000 MW (nameplate) of capacity in PJM's interconnection queue. Solar has more than doubled over 2019, it is now comprising 56% of PJM's queue." Slide #8 in Rebuttal Exhibit DSS-3 from PJM itself shows similar data.[33]

- The risk associated with retiring coal generation, the challenges associated with building new gas generation, as well as the large concentration of new generation in intermittent wind and solar generation, is the reason that PJM issued its report, "Energy Transition in PJM: Resource Retirements, Replacements & Risks" in February 2023. That report identified 24,000 MW of ICAP at risk of retirement by 2030 due solely to government policies. Given that this proceeding is driven, in part, by a response to government regulations, it is odd that Mr. Goggin would overlook PJM's own concerns about retirements driven by the same types of issues in justifying his view that PJM has plenty of capacity. Also, as noted at the beginning of my testimony, PJM itself is concerned about "being in a supply crunch by the end of this decade."[34]
- As shown on slide 11 of Rebuttal Exhibit DSS-3, PJM is forecasting 40 GW of retirements by 2030, representing 21 percent of PJM's current installed generation. This far exceeds the retirement assumptions in NERC's assessment.

[33] The slides in Rebuttal Exhibit DSS-3 are from an August 3, 2023 presentation by a PJM representative to the Joint Interim Committee of the Kentucky General Assembly.
[34] Interim Joint Committee on Natural Resources and Energy Hearing August 3, 2023, YouTube video at 13:25-13:33, available at https://www.youtube.com/watch?v=Bja3IDPFPMs (accessed August 4, 2023).

- On Slide #13 in Rebuttal Exhibit DSS-3, PJM states, "Generation retirements may outpace new entry with a simultaneous likelihood of load increasing, thereby creating resource adequacy concerns." Based on PJM's own statement, it would be imprudent for the Companies to rely on PJM for the ability to reliably meet our customers' energy needs.
- Even with today's larger reserve margins, on July 27-28, 2023 PJM declared an Energy Emergency Alert 1 ("EEA1"), which according to NERC typically requires all available generation to be committed and the *curtailment of non-firm wholesale energy sales*.[35]

As it relates to MISO:

- NERC categorized MISO as "High Risk" because it is "failing to meet the established resource adequacy target or requirement." NERC goes on to say:

  > The Midcontinent Independent System Operator (MISO) area, the previously reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.

  Clearly NERC believes that MISO is struggling to address its capacity needs. It would be imprudent to rely on importing non-firm energy from MISO as a possible means to ensure the Companies can reliably serve their customers' loads.

- Even MISO itself is concerned about its ability to meet load. As recently as July 17, 2023, S&P Global Market Intelligence reported on a July 14 webinar

[35] https://emergencyprocedures.pjm.com/ep/pages/viewposting.jsf?id=103959, https://emergencyprocedures.pjm.com/ep/pages/viewposting.jsf?id=103964

with MISO regarding its future resource adequacy.[36] According to S&P, "MISO could have a capacity shortfall as soon as summer 2025, and capacity deficits in 2028 and beyond could be affected by the organization's plans to tighten its capacity accreditation." Furthermore, S&P reported that "planned accreditation reforms could drastically reduce renewable accreditation."

- As it relates to TVA:
  - Relying on energy from TVA in peak times is risky because TVA does not plan its system to serve the Companies' load. Moreover, if TVA followed the same approach Mr. Goggin recommends for the Companies, then TVA would likely plan to rely on the Companies' generation to serve TVA's load because the Companies are currently at the upper end of their target reserve margin range.
  - Notably, the Sierra Club announced on June 15, 2023 that they and others were suing TVA to stop a new gas-fired power plant in Cumberland City, Tennessee that is being proposed to replace a retiring coal plant.[37] If Sierra Club succeeds, it could result in TVA's system becoming less reliable, and its action undermines Mr. Goggin's assurances that the Companies can rely on their neighbors to have ample excess capacity and energy to serve the Companies' customers.

[36] "Midcontinent ISO, states eye possible 2.1 GW capacity shortfall in 2025," July 17, 2023, S&P Global Commodity Insights' *Megawatt Daily* and published on S&P Global Platts Dimension Pro (https://platform.platts.spglobal.com/).

[37] https://biologicaldiversity.org/w/news/press-releases/lawsuit-challenges-tvas-backroom-deal-flimsy-environmental-analysis-2023-06-15/#:~:text=%E2%80%94%20The%20Sierra%20Club%2C%20Appalachian%20Voices,plant%20in%20Cumberland%20City%2C%20Tennessee.

Q. Are RTO markets "inherently self-correcting" to prevent a capacity shortfall as stated by Mr. Goggin?

A. As an economist, I would agree with the concept that market participants will respond to price signals in a market both in the short-term and long-term. The capacity and reliability challenges facing the RTO markets is that they are not natural supply and demand based "markets" but rather creatures of the numerous rules, tariffs, designs, and objectives set forth by the RTO. Hence, they currently have many attributes that prevent them from being "inherently self-correcting." That is why PJM and MISO are engaging in various activities with their stakeholders to develop new rules, new tariffs, and new market designs to meet the new reliability objectives that are required by a shift from fuel dispatchable generation technology to intermittent solar and wind generation technology.[38] As stated by PJM's market monitor, "It is not guaranteed that the market design will successfully adapt to the changing realities, including the role of renewable and intermittent resources, the role of distributed resources, the role of regulated EDCs in competitive wholesale power markets, and the role of states in subsidizing resources."[39] The concerns expressed by the market monitor would make no sense if RTO markets are "inherently self-correcting."

[38] FERC approves MISO's seasonal capacity and resource accreditation construct, August 31, 2022, See FERC Docket No. ER22-495,
FERC approves new MISO plant retirement notification deadline, February 10, 2023, See FERC Docket No. ER23-630,
PJM announces implementation of Critical Issue Fast Path (CIFP) accelerated stakeholder process, February 24, 2023, See https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx,
FERC approves PJM's request to delay the Base Residual Auction (BRA) and Incremental Auction schedules for the 2025/2026 through the 2028/2029 delivery years, June 9, 2023, See FERC Docket ER23-1609.
[39] "2022 Quarterly State of the Market Report for PJM: January through June", Monitoring Analytics, LLC

Q. What is your recommendation to the Commission regarding the recommended generation portfolio Messrs. Goggin and Levitt on behalf of the Sierra Club?

A. The Commission should disregard their recommendation to deny CPCNs for Mill Creek Unit 5 and Brown Unit 12. Without those two units, the generation portfolio recommended by Messrs. Goggin and Levitt can best be summed up as, "Hope someone else has the energy to serve the Companies' customer and that it can be delivered if it is available," especially if the coal units were to be retired as they support. Mr. Goggin's recommendation seems largely based on his erroneous interpretation of LGEE BA data. Finally, his optimism regarding future generation availability in neighboring systems rests on a faulty analysis of NERC data and overlooks Sierra Club's efforts to shut down coal capacity and oppose new gas-fired capacity,[40] the uncertain future for coal generation created by the proposed 111(d) rules, and an extreme discounting of the expressed concerns of MISO and PJM regarding capacity retirements and additions and their efforts to change market rules to address the likely change in generation technology. While I will address Mr. Levitt's analysis and recommendations regarding PJM in Section 3, his recommended generation portfolio is the same as Mr. Goggin's portfolio and will lead to similar risk, even in PJM.

Section 2.4: Addressing the Joint Intervenors' Proposals

Q. Please summarize the modeling results for the Joint Intervenors' recommended generation portfolio.

A. The recommended generation portfolio of the combined witnesses for the Joint Intervenors is the same as that proposed by the witnesses for the Sierra Club.

[40] *See, e.g.*, https://coal.sierraclub.org/ ("America, Let's Move Beyond Coal and Gas.") (accessed Aug. 5, 2023).

Therefore, all of the same risks and criticisms apply. It is also noteworthy that Joint Intervenors witness Ms. Sommer did not recommend either of the generation portfolios she modeled or model the proposals the Joint Intervenors recommended, but presented it only for illustrative purposes.

Q. What is your recommendation to the Commission regarding the recommended generation portfolio of the witnesses for the Joint Intervenors?

A. The Commission should disregard their recommendations for the same reasons related to the Sierra Club witnesses.

<u>Section 3 – Mr. Levitt's Analysis that PJM Membership Would Result in Net-Benefits Is Incomplete and Fails to Address Material Uncertainties</u>

Q. Do the Companies have any aversion to joining an RTO such as MISO or PJM?

A. No. The Companies were founding members of MISO in 1998 and only exited MISO when the costs customers were incurring for membership became greater than the benefits they were receiving. Thus, in 2006, the Companies exited MISO and have operated their own balancing area since then. Every year since 2020, the Companies have performed an RTO analysis and filed it with the Commission. If membership in an RTO clearly demonstrated sustained net-benefits for customers, I would expect the Companies to seek to join that RTO.

But it is important to keep in mind that joining an RTO is an option. Like any option, it should only be exercised when it is clearly in the money. That is particularly true concerning RTO membership because it will likely be much more challenging to exit an RTO in the future than it was almost 20 years ago.

Q. Do you have personal knowledge of the Companies' filing before this Commission to exit MISO, and if so, do you recall the primary financial drivers that caused membership to be a net cost?[41]

A. Yes. MISO was formed, in part, to address the open access transmission requirements that emerged from federal legislation and FERC regulations in the mid-1990s. Thus, most members were like the Companies: vertically integrated utilities with adequate generation and transmission designed to serve their customers' load in real-time. When MISO introduced centralized dispatch and energy markets in the early 2000s, the costs of MISO operations rose, but because the Companies already had a generation fleet designed to serve their own load, essentially the Companies were paying significant overhead costs to MISO simply to provide service from their own generators to their own load. Because the Companies' generation fleet had low energy costs (and still does), MISO's argument in the Companies' MISO exit proceeding was that central dispatch would increase off-system sales margins, which would benefit customers, whereas the Companies' position was that virtually all of that margin could be realized as a standalone balancing area without paying MISO's overhead. Thus, it was the economic impact to the Companies' customers that drove the exit decision, not a philosophical aversion to RTOs.

Q. Do you agree with Mr. Levitt's general description of the potential benefits of RTOs?[42]

[41] The Companies' MISO exit proceeding was *Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266.

[42] Levitt, p 5, lines 8-21

A. Yes. The basic value proposition of RTO membership for a vertically integrated utility in a non-retail access state like Kentucky is that the Companies' customers' load would be pooled with other RTO members and that all load would be served in real-time by the generation assets of the RTO, regardless of ownership.[43] To address the generation needs of the pool, the RTO creates various markets that are governed by rules and tariffs in an effort to ensure that all load in the RTO is capable of being served. In theory, the cost of generation and transmission of serving the pooled load will be less than the sum of the cost of individual utilities to serve their own load. However, while the sum of the parts may turn out to be less, there is no guarantee that every participant will save money. The outcome for a specific entity will be very fact specific.

On Slide #3 in Rebuttal Exhibit DSS-3, PJM clearly shows that it is "markets" that are supposed to provide reliable capacity, energy, and ancillary services. The RTO focus on "markets" to provide reliability is different than the Companies' approach of identifying customers' energy needs and then assembling the portfolio of generation and demand-side resources to reliably meet that need at the lowest reasonable cost. Both can work but they are different.

But what will *not* work, either in or out of an RTO, is a situation in which all relevant parties are capacity deficient. And that is exactly what PJM is concerned it is facing—a "supply crunch"—in the near future.

[43] In a state with retail access, an RTO is a critical mechanism to connect generation to actual load in real time because most retail access "providers" are simply financial intermediaries between wholesale market prices and retail rates. Given the ability of retail customers to rapidly switch "providers" in such an environment, these providers are typically not controlling physical generation assets and have no long-term responsibility to plan to serve the load of their customers which could change to a different "provider" on very short notice.

Q. Would the Companies' generation planning activities be different as RTO members compared to their current approach?

A. Yes. RTOs are first and foremost designed to ensure non-discriminatory open transmission access; they are not "resource planning" organizations. RTOs set market rules and tariffs that are supposed to send price signals to market participants to retire or invest in generation assets to meet resource adequacy needs. Also, it is the RTO that directs generation unit commitment and dispatches units to meet the real-time energy needs via a security constrained economic dispatch for the entire footprint that sets real-time energy prices at various load and generation nodes in the RTO. Thus, it is the market design, rules, tariffs, and prices that would be the focus of generation planning in an RTO, not the physical serving of real-time load that is currently the focus of the Companies.

For example, if the Companies were in PJM as recommended by Mr. Levitt, the Companies' capacity focus would be on satisfying PJM's capacity requirements in the least-cost manner (e.g., minimally compliant volume, lowest cost). It is vital to understand that "capacity" in PJM is a standalone product that is disassociated from the energy production cost and capability of a particular generating asset. The construct of "capacity as a product" is why there is so much debate in PJM today surrounding how to measure the "capacity value" of certain generation technologies, how to determine its value (e.g., Effective Load Carrying Capability), and the time periods necessary to have capacity (e.g., summer versus seasonal capacity).

The other primary focus of generation planning in PJM would be the decision around how much of customers' market-priced energy exposure is appropriate to hedge, if any. In an RTO like PJM, all load pays the market price for energy every hour, and all generation receives the market price for energy that the RTO dispatches in an hour. There are many ways to hedge energy prices in PJM, including financial products and physical generation. In effect, generation planning would be transformed from today's focus on maintaining a generation portfolio that can reliably meet our customers' physical electricity needs to one of a financial risk management exercise that focuses on PJM's market designs, rules, tariffs, and projections of the combined activities of PJM participants and how all of these things might impact the future prices of various PJM products like capacity and energy.

Q. Does all of this make PJM membership especially risky?

A. No. But it is crucial to understand that planning and operating in an RTO like PJM is different than planning and operating as a standalone vertically integrated utility operating in its own balancing area and responsible for physically serving its own customer load. Both can and do work, but they are different. Those differences are material and should be clearly understood. Therefore, any decision to join an RTO must be clear-eyed and with a full understanding of what, exactly, the Companies (and their customers) would be joining.

A simple example regarding gas transportation illustrates the point. The Companies determine the volume and type of gas transportation service (e.g., firm, no-notice) required for their gas-fired generation based on when and how those units will be needed to serve customers load. However, in PJM the volume and type of gas transportation required will be a financial decision based on when PJM is anticipated to dispatch the units and the financial implications (potential energy margin or financial penalties) of not being able to follow their dispatch instructions. This difference is why the Companies from the beginning have had firm gas transportation for their Trimble County combustion turbines and Cane Run Unit 7 NGCC. On the other hand, PJM has continued to evolve its market rules to try to find the right structure that will incentivize natural gas generators in their footprint to have a secured fuel supply that includes the appropriate gas transportation service to meet real-time load, especially since the 2014 polar vortex when many gas generators could not operate because they did not have firm gas transportation.[44]

In addition to gas transportation, the Companies purchase and schedule natural gas with more certainty than they would have as PJM members. Today, the integrated decision process is performed by the Companies; the same Power Supply team forecasts load, purchases and schedules gas, and dispatches the generating units. The Companies are not awaiting another party's dispatch instruction when making a unit commitment decision that involves the purchase of gas and synchronizing that decision with the suite of available transportation services.

Q. Are the circumstances surrounding joining an RTO in 2023 different than when the Companies helped found MISO in the 1990s?

A. Yes. When RTOs first started operating many utilities were vertically integrated and had adequate generation portfolios to reliably serve their customers' energy needs 8,760 hours a year. Over the last two decades, RTO participants have taken advantage of the pooling of load and resources to retire generating assets (due to economics, age, various environmental regulations, etc.) without concern for new generation assets

[44] https://www.pjm.com/-/media/committees-groups/committees/elc/20140822/20140822-pjm-capacity-performance-proposal.ashx, page 5.

because most RTOs began with excess capacity. Also, the declining cost of wind and solar generation, combined with state mandates and federal tax incentives, have resulted in the addition of generation assets that have put downward pressure on RTO energy prices due to their zero (or even negative with production tax credits) marginal energy cost.

But RTOs are growing concerned that the market designs that worked well when there was abundant generation that was fuel-dispatchable might not entice the construction of generation assets that can ensure the necessary portfolio mix that can reliably serve load 8,760 hours per year. That is why RTOs are contemplating various changes to address this growing risk as the energy transition progresses.[45] NERC and the RTOs have recognized the growing risk of an unbalanced generation fleet and are working hard to correct the growing imbalances through changes in their market rules and tariffs.[46]

Another development related to resource adequacy that is particularly challenging for PJM to address is that a large number of their participating states allow "retail choice."[47] Retail providers are typically focused on short-term market pricing and have no responsibility for long-term planning. Thus, it is up to PJM's market design and associated price signals to attract merchant generators to the wholesale market in order to support the retail choice load in those states.

[45] As the PJM market monitor states on page 3 in its 2022 "Quarterly State of the Market Report for PJM: January through June," "The only purpose of the capacity market is to make the energy market work." The market monitor goes on to state on page 4 that "Reliability is not correctly defined as supplying energy during only a limited number of hours. The obligation of capacity resources is to offer energy in all 8,760 hours of the year."

[46] NERC states in its 2022 Long-term Reliability Assessment on page 63 regarding PJM, "A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility."

[47] Nine of 14 states served entirely or partially by PJM have some form of retail choice: Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and Washington, D.C.

Q. You have said you agree with Mr. Levitt's general description of potential RTO benefits. Do you agree with his financial analysis regarding the Companies' potential membership in PJM?

A. No. Before getting into the specific concerns I have about his analysis, it is important to recognize that Mr. Levitt appears to be trying to redefine the issues in this proceeding. His analysis and recommendations seem to assume the question in this proceeding is, "Is it better to join PJM or build Mill Creek and Brown NGCCs to serve customers' load?" That is not the question in this proceeding. Rather, the question, as it relates to PJM membership and its potential impact on this proceeding is, "If the Companies' construct the Mill Creek and Brown NGCC units and, at a later date, decide to join an RTO (PJM or another RTO), would the Companies' and its customers regret that decision?" This "regrets" analysis is very important and is similar in nature to the issues addressed in response to PSC 5-2 and PSC 6-2 regarding the proposed 111(b) and 111(d) greenhouse gas regulations. Furthermore, it will be demonstrated that Mr. Levitt's analysis falls far short of the rigor and thoroughness required for the Companies to conclude that joining PJM at this point in time is in the best interest of customers.

Mr. Levitt's PJM financial analysis consists of two parts: an alleged annual capacity savings of $125 million to $140 million and a forecasted energy savings of up to $66 million annually. Addressing the energy savings first, it is important to be clear that Mr. Levitt performed no analysis regarding the future of PJM market prices and the value of the Companies' existing and proposed generation assets in PJM. While he and I describe the functioning of energy markets generally in the same manner,[48] his only assessment of the energy market implications of the Companies joining PJM is to apply a fixed savings rate of 4 percent to 8 percent to a projection of the Companies' annual production costs.[49] Furthermore, the sources he cites for this savings range are all studies performed by his employer, The Brattle Group, and appear to be largely on behalf of western RTOs.[50] Clearly his firm has the capability to model RTO energy markets, yet Mr. Levitt did not do so in preparing his testimony. It is not analytically appropriate to simply assume away one of the largest cost implications of joining an RTO and not to perform any analysis regarding the energy value of the Companies' existing and proposed generating assets. For example, his conclusion that the Companies should meet future capacity needs in PJM with only the proposed solar and battery projects and PPAs instead of NGCC capacity lacks any analysis of the energy value of these resources.

Mr. Levitt's claim that the Companies can save \$125 million to \$140 million annually in capacity costs rests on a narrow set of dubious assumptions: (i) the Mill Creek and Brown NGCC units will *never* be needed, (ii) the PJM capacity market rules will *never* change in any material way, (iii) the PJM capacity price will *not* be affected by the rapidly changing resource mix in PJM despite Mr. Levitt's Attachment 1 showing the capacity value of solar will be zero by 2033, (iv) there is *no* energy margin value earned by the NGCC units, and perhaps most importantly, (v) the Companies' remaining 3,200 MW of coal generation (after the retirements at issue in this

[48] Levitt, page 33, lines 451-460.
[49] Levitt, page 34, lines 461-473.
[50] Levitt, page 35, Table 5.

proceeding) will *never* have to be replaced. Each of these assumptions falls somewhere in a range from dubious (PJM capacity prices will remain unaffected by PJM's transforming resource mix) to plainly incorrect (the Companies' remaining coal units will never have to be replaced).

But the assumption that is perhaps easiest to debunk using Mr. Levitt's own approach is the assumption that the Companies would be better off adding no NGCC capacity because there would be no energy margin value. (Notably, the owner of the 1,300 MW of NGCC capacity added in the past year in PJM's footprint that PJM Vice President Asim Haque noted in his remarks to the Interim Joint Committee presumably disagrees with Mr. Levitt's assumption.) Because capacity and energy are valued in PJM at "market" prices, it is easy to use Mr. Levitt's assumptions about the cost of a new NGCC and the market price of capacity to determine the energy margin that a new NGCC would have to earn to cover its full cost (include return on and of investment) in a given year. Table 2 shows that the range of PJM electricity prices that would be needed to earn enough margin to cover the annualized capacity cost of a new NGCC unit would be approximately \$42/MWh to \$50/MWh assuming the Companies' mid-gas, mid CTG price forecast. The energy margin is a huge contributor to the economics of a low cost energy and must be included as part of any investment decision. Based on the recent past and given the concerns that PJM has expressed about coal plant retirements this decade, the range of annual energy prices does not seem unreasonable to achieve.[51] This demonstrates that having the proposed NGCC units in the

[51] From 2018 through the first half of 2023, the implied heat rate of PJM South Import electricity prices to Henry Hub natural gas prices was 10,800 Btu/kWh. This indicates that a NGCC in PJM with at 6,500 Btu/kWh heat rate would have earned a significant energy margin.

Companies' resource portfolio is likely to result in "no regrets" even if the Companies later become PJM members; adding two NGCC units and PJM membership are not mutually exclusive.

Table 2: PJM Merchant NGCC Analysis

		2027	2028	2029	2030	2031	2032
NGCC Summer ICAP	MW	621	1,242	1,242	1,242	1,242	1,242
NGCC Carrying Charge	$M	69	139	139	139	139	139
Mid Natural Gas Price	$/mmBtu	4.54	4.62	4.70	4.78	4.86	4.94
Average Energy Cost	$/MWh @ 6,500 Btu/kWh	29.51	30.03	30.55	31.07	31.59	32.11
NGCC Summer UCAP	MW	581	1,162	1,162	1,162	1,162	1,162
PJM Capacity Price	*($/UCAP MW/d)*	60	81	91	93	87	82
PJM Capacity Value	$M	13	34	39	39	37	35
PJM Energy Price Required to Break Even							
50% Capacity Factor	$/MWh	50.30	49.25	48.93	49.31	50.29	51.24
60% Capacity Factor	$/MWh	46.84	46.05	45.86	46.27	47.17	48.05
70% Capacity Factor	$/MWh	44.36	43.76	43.68	44.10	44.94	45.77
80% Capacity Factor	$/MWh	42.50	42.04	42.04	42.47	43.27	44.07

Note that this is essentially the same type of analysis that Guidehouse performed in their PJM study for the Companies that led to the conclusion that two NGCC units would be valuable assets in the Companies' portfolio should they join PJM in the future.

Having demonstrated that a merchant NGCC unit is certainly likely to be a valuable asset in the PJM market, it is easier to understand the flaws in Mr. Levitt's opinion that the same generation technology would never be valuable for the Companies in PJM. Mr. Levitt's $125 million to $140 million of annualized capacity savings is almost entirely driven by his removal of the $139 million associated with the two new NGCC units. To imply that this savings will go on through 2050 as he does in Table 4 of his testimony requires at a minimum that the Companies never have to replace any of the remaining 3,200 MW of coal units. If Mr. Levitt had addressed this risk (due to 111(b) regulations, age, etc.), then he would have had to suggest a replacement portfolio. Because he acknowledges that the current projection of solar installation will cause PJM to assign an ever diminishing capacity value to that technology, adding more solar would not be a viable technology to meet even PJM's current capacity rules that he assumes. Mr. Levitt would have been forced to address this shortfall risk with some other type of technology than solar, which he does not.

Furthermore, while Mr. Levitt acknowledges the uncertainties regarding PJM's future capacity market design (e.g., a move to a seasonal capacity market) and resource adequacy model, he asserts that even "though it is not possible at this time to estimate the net impacts on my estimated capacity savings if PJM's seasonal market should be finalized and implemented,"[52] the Companies would nonetheless experience savings by joining PJM.[53] Indeed, Mr. Levitt acknowledged in response to data request from the Companies that new PJM rules would change Table 4, but he still seems to stand

[52] Levitt, page 30, lines 423-425.
[53] Levitt, page 30, lines 426-427.

by his original opinion.[54] As I have discussed at length, PJM is evaluating a number of changes to its market rules in order to send the market the appropriate price signals to develop generation assets that can reliably meet load throughout the year. Simply ignoring the likely significant changes in PJM's capacity markets and assuming that it will all work out is not prudent. Joining an RTO is an option, but it would be imprudent to exercise that option without a clear understanding of what the Companies would be joining and the financial implications of that decision. And nothing about the possible exercise of that future option makes the Companies' proposed resource portfolio imprudent; rather, as Table 2 above and Guidehouse's more sophisticated analysis show, there is real value in adding more NGCC capacity to the Companies' resource portfolio even if the Companies later become PJM members.

In short, adding the Companies' two proposed NGCC units and joining PJM are not mutually exclusive, though Mr. Levitt's testimony effectively treats them as such, and he did not even attempt to model the potential benefits of having the NGCCs in PJM. In reality, having the NGCC units would be valuable to the Companies' customers both in and out of PJM; indeed, just days ago PJM Vice President Haque repeatedly stated the importance of thermal resources to PJM. Thus, nothing about possible PJM membership either precludes or makes imprudent adding the NGCCs and other resources the Companies have proposed.

Q. Do you have any other concerns about Mr. Levitt's general claim that the Companies' could save $66 million in annual energy cost by joining PJM?

[54] SC 12

A. Yes. Joining PJM (or any RTO) will have no impact on the Companies' cost of fuel – coal and natural gas suppliers are not going to discount their prices because the Companies are in an RTO. Therefore, energy savings in an RTO must primarily come from purchasing energy from others at a lower cost than would have been the case from running the Companies' own generating units. Historically, because the Companies' generation portfolio has been optimized to have the appropriate mix of low-energy cost technology (coal and NGCC) and higher-cost peaking units (SCCT), it has been a challenge to purchase economy energy at lower cost than the Companies' cost of generation. Table 3 shows the volume of economy energy purchased has historically been around almost non-existent as a percent of annual total energy requirements.

Table 3: Annual Economy Energy Purchases

	2018	2019	2020	2021	2022
Economy Energy Purchases (MWh)	0	5,502	60,894	10,200	27,358
Energy Requirements (MWh)	35,305,062	33,183,956	30,698,555	31,702,305	32,141,307
Purchases as % of Energy Requirements (%)	0.00	0.02	0.20	0.03	0.10

As I have already discussed, not constructing the two proposed NGCC units will leave the Companies in significant energy deficit situation, forcing the Companies to purchase large quantities of energy from others.[55] Therefore, Mr. Levitt's claims of energy savings in PJM implies that the market price of energy for those purchases will be less than the energy cost of the new NGCCs that are included in the annual energy cost that he uses as the basis for his energy savings calculation. As I have just discussed, there is no reason to believe that a NGCC unit operating in PJM would not

[55] Being a net purchaser of energy would be a material change from the Companies' historical experience of being a net seller of energy in the off-system sales market.

earn a significant energy margin. Also, while the Companies' fleet of modern SCCT units will likely dispatch differently in PJM, the high correlation between PJM and the Companies' load would likely *not* result in significant savings, and the cost of purchasing energy from other SCCTs will not likely be materially different (which is why the Companies' have historically not been able to purchase much economy energy to displace their own generation). Thus, it is hard to identify a source of energy savings for the Companies, especially given Mr. Levitt's recommendation to remove 1,240 MW of low-cost NGCC energy from the Companies' generation portfolio and replace that energy with market purchases. If anything, with the large volume of market purchases, I would expect the Companies' energy costs to *increase* in PJM with his recommended generation portfolio compared to the Companies' recommended generation portfolio.

Q. What is your recommendation to the Commission regarding Mr. Levitt's conclusion that "PJM membership is expected to yield a significant overall net benefit"?[56]

A. His financial analysis of the costs and benefits of the Companies joining PJM is both incomplete and incorrect. Far from performing an objective, complete, and correct analysis, Mr. Levitt performed no energy market analysis at all and an incorrect capacity analysis, and he ignored PJM's likely adoption of seasonal capacity requirements.

In contrast, the RTO analysis prepared by the Companies in November 2022 was a comprehensive assessment of the financial and operating implications of joining

[56] Levitt, page 42, lines 598-599.

PJM. The Companies engaged Guidehouse, a large, international consulting firm to model the Companies' operating in PJM. Their analysis reflected the energy and capacity market implications of joining PJM and enabled the type of generating asset energy market financial analysis that Mr. Levitt failed to perform. The Companies then used the results of the Guidehouse analysis to fully assess the costs, benefits, risks, and uncertainties that joining PJM would entail. While the Guidehouse study did not explicitly address the Good Neighbor Plan, its results showed that whether the Companies operated as standalone entities or joined PJM, coal units would be retired and a combination of NGCC and solar capacity would be added. As it pertains to the issues in this particular proceeding, the Guidehouse analysis supports the Companies' recommended generation portfolio as a "no regrets" portfolio. If PJM (or MISO) clearly addresses their future market design so the Companies can understand what they would be joining, and if the financial benefits of joining an RTO are demonstrated to be clear and sustainable at some point in the future, then the Companies' customers will benefit from Mill Creek Unit 5, Brown Unit 12, the various solar PPAs, the proposed Companies-owned solar assets, and the Brown BESS as valuable resources to meet both capacity requirements and generate energy margin.

Section 4 – KCA's Assessment of Coal and Natural Gas Markets Is Misleading and their Comments on Solar PPAs Are Incorrect

Q. Do you agree with KCA's witness Ms. Medine that the Companies' coal and natural gas forecasts were developed to support a desired outcome, the construction of NGCC units?[57]

[57] Medine, page 40, line 17.

A. Absolutely not. For that to be true, one has to believe that the Companies performed the entirety of the analysis described in Stuart Wilson's Direct Testimony and Exhibit SAW-1 for multiple iterations to back-solve for a combination of coal and gas prices that produced Ms. Medine's alleged "desired result." That would have been a risky strategy at best because the Companies are well aware that every single piece of data, model run, analysis, and spreadsheet would be subject to discovery in this proceeding. In short, it is an absurd and cynical claim. The Companies would have nothing to gain—and much to lose—from deceiving anyone or preparing an analysis just to rationalize a particular desired outcome. The Companies can recover only prudently incurred costs. Thus, it would be ill-advised and short-sighted at best for the Companies to file testimony or other evidence supporting a course of action the Companies knew was imprudent. Any claim that the Companies intentionally rigged their analyses to achieve a predetermined imprudent result is meritless.

Q. Please describe why the coal-to-gas ratio methodology ("CTG") was used in the Companies' analysis.

A. An important driver underlying any financial analysis of technologies that involve different fuel types is the spread between the prices of those fuels.[58] Ms. Medine understands that and disapproves of the approach the Companies employed to develop a range of possible spreads, yet she does not proffer any alternatives or any generation planning analysis based on such alternatives.

[58] It is also true that the absolute price level forecast is important for evaluating wind and solar generation that do not have a marginal fuel cost. That is why the analysis in SAW-1 indicated that the financial benefit of the solar PPAs and owned projects varies with the level of fuel prices.

Because the Companies are making long-term investment decisions, and because it is impossible to know coal and natural gas prices through 2050 and beyond, it is important to stress each alternative being evaluated under a broad set of possible futures. As explained at length in Appendix E to Stuart Wilson's Exhibit SAW-1, six CTG ratios were developed based on the historical long-term and short-term relationships over the last decade between Illinois Basin coal prices (the Companies' primary source for coal) and Henry Hub natural gas prices. This analysis produced a broad range of possible relationships, with 0.52 on the low end, 0.82 on the high end, and others in between with a long-term value of 0.57. The Companies then applied those ratios to three different long-term natural gas forecasts (high, mid, low) prepared by the U.S. Energy Information Administration to produce six long-term pairs of coal and natural gas price forecasts. Figures 6 and 7 in Exhibit SAW-1 graph the combinations of coal and natural gas prices used in the Companies' analysis. This approach produced a wide range of possible prices to evaluate the various technologies that responded to the Companies' RFP.

Q. What is Ms. Medine's views on the future of coal and natural gas prices?

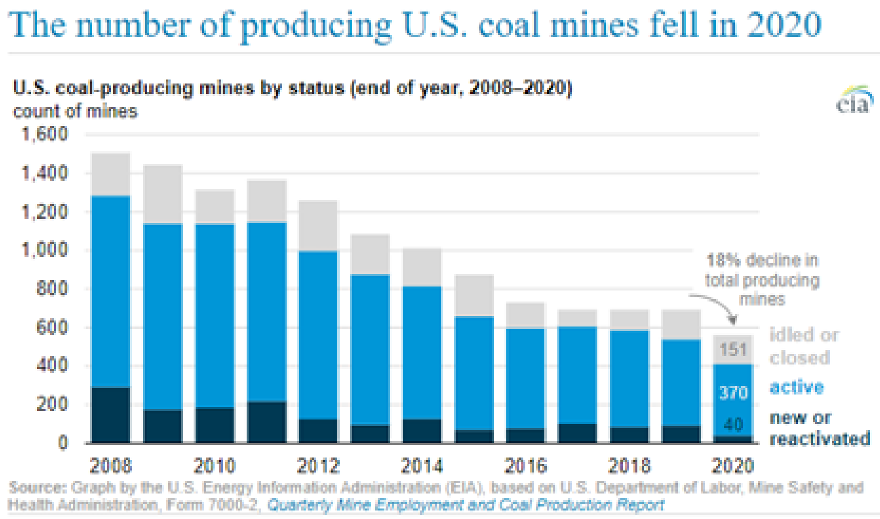
A. The vast majority of Ms. Medine's testimony relating to fuel prices focuses on explaining recent events in the coal and natural gas markets, but she provides no forecast of her own for either commodity. She also seems to rationalize the rapid increase in coal prices in 2022 in a way that tries to excuse it as an anomaly, and she seems to believe that coal generation is the only thing that keeps a "cap" on natural gas prices. Finally, she seems critical of the CTG process as not reflecting the short-term volatility that all commodity markets experience.

Q. Do you agree with Ms. Medine's characterization of how coal and natural gas markets interact now and in the future?

A. No. While it is certainly true that coal and natural gas generation can be short-term substitutes up to a point, it is also true that it is increasingly easier for natural gas generation to substitute for coal generation than it is for coal generation to substitute for natural gas generation. This changing dynamic is due to the growth in natural gas capacity that has occurred in the last decade and is likely to continue into the future, combined with declining coal capacity (due to age and EPA regulations), with no prospects of new domestic coal-fired generation on the horizon. As coal capacity shrinks relative to both natural gas capacity and as a share of total load, its ability to impact electricity markets, much less natural gas prices, will diminish. The evidence in this proceeding demonstrates that the efficiency of new NGCC technology compared to existing coal units means that not only will coal units face pressure to retire, the remaining ones will likely operate at lower capacity factors.

Furthermore, the events of 2022 illustrate that coal companies know that they can raise their prices if natural gas prices increase. Though Ms. Medine attributes high coal prices to a shortfall of production capacity caused by COVID, coal production and the number of mines have been declining for years, and the trend in increases in coal prices is likely to continue as U.S. coal generation is retired. Figure 2 shows that the number of producing U.S. coal mines has been declining for over a decade.

Figure 2: Declining U.S. Coal Mines



Tracking this national trend, the number of mines and the number of suppliers that the Companies rely on to provide coal has also declined and resulted in two suppliers becoming the Companies' dominant suppliers (79 percent in 2022). Table 4 illustrates the dwindling options for the Companies' coal supply.

Table 4: Companies' Coal Supply				
	2010	**2015**	**2020**	**2022**
Suppliers	27	23	13	13
Mines	36	31	26	22
Two Largest Suppliers (%)	45%	65%	55%	79%

Ms. Medine's analysis fails to acknowledge that in the past coal-on-coal competition kept coal prices in check when natural gas prices increased. That form of competition is disappearing and will not improve in the future as domestic coal generation retires.

The demand for natural gas from power generation, despite its growth over the last two decades, represents only 38% percent of total annual U.S. demand for natural gas.[59] Many factors influence the price of natural gas, and Ms. Medine's view that "gas prices will be unchecked by coal if coal plant retirements eliminate or diminish coal generation as an option" greatly overstates coal's declining importance in influencing the long-term level of natural gas prices without any support.

Finally, contrary to Ms. Medine's view, it is not necessary to attempt to reflect the random fluctuations in prices that will inevitably occur over time. The key in a long-term analysis is to test the possible *ranges* of long-term price trends to see how each investment alternative performs. If the initial results of the trend analysis were to produce materially different results depending on the commodity price trend, then perhaps additional stress tests regarding changes in trends could be important. However, as demonstrated in the Companies' analysis, unless the absolute price of natural gas were to be consistent with the high EIA forecast and coal prices were to be depressed at a historically low relationship with natural gas through 2050+, only then would installing an SCR on Ghent Unit 2 perhaps be preferable to the Brown Unit 12 NGCC, and only if there were never any CO_2 compliance risk during that period.

Q. Is it reasonable to expect that coal companies will seek to take advantage of any increase in natural gas prices or the diminishing supply of coal?

A. Absolutely. The sharp increase in coal prices described by Ms. Medine was no accident and coal companies and their shareholders benefited from it. One of the Companies' largest coal suppliers, Alliance Resources, reported record financial results in 2022,[60]

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[59] See EIA's 2022 historical consumption data in "Natural Gas Summary" at https://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

[60] Alliance Resource Partners, L.P. Reports Record 2022 Results; Increases Quarterly Cash Distribution 40% to $0.70 Per Unit; Increases Unit Repurchase Program to $100.0 Million; Announces $72.3 Million Mineral Acquisition; and Provides 2023 Guidance | Alliance Resource Partners, L.P. (arlp.com)

and it reported that its strong financial performance continued into the first quarter of 2023, stating it was "able to achieve significantly higher realized pricing per ton sold relative to the prior year."[61] Similarly, Peabody (another supplier to the Companies) reported record earnings and record free cash flow in 2022.[62] Their strong financial performance continued into the first quarter of 2023 as they announced a "robust shareholder return program."[63]

Q. Do you believe that the risk of coal companies seeking to extract higher prices from domestic utilities such as the Companies will increase in the future?

A. Yes. Because both the number of mines and the number of suppliers have been shrinking as domestic demand declines, there is less coal-on-coal competition to serve as its own check on coal prices. For natural gas to be an effective cap on the pricing power of the remaining coal suppliers, the Companies would need to have far more natural gas generation than they do currently. Also, it is important to keep in mind that, as this proceeding demonstrates, a new NGCC unit can take four to five years from concept to commercial operation. During that time, the Companies and their customers would be at the mercy of a handful of suppliers. Absent a change in environmental regulations, one should expect coal suppliers to push their prices to just below the level that would cause the Companies to retire coal and build new generation (regardless of technology; the same concept applies to renewables as replacement generation). It is clear that coal mines can close much faster than alternative generation of any kind can

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[61] Alliance Resource Partners, L.P. Reports Strong First Quarter Performance; Completes $75.1 Million Oil & Gas Mineral Interest Acquisitions; Declares Quarterly Cash Distribution of $0.70 Per Unit; and Updates 2023 Guidance | Alliance Resource Partners, L.P. (arlp.com)

[62] Peabody - Newsroom (peabodyenergy.com)

[63] Peabody - Newsroom (peabodyenergy.com)

be constructed, and the Companies' risk of future coal supply is growing. This type of pricing strategy by coal companies will increase the likelihood that coal prices over time will tend to track natural gas prices *more* closely in the future, not less, consistent with the typical CTG ranges that the Companies have observed historically and assumed in their modeling.

From an economics perspective, in a long-term declining demand market like coal, profit maximizing suppliers should seek to contract supply faster than demand in order to maintain high prices and eliminate less profitable operations. This will be easier to do as market share becomes concentrated in fewer firms. As an economist and the officer responsible for coal supply, my long-term concern is that the coal market will shrink to the point that it resembles a duopoly; even today, just two suppliers dominate the Companies' supply market. The risk in a duopoly is that prices may be higher than would be the case in a competitive market.[64]

Q. Do you agree with Ms. Medine's view that coal inventory mitigates against loss of generation compared to relying on natural gas generation with firm gas transportation?

A. No. Ms. Medine's view is informed by only short-term (measured in hours) fuel security risk. The entire basis for her view seems to be driven by the Companies' experience for a few hours on December 23, 2022, when the Companies could not get full load from some of its gas-fired generators due to lower than necessary pressure on the Texas Gas Transmission ("TGT") system caused by a combination of equipment

[64] https://www.investopedia.com/terms/d/duopoly.asp#:~:text=With%20a%20duopoly%2C%20prices%20may,more%20and%20have%20fewer%20alternatives.&text=The%20two%20companies%20benefit%20by%20cooperating%20to%20improve%20profits.

failure and operating procedures. This is the first time such an event has ever occurred in the more than 20 years that the Companies have relied on TGT for gas transportation, and TGT has a clear understanding of the equipment upgrades and changes in operating procedures necessary to address the events of December 23rd.[65]

Notably, Ms. Medine does not advocate that the Companies evaluate back-up fuel oil to address this risk for the Companies' proposed NGCCs notwithstanding her stated concern about short-term fuel interruptions in the winter. Instead, she advocates to continue operating uneconomic coal units to address the risk, but she provides no analysis to support her position. As Mr. Bellar discusses in his rebuttal testimony, the Companies have requested fuel oil information from each of the respondents to the NGCC construction RFP.

While having 20 days to 40 days of coal inventory at a plant site mitigates against a short duration fuel supply disruption—and that is the Companies' target coal inventory range for Illinois Basin coal—the risk of coal supply disruption is not zero, and it is the risk of supply disruption that informs the volume of coal inventory that the Companies target. It is not costless to hedge that risk: as shown in Table 5, in the Companies' last rate case approximately $8.2 million a year is being paid by customers to cover the carrying cost of the $95 million of coal inventory in the test year.

[65] See Mr. Bellar's Rebuttal Exhibit LEB-1 for a letter from TGT with an update on the actions that they have taken to date and will take in the future.

Table 5: Fuel Inventory Revenue Requirements (Test Year Ending 6/30/22)			
	LG&E	**KU**	**Source**
Fuel Stock	$33,100,685	$62,536,188	Schedule B-5.1 Final
Cost of Capital (Grossed-Up)	8.54%	8.60%	Schedule J-1 Final
Revenue Requirement	$2,826,798	$5,378,112	
Case Nos. 2020-00349 and 2020-00350			

It typically only takes around one to five days to move coal by rail to our plants and three to nine days to move coal by barge to our plants. Thus, the need to have coal inventory is a direct result of the numerous long-duration events that can and do disrupt coal deliveries. These events include supplier bankruptcies, coal mine accidents or other events that result in long-term force majeure, geological events at mines that disrupt production, transportation disruptions, and unloading equipment issues at the Companies' plants. Because it is costly to keep inventory, the Companies attempt to model the nature of disruptions and balance the cost of inventory against the risk of unserved energy (similar to the approach used to determine the economic reserve margin). In fact, our coal inventories are lower than they otherwise would be because of the ability to call on natural gas generation to mitigate the risk of loss of load due to the lack of coal supply. The Coal Supply group works diligently to manage the numerous supply events that have occurred, but, as I have discussed, the dwindling number of mines and suppliers will make their task even more challenging in the future. Indeed, the Companies' most recent inventory modeling suggests that, based on the inability to purchase spot coal in 2022 at almost any price, additional inventory (and money) will likely be needed in the future. Ms. Medine is correct that our coal supply plans rely on a portfolio of coal contracts, but when events occur that disrupt supply (e.g., a long-term supplier force majeure), the Companies have had to execute spot purchases. Thus, as the number of mines and suppliers continues to shrink, the ability to manage long-term coal supply disruption risk with spot purchases will likely diminish, and there is simply no way to store six or more months of coal at the Companies' facilities.

Q. Do you agree with Ms. Medine's characterization of the Companies' natural gas procurement strategy?

A. No. She seems to imply that there is something particularly risky about how the natural gas markets operate, especially in the daily market.[66] It is important to remember that spot natural gas price can go both up and down. In the first half of this year, the Companies purchased spot gas for around $2.30/MMBtu for Cane Run Unit 7, which translates into around $15.50/MWh. That is far lower cost than any generation from the Companies' coal units. The Companies also engage in the purchase of fixed price forward physical gas for the Cane Run Unit 7 NGCC to reduce the quantity of fuel purchased on a short-term basis and to reduce overall natural gas price volatility. Generally, the plan is to have between 50 percent and 60 percent of Cane Run Unit 7's daily gas burn under contract well before the beginning of the month. The financial implications of these purchases are no different than a coal contract at a fixed price for future delivery. As has been discussed by Mr. Schram, the Companies anticipate engaging in similar forward physical gas purchases for the two new NGCC units.[67]

[66] Medine, page 38, lines 8-21.
[67] Direct Testimony of Charles Schram, page 14.

Q. Ms. Medine discusses advances in small modular reactors ("SMRs") in the context of compliance implications regarding EPA's proposed 111(b) and 111(d) regulations.[68] What is your understanding of SMRs and their potential to impact this CPCN proceeding?

A. The Companies are closely following SMR technology development. The topic of nuclear generation is discussed in Section 8 of my Direct Testimony.[69] As I discussed, based on the permitting time requirements and the need for SMRs to be constructed and demonstrated at scale, at this time I believe they would be an option to serve load for the Companies in the early 2040s.

Based on news reports, TVA is the utility that appears to be furthest along in a decision (which is expected early next year) to proceed with an application with the Nuclear Regulatory Commission for a construction license. If TVA proceeds, they seem to be targeting a mid-2030s commercial operation date.[70]

Also, in the recent hearing before the Kentucky General Assembly's Interim Joint Committee on Natural Resources and Energy, PJM Vice President Asim Haque stated concerning SMRs:

> I've gotten quite a few questions about, "Well, just put a bunch of small modular nuclear reactors in the system and we're good." And my response is, you know, we would love that. But at the present, I don't believe the first small modular reactor is expected to actually be online and produce power until later in this decade. And so we need resources that are deployable at scale, in order to meet this sort of reliability challenge on the essential reliability services piece.[71]

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[68] Medine, page 19 lines 11-24 and page 20. Lines 1-10.
[69] Sinclair Direct Testimony, page 27-28.
[70] Advanced Nuclear Solutions (tva.com)
[71] Interim Joint Committee on Natural Resources and Energy Hearing August 3, 2023, YouTube video at 1:02:47-1:03:23, available at https://www.youtube.com/watch?v=Bja3IDPFPMs (accessed August 4, 2023).

Finally, Ms. Medine's citation regarding a NuScale SMR that would be operational by 2024 is a source from *2013*. I have personally spoken with representatives of NuScale in the recent past, and while NuScale continues to pursue that project, it still has significant permitting, commercial, and economic issues to address before they even begin construction.[72] In other words, this project was a decade out in 2013 according to the article cited by Ms. Medine, and it appears to be still a decade out based on my recent conversations and new reports. As it relates to the issues in this proceeding, Ms. Medine's discussion of SMRs appears to be a distraction rather than a legitimate concern regarding an alternative technology to the Companies' proposed NGCC units.

Q. Do you agree with Ms. Medine's analysis and recommendations regarding solar PPAs?

A. No. Ms. Medine expressed several concerns, including:

- Long-term contracts must have buy-out provisions and the must-take provision is problematic. While long-term contracts can have certain risks, it is important to recognize that these solar PPAs are for yet-to-be-built generation facilities that will be project financed by the developer. In a project finance structure, the special purpose entity that owns the asset will be highly leveraged (70 to 90 percent debt) with the Companies' PPA being the credit on which the banks are willing to lend to finance the project. The banks will not finance a project that would allow the Companies to walk away before the debt was repaid and the special purpose entity has no incentive to terminate the PPA because that would

[72] https://www.reuters.com/business/energy/western-us-cities-vote-move-ahead-with-novel-nuclear-power-plant-2023-02-28/

likely result in default on the debt. The must-take provision of the PPA is a critical part of the project finance structure since that is likely to be the sole (or primary) source of revenue for debt repayment. The primary risk to the PPA is post-debt repayment, which is likely to be about five years prior to the end of the PPA (banks typically want out before the end of the PPA). The Companies have inserted several provisions in the PPA to address the risk of early termination (in case power prices are higher than the PPA) and the level price structure reduces the risk that customers in 20 to 30 years will regret the PPA pricing compared to generation options and economics that might be available at that distant date.

- Transmission constraints would require the Companies to pay for energy that cannot be delivered due to transmission constraints. Ms. Medine is simply mistaken on this issue.[73] The PPAs clearly address an event wherein the balancing area requests the output of the solar facility to be curtailed. The Companies will not pay for curtailed energy due to transmission issues. Also, the Companies will be requesting network transmission service (just like it has for all other generating units) so that energy from each of the solar facilities can be delivered to the Companies' customers.

Thus, Ms. Medine's concerns are misplaced and do not recognize the specific circumstances associated with these particular solar PPAs, and her suggestions for alleviating her concerns could ensure the PPAs became uneconomical. For example,

[73] See Companies response to JI 4-1.

her recommendation that the solar PPAs include a buy-out option would ensure that the projects would likely not get financed and therefore never be built.

Section 5 – KCA Ignores the Companies' Evaluation of EPA's Proposed 111(b) and 111(d) Greenhouse Gas Rules and Misstates Implications of the Rules on Future Generation

Q. Please summarize your understanding of Ms. Medine's testimony regarding the Companies' analysis of the EPA's proposed 111(b) and 111(d) greenhouse gas rules.

A. Ms. Medine alleges that the Companies have not performed sufficient analysis regarding the EPA's proposed 111(b) and 111(d) rules to support their recommendations in this proceeding. She also discusses the EPA's Regulatory Impact Analysis ("RIA") of the proposed rules and attempts to draw conclusions regarding the effect the proposed rules would have on the role of NGCC generation over time.

Q. Do you agree that the Companies have "not shared any such analysis (operation of NGCCs as intermediate load plants) if one has been performed"?[74]

A. No. In response to data request PSC 5-2, the Companies explicitly limited the annual capacity factor of the Mill Creek and Brown NGCC units to 50 percent as could be required to comply with the proposed 111(b) regulation. As discussed in the response, limiting the annual capacity factor of these units to 50 percent annually is the worst case for new gas units because the Companies would always have the option to utilize hydrogen blending and carbon capture ("CCS") if the benefits of exceeding the 50 percent capacity factor limit outweighed the cost of hydrogen or CCS. The results of

[74] Medine at 16, line 19.

that stress test showed that the Companies' recommended portfolio (including the Mill Creek and Brown NGCC units) is the most robust portfolio for compliance with the Good Neighbor Plan, replacing Brown Unit 3, and complying with the proposed new greenhouse gas rules.

Q. Have the Companies recently provided another analysis of the potential 111(b) and 111(d) rules in this proceeding?

A. Yes. In response to data request PSC 6-2, the Companies used PLEXOS to evaluate optimal resource portfolios across three CO_2 price scenarios net of 45Q tax credits for carbon capture and storage ("CCS") and six fuel price scenarios. The results showed that in all 18 portfolios developed (one for each combination of CO_2 and fuel price scenario) it was economical to retire Mill Creek Unit 2, Ghent Unit 2, and Brown Unit 3 by 2028 and add at least two (2) and up to seven (7) NGCC units by 2030. These results are yet more indication of the robustness of Companies' recommended generation portfolio if the proposed greenhouse gas regulations become final.

Q. One of the CO_2 pricing scenarios the Companies considered in their analyses of the potential 111(b) and 111(d) rules in this proceeding is zero, i.e., an assumption that CCS costs net of tax and any other incentives would be zero. Are there any recent developments that make such a net zero-cost scenario even less likely than when the Companies modeled it?

A. Yes. On August 4, 2023, the North Dakota Public Service Commission rejected a CO_2 pipeline permit application by Summit Carbon Solutions. According to the Associated Press:

> The North Dakota Public Service Commission denied the permit for Summit's Midwest Carbon Express pipeline, which planned a 320-mile

> (515-kilometer) route through North Dakota. Summit proposed the $5.5 billion, 2,000-mile (3,219 kilometer) pipeline network to capture carbon dioxide from more than 30 ethanol plants in Iowa, Minnesota, Nebraska, North Dakota and South Dakota, and to store it deep underground in North Dakota.[75]

The opposition to the pipeline is making for some interesting alignments: at least one Republican state senator, whose district is in the proposed pipeline path, opposes the project,[76] as does at least one Sierra Club organizer:

> Jess Mazour, an organizer with the Sierra Club in Iowa, which opposes the carbon pipelines, said the decision in North Dakota should set an example for other states where tense disputes are underway between landowners and the pipeline companies over issues like eminent domain.
>
> "This decision is huge," she said. "We're fighting the exact same battle [and] it should be the same outcome."[77]

The point of observing this is that any assumption that CCS will be readily available in time to comply with the proposed 111(b) or (d) greenhouse gas regulations—especially at a net-zero cost—is generous at best. As with any pipeline project, there will be many parties who will oppose it—including possibly the Sierra Club—and it is reasonable to expect delays and cost increases to result.[78] Thus, I do not think it would be reasonable to assume that the net-zero scenario the Companies modeled is equally likely as the other scenarios; rather, I believe it represents a remote possibility.

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[75] Associated Press, "North Dakota regulators deny siting permit for Summit carbon dioxide pipeline; company will reapply," (Aug. 4, 2023), available at https://apnews.com/article/north-dakota-carbon-dioxide-pipeline-29d15d0d29782f9f28b7907b6bb1896e (accessed Aug. 8, 2023).
[76] *Id.*
[77] Reuters, "North Dakota regulator rejects Summit Carbon Solutions carbon pipeline application," (Aug. 4, 2023), available at https://www.reuters.com/sustainability/climate-energy/north-dakota-regulator-rejects-summit-carbon-solutions-carbon-pipeline-2023-08-04/ (accessed Aug. 8, 2023).
[78] According to the North Dakota Public Service Commission, Summit filed its application in October 2022. *See* N.D. PSC, "PSC Denies Siting Permit for Summit Carbon Pipeline Project," (Aug. 4, 2023), available at https://www.psc.nd.gov/public/newsroom/2023/8-4-23SummitCarbonPipelineOrderNR.pdf (accessed Aug. 8, 2023).

Q. Do you have any other thoughts on the proposed 111(b) rule and its potential to limit the operation of the new Mill Creek and Brown NGCC units to a 50 percent annual capacity factor?

A. Yes. While it would be unfortunate for customers if the rule were to limit customers' access to incremental low cost (and low CO_2 emitting) energy from the new units, it is odd that Ms. Medine focuses so much on the capacity factor limit given the actual capacity factor of the coal units (Mill Creek 1 & 2, Brown 3, and Ghent 2) that she argues should be kept operating. Table 6 shows the actual annual capacity factors for each of the coal units at issue in this proceeding and their combined capacity factor, both including and excluding Mill Creek 1, because the total amount of coal capacity being retired is comparable to the NGCC capacity that is being added. As the data shows, the combined capacity factor of the coal units that are proposed for retirement is already around 50 percent annually over the last six years. It is also notable that Brown Unit 3 has averaged only a 29 percent annual capacity factor during this period. In the last two years, only one of the units each year achieved at least a 60 percent annual capacity factor (Ghent Unit 2 in 2021 and Mill Creek Unit 2 in 2022). If Ms. Medine believes operating a generation unit at a 50 percent or less annual capacity factor is an economic issue, then she should be just as concerned about the economics of these particular coal units, especially Brown Unit 3.

Table 6: Annual Capacity Factor of Coal Units at Issue in this Proceeding								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**		**2017-2022**
BR3	28%	35%	25%	29%	26%	27%		29%
GH2	70%	80%	63%	59%	60%	52%		64%
MC1	64%	75%	57%	65%	51%	47%		60%
MC2	65%	60%	70%	36%	43%	63%		56%
MC1-2, BR3, GH2	56%	62%	53%	47%	45%	46%		52%
MC2, BR3, GH2	54%	59%	52%	43%	44%	46%		50%

The real question is, "What is the best *portfolio* of generation assets to reliably meet customers' energy needs at the lowest reasonable cost?" The Companies' annual system load factor, which is the load version of a generation capacity factor, is around 58 percent to 60 percent. Due to weather and other factors that affect energy consumption, some hours of the year are going to require more energy than other hours. Thus, it is important that the generation portfolio has a mix of generation technologies that can meet the totality of system load. (Note that this same concept applies to RTOs, as well.) This means that some units will likely operate at a capacity factor that is greater than the system load factor while others will operate at a lower level. Ultimately, the best portfolio will be one that takes advantage of the strengths of generation technologies and avoids adding resources that would emphasize their weakness (operations, availability, economics, etc.).

Q. Did the EPA issue a subsequent update to their RIA of the proposed 111(b) and 111(d) regulations, as noted in Ms. Medine's testimony?

A. Yes. The EPA released an update to their analysis on July 7, 2023. The updated analysis reflects gas forecasts consistent with the EIA's 2023 Annual Energy Outlook, along with some modeling improvements such as allowing NGCC units the flexibility to temporarily retrofit with hydrogen blending in baseload operations and later revert to full natural gas combustion in intermediate load operations if hydrogen blending is no longer economic.[79]

Q. Do you agree with Ms. Medine's characterization of the EPA's own analysis of the proposed 111(b) and 111(d) rules as it relates to the Companies' future generation portfolio?

A. No. Ms. Medine's characterization overemphasizes the effect of the updated analysis on the quantity of NGCC capacity built, while largely ignoring the drastic near-term reduction in coal-fired generation in the EPA's analysis.

Q. Does the EPA's updated analysis continue to support the addition of new NGCC capacity?

A. Yes. While the updated analysis for SERC-KY projects a lower total quantity of new NGCC capacity being built by 2030, the EPA's 'Updated Baseline with LNG Update' and 'Integrated Proposal with LNG Update' models reflect 2,233 MW and 2,274 MW of new NGCC capacity respectively, *roughly 1,000 MW more than the Companies are requesting to build in this proceeding*.[80]

Q. How does the EPA's updated analysis reflect 111(b) compliance for this new NGCC capacity?

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[79] See Integrated Proposal Modeling and Updated Baseline Analysis pages 2 and 5, available at https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf

[80] Taken from the "S_C_KY" tabs of the "Updated Baseline with LNG Update RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-07/Updated%20Baseline%20with%20LNG%20Update.zip and of the "Integrated Proposal with LNG Update RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/other-files/2023-07/Integrated%20Proposal%20with%20LNG%20Update.zip.

A. The EPA's analysis assumes this new NGCC capacity will be retrofitted to blend 30% low-GHG hydrogen for their period that includes 2032 to 2037 but the capacity will revert to full natural gas combustion at a 50 percent or lower capacity factor in the remaining five-year intervals shown in EPA's modeling results.[81]

Q. Do the EPA's modeling results mean the Companies must plan to blend hydrogen on NGCC capacity beginning in 2032?

A. No. In fact, the EPA's analysis assumed the Companies' existing NGCC capacity, Cane Run Unit 7, would operate as an intermediate load unit and restrict its capacity factor to 50 percent.[82] The EPA's analysis assumes low-GHG hydrogen will be readily available at a cost of $0.50/kg by 2032, making it competitive with natural gas. While no large-scale market for low-GHG hydrogen exists today, and low-GHG hydrogen cannot be produced or procured at that price today, if the research and development in low-GHG hydrogen results in hydrogen blending being economic by 2032, the Companies would elect hydrogen blending in the new NGCC capacity to take advantage of the ability to generation more energy from the units. However, as a worst-case scenario, the Companies could comply with 111(b) by electing intermediate load operations and restricting capacity factors for NGCC capacity to 50 percent, which is exactly what the Companies modeled in response to PSC 5-2.

[81] Per the EPA, their Integrated Planning Model (IPM) "uses model years to represent the full planning horizon being modeled. By mapping multiple calendar years to a run year, the model size is kept manageable. IPM considers the costs in all years in the planning horizon while reporting results only for model run years. For this analysis, IPM maps the calendar year 2028 to run year 2028, calendar years 2029-31 to run year 2030, calendar years 2032-37 to run year 2035, calendar years 2038-42 to run year 2040, calendar years 2043-47 to run year 2045 and calendar years 2048-52 to run year 2050." See footnote 2 of https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

[82] Taken from the "S_C_KY" tabs of the "Integrated Proposal with LNG Update RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

Q. What implications does the EPA's modeling have for the Companies' coal fleet?

A. In the EPA's 'Integrated Proposal with LNG Update,' roughly 4,000 MW of today's coal generation capacity is retired by 2032.[83] The remaining capacity (approximately 1,100 MW) is retrofitted with CCS by 2030 but ultimately retired by 2045 as the 45Q CCS tax credit is exhausted. Unsurprisingly, the EPA's proposed greenhouse gas regulations for existing coal units does not support the long-term continuing operation of coal.

Q. How do the results of the Companies' modeling in response to PSC 6-2 compare to the EPA's analysis?

A. The Companies' PLEXOS modeling of EPA's proposed 111(b) and 111(d) regulations indicated that retiring coal and installing NGCC units would be part of the least-cost compliance strategy. Additionally, the analysis performed in response to PSC 6-2 showed the large addition of renewable generation and very limited installation of CCS on existing coal units (primarily Trimble County Unit 2). These results are broadly consistent with EPA's analysis.

Q. Ms. Medine alleges that the Companies did not include any analysis of carbon capture on coal in the 2021 IRP or the Resource Assessment. What is your response?

A. First, assumptions and modeling, performed or not, in the 2021 IRP have no bearing on this proceeding. The Companies have provided a full and robust analysis of the responses to its RFP to address Good Neighbor Plan compliance and the economics of

[83] Taken from the "S_C_KY" tabs of the "Integrated Proposal with LNG Update RegionalSummary" Excel file in the zip file available at https://www.epa.gov/system/files/documents/2023-07/Integrated%20Proposal%20Modeling%20and%20Updated%20Baseline%20Analysis.pdf.

Brown Unit 3. Second, until the EPA released its proposed 111(d) regulations in May, there were no proposed or promulgated regulations requiring carbon capture for existing coal units, and various studies have shown that carbon capture on existing coal was not economic.[84] Thus, to date there has been no compelling reason to invest the time and resources required to identify potential geological sites, pipeline routing, and the myriad of other details that will be required to eventually fully evaluate the economics of CCS on the Companies' existing coal units. Indeed, the recent denial of approval for Summit's CO_2 pipeline project in North Dakota I discussed above shows just how complicated such projects can be.

Q. Ms. Medine alleges that "the role for NGCCs is expected to dramatically decline over time under both the updated baseline and the GHG proposal."[85] Do you agree with her assertion?

A. No. EPA's modeling reflects new and existing NGCC capacity in the SERC-KY region operating between a 44% and 50% capacity factor from 2040 through the end of their analysis period of 2055, at or near the maximum allowed for intermediate load units. Coal, by comparison, is mostly retired by 2032 and completely retired by 2045. Thus, the EPA's modeling results are similar in nature to the Companies' model results in response to PSC 6-2. It is fair to say that Ms. Medine's characterization of the role of NGCC over time is incorrect and would be more accurately attributed to coal.

[84] One of the likely comments on the proposed 111(d) regulations is that 90 percent CCS has not been "adequately demonstrated." For an example of such a likely comment, see https://www.globalenergyinstitute.org/sites/default/files/2023-06/USCC_EPA%20Powerplant%20Rule%20Analysis_2023.FINAL_.pdf

[85] Medine at 19, lines 1-3.

Q. Do you have any other concerns regarding Ms. Medine's testimony regarding the potential impact of the proposed 111(b) and 111(d) regulations?

A. Yes. Ms. Medine's testimony on this topic seems intended to distract from the real decisions in this case to support her recommended outcome – do nothing. For example, many of her comments are focused on the potential impact of the proposed rules on the Mill Creek and Brown NGCC units, yet she says very little about the consequences of the proposed rules on existing coal units, including the 3,200 MW of coal capacity that is not at issue in this case. The Companies' response to PSC 5-2 and PSC 6-2, as well as both of EPA's analysis of SERC-KY, support NGCC operation over the analysis period and reduced investment in coal. Based on known and understood technology today, it is hard to envision a generation portfolio in a carbon-constrained world that does not include at least the Mill Creek and Brown NGCC units. It is highly unlikely that the EPA would propose a set of CO_2 regulations that would favor coal continuing to operate over the long-term; based on both the Companies' and EPA's analysis, it appears that EPA's proposed rules do indeed disfavor the long-term operation of coal-fired units. Thus, moving forward with the Mill Creek and Brown NGCC units now will significantly reduce the risk and challenges of addressing the proposed 111(d) greenhouse gas regulations or any others that are likely to follow.

Section 6 – The Companies Have Appropriately and Adequately Addressed Risks in Developing A "No-Regrets" Portfolio

Q. The Joint Intervenors witness Ms. Sommer lists some specific concerns regarding "Planning in an Uncertain and Changing World." What are your thoughts on her comments?

A. I fully agree with her statement that "the electric power industry is confronted with numerous challenges."[86] Indeed, in my nearly 40-year professional career, much of which has involved forecasting and planning, I have consistently found that "numerous challenges" are the norm rather than the exception. As Yogi Berra observed, "Some things are difficult to predict, especially the future." Therefore, the need to adequately and appropriately address uncertainty and risk is critical to any planning exercise, but it is especially so when actual decisions are being made about real resources to serve real customers, as they are in this proceeding. It is vital that everything the Companies plan for in the models works in the real world. The Companies have no incentive to do anything else.

The Companies' focus on real-world planning and execution is why my direct testimony addressed topics such as:

- Understanding customers' hourly load and how technologies and economic growth could alter that over time;
- Ensuring that the generation portfolio has ample ramping capability throughout the year to address hourly load changes;
- Ensuring the proposed generation portfolio was reliable and least-cost over a broad range of possible fuel, CO_2 price, and weather scenarios;
- Addressing the uncertainty and risk associated with solar PPAs;
- Reviewing technologies such as pumped storage hydro and nuclear generation and why they are not viable solutions to address the Good Neighbor Plan and Brown 3 economics but could be at a later date;

[86] Sommer, page 36, line 3.

- Recognizing that, even after the proposed generation portfolio is implemented, the Companies will still have over 3,200 MW of coal units that are only going to get older (and more expensive to maintain) and will likely face increasing environmental regulatory challenges;
- Discussing how the proposed generation portfolio will be a major step, in what will undoubtedly be many more in the coming decade or so, as the Companies' generation fleet is transformed to one that will continue to do what the past and present generation fleets have done, provide reliable, cost-effective energy to meet our customers' energy needs.

Q. Do you have any thoughts on some of the particular issues raised by Ms. Sommer?

A. Yes, I have several concerns with how she has characterized the Companies' planning and risk assessment.

Her discussion regarding temperature risk, especially in winter, is misleading, and it would be inappropriate to make the assumptions she seems to be suggesting.[87] First, she describes Figure 13 and Figure 14 as "Data Used to Create SERVM Loads."[88] These charts represent the average temperatures for three-month periods (December, January and February) so that there is only one data point for the entire three-month period for each of the maximum, minimum, and average. The Companies use hourly temperatures assigned to hourly load in SERVM to assess reliability, not three data points to represent winter weather risk as she implies.

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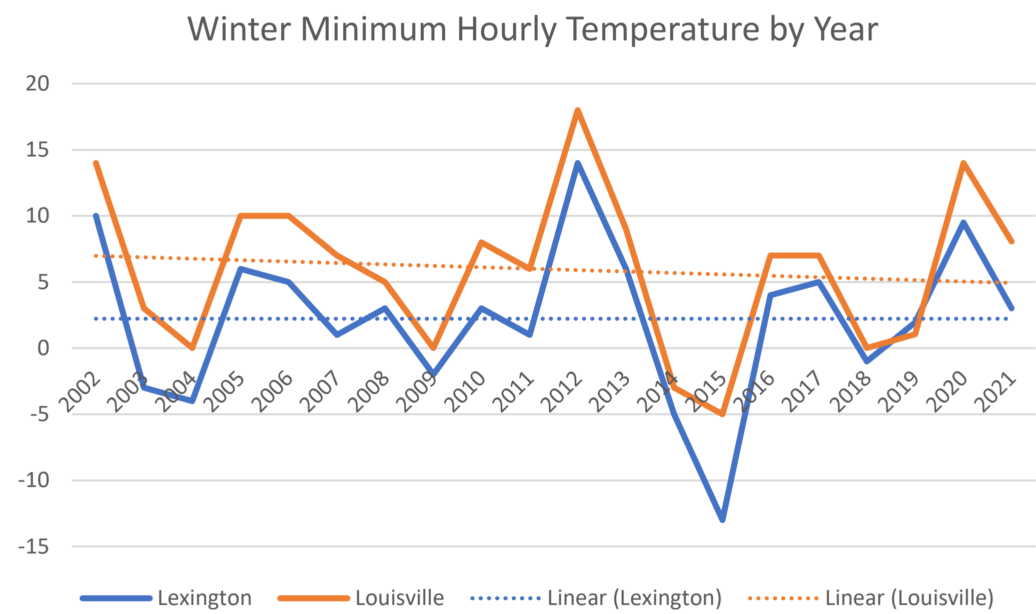
[87] Sommer, page 40-43.
[88] Sommer, page 42, lines 4-5 and page 43, lines 3-4.

Second, she uses Figure 13 and Figure 14 to suggest that average winter temperatures are increasing.[89] It is important to note that her conclusion rests on simply drawing a trend line through the data that she graphed. This simplistic approach is highly dependent on the beginning and ending data point, which includes the very cold average winters of the late 1970s. Because Ms. Sommer suggests that winters are getting warmer on average, plotting (see Figure 3) the coldest temperature for each of the last 20 winters (truncated earlier data since her method suggests recent data will be more indicative of future warming) and drawing a trend line through the data as Ms. Sommer did shows a different conclusion. Using her "draw straight lines through time-series data" method, one might conclude from Figure 3 that Louisville's extremely cold events are only going to get colder through time while there is no trend up or down in Lexington's extreme cold weather. Climate science is much more complicated than drawing straight lines on charts, and so is power system reliability planning.

[89] Sommer, page 43, lines 5-6.

Figure 3: Historical Extreme Cold Temperatures for Louisville and Lexington



But from a reliability planning and risk analysis perspective, long-term trends in average temperatures, whether up or down, are irrelevant. It is the extremes that matter, and it is prudent planning to assume that the same extremes could occur again. As discussed by Mr. Jones, using actual historical hourly weather allows the Companies to properly assess load risk due to weather based on real-world experiences.[90] Ms. Sommer seems to imply that our future reliability assessments should assume that winters will get warmer on average. She may or may not be correct about her forecast, but in the real world of operations, the Companies need to be prepared to serve load during extreme temperature events that like those that have actually occurred because the cost of being wrong—erroneously assuming it will get warmer in the winter—is that the Companies may not be able to serve load on the coldest of days.

[90] Jones Direct, page 15, lines 4-14; see also Section 5.2.2 of Exhibit TAJ-2 at page 18.

Ms. Sommer also lists various climate-related risks that could impact utility industry infrastructure.[91] The source of that list is an EPRI initiative in which the Companies already participate and of which PPL Corp. is a sponsor.[92] The Companies are focused on climate-related infrastructure risks.

Ms. Sommer suggests that EPA's recently proposed 111(b) and 111(d) greenhouse gas regulations are an example of looming risks that the Companies are not adequately addressing in our planning.[93] First, the Companies' initial analysis presented in Mr. Wilson's Exhibit SAW-1 stress tested numerous generation portfolios using a $15 and $25 per ton CO_2 price.[94] Second, once the EPA's rules were proposed, as the Companies discussed in response to the KCA's data request 3-3 and I addressed in this testimony regarding EPA's updated analysis for SERC-KY, the Companies' recommended portfolio in this proceeding is supported by EPA's own analysis of their rules. Third, I note that she, like Ms. Medine, mistakenly believes that EPA's proposed rules for new NGCC units require units operated at less than 50 percent annual capacity factor to utilize 30 percent hydrogen co-firing beginning in 2032.[95] As our responses

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[91] Sommer, page 37, lines 1-8.

[92] https://www.epri.com/research/sectors/readi/sponsors

[93] Sommer, page 36, lines 10-15, and pages 45-51.

[94] The Joint Intervenors' response to the Companies' DR 13(a) states that "a modeled cost does not necessarily equal inclusion of meaningful CO_2 regulation particularly if the spectrum of options to reduce CO_2 emissions are not included in the modeling and/or if the costs per ton are not good proxies for potential CO_2 regulation." I disagree for the reasons stated in their responses to PSC 5-2, 6-1, and 6-2. When actual compliance costs are largely, if not entirely, speculative and the contours of the final regulation are unknown, compliance pricing per ton of emissions is an entirely reasonable proxy. Also, the Commission Staff Report in the Companies' 2021 IRP stated, "Commission Staff believes such issues and potential delays in other forms of regulation raise the prospect, particularly over a timeline of 15 years or more, that a federal price or tax on CO_2 emissions could be implemented through the reconciliation process in the same way the tax on methane emissions was imposed in the Inflation Reduction Act. Thus, Commission Staff believes that the regulatory risk or prospect of a tax on CO_2 emissions should be seriously considered and discussed in detail in LG&E/KU's next IRP ….." Case No. 2021-00393, Commission Staff Report at 62 (Ky. PSC Sept. 16, 2022).

[95] *See* Joint Intervenors' Response to the Companies' DR 15(b). In the same response, Ms. Sommer states that she "is unable to agree" that a new NGCC unit could comply with the proposed 111(b) greenhouse gas standards

to PSC 5-2 and PSC 6-2 demonstrate, that is simply not true; EPA's own modeling and its supporting documentation refute that interpretation. The Companies' and EPA's analyses show that if the new NGCC units were constrained to a 50 percent annual capacity factor (which is a worst-case scenario given the option to co-fire with hydrogen or install CCS, either of which would only be done if it lowered cost), then they will still be valuable assets to serve load well into the 2050s (i.e., at least to the end of the analysis period).

Finally, Ms. Sommer states, "A comprehensive climate risk assessment would help direct planning efforts and determine which physical assets are most at risk."[96] The Companies, in concert with our parent PPL Corp., have done just that and are continuously reviewing and analyzing exposure to climate change. In November 2017, PPL Corp. (with input from the Companies) published a comprehensive "Climate Assessment".[97] PPL Corp. produced a new assessment report in 2021 and supplemented it in 2022.[98] Furthermore, PPL Corp. publishes an annual sustainability report, participates in the Climate Disclosure Project, and various other activities involving climate change.[99] The Companies are also very much aware of the work of the Intergovernmental Panel on Climate Change ("IPCC") and have reviewed their

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by transitioning from baseload to intermediate load operation in part because the standards "may be further clarified or modified by EPA at the time that the rule is finalized." This is an invitation to indefinite paralysis by analysis; things can always change, but decisions still must be made. Moreover, Ms. Sommer cannot have it both ways: either the proposed 111(b) and (d) greenhouse gas standards are to be taken seriously or they are not. But it is inconsistent at best to insist both that they must be studied and modeled and that they are too vague or subject to change to be worth understanding or modeling.

[96] Sommer, page 44, lines 10-12.

[97] https://www.pplweb.com/wp-content/uploads/2017/12/PPL-Corporation-Climate-Assessment-Report.pdf

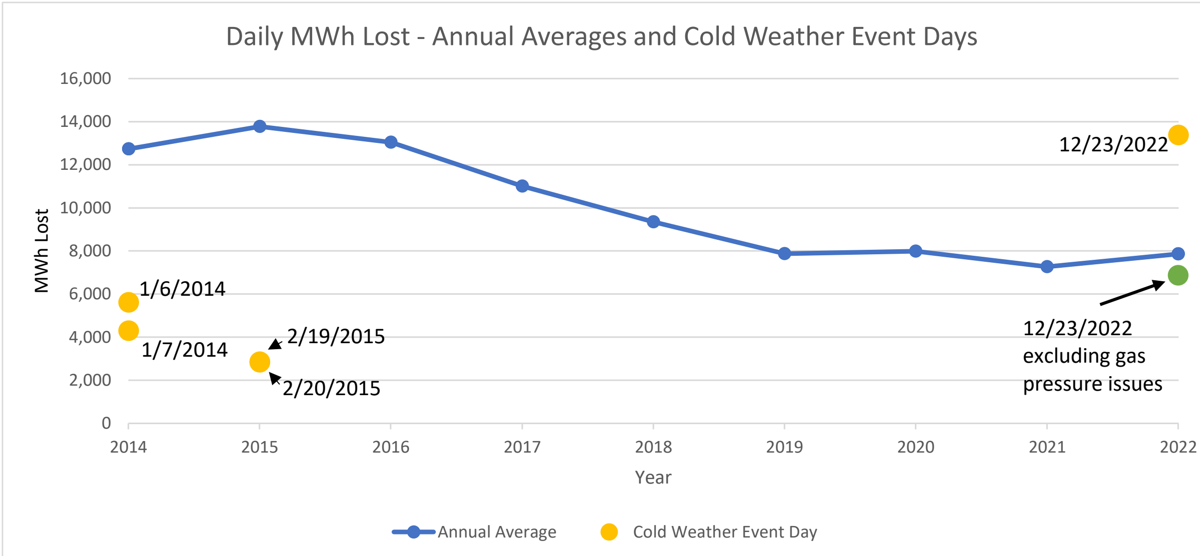
[98] https://www.pplweb.com/wp-content/uploads/2022/01/PPL_Corp-2021-Climate-Assessment_2022-01-04.pdf and https://www.pplweb.com/wp-content/uploads/2022/12/PPL_Corp-2022-Generation-Study-FINAL.pdf

[99] For more information and details on PPL's climate activities and reports see https://www.pplweb.com/sustainability/reports-disclosures/

recent AR-6 report. For example, Rebuttal Exhibit DSS-5 shows a listing of the IPCC's "Climate Impact Drivers" that should be tracked for assessing climate risk. In sum, the Companies are fully engaged on climate issues.

Q. Have you evaluated Ms. Sommer's claims on pages 8 and 9 that the Companies' generating unit outage risk is likely increased in cold weather?

A. Yes. Ms. Sommer cites a report by Astrape that discusses incremental outage impacts by generation technology during cold weather events (below 32 °F). The Astrape report also claims there is an impact on outages due to natural gas availability, but it acknowledges on pages 16-17 that "it was not possible from the available empirical data to create a direct correlation between temperature and fuel availability." Instead, the report used "anecdotal evidence from a variety of sources" to conclude that up to 10% of the natural gas supply could become unavailable at 0 °F. The Companies have decades of experience operating their generation fleet during periodic cold weather events, but they have not seen the types of incremental outages described by Ms. Sommer and the Astrape report. Furthermore, the Companies have never experienced difficulties in purchasing natural gas. The graph below plots the daily energy unavailable (lost MWh) due to cold weather-related forced outages and derates during the five coldest weather events since 2014. Outages that occurred prior to the onset of cold weather are not included because they obviously were not caused by the cold weather event. Comparing these daily values to the average daily lost MWh for each year, only the December 23, 2022 cold weather event exceeded the annual average.



The Companies have previously discussed the first-ever experience of the interstate pipeline pressure issue that resulted in the loss of generation on December 23, 2022. The Texas Gas Transmission pipeline is actively addressing equipment issues, winterization, and operational procedures to prevent a reoccurrence as discussed in Mr. Bellar's Rebuttal Exhibit LEB-1. Excluding the gas pressure event, the Companies' generation fleet again performed better than the annual average on a lost MWh basis.

Q. Is Ms. Sommer's claim of extreme weather-related events increasing outages similar to the claims of Mr. Goggin regarding correlated outage risk?

A. Yes. Indeed, Mr. Goggin cites the same Astrape study as Ms. Sommer. The Companies' generation outage data does not support this notion of "common mode" failures during cold temperatures. As displayed in the graph above, the Companies' generation assets performed *better* during cold weather events than the average annual levels. Furthermore, it is incorrect to classify the gas pressure event of December 23, 2022, in the same category as fuel availability events in other areas related to factors such as generation owners not securing gas supply or firm gas transport to deliver gas to their units.

Q. It seems that Ms. Sommer and Mr. Goggin and the studies they cite are particularly focused on cold weather events. Based on your experience, does hot weather typically cause mechanical operating issues with generation facilities or negatively impact the delivery of natural gas?

A. No. I have been the vice president responsible for the Companies' generation dispatch since 2008. During that time, I cannot recall having a unit failure or a start-up failure due just to hot weather. Also, I am not aware of a hot weather event that disrupted the production and transportation of natural gas. All of the mechanical (e.g., heat tracing, warm enclosures) and operational (e.g., pre-starting and temporary weatherization of equipment) actions that must be taken to address cold weather are not required in hot weather. Furthermore, since daily natural gas demand is lower in the summer than in the winter, the supply of natural gas into the pipeline system is not an issue, although the price might be higher than during milder weather as current utilization competes with demand to put gas into storage for upcoming winter. The Astrape report cited by Ms. Sommer and Mr. Goggin relied on a Carnegie Mellon study that showed higher forecasted levels of unavailable capacity for gas generators at low temperatures versus high temperatures.[100]

[100] Sinnott Murphy et al, *A time-dependent model of generator failures and recoveries captures correlated events and quantifies temperature dependence*, 253 Applied Science 113513 (Nov. 2019), https://www.sciencedirect.com/science/article/pii/S0306261919311870, page 9.

Q. Based on your 37 years of industry experience, what is your assessment of the reasonableness of the Companies' approach to addressing the risks that are inherent in any long-term generation resource decision?

A. The Companies have an extremely robust planning and analysis process that is implemented by a large team of highly educated and experienced people who know and understand customers, economics, financial analysis, engineering and operations, policy issues, technologies, and the importance of providing safe, reliable, and cost-effective energy to our customers every second of the day in all weather conditions. We have every incentive to do this job well and no incentive to do otherwise. As I stated in my Direct Testimony,[101] the Companies' generation resource decisions since my involvement in the mid-2000s have been informed by:

- Safely operating their facilities for employees, customers, and the public,
- Ensuring reliable generation supply 8,760 hours a year in all weather conditions,
- Working to comply with all laws and regulations,
- Investing in generation assets based on long-run economics for customers,
- Avoiding speculative technologies that would create unnecessary financial and reliability risks for our customers,
- Making decisions based on a thorough and thoughtful analysis of the alternatives and risks,[102] and
- Having a clear, executable plan to implement (primarily through construction) new generation decisions on time and on budget.

To better illustrate the value that this process has created for customers, listed below are all of the types of generation decisions that the Companies have brought to the Commission for the last two decades:

[101] Sinclair Direct Testimony, page 8 lines 5-22.

[102] Since the early 2000s, my department has utilized a decision quality model developed by Strategic Decisions Group ("SDG"). Over the last two decades, SDG has provided training sessions for employees and my leadership team has provided training to new employees on the process. An overview of the SDG decision quality model can be found at https://sdg.com/thought-leadership/decision-quality-defined/

- Building new coal units (Trimble County Unit 2) and retiring existing coal units (Cane Run 4-6, Green River 3-4, Brown 1-2);

- Seeking and receiving a CPCN for a SCR on Ghent Unit 2, and canceling the project when the economics changed;

- Building a new NGCC unit (Cane Run Unit 7) and cancelling a new NGCC unit (Green River Unit 5 when certain municipal customers terminated service);

- Buying existing simple cycle CTs (3 F-class SCCTs located at the Bluegrass station) and terminating the purchase of simple cycle CTs (FERC put conditions on the Bluegrass purchase that reduced the value to serving customers);

- Installing environmental controls and upgrades for existing coal units (SCRs, FGDS, baghouses, water treatment, landfills) and not installing new controls (Cane Run 4-6, Green River 3-4, Brown 1-2, Mill Creek Unit 1); and

- Building solar generation (Brown solar) and purchasing solar energy (the 25 percent of the Rhudes Creek project that will serve all customers).

This is the process that has produced the reliable, cost-effective generation portfolio that serves customers today, and it is the process that produced the generation portfolio recommended in this proceeding. As this list clearly illustrates, the Companies have no biases or preferences when it comes to technology except that it is needed to reliably serve load and is cost-effective.

As I stated at the outset of this testimony, many of the intervenor witnesses want to rely on "hope" to support their recommendations. On the other hand, the Companies have employed a rigorous, comprehensive, and thoughtful process that has resulted in a "no-regrets" set of generation decisions driven by data—not hope—that will provide reliable, cost-effective service to customers for decades to come. Neither the events that have occurred since the Companies filed their application in this proceeding nor the intervenor testimony has altered my opinion.

Section 7 – Conclusion and Recommendation

Q. Do you have any closing thoughts for the Commission to consider?

A. Yes. Much has been made by various intervenor witnesses that there is too much uncertainty in the world today and that more time and study are required before decisions can be made regarding compliance with the Good Neighbor Plan, the economics of Brown Unit 3, the viability of the proposed Mill Creek Unit 5 and Brown Unit 12 NGCC units, and more. But uncertainty is a constant in business, and doing nothing is doing something. Planning models always have perfect information, but that is never the case in real-world operations. The Companies must make decisions under uncertainty; indeed, all of long-term generation decisions recounted in the previous section of my testimony had their own unique uncertainties. The question at hand is, "Do we have enough information to decide and have we addressed the risks, especially the cost of being wrong?" An objective review of the totality of information provided in this proceeding can lead to only one answer to this question: yes.

Finally, in reflecting on the decisions required in this proceeding, I am reminded of a quote from President Harry S. Truman, who had to make many important decisions without perfect information, "Some questions cannot be answered, but they can be decided."

Q. What is your recommendation for the Commission?

A. I recommend the Commission approve the Companies' requested CPCNs as providing valuable, vital resources to ensure the Companies can continue to provide reliable service at the lowest reasonable cost while also positioning the Companies for a lower-carbon future.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 3rd day of August 2023.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

KIUC Member Company Scope 2 and Renewable Goals		
COMPANY	**SCOPE 2**[1]	**RENEWABLE GOALS**
Air Liquide Industrial U.S. LP *Air Liquide Sustainability Report 2022* air-liquide-sustainability-report-2022.pdf (airliquide.com)	In an important step this year, our target to reduce absolute Scopes 1 & 2 CO2 emissions by 2035 was validated by the Science Based Targets initiative (SBTi) as qualified and aligned with climate science.	We commit to be carbon neutral by 2050, by targeted emission reductions across all our assets and operations. In order to achieve that, we have clear plans: deploy new technologies and efficiencies, procure more renewable energy and invest in carbon capture projects.
Corning Incorporated *Corning/Sustainability/Climate Goals* Climate Goals (corning.com)	Reduce Scope 1 and 2 greenhouse gas (GHG) emissions by 30% (absolute basis) by 2028 compared to a 2021 baseline	Corning has committed to a four-fold increase in their renewable electricity use (2018 baseline) and is on a path to 100% renewables in the next few years in the US, Canada, and Europe.
Dow Silicones Corporation *Dow Corporate/Science & Sustainability/Sustainability Targets* Sustainability Commitments and Targets | Dow Corporate	By 2050, Dow intends to be carbon neutral (Scopes 1+2+3 plus product benefits).	

[1] Scope 2 CO_2 emissions are indirect emissions from the generation of purchased power. The Companies' CO_2 emissions are the Scope 2 emissions for our customers because they purchase power from the Companies.

KIUC Member Company Scope 2 and Renewable Goals		
COMPANY	**SCOPE 2**[1]	**RENEWABLE GOALS**
Ford Motor Company *On the Road to Better, Helping Build a Better World – Integrated Sustainability and Financial Report 2023* Helping Build a Better World (ford.com)	Reduce Scope 1 and 2 GHG emissions by 76% by 2035 from a 2017 baseline.	100% carbon-free electricity for global operations by 2035.
North American Stainless *North American Stainless/Home/Environment/Climate Change & Clean Energy* Climate Change & Energy - North American Stainless	NAS established a set of carbon targets for 2030, comprising a 20% reduction in the direct and indirect carbon emissions intensity (Scope 1 and 2) with respect to 2015 levels.	

KIUC Member Company Scope 2 and Renewable Goals		
COMPANY	**SCOPE 2**[1]	**RENEWABLE GOALS**
The Chemours Company FC, LLC *Essential. Responsible. Chemistry. 2022 Sustainability Report Executive Summary* Chemours 2021 Corporate Responsibility Commitment Report	Reduced total Scope 1 and 2 GHG emissions by 30% from our 2018 baseline, hitting the halfway point to our goal of an absolute reduction of 60%	Committed to renewable power at our Louisville, Kentucky; Starke, FL; New Johnsonville, TN; Belle, West Virginia; and Dordrecht, the Netherlands sites. Overall, by year-end 2022 we are committed to approximately 100,000 MWh per year of renewable power.
Toyota Motor Manufacturing, Kentucky, Inc. *Toyota Environmental Sustainability/Goals & Targets/Mid-Term Milestones* Goals & Targets (toyota.com)	Reduce absolute CO_2 emissions from suppliers by 10% from FY2018 levels, by FY2026.	Increase purchased renewable electricity to 45% or more of total electricity purchased by 2025.

Rebuttal Exhibit DSS-2: Companies' Modelling of Intervenor Recommended Portfolios

All assumptions match those used in the Resource Assessment (Exhibit SAW-1) in the CPCN except those specified for each portfolio. All portfolios include Ragland and Rhudes Creek solar PPAs and assume Mill Creek 1, Paddy's Run 12, and Haefling 1-2 are unavailable beginning January 1, 2025.

KIUC

The Companies evaluated the portfolios specified in Table 1 to demonstrate the incremental changes between the portfolio proposed by the Companies in the CPCN and the portfolio proposed by KIUC witness Kollen.

Table 1: KIUC Portfolios

Portfolio Name	Subtractions from CPCN Portfolio	Additions to CPCN Portfolio
KIUC-00	None	None
KIUC-01	Brown BESS	None
KIUC-02	Brown BESS, New Solar PPAs	None
KIUC-03	Brown BESS, New Solar PPAs	Ghent 2 remains online, limited to non-ozone season operation beginning in 2028 (retired in 2035)

Table 2 shows the <u>incremental</u> PVRR difference through 2050+ for each successive portfolio across the range of fuel price scenarios modeled in the Resource Assessment. Note that a negative value means the incremental portfolio change would decrease PVRR and a positive value means the incremental portfolio change would increase PVRR. The total impact of all of the changes is shown on the last row where KUIC-03 (all of Mr. Kollen's recommendations) is compared KIUC-00 (the Companies' recommended portfolio).

Table 2: Incremental PVRR ($M)

	Mid CTG Ratio					Other CTG Ratios			
Portfolio	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Avg of Mid CTG Scenarios**		**Low Gas, High CTG**	**High Gas, Low CTG**	**High Gas, Curr CTG**	**Avg Excl High Gas, Curr CTG**
KIUC-00: CPCN	NA	NA	NA	NA		NA	NA	NA	NA
KIUC-01: CPCN + No Brown BESS	(130)	(127)	(95)	(118)		(130)	(78)	(79)	(112)
KIUC-02: CPCN + No Brown BESS No Solar PPAs	(97)	69	491	154		(78)	478	734	172
KIUC-03: CPCN + No Brown BESS No Solar PPAs GH2 Non-Ozone (2035)	57	47	33	46		58	17	44	42
KIUC-03 less KIUC-00	**(171)**	**(11)**	**429**	**82**		**(150)**	**417**	**699**	**103**

The results of the incremental changes are not surprising given the analysis that was already performed in Exhibit SAW-1. From a purely PVRR perspective (ignoring any reliability, ancillary service and operating experience benefits), removing the Brown BESS decreases overall PVRR. On the other hand, removing the solar PPAs increases PVRR as does operating Ghent Unit 2 in the non-ozone season only.

Table 3 shows the annual CO_2 emissions of each portfolio in the Mid Gas, Mid CTG Ratio fuel price scenario. These results are consistent with expectations - removing solar and increasing the availability of coal generation will increase CO_2 emissions compared to the Companies' recommended portfolio.

Table 3: Annual CO_2 Emissions, Mid Gas, Mid CTG Ratio Scenario (Million Short Tons)

Portfolio	2028	2029	2030	2031	2032	2033	2034
KIUC-00	22.7	22.2	22.5	22.3	22.6	22.3	22.2
KIUC-01	22.7	22.2	22.5	22.3	22.6	22.3	22.2
KIUC-02	23.7	23.3	23.4	23.3	23.7	23.3	23.2
KIUC-03	24.1	23.6	23.7	23.6	24.1	23.7	23.6
KIUC-03 less KIUC-00	**1.4**	**1.4**	**1.3**	**1.3**	**1.4**	**1.4**	**1.4**

Table 4 and Table 5 show the energy by generation type that will likely replace the energy lost by the removal of the solar PPAs and the energy by generation type that will be displaced by Ghent Unit 2 non-ozone operation, respectively. It is interesting that retaining Ghent Unit 2 for non-ozone season operation mainly replaces other coal generation and that only 28 percent of the energy displaced is from higher cost SCCT units that normally run during higher load periods.

Table 4: Average Annual Energy that Replaces Energy from Solar PPAs, 2028-2034
(Mid Gas, Mid CTG Ratio Scenario)

Energy Source	Avg Annual Generation (MWh)	Avg Annual Generation (%)
Coal	727,314	51%
NGCC	441,357	31%
SCCT	247,929	17%

Table 5: Average Annual Energy Displaced by Ghent 2 Non-Ozone, 2028-2034
(Mid Gas, Mid CTG Ratio Scenario)

Energy Source	Avg Annual Generation (MWh)	Avg Annual Generation (%)
Coal	694,100	53%
NGCC	244,643	19%
SCCT	368,743	28%

KCA

KCA witness Medine proposed that the Companies not take any action. The Companies are interpreting this to mean that Mill Creek 1 should be unavailable beginning January 1, 2025, due to lack of existing ELG controls, and Paddy's Run 12 and Haefling 1-2 should be unavailable due to experiencing major maintenance failures that are uneconomic to repair. The Companies would consider these mothballed until further decisions could be made regarding future investments.

The Companies evaluated the portfolios summarized in Table 6 to demonstrate the energy unserved by the KCA's portfolio and show the incremental changes to generation from the CPCN portfolio. The Companies focused on 2028, which reflects when the three coal units are fully retired in the CPCN portfolio and where the Companies expect to continue to have a potential deficit in ozone season allowances due to the Good Neighbor Plan or the inability to operate Mill Creek Unit 2 due to local Jefferson County NO_x requirements.

Table 6: KCA Portfolios

Portfolio Name	Subtractions from CPCN Portfolio	Additions to CPCN Portfolio
KCA-00	None	None
KCA-01	Mill Creek and Brown NGCCs, New Solar PPAs and Assets, Brown BESS	Brown 3, Ghent 2 Non-Ozone Operation, Mill Creek 2 Non-Ozone Operation, SCCT operating limits relaxed from 25% to within air permit limits

The Companies evaluated the KCA-01 portfolio in the context of meeting load and complying with the Good Neighbor Plan within ozone season allowances. The Companies forecast a capacity shortfall using this portfolio, and the PROSYM run has "Energy Not Served" as a consequence. The Companies are viewing "Energy Not Served" as a proxy for the Good Neighbor Plan energy deficit, which would need to be overcome through some combination of additional ozone season NO_x allowances (if available), market purchases, or curtailed load. This portfolio was evaluated under normal weather; deviations from normal weather could exacerbate the Good Neighbor Plan energy deficit.

Table 7 shows the Energy Not Served in the KCA-01 portfolio in the Mid Gas, Mid CTG Ratio fuel price scenario. All Energy Not Served in this scenario is concentrated within ozone season (May through September).

Table 7: 2028 Energy Not Served in Ozone Season, KCA-01 Portfolio (MWh)

Hour Beginning	May	Jun	Jul	Aug	Sep	May-Sep Total
12:00 AM	0	0	0	0	0	0
1:00 AM	0	0	0	0	0	0
2:00 AM	0	0	0	0	0	0
3:00 AM	0	0	0	0	0	0
4:00 AM	0	0	0	0	0	0
5:00 AM	0	0	0	0	0	0
6:00 AM	0	0	0	0	0	0
7:00 AM	0	0	0	0	0	0
8:00 AM	0	0	0	0	0	0
9:00 AM	0	0	0	0	0	0
10:00 AM	0	0	199	16	0	214
11:00 AM	0	0	468	124	0	592
12:00 PM	0	0	516	897	0	1,412
1:00 PM	0	0	567	997	0	1,564
2:00 PM	0	0	503	1,010	0	1,512
3:00 PM	0	0	425	1,037	0	1,462
4:00 PM	0	44	394	745	175	1,358
5:00 PM	0	0	410	585	0	995
6:00 PM	0	0	383	588	0	971
7:00 PM	0	0	355	461	0	816
8:00 PM	0	0	122	298	0	420
9:00 PM	0	0	0	0	0	0
10:00 PM	0	0	0	0	0	0
11:00 PM	0	0	0	0	0	0
Total	0	44	4,341	6,757	175	11,316

Figure 1 shows the load duration curve for 2028 load (blue line) with the respective hours of Energy Not Served in the KCA-01 portfolio (orange dots).

Figure 1: Comparison of Energy Not Served in KCA-01 Against Load Duration Curve

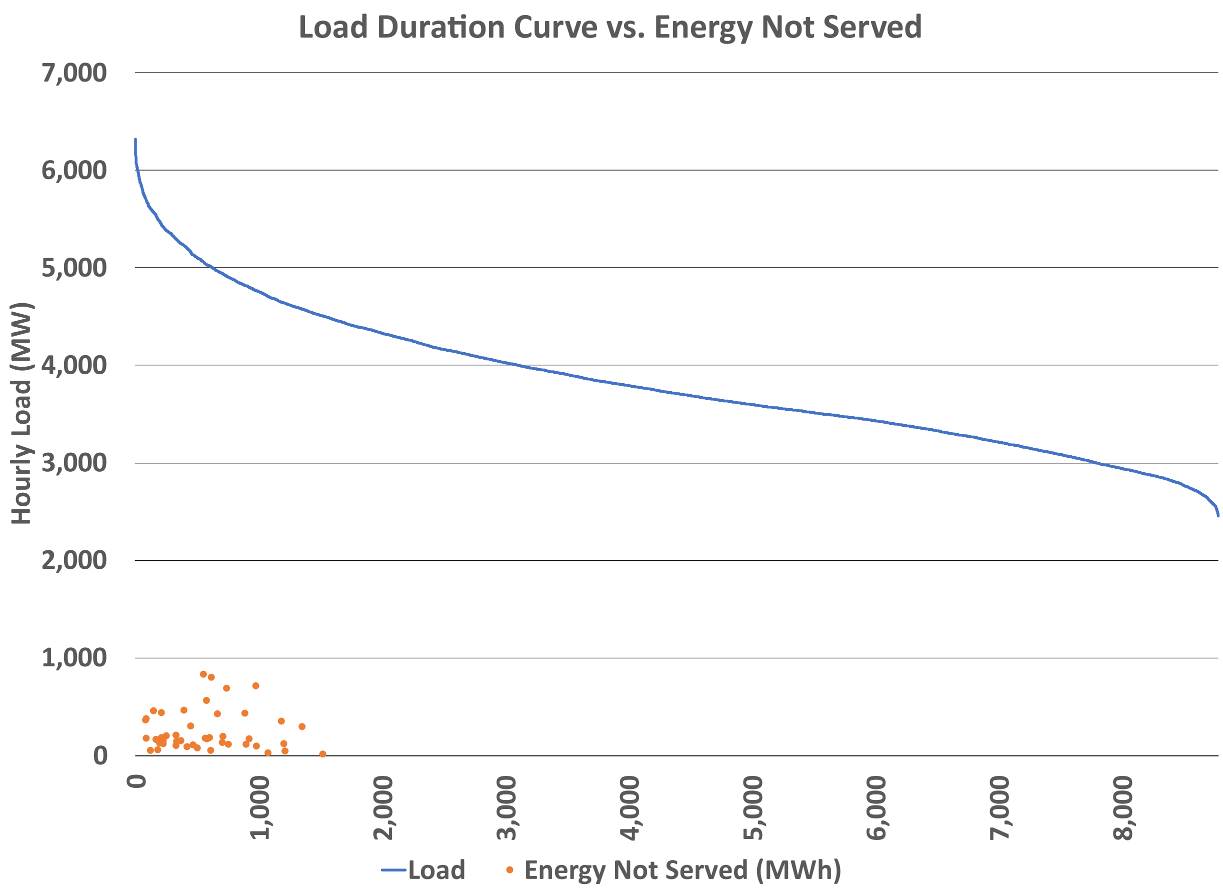


Table 8 shows the incremental added generation between the KCA's proposed portfolio and the CPCN portfolio. The energy shift that results from the KCA's portfolio are as expected:

- The 8.5 million MWh that would have been generated by the Mill Creek and Brown NGCC units shifts primarily to coal units – both the units that would otherwise have been retired and the Companies' other coal units.
- OVEC generation increases by around 45 percent.
- Even Cane Run Unit 7 NGCC picks up some energy but not much given that it was already running at over a 75 percent capacity factor.
- The loss of solar PPAs and owned solar combined with no availability of Mill Creek Unit 2 and Ghent Unit 2 in the summer ozone season (May through September) more than doubles energy from the SCCT units.
- Brown Unit 3 (which burns coal from Indiana) would increase its annual capacity from its historical level of around 30 percent to operate at over 40 percent.

Table 8: Incremental 2028 Generation Between KCA And CPCN Portfolios (MWh)

Generation Source	KCA-00 (CPCN Portfolio)	KCA-01 (KCA Portfolio)	KCA-01 less KCA-00
Brown 3	0	1,500,800	1,500,800
Ghent 2	0	1,683,600	1,683,600
Mill Creek 2	0	1,314,300	1,314,300
Other LKE Coal	16,043,900	20,249,400	4,205,500
OVEC	592,400	864,000	271,600
Cane Run 7	4,467,500	4,701,600	234,100
SCCTs	1,000,900	2,328,200	1,327,300
Mill Creek and Brown NGCCs	8,567,300	0	(8,567,300)
Solar PPAs(*)	1,949,800	523,900	(1,425,900)
Solar Assets(#)	567,800	22,100	(545,700)
Other	390,800	392,500	1,700
Total	33,580,400	33,580,400	0

(*) Prior solar PPAs with Rhudes Creek and Ragland are not impacted by Ms. Medine's recommendation.
(#) Existing owned solar projects continue to operate.

The Companies' CPCN case reflects an immediate phasing out of capital investment in units slated for retirement based on a known and planned retirement dates, particularly Brown Unit 3, Ghent Unit 2, and Mill Creek Unit 2. Table 9 reflects the forecasted incremental capital investment needed to extend the lives of Brown Unit 3, Ghent Unit 2, and Mill Creek Unit 2 to continue operating if the Companies' proposed portfolio were to be delayed. Values include major turbine overhauls in 2027, 2027, and 2026, respectively, as well as capital investment that would otherwise be tapering down as units approach a planned retirement.

Table 9: Forecasted Incremental Capital Investment to Extend Life of Proposed Coal Retirements to 2030

Year	Brown 3	Ghent 2	Mill Creek 2
2023	1.1	1.3	1.5
2024	2.1	5.0	8.7
2025	4.3	1.6	5.9
2026	8.3	11.9	12.8
2027	22.6	33.8	4.3
2028	4.0	2.2	5.5
2029	7.2	3.3	4.5
2023-2029 Total	**49.6**	**59.0**	**43.3**

Battery Dispatch Potential

Based on the Companies' expected generating portfolio, the Brown BESS is most likely to be charged overnight when load is lowest (and incremental generation is cheapest), and the likeliest source of generation to charge it will be coal, as SCCTs are generally offline and NGCCs are expected to run near maximum capacity. Assuming the Brown BESS is fully cycled 5 times per week, and assuming coal makes up 80% of the charging generation, Brown BESS has the potential to support 104,000 MWh of incremental coal generation.

500 MWh/cycle x 5 cycles/week x 52 weeks/year x 80% = 104,000 MWh

SC/JI

SC witnesses Goggin and Levitt proposed that the Companies not build NGCCs at Mill Creek and Brown. JI witness Sommer evaluated two alternative portfolios but did not recommend either portfolio. The Companies evaluated the portfolio summarized in Table 10 below to demonstrate the energy unserved by the SC's portfolio and show the incremental changes to generation from the CPCN portfolio. The Companies focused on 2028, which reflects when the three coal units are fully retired in the CPCN portfolio.

Table 10: SC Portfolio

Portfolio Name	Subtractions from CPCN Portfolio	Additions to CPCN Portfolio
SC-01	Mill Creek and Brown NGCCs	SCCT operating limits tightened to 10% to reflect typical operations (and what might be expected in an RTO)

The Companies evaluated the SC-01 portfolio in the context of meeting load with available resources and operating simple-cycle combustion turbines at a utilization level similar to historical operations. The Companies forecast a capacity shortfall using this portfolio, and the PROSYM run has "Energy Not Served" as a consequence. The Companies are viewing "Energy Not Served" as a proxy reliance on the market, which would need to be overcome through some combination of reliance on market purchases/RTOs, or curtailed load. This portfolio was evaluated under normal weather; deviations from normal weather could exacerbate the reliance on the market.

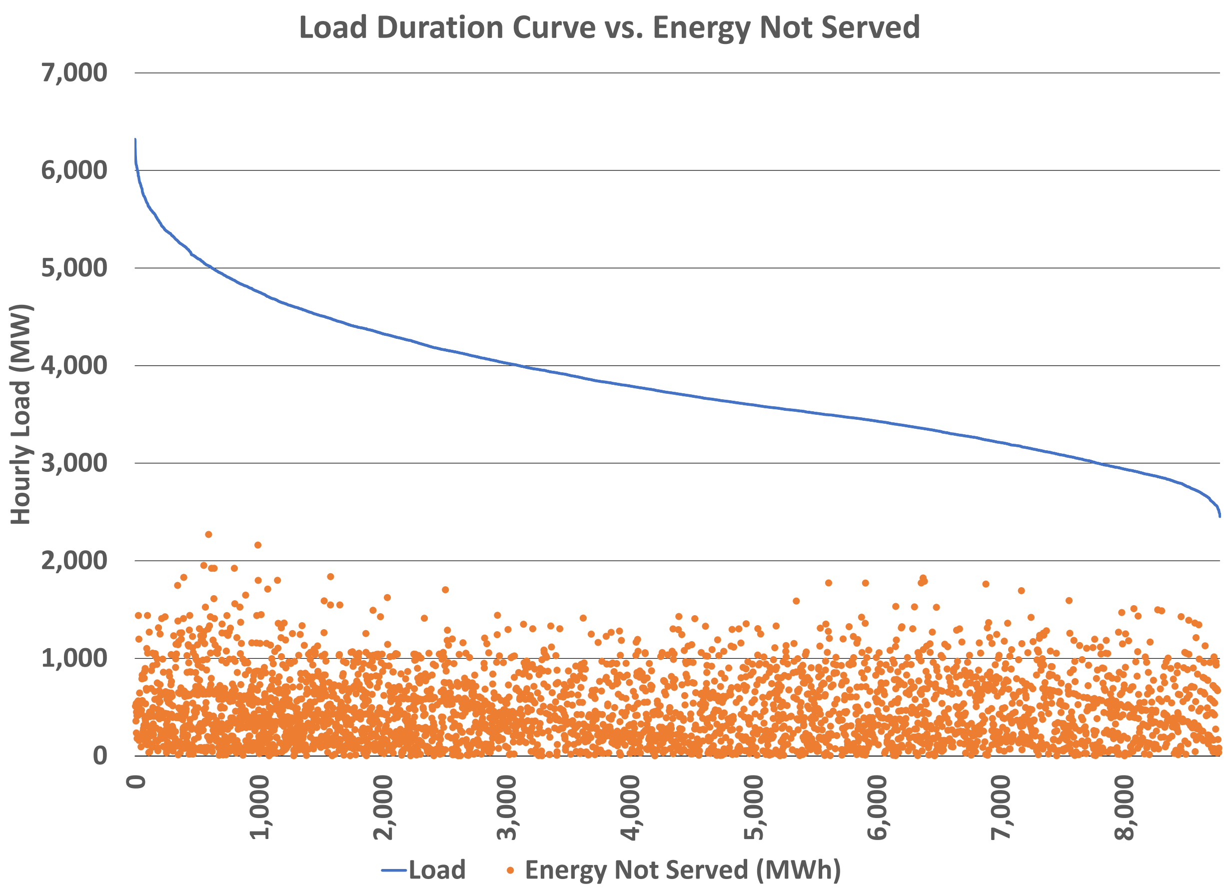
Table 11 shows the Energy Not Served in the SC-01 portfolio in the Mid Gas, Mid CTG Ratio fuel price scenario. Energy Not Served reflects approximately 5.2% of the Companies' total energy requirements and is distributed throughout all months of the year and hours of the day. Energy Not Served is concentrated in the evenings in the summertime (resulting in a "duck curve" effect) and is also concentrated in the peak hours of mornings and evenings during winter months. Energy Not Served is also particularly high in shoulder months (e.g., March/April and October/November) as some thermal capacity is taken offline for scheduled maintenance.

Table 11: 2028 Energy Not Served, SC-01 Portfolio (GWh)

Hour Beginning	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
12:00 AM	7.6	5.1	9.3	19.6	4.3	0.3	5.5	1.6	0.0	6.4	4.0	5.1	68.8
1:00 AM	7.2	4.6	9.1	17.3	2.9	0.5	3.5	0.7	0.2	6.1	3.8	4.8	60.5
2:00 AM	6.6	3.9	9.4	16.1	1.8	0.2	2.5	1.1	0.1	5.7	3.6	4.4	55.4
3:00 AM	6.8	3.7	9.3	16.1	1.8	0.1	1.7	0.7	0.0	5.8	3.7	4.0	53.8
4:00 AM	7.2	5.1	11.0	19.8	2.4	0.3	1.9	0.8	0.1	6.6	3.9	5.0	63.9
5:00 AM	8.9	6.3	13.8	24.8	5.8	0.5	2.4	2.2	1.0	8.2	4.9	5.9	84.5
6:00 AM	10.8	7.5	13.6	24.7	4.3	0.6	2.3	4.2	1.6	8.1	5.0	5.8	88.7
7:00 AM	11.5	8.2	11.9	16.7	2.4	1.1	1.7	3.2	1.2	8.1	5.3	6.1	77.6
8:00 AM	9.9	6.8	5.8	10.2	1.8	1.4	1.9	2.2	0.5	3.0	2.9	4.8	51.3
9:00 AM	6.2	5.4	3.1	9.5	2.3	2.1	2.4	2.3	0.4	1.7	2.0	1.9	39.3
10:00 AM	5.7	5.1	3.1	9.3	1.3	1.9	2.7	2.5	0.5	1.5	2.0	1.3	36.7
11:00 AM	5.2	4.4	1.9	8.2	1.2	1.6	2.8	2.6	0.5	2.2	2.0	1.1	33.7
12:00 PM	5.3	3.7	1.6	8.0	1.0	1.8	2.7	2.4	0.1	2.8	2.4	0.8	32.6
1:00 PM	5.0	3.0	1.4	7.8	0.9	1.5	2.5	2.7	0.0	3.0	2.3	1.0	30.9
2:00 PM	4.7	3.3	1.4	8.4	2.0	1.3	3.5	3.0	0.1	3.0	2.3	1.9	34.9
3:00 PM	5.5	3.6	2.5	9.2	2.6	1.7	3.9	3.4	0.1	2.5	2.6	2.6	40.2
4:00 PM	5.5	4.0	3.3	10.9	2.4	1.6	4.8	3.8	0.3	3.2	1.8	3.0	44.8
5:00 PM	10.0	5.4	4.5	12.9	3.5	1.7	5.4	5.4	1.4	8.0	6.4	8.7	73.5
6:00 PM	13.3	9.3	11.0	21.8	5.6	2.1	7.8	8.9	6.7	11.1	6.9	8.6	113.2
7:00 PM	12.6	9.1	14.9	30.4	13.1	6.4	15.6	17.0	6.5	10.4	6.9	8.7	151.6
8:00 PM	12.4	8.3	14.2	30.5	13.9	8.5	18.2	17.7	5.4	9.7	6.5	8.6	153.8
9:00 PM	10.9	6.9	12.6	29.2	12.1	6.9	17.0	15.2	3.3	9.4	5.9	7.2	136.7
10:00 PM	10.2	7.2	11.8	27.7	10.6	4.4	13.6	11.6	2.6	8.4	5.3	7.5	120.9
11:00 PM	7.7	5.8	9.5	23.1	6.9	1.2	8.5	4.4	0.5	7.2	3.8	6.7	85.3
Total	196.7	135.8	190.0	412.1	107.0	49.6	134.7	119.7	33.2	142.4	96.0	115.4	1,732.7

Figure 2 shows the load duration curve for 2028 load (blue line) with the respective hours of Energy Not Served in the SC-01 portfolio (orange dots).

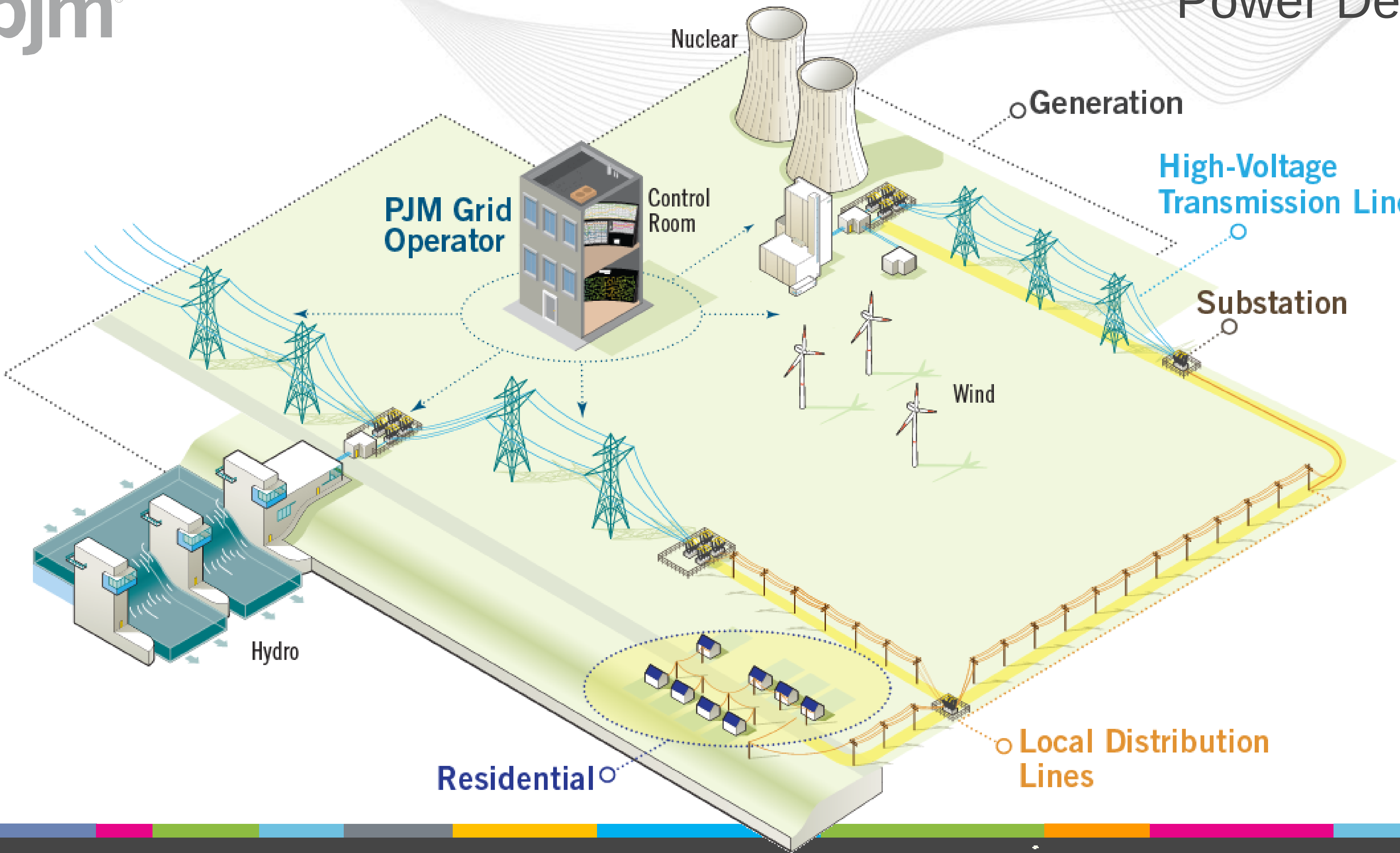
Figure 2: Comparison of Energy Not Served in SC-01 Against Load Duration Curve



Ensuring a Reliable Energy Transition

Asim Z. Haque
Vice President, State and Member Services
PJM Interconnection, LLC

Power Delivery



PJM – Primary Focus

RELIABILITY

Markets
- Energy
- Capacity
- Ancillary services

Operations
- Grid operations
- Supply/demand balance
- Transmission monitoring

Regional Planning
- 15-year outlook

PJM’s Role as a Regional Transmission Organization

PLANNING

Planning for the future like...

OPERATIONS

Matches supply with demand like...

MARKETS

Energy Market Pricing like...

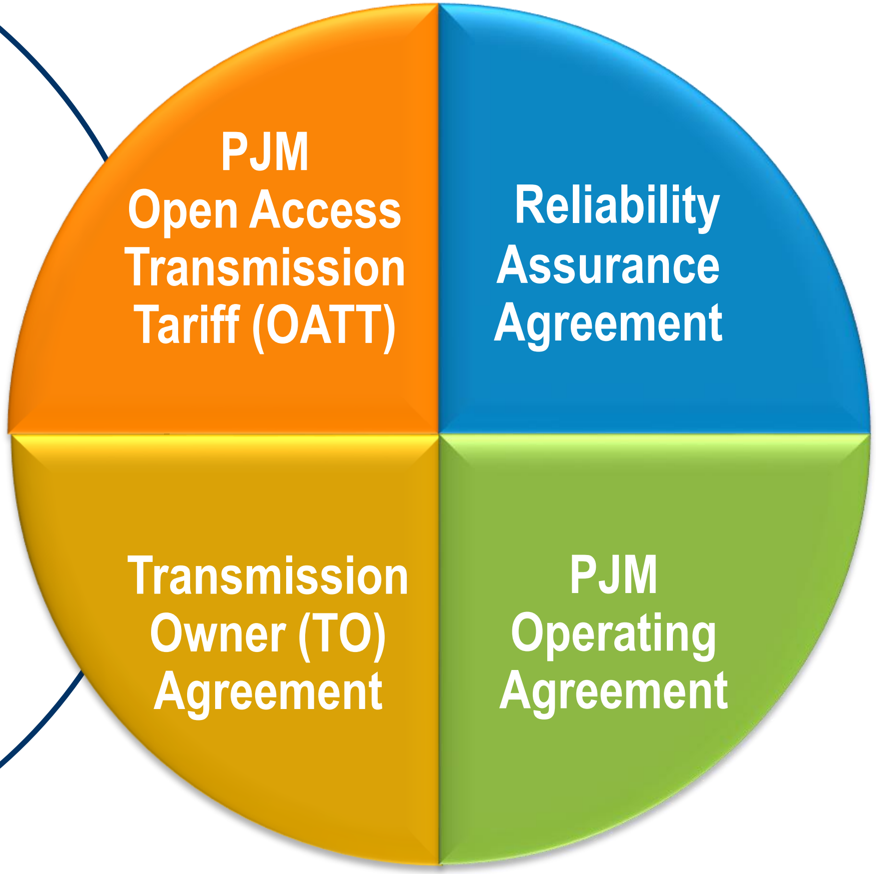
How Is PJM Different from Other Utility Companies?

PJM Does:

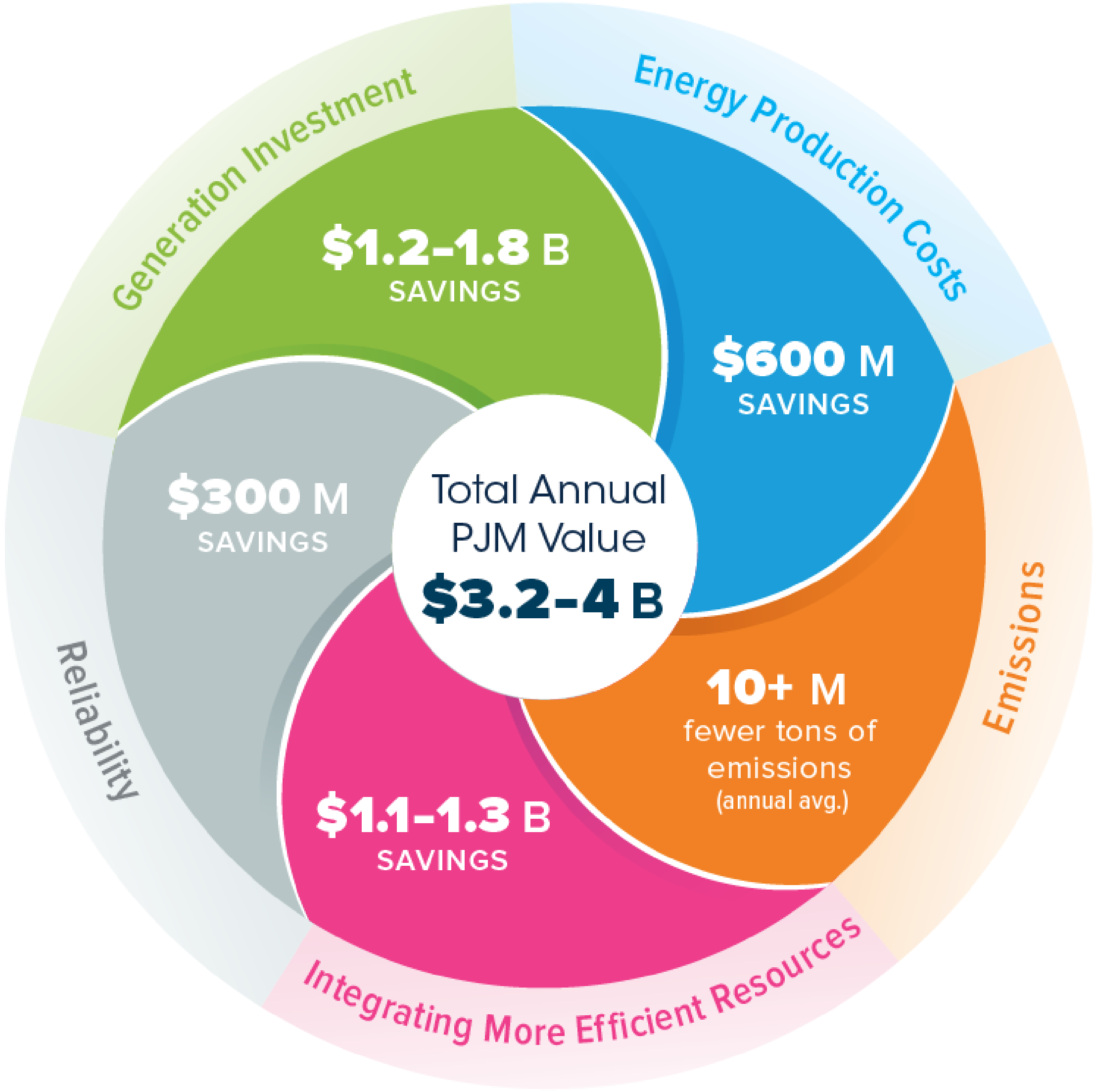
- Direct operation of the transmission system
- Remain profit-neutral
- Maintain independence from PJM members
- Coordinate maintenance of grid facilities

PJM Does *NOT:*

- Own any transmission or generation assets
- Function as a publicly traded company with shareholders and concerns around “earnings”
- Perform maintenance on generators or transmission systems (e.g., repair power lines)
- Serve or direct any end-use customers (retail)



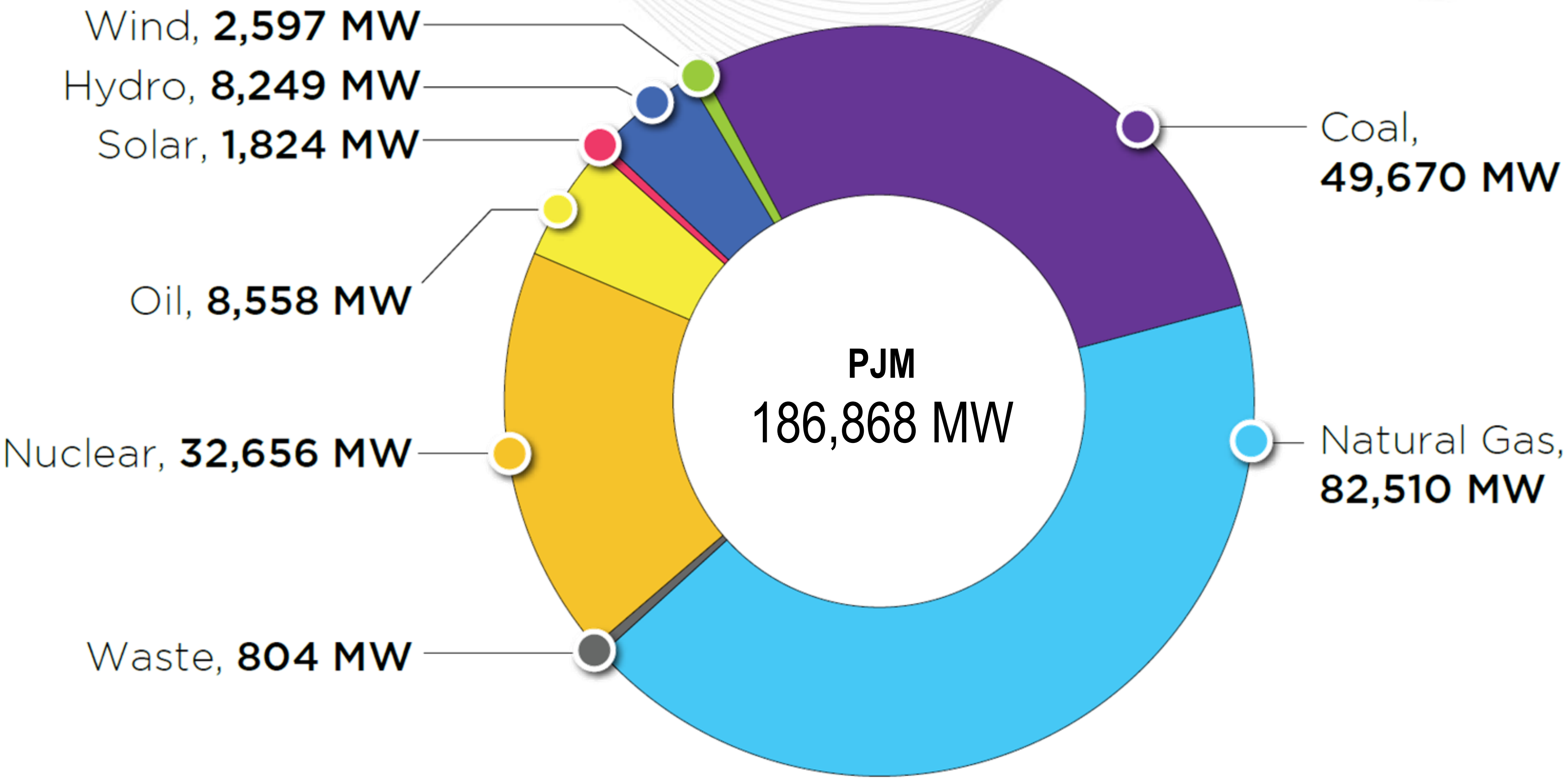
Value Proposition



All numbers are estimates.

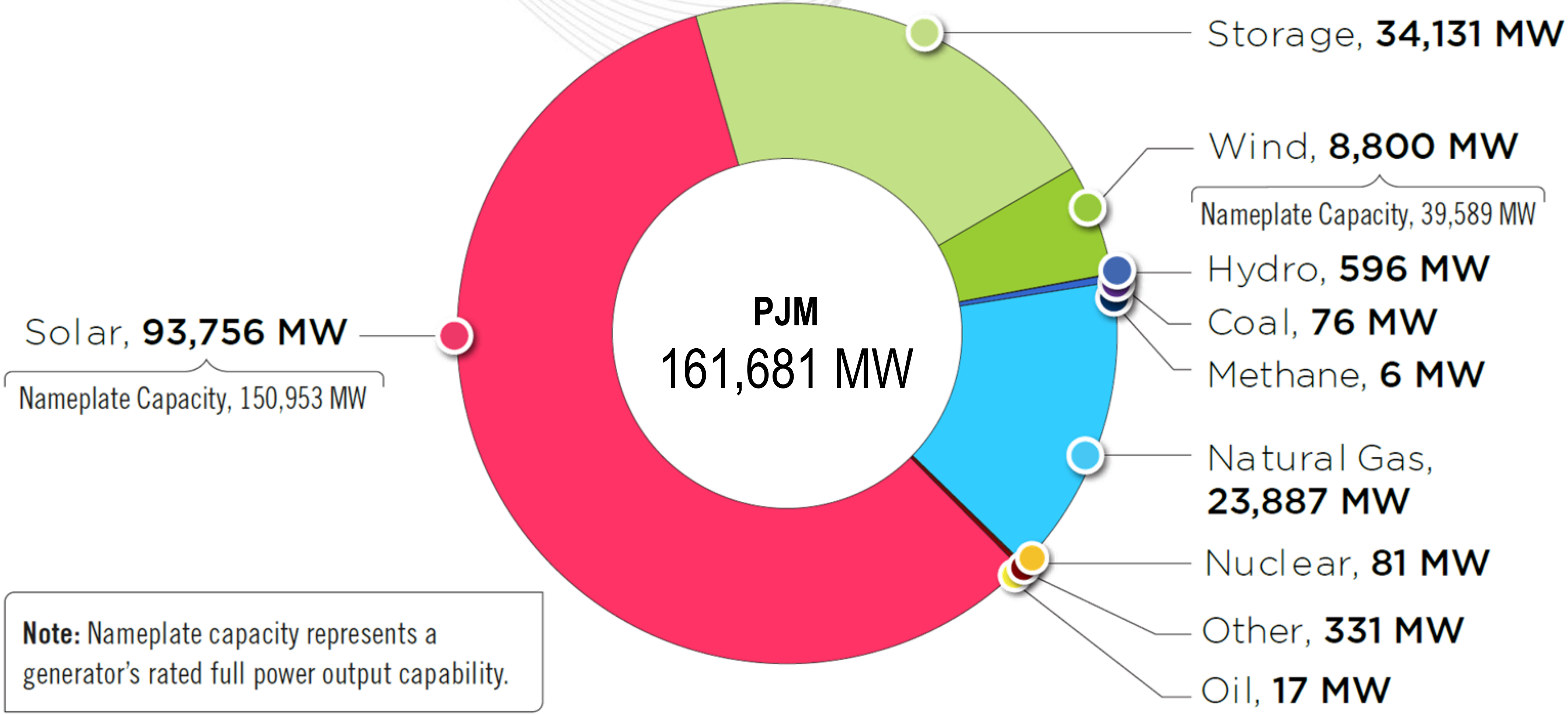
PJM – Existing Installed Capacity

(CIRs – as of Dec. 31, 2021)



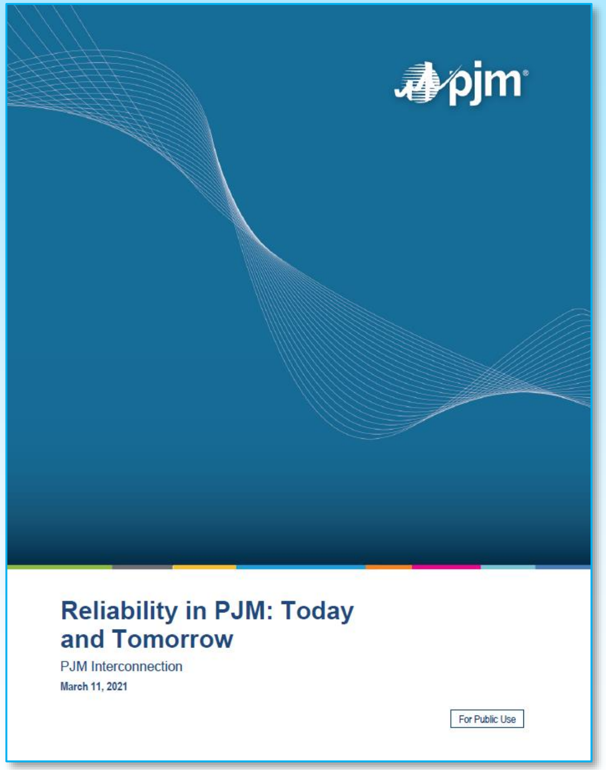
PJM – Queued Capacity (MW) by Fuel Type

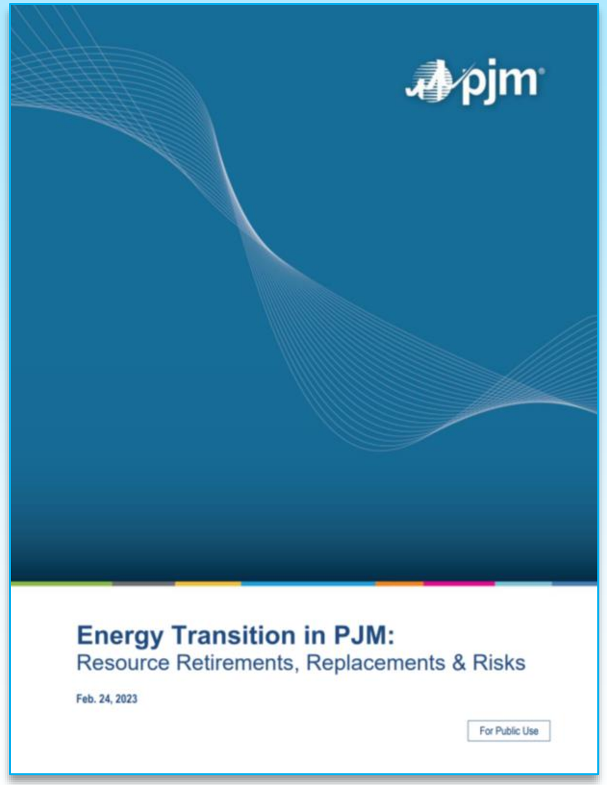
(Requested CIRs – as of Dec. 31, 2021)

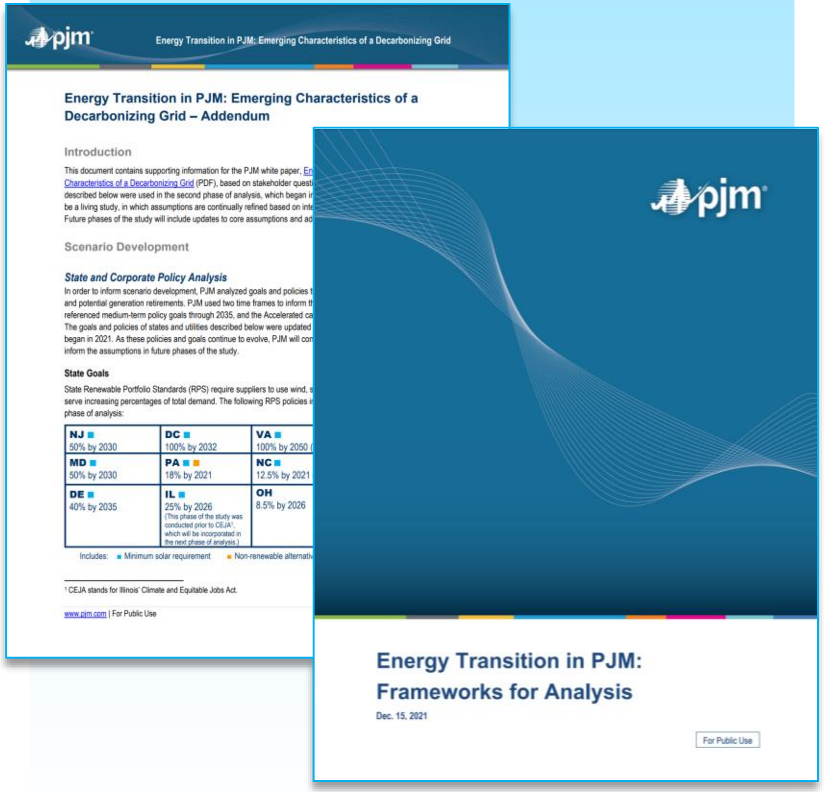


Note: Nameplate capacity represents a generator's rated full power output capability.

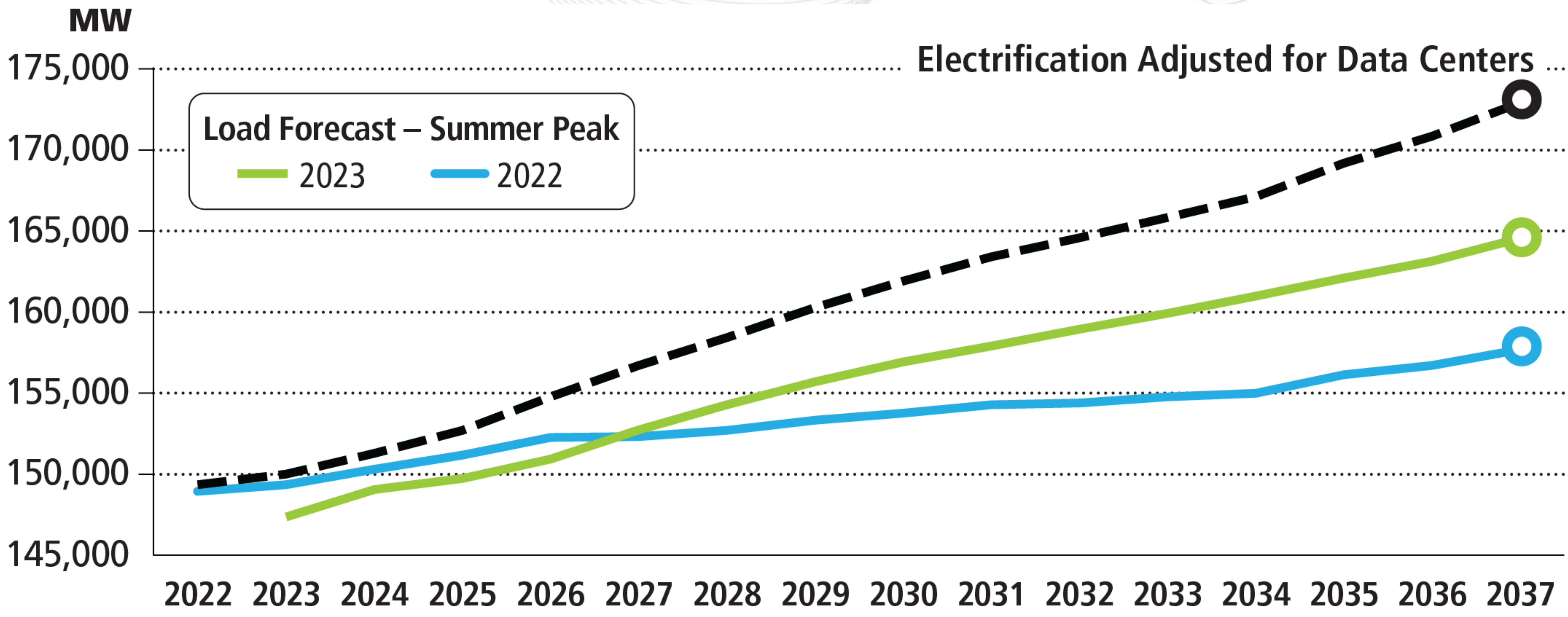
Reliability Papers and Studies





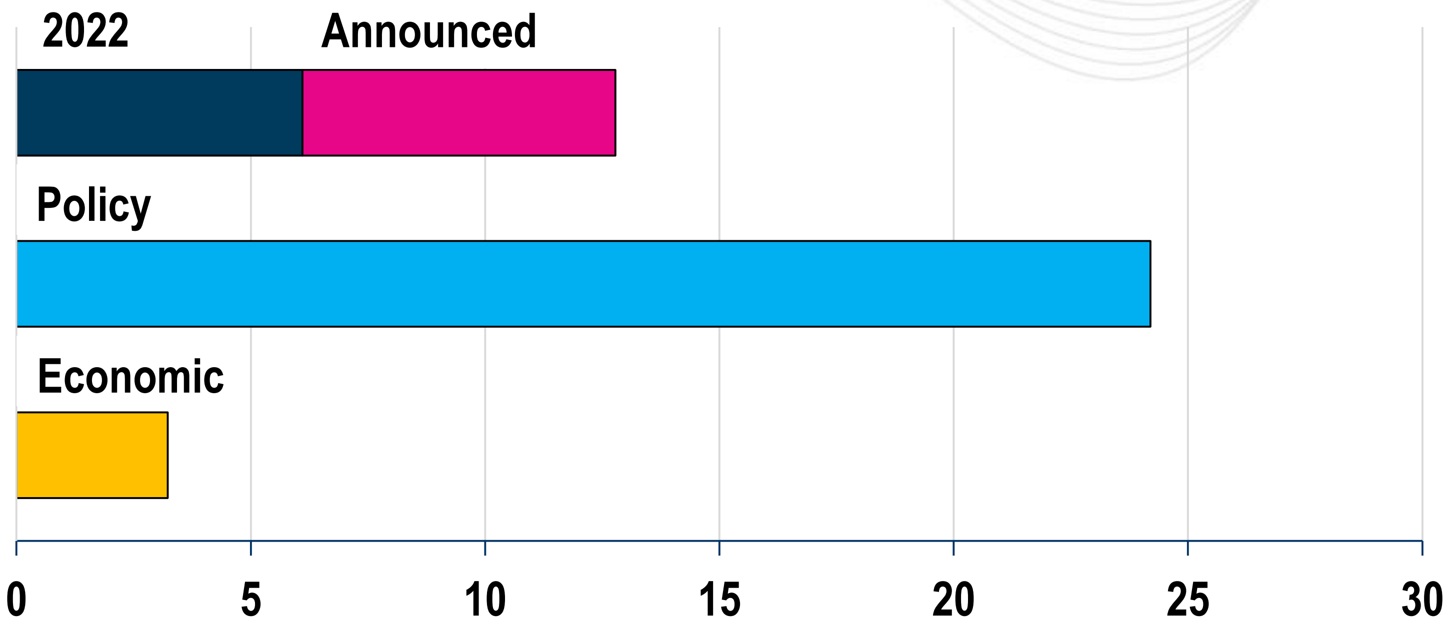


Load Growth Forecasts

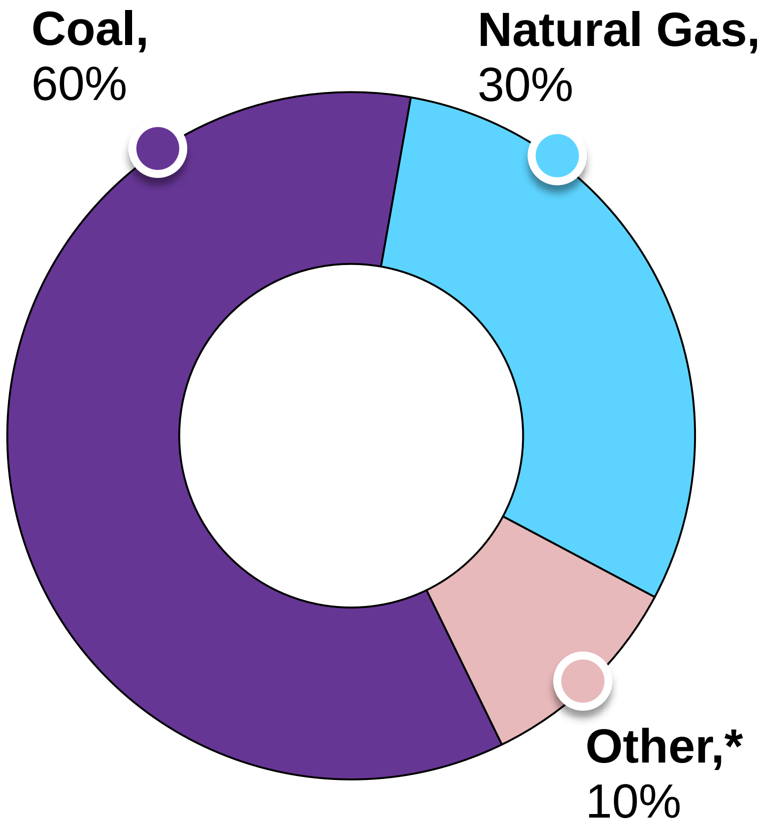


Forecasted Retirements (2022–2030)

Total Forecasted Retirement Capacity (GW)

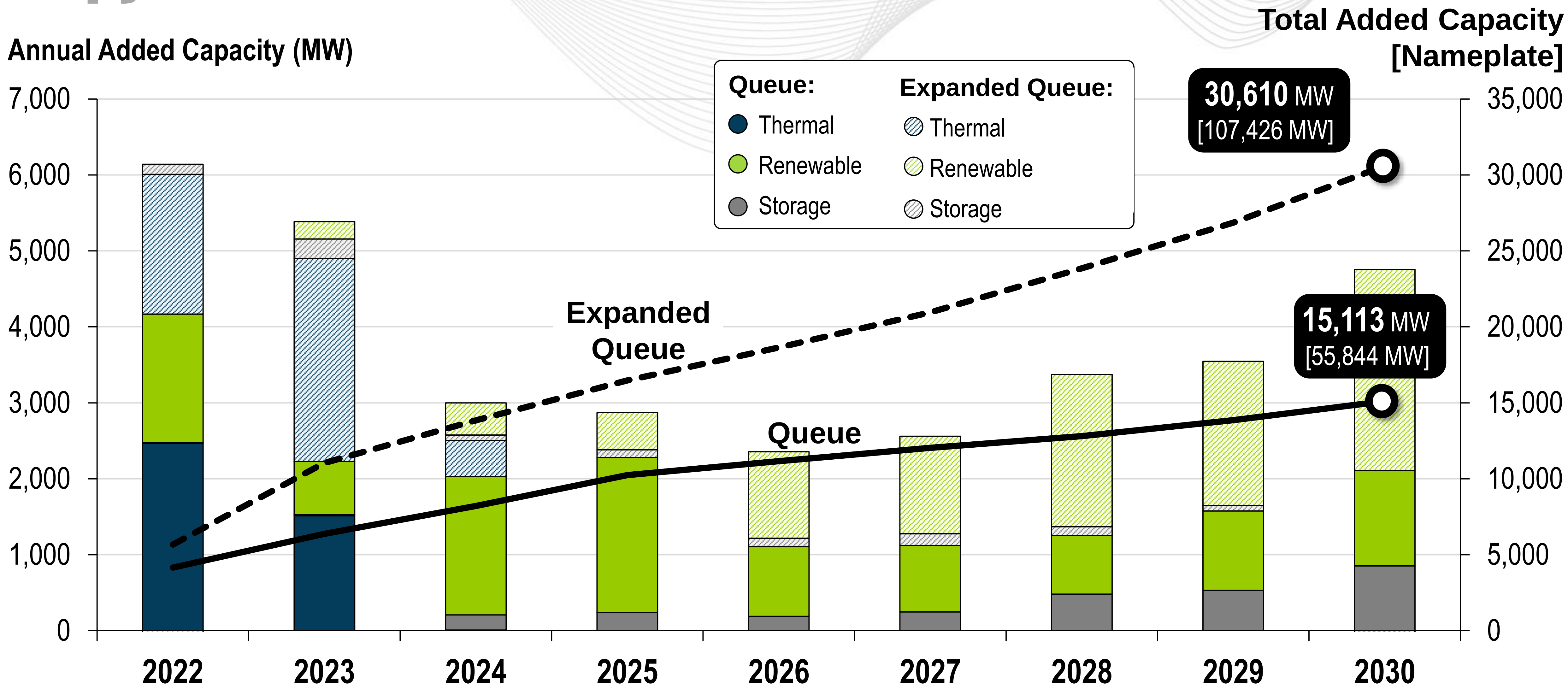


This **40 GW** represents
21% of PJM's current
192 GW of installed generation



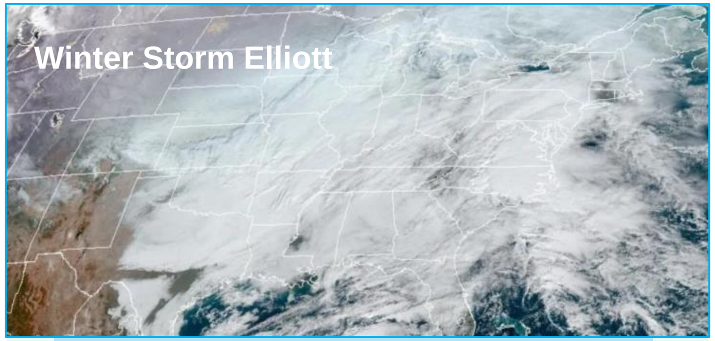
**Other includes diesel, etc.*

PJM Forecasted New Entry (2022–2030)

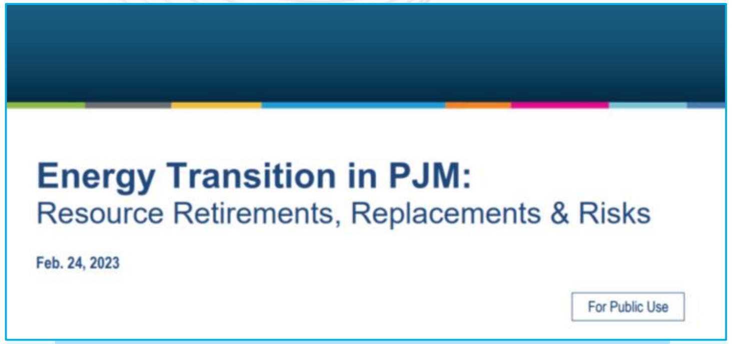


What Problem(s) Are We Solving For?

RELIABILITY



The PJM fleet has adequate resources and enough essential reliability services, but we need our generators to perform when called upon.



Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

Generation retirements may outpace new entry with a simultaneous likelihood of load increasing, thereby creating resource adequacy concerns.

Energy Transition in PJM:
Frameworks for Analysis

Dec. 15, 2021

For Public Use

We will continue to need some amount of thermal generation to provide certain essential reliability services until a replacement technology is deployable at scale.

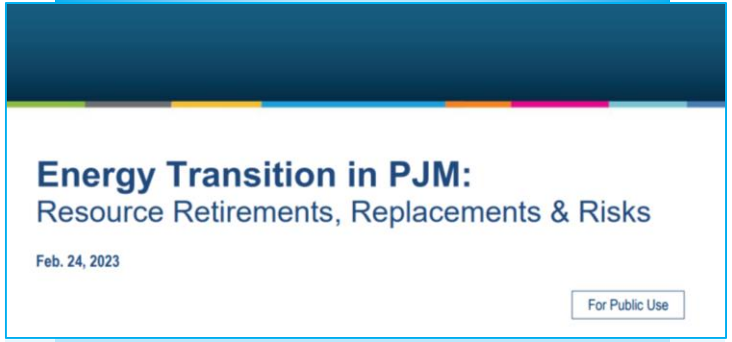
Our Reliability Concerns

The Immediate Concern

Support

Resource Performance

The Near-Term Concern


Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

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Ensure

Resource Adequacy

The Upcoming Concern


Energy Transition in PJM:
Frameworks for Analysis

Dec. 15, 2021

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Maintain & Attract

Essential Reliability Services

Initial Actions To Support Reliability

CIFP/RASTF Priorities

Reserve Certainty

Load Following/ Dispatchability

Short-Term Forecasting

Proactive Planning: LTRTP

Proactive Planning: Resilience

Proactive Planning: Interregional

LDA Modeling

RMR Improvements

Policy Reliability Safety Measures

Continued Queue Improvements

Energy Assurance

Gas/Electric Coordination

Elliott Placeholder

Ensuring a Reliable Energy Transition

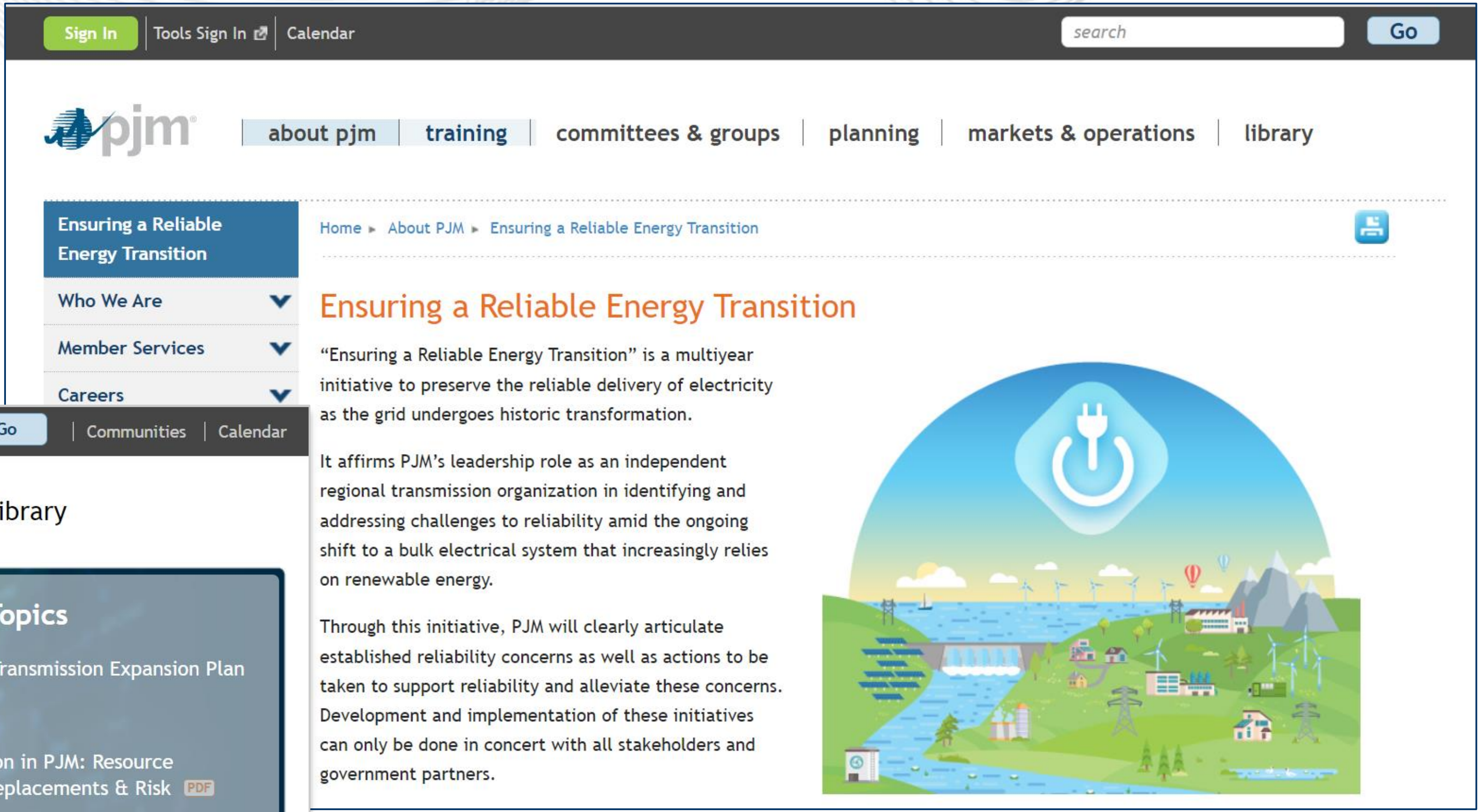

Table 12.12 | Emergence of CIDs in different time periods, as assessed in this section. The colour corresponds to the confidence of the region with the highest confidence: white cells indicate where evidence is lacking or the signal is not present, leading to overall *low confidence* of an emerging signal.

Climatic Impact-driver Type	Climatic Impact-driver Category	Already Emerged in Historical Period	Emerging by 2050 at Least for RCP8.5/SSP5-8.5	Emerging Between 2050 and 2100 for at Least RC8.5/SSP5-8.5
Heat and Cold	Mean air temperature	1		
	Extreme heat	2	3	
	Cold spell	4	5	
	Frost			
Wet and Dry	Mean precipitation		6 7	
	River flood			
	Heavy precipitation and pluvial flood			8
	Landslide			
	Aridity			
	Hydrological drought			
	Agricultural and ecological drought			
	Fire weather			
Wind	Mean wind speed			
	Severe wind storm			
	Tropical cyclone			
	Sand and dust storm			
Snow and Ice	Snow, glacier and ice sheet		9	10
	Permafrost			
	Lake, river and sea ice	11		
	Heavy snowfall and ice storm			
	Hail			
	Snow avalanche			
Coastal	Relative sea level		12	
	Coastal flood			
	Coastal erosion			
Open Ocean	Mean ocean temperature			
	Marine heatwave			
	Ocean acidity			
	Ocean salinity	13		
	Dissolved oxygen	14		
Other	Air pollution weather			
	Atmospheric CO_2 at surface			
	Radiation at surface			

1. *High confidence* except over a few regions (CNA and NWS) where there is *low agreement* across observation datasets.
2. *High confidence* in tropical regions where observations allow trend estimation and in most regions in the mid-latitudes, *medium confidence* elsewhere.
3. *High confidence* in all land regions.
4. Emergence in Australia, Africa and most of Northern South America where observations allow trend estimation.
5. Emergence in other regions.
6. Increase in most northern mid-latitudes, Siberia, Arctic regions by mid-century, others later in the century.
7. Decrease in the Mediterranean area, Southern Africa, South-west Australia.
8. Northern Europe, Northern Asia and East Asia under RCP8.5 and not in low-end scenarios.
9. Europe, Eastern and Western North America (snow).
10. Arctic (snow).
11. Arctic sea ice only.
12. Everywhere except WAN under RCP8.5.
13. With varying area fraction depending on basin.
14. Pacific and Southern oceans then many other regions by 2050.

High confidence of decrease | Medium confidence of decrease | Low confidence in direction of change | Medium confidence of increase | High confidence of increase

12

Case No. 2022-00402
Rebuttal Exhibit DSS-5
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