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 RETIRMENTS	:	CASE NO. 2022-00402

TESTIMONY OF EMILY MEDINE

ON BEHALF OF

THE KENTUCKY COAL ASSOCIATION, INC.

Filed: July 14, 2023

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Emily S. Medine. I am employed by Energy Ventures Analysis, Inc. My business address is 8045 Leesburg Pike, Suite 200, Vienna, VA 22182.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS HEARING?

A. I am testifying on behalf of the Kentucky Coal Association (KCA).

Q. WHAT IS YOUR EDUCATION AND EXPERIENCE?

A. I am a Principal with the firm Energy Ventures Analysis, Inc., an energy consultancy that was formed in 1981. I have provided consulting services for producers, consumers, transporters, regulators, trade associations, and governmental agencies. My education and experience are set out in Attachment ESM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide my review of the December 15, 2022 filing by Kentucky Utilities ("KU") and Louisville Gas and Electric (LGE") (collectively the "Companies") for a Certificate of Public Convenience and Necessity ("CPCN"), Site Compatibility Certificates ("SCC"), and Approval of a Demand Side Management ("DSM") plan and the May 10, 2023 filing by the Companies pursuant to Senate Bill 4 enacted by the Kentucky General Assembly during its 2023 Regular Session ("SB 4") for an order authorizing the retirement of seven fossil fuel-fired electric generating units, namely E.W. Brown Unit 3, Ghent Unit 2, Haefling Units 1 and 2, Mill Creek Units 1 and 2, and Paddy's Run Unit 12 (collectively "Affected Units").

Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS UNDER THE CPCN FILING.

A. The Companies are seeking CPCNs for the construction of two 621 MW natural gas combined cycles ("NGCC") plants, one to be located at the Mill Creek Generating Station

("Mill Creek NGCC") and one to be located at the E.W. Brown Generating Station ("Brown NGCC"), a 120 MWac solar photovoltaic ("PV") generating facility in Mercer County (Mercer County Solar Facility), and a 125 MW, 4-hour (500 MWh) battery energy storage system ("BESS") at the Brown station ("Brown BESS"). The Companies are seeking approval to acquire the 120 MWac Marion County Solar Facility which is to be built by BrightNight, LLC its proposed 2024-2030 Demand-Side Management and Energy Efficiency Program Plan ("Proposed DSM-EE Program Plan") and related charges to the Demand-Side Management Cost Recovery Mechanism ("DSM Mechanism") tariff. Finally, the Companies are seeking a declaratory order that their entry non-firm energy-only power purchase agreements ("PPAs") for the output of four solar PV facilities with a combined capacity of 637 Mw does not require Commission approval.

Q. WHAT IS THE STATUS OF THE COMPANIES' REQUEST FOR A DECLARATORY ORDER REGARDING THE FOUR PPA'S?

A. The Commission denied the Companies' request for the Declaratory Judgement.

Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS UNDER THESB 4 FILING.

A. Under SB 4, there is a presumption against fossil fuel plant retirements requiring a utility to demonstrate that replacement generating capacity for the retiring unit(s) is dispatchable, will maintain or improve system reliability and resilience, and will maintain sufficient reserve margins, will not harm utility ratepayers, the unit retirement does not result from federal financial incentives or benefits and the unit retirement will result in cost savings for customers after accounting for all known direct and indirect costs of the retirement. The Companies in the SB 4 filing claim to provide the required support for the retirement of seven fossil-fuel fired plants: E.W. Brown Unit 3, Ghent Unit 2, Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run Unit 12.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARATION OF THIS TESTIMONY?

A. I reviewed the following:

- Filings in Cases No. 2022-00402, 2023-00122, 2021- 00393, 2020-00060, 2020-00061,
- PPL Corporation 2022 and 2023 Proxy Statements
- PPL Corporation Annual and Quarterly Filings
- PPL Corporation 3rd Quarter Investor Update filed November 4, 2022
- PPL Corporation Fall Shareowner Outreach
- PPL Corporation 2021 Climate Assessment
- Industry periodicals and data
- FERC Order Docket No. ER20-495-000 and 495-001
  https://www.ferc.gov/sites/default/files/2020-06/ER20-595-000_1.pdf
- EPA's published Good Neighbor Rule and challenges to it
  https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs
  https://www.epa.gov/system/files/documents/2023-03/23-3225_DocketEntry_03-17-2023_1.pdf
  https://www.ag.ky.gov/Press%20Release%20Attachments/DN%2028%20Administrative%20Stay.pdf
  https://www.pbs.org/newshour/politics/federal-appeals-court-halts-epa-effort-to-impose-good-neighbor-air-pollution-plan-in-missouri
- EPA's proposed new carbon standards and related documents
  https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power
  https://www.epa.gov/power-sector-modeling/retail-price-model

Q. PLEASE SUMMARIZE YOUR PRIMARY FINDING.

A. Based on my review and assessment of the Companies request, my primary finding is that it is premature for the Commission to approve the Companies' request to construct two NGCC plants, two solar facilities, one 500 Mwh battery storage system, at the Companies estimated cost to ratepayers of over $2.0 billion, and the associated development plan which would result in the closure of 1,500 MW of reliable and lower cost coal-fired generating capacity at a time when the Federal Energy Regulatory Commission ("FERC) is warning that the U.S. is heading for a very catastrophic situation in terms of electric reliability.[1]

It is premature to approve the Companies request to commit to the two proposed NGCC plants at this time given the uncertainty regarding costs and compliance requirements under the Good Neighbor Rule ("GNR") and the revisions to Sections 110(b) and 110(d) of the Clean Air Act ("CAA"). Customers would be well-served by the delay as a longer exit ramp preserves generation capacity, reduces the stranded costs of the coal plants, and extends the date upon which customers would need to begin paying for the proposed high-cost replacement generation sources. Further, the Companies have failed to satisfy the obligations imposed upon it by Senate Bill 4 ("SB 4") which require the Companies to (1) demonstrate there would not be an adverse impact on customers, (2) maintain or improve reliability and resiliency, and (3) demonstrate the replacement resources are equally dispatchable to the ones they propose for early retirement. The denial of the Companies request at this time will allow the Companies to 1) better define the critical input assumptions in their analyses that are the basis for their conclusions, 2) expand their analyses to include scenarios which include load growth over the study period that incorporates the aggressive economic development strategy being employed by the Kentucky Cabinet for Economic Development, 3) perform a detailed rate impact analysis, and 4) develop and analyze other resource options that include carbon capture retrofits on coal plants, small modular nuclear reactors, and hydrogen co-firing, and file a complete application with the Commission in the future.

With respect to the other components of the Filings, I conclude the four solar Power Purchase Agreements should not be approved as written due to their failure to provide any guarantee of performance at a specified price, the must-take requirements in their agreements, and the failure to include options that would allow the Companies to acquire the projects or terminate the agreements should circumstances change.

Q. PLEASE SUMMARIZE THE FINDINGS THAT SUPPORT YOUR PRIMARY FINDING?

A. The supporting findings which are discussed in the balance of my testimony are as follows:

- The most recent Integrated Resource Plan ("IRP") performed by the Companies occurred in 2021. It did not produce an actionable plan and was heavily criticized by a number of parties. The Staff listed dozens of recommendations for the next IRP to address its many concerns.[1] Most of these recommendations were not considered prior to the submission of the CPCN.[2] The Companies claim these recommendations will be considered in future IRP's.
- The Companies CPCN Filing is tied to a regulation referred to as the Good Neighbor Rule ("GNR") that had been proposed but not promulgated at the time of the filing. The GNR was promulgated on March 14, 2023 but was not published in the Federal Register until June 5, 2023. The proposed rule differs from the promulgated rule in a number of material respects. In addition, legal challenges which can only be mounted after a promulgated rule has been published in the Federal Register can result in vacatur and/or modifications.

[1] Order in Case No. 2021-00393, pages 66-67.
[2] Companies' Response to KCA 2-6.

- There are sufficient differences in the timing of the promulgated rule that require a reconsideration of the CPCN filing.
- On May 31, 2023, the GNR was stayed in Kentucky by the Sixth Circuit Court of Appeals. A Stay is typically granted only if the appeal is deemed to have legal merits and there would be irreparable harm, e.g., an irreversible commitment to close a power plant. Given the CPCN Filing was largely predicated on the GNR, the potential that this rule will not go into effect argues for a delay in the Companies' plans to replace the coal capacity with new NGCCs.
- On March 29, 2023, SB 4 in Kentucky became a law. SB 4 created new sections of the Kentucky Revised Statutes Chapter 278 which prohibit the Kentucky Public Service Commission from approving a request to retire a fossil-fuel fired electric generator unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customer's electric utility rate.
- In acknowledgement of these new requirements, the Companies filed Case No. 2023-00122 to comply with SB 4 and sought approval of the consolidation of the on-going Case 22-00402 with the new Case 2023-00122. Case 2023-00122 requests the approval to close 1,500 MW of winter and 1,500 MW summer coal capacity.
- The Companies failed to demonstrate that the plan put forward in Case 2022-00402 would not have a negative impact on the reliability or the resilience of the electric grid. The replacement resources do not have onsite fuel storage nor do they have the same dispatchability profile of the resources being proposed for retirement.
- The Companies also failed to demonstrate that the proffered plan does not have an adverse impact on customers' electric rates given the fact that the Companies expect to continue to recover their return of and on undepreciated capital on the retired resources as well as their return of and on capital of the new resources even if the

Companies elect to retrofit Selective Catalytic Reduction ("SCR") on Mill Creek 2 and Ghent 2.

- The Companies confirmed it did not perform a residential rate analysis because rates are not determined until the Companies file for a rate increase arguing that the relative net present value ("NPV") determines what is least cost. Given an NPV is based upon levelized costs and utility rates are based upon undepreciated capital, they are obviously not equivalent from a ratepayer's perspective. The situation is exacerbated as "sunk" costs are not even considered after a certain point even though ratepayers continue to be obligated for them.
- Eventually, in response to KCA 3.23, the Companies acknowledged that rates in at least the first 10 years would be higher but lower thereafter. The Companies did not address the fact that either under the proposed new EPA GHG rules or other rules, there are likely to be additional costs not currently considered in the latter part of the assets' life which will likely more than eliminate the alleged savings. One need look no further than the proposed EPA GHG rules to see this would likely be the case.
- The Companies' plans appear to be motivated by a desire to increase earnings, i.e., earnings growth ("EG") and ESG compliance and the closure of coal plants as suggested in number of recent PPL filings. EG is directly tied to large capital investments in base rates which is achieved initially by the investments contemplated in the CPCN. Further, beginning in 2022 PPL announced executive compensation is explicitly being tied to achievement of these plans. In 2023, PPL announced with great enthusiasm of it plans to further increase capital in the rate base.[3]

[3]/https://filecache.investorroom.com/mr5ir_pplweb2/1015/PPL_2023_Q1_Investor_Update_Final.pdf

- On May 11, 2023, the Environmental Protection Agency ("EPA") proposed new greenhouse gas ("GHG") rules for new gas power plants and existing coal and gas power plants under Sections 111(b) and 111(d), respectively. The proposed NGCC's plants will be subject to the new rules under Section 111(b) which are referred to as New Source Performance Standards ("NSPS").
- Best System of Emission Reduction ("BSER") for baseload NGCCs is defined as either 90 percent reduction via carbon capture by 2035 or 30 percent co-firing with low GHG hydrogen by January 2032 with ultimately reaching a 96 percent blend.
- Due to the timing of the newly announced EPA rules, the analyses supporting the CPCN and SB 4 filings do not reflect consideration of the proposed changes to 111(b) and111(d). Therefore, it goes without saying there is no supporting analysis provided in either the CPCN or the SB 4 filings related thereto.
- With respect to the analyses actually performed by the Companies, significant flaws were identified.
    - The proposal to replace the proposed retirement of 1,242 MW of coal with two new NGCC plants is economically justified by assuming plant lives of 40 years, baseload performance, no costs to retrofit the plants with carbon capture and/or no costs associated with a low GHG hydrogen conversion.
    - A 40-year life is inconsistent with the PPL Corporation's ESG goal of net-zero by 2050. The economic analysis should reflect at most a 22-year life absent a significant investment pre-2050 to modify the plant to net-zero.
    - The Companies do not have agreements supporting the estimated costs for the new NGCC plants or for the Firm Transportation to supply the NGCC plants. In other words, the Companies do not actually know what the costs are of this plan and yet justify them based upon the estimates.
    - The Companies' analyses misstate the costs for solar energy and use a non-standard methodology to develop coal price forecasts which virtually

ensures gas resources will be lower in cost than existing coal plants even retrofit with Carbon Capture. For example, using the Companies' methodology, the forecast 2023 coal price would be multiples of the actual price paid by the Companies in Q1 2023.

- The plants proposed in the CPCN do not contemplate either carbon capture or co-firing and Companies argue that they could comply by turning their baseload plant into an intermediate load plant. This strategy is neither certain nor is it without cost. There would be implications related to heat rates, Firm Transportation contracts, and, most importantly, capacity and energy costs.
- The Companies are relying on the EPA's Regulatory Impact Analysis ("RIA") inferring incorrectly a specific result of the RIA demonstrates the Companies conclusions are with merit. And, a $2 billion dollar plus investment deserves a situation-specific justification unless the Companies are willing to "guarantee" to customers a specific economic outcome. The Companies have consistently stated they are unwilling to accept financial exposure from this recommendation.
- Despite stating an objective under the CPCN filing to provide customers with "low-cost service" and a requirement under SB 4 to demonstrate the retirement of the coal plants will not have an adverse impact on customers' electric rates, the Companies failed to consider the rate impacts on at least residential customers looking simply to the net present value of revenue requirements ("NPV") which is demonstrably not a proxy for ratepayer impacts.[4]

[4] Ironically, even the RIA which the Companies are erroneously trying to use to support the CPCN expends considerable efforts on a retail rate analysis.

    - The Companies did not evaluate the impact of its plans on the areas served by the Companies and on the economic development and overall economy of the state of Kentucky.

- The analyses performed by the Companies do not reflect the Stay of the GNR nor do they reflect the proposed EPA GHG rules. If the Companies still want to pursue the retirements at this time, it must redo its analyses to reflect both the Stay of the GNR as well as the consequences of the proposed EPA GHG rules on the new natural gas plants. Any updates also need to reflect the proposed changes to the existing units,
- In addition, the Companies have clearly not met their SB 4 obligations to demonstrate that the retirements put forward in 23-00122 would not have a negative impact on the reliability or the resilience of the electric grid. The replacement resources do not have onsite fuel storage nor do they have the same dispatchability profile of the resources being proposed for retirement. Further, the Companies failed to demonstrate that the proffered plan does not have an adverse impact on customers' electric rates given the fact that the Companies expect to continue to recover their return of and on undepreciated capital on the retired resources. Given the obligation under SB 4, the Companies need to conduct such an analysis.[5]
- It will be a significant effort on the part of the Companies to revise their plans in a manner consistent with the EPA GHG proposal. For example, the outright dismissal by the Companies of Carbon Capture on coal plants must be reconsidered as well given the proposed regulations on existing coal plants.

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[55] It would be useful to include in this analysis the rate impacts on Kentucky Power customers following the closure of the Big Sandy coal plant. According to a July 10, 2023 article in the Lexington Herald, Kentucky Power is asking for an 18.3 percent increase in residential rates.

- In order to ensure an appropriate analysis and decision, the Companies should prepare to pursue the retrofits of SCR on Mill Creek 2 and Ghent 2 if the GNR is neither stayed nor rescinded.
- The four solar Power Purchase Agreements should not be approved as written due to their failure to provide any guarantee of performance at a specified price, the must-take requirements in their agreements, and the failure to include options that would allow the Companies to acquire the projects or terminate the agreements should circumstances change.
- The EB Brown Battery project should be rejected because of its high costs and limited capability. A Simple Cycle Combustion Turbine should be considered as the lower cost alternative for firm capacity and operational flexibility.

Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

A. The next section provides a review of regulatory changes since the filing of the CPCN. The third section provides an overview of PPL Corporation's statements regarding LG&E and KU. The fourth section provides a review of the analysis supporting the CPCN. The final section of this testimony addresses the other requests in the CPCN.

SECTION II

Q. PLEASE DESCRIBE REGULATORY CHANGES THAT HAVE OCCURRED SINCE THE FILING OF THE CPCN THAT AFFECT ITS CONSIDERATION.

A. Three material events have occurred. First, the GNR was finalized on March 15, 2023 and published in the Federal Register on June 5, 2023. Second, Kentucky challenged the GNR on the grounds that the EPA's plan to impose a Federal Implementation Plan ("FIP") on Kentucky was inappropriate as the Kentucky State Implementation Plant ("SIP") had not been rejected in a timely manner. The Sixth Circuit Court of Appeals agreed this was a concern and stayed EPA's rejection of the SIP which was necessary to impose the FIP. The Motion and Stay are provided respectively in Attachments ESM-2 and ESM-3. Third, the changes in the Final GNR provided power companies greater flexibility to comply in a more cost-effective manner.

Q. WOULD THESE CHANGES AFFECT THE COMPANIES' CPCN FILING?

A. Yes. The enhanced flexibility could have allowed the Companies to delay its requests which would have allowed a fuller analysis of the timing and desirability of the proposed NGCC's. It would also have reduced the impact on customers in the near-term.

Q. DID THE COMPANIES UPDATE THEIR ANALYSIS TO REFLECT THESE CHANGES?

A. No.

Q. WHAT IS THE GNR STAY?

A. The Commonwealth of Kentucky sought a review by the U.S. Court of Appeals for the Sixth Circuit of the GNR based upon the EPA's delayed disapproval of its 2019 State Implementation Plan which is the basis for EPA imposing the Federal Implementation Plan ("FIP") in Kentucky. The Sixth Circuit granted the Stay on May 31, 2023.

Q. WHAT IS THE SIGNIFICANCE OF THE STAY?

A. Four factors determine the appropriateness of a stay. They are (1) whether an appeal is likely to succeed on its merits, (2) whether there would be irreparable harm without a Stay, (3) whether other parties will be injured without a Stay, and (4) whether a Stay is in the public interest. As the Commonwealth's petition notes, the legal merits of the appeal and irreparable harm absent the Stay are the primary considerations.

Q. HAVE OTHER ENVIRONMENTAL REGULATIONS BEEN STAYED?

A. Yes, although Stays are not routine. In 2016, the Clean Power Plan ("CPP") was stayed by the U.S. Supreme Court due to the legal merits of the petition and irreparable harm. The CPP was ultimately repealed.

Q. IS THE STAY PARTICULARLY RELEVANT FOR THIS PROCEEDING?

A. Yes. The Companies' primary justification for the CPCN was related to compliance with the GNR. If the GNR is delayed, modified or repealed, the timing and justification for the CPCN should be reconsidered.

Q. DOES DELAYING A DECISION PROVIDE VALUE TO RATEPAYERS?

A. Absolutely. Imagine you have purchased a house and financed it with a 30-year mortgage. If you cannot sell your home and buy a new home elsewhere, you would still be obligated for the first mortgage payment and now would be obligated for the second mortgage payment as well. The same thing is true for the plants and ratepayers. The Commission has agreed to a depreciation schedule and the Companies earn a return of and on their undepreciated capital during the depreciation period. If the Companies stop running these plants, the Companies are still "due" their return of and on capital which is charged to customers. If they add additional resources that are deemed to be prudent, they earn the return of and on their new resources as well as their old resources. If the Companies delay the new investment, customers are only reimbursing the utility for the existing resources. If the Companies get approval for the new resources, they are now getting reimbursements from ratepayers for the retired capacity and the new capacity. The closer the Companies are to full depreciation of their existing plants, the smaller the stranded cost component. In a number of jurisdictions, the Commissions revise the depreciation period to "match" the expected operating plant lives thereby increasing short-term rates but reducing or eliminating the stranded cost component.

If the investment in NGCC's is delayed, ratepayers will benefit as the increased capital associated with the two NGCC'S in rate base will also be delayed. Further, and more importantly, the Companies will not regret making an investment that could be partially stranded before it is fully depreciated or that will require a significant incremental investment that was not considered in the economic evaluation in order to remain online.

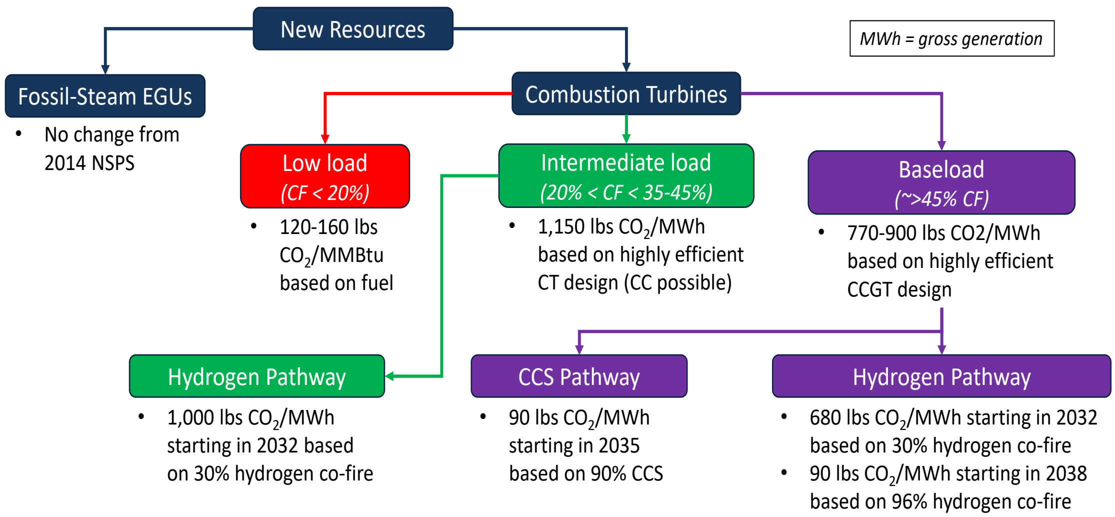
Q. WHAT ARE THE PROPOSED GHG REGULATIONS FOR POWERPLANTS?

A. The EPA proposed rules for new NGCC's under Section 111(b) of the Clean Air Act (CAA) and for existing fossil fuel plants under Section 111(d) of the CAA. The Companies do not dispute the proposed NGCC's would be subject to Section 111(b).[6] As shown in Exhibit ESM-1, Best System of Emission Reduction (BSER) for new NGCCs is defined as either 90 percent reduction via carbon capture by 2035 or 30 percent co-firing with low GHG hydrogen by January 2032 rising to 96 percent co-firing by 2039. The plants proposed in the CPCN do not reflect the costs associated with carbon capture, co-firing or a reduced capacity utilization.

[6] Companies' response to KCA 3.3.

EXHIBIT ESM-1

Graphic Presentation of Section 111(b) Requirements



Source: EVA

Q. DO YOU BELIEVE THAT THE COMPANIES HAVE SUFFICIENTLY ANALYZED CARBON CAPTURE AND/OR CO-FIRING TO UNDERSTAND WHETHER THESE ARE OPTIONS FOR THE PROPOSED MILL CREEK OR THE GHENT COMBINED CYCLE PLANTS?

A. No. The Companies Filings indicate that Carbon Capture on natural gas plants was abandoned as a consideration following the 2021 IRP. [7] The Companies recognize that co-firing is a potential but also did not evaluate it. The Companies included no analysis of carbon capture on coal in the 2021 IRP or the Resource Assessment.

Q. DO THE COSTS REPRESENTED FOR THE NGCC PLANTS INCLUDE COSTS ASSOCIATED WITH SECTION 111(D) COMPLIANCE?

A. No.

[7] Response to KCA 2-12

Q. HAVE THE COMPANIES ARGUED THERE IS ANOTHER COMPLIANCE OPTION?

A. Yes. The Companies are stating that if the new EPA rules are finalized, they could comply by the plants being reduced to intermediate load.

Q. IS THIS POSITION SUFFICIENT TO APPROVE THE COMPANIES CPCN?

A. No. The GHG Rules are a proposal, not a final rule. Further, the Companies' filings do not reflect the costs associated with the new NGCC's operating as an intermediate load resource.

Q. WHAT ARE THE COSTS FOR THE RECLASSIFICATION?

A. There is no indication that the Companies developed a specific cost for the two NGCC's assuming intermediate load. My company EVA estimates that the reclassification would increase the Levelized Cost of Energy ("LCOE") by about 25 percent. This is consistent with a recent IRP for UNS Electric which showed the increase to be about 20 percent.[8] Ultimately, the increase in costs will be system specific. The Companies need to develop a full analysis, not only of the incremental costs to the NGCC's but to the entire system cost.

Q. HAVE THE COMPANIES PROVIDED ANY ANALSIS OF THE NGCC'S AS INTERMEDIATE LOAD PLANTS?

A. The Companies have not shared any such analysis if one has been performed. Rather, the Companies in their response to KCA 3-3 attempt to justify its proposed NGCCs without conducting any further analysis beyond a review of the initial RIA analysis sponsored the EPA.[9] The Companies looked at the results for SERC-KY, which is the region that includes

[8] https://docs.uesaz.com/wp-content/uploads/UNSE-2020-Integrated-Resource-Plan.pdf, Page 76.

[9] https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines

the Companies, and found that the "IPM model constructs much more NGCC capacity (about 3,000 MW) in 2028 that the Companies have proposed in this proceeding (about 1,300 MW) all of which operates through the end of EPA's modeling period."

Q. DID EPA QUALIFY THE RIA RESULTS?

A. Yes. The EPA identified several major weaknesses in its modeling[10].

- The RIA modeling did not include compliance with Section 111(d) for existing natural gas baseload units.
- The RIA modeling did not "include some elements of the proposed 111(b) standards on new natural gas-fired EGUs" including "the requirement for new gas-fired capacity operating at greater than 50 percent annual capacity fact in run year 2040 to increase Hydrogen co-firing to 96 percent by volume or convert to CCS."[11]
- The RIA baseline assumed significant investments in renewable energy as a result of the Inflation Reduction Act, thereby reducing capacity needs.
- The RIA electric demand forecast is largely driven by electric demand in the AEO 2021. Results could be different with higher or lower demand.
- The recent run up in natural gas prices is assumed to have abated by 2028. Further, prices are expected to reflect large increases in supply. If gas prices are higher, the overall competitiveness of coal and nuclear would improve.
- The cost of hydrogen is still unknown. The IPM assumes a delivered cost of $1/kg under the baseline falling to $0.50/kg during the second phase of the NSPS.
- The timing and amounts of coal plant retirements is uncertain.

Q. HAS EPA UPDATED ITS ANALYSIS TO CORRECT SOME OF THESE ISSUES?

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[10] RIA, pages 334-335.

[11] RIA, page 333

A. Yes. On July 7, 2023, EPA published an update to the RIA and new IPM modeling results. According to EPA, the prime driver behind the update was the fact that the IPM modeling had not been updated following the issuance of the Annual Energy Outlook ("AEO") in March 2023 which forecast significantly higher volumes of gas associated with the growth in Liquified Natural Gas ("LNG") exports.[12] A summary of the revised results for NGCC's in the SERC-KY sub-region are shown in Exhibit ESM-2. The updated modeling reduced the new NGCC capacity between the Post-IRA Baseline and the GHG Proposal with the LNG adjustments by about one GW, about the size of the Companies' proposed NGCC's. More interesting and relevant, it found it was economic for all the new NGCC's to switch to hydrogen co-firing for a period which included 2035.[13]

Exhibit ESM-2
NEW GAS COMBINED CYCLE CAPACITY FORECASTS

New Gas CC (GW)

Scenario	2028	2030	2035	2040	2045	2050	2055
Pre-IRA	1.0	1.0	1.9	2.2	3.6	5.0	5.0
Post-IRA	3.2	3.2	3.2	3.2	3.2	3.2	3.2
New LNG Baseline	2.2	2.2	2.2	2.2	2.2	2.2	2.2
GHG Proposal with LNG	2.1	2.3		2.3	2.3	2.3	2.3
	-	-	-	-	-	-	-

New Gas CC w/ Hydrogen Co-Firing (GW)

Scenario	2028	2030	2035	2040	2045	2050	2055
Pre-IRA	-	-	-	-	-	-	-
Post-IRA	-	-	-	-	-	-	-
New LNG Baseline	-	-	-	-	-	-	-
GHG with LNG	-	-	2.3	-	-	-	-

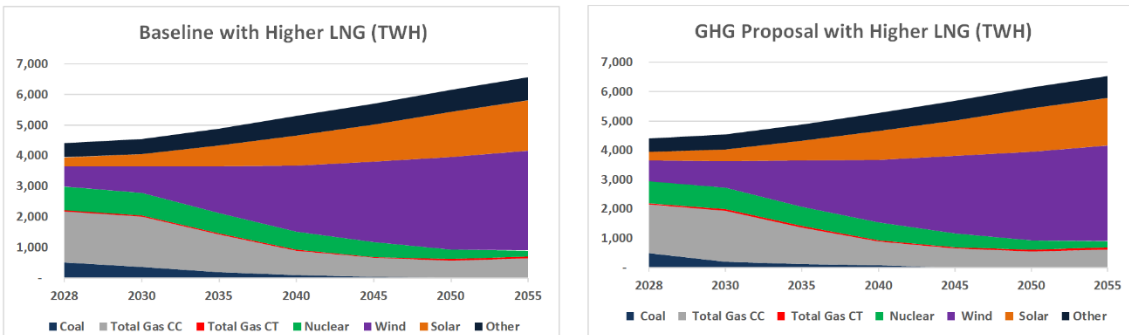
Source: IMP Results for New NGCC in SERC-KY

Q. WHAT IS THE OVERALL OUTLOOK FOR NGCCS IN THE IPM MODELING?

[13] The exact years are unclear as data are only provided in five-year increments.
[13] The exact years are unclear as data are only provided in five-year increments.

A. While expected to account for about half of total generation in 2028, the role for NGCC's is expected to dramatically decline over time under both the updated baseline and the GHG proposal with the updated baseline as shown in Exhibit ESM-3.

Exhibit ESM-3
GENERATAION FORECAST BY TYPE



Q. GIVEN THE RESULTS OF THE IMP, DO YOU AGREE WITH THE COMPANIES STATEMENT IN ITS KCA RESPONSE 3-3 THAT NGCC TECHONOLOGY "LIKELY TO MEET LONG-TERM DEMAND."

A, I think it is fair to conclude that this is not the conclusion of the RIA.

Q. DO YOU HAVE ANY OTHER ISSUES WITH THE RIA?

A. Yes. The IPM assumes almost all operating nuclear plants retire at the end of their current licenses. Further, the RIA does not project the addition of any Small Modular Nuclear Reactors ("SMRs"). The loss of existing nuclear generation which has historically supplied about 20 percent of U.S. electricity generation and the failure to include SMR penetration creates a baseload shortfall.

Q. WHAT ARE SMALL MODULAR NUCLEAR REACTORS?

A. SMR's are advanced nuclear reactors that have a power capacity of up to 300 MW per unit, can be factory assembled, and produce no carbon emissions. Other benefits include savings in construction time and the ability to deploy in increments that match increasing demand.

Q. HOW WIDESPREAD IS THE INTEREST?

A. The interest is widespread and growing. According to the Center for Strategic and International Studies (CSIS), "a number of electric utilities are actively working to advance the SMR agenda. For example, the Tennessee Valley Authority is working with Babcock & Wilcox to build a pair of small reactors to supply power to Oak Ridge, while Ameren Missouri has partnered with Westinghouse to develop and license the latter's SMR technology. NuScale[15] announced The Western Initiative for Nuclear (WIN), a broad, multi-western state collaboration, to study the demonstration and deployment of a multi-module NuScale SMR plant that would be operational by 2024." [16] Duke Energy Indiana is also exploring SMR's."[17]

Q. DID THE RIA EVALUATE RATE IMPACTS?

A. Yes. Unlike the Companies' analysis, retail rate impacts are a critical component of the RIA. EPA has developed a retail price model to assess rate impacts.[18]

Q. DO YOU ANTICIPATE LEGAL CHALLENGES TO THE NEW GHG RULES?

A. Yes. Legal challenges cannot be made until after the Final Rules are published in the Federal Register. EPA indicated it expected the new GHG rules to be finalized in June 2024.[19] EPA recently extended the date by which comments are due to August 8, 2023[20] suggesting that the June 2024 date may be a challenge. In addition, there is often a lag between new rules being finalized and their being published in the Federal Register.

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[15] NuScale received U.S. Nuclear Regulatory Commission (NRC) design approval in 2022. www.nuscalepower.com/-/media/nuscale/pdf/fact-sheets/about-nuscale-fact-sheet.pdf

[16] https://www.csis.org/analysis/why-utilities-want-small-modular-reactors

[17] https://news.duke-energy.com/releases/purdue-and-duke-energy-to-explore-potential-for-clean-nuclear-power-source-for-campus

[18] https://www.epa.gov/power-sector-modeling/retail-price-model

[19] **https://www.federalregister.gov/documents/2023/05/23/2023-10141/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed**

[20] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power

Q. WOULD LEGAL CHALLENGES LIKELY DELAY THE IMPLEMENTAION OF THE GHG RULES?

A. They could but at this point that would be speculation. Absent a withdrawal of the regulations, I believe the determination as to which units are subject to the Section 111(b) requirements would be based upon the date upon which the proposed regulation is published in the Federal Register. Note the "proposal" date for NSPS determines applicability because of concerns as to how "under construction" is defined and the potential rush to start construction if applicability is determined by the date of the final rule being published.

SECTION III

PPL CORPORATION

Q. WHAT IS THE CORPORATE STRUCTURE FOR THE COMPANIES?

A. The Companies are owned by PPL.

Q. ARE THE COMPANIES' GENERATING ASSETS THE SOLE GENERATING ASSETS OF PPL?

A. Yes.

Q. ARE YOU FAMILIAR WITH THE 2021 PPL CLIMATE ASSESSMENT?

A. Yes.

Q. HOW DOES THE 2021 PPL CLIMATE ASSESSMENT DESCRIBE THE 2021 IRP?

A. The "2021 Kentucky IRP addresses issues associated with the clean energy transition, including future load changes and the addition of new clean generation technologies. The IRP includes the retirement of nearly 2,000 megawatts of coal by 2036 and the addition of solar supported by storage, as well as natural gas simple cycle peaking plants, mainly for winter reliability." It states that the Companies "are not building new coal generation, and … does not include plans for new combined-cycle gas facilities."

Q. DOES THE 2021 PPL CLIMATE ASSESSMENT PROVIDE CORPORATE GOALS REGARDING CARBON?

A. Yes. The document states that PPL has clear ESG goals to achieve net-zero carbon emissions by 2050 with interim reduction target of 80 percent from 2010 levels by 2040 and 70 percent by 2035.

Q. ARE PPL EXECUTIVES DIRECTLY COMPENSATED TO ACHIEVING ESG AND CLIMATE-RELATED PERFORMANCE INCLUDING GOALS LINKED TO COAL PLANT RETIREMENTS.

A. Yes. They are compensated both directly through their incentive compensation and indirectly through the performance of the Companies as the new investments in replacement generation increase earnings.

Q. DO YOU FIND THIS PROBLEMATIC?

A. With billions of dollars remaining in coal generation assets, it is problematic that executives are being compensated to shut down fossil fuel capacity. This creates a conflict of interest between what is best for PPL executives and what is in the best interest of ratepayers and the State of Kentucky.

Q. ARE YOU CONCERNED THAT CUSTOMERS ARE NOT ADEQUATELY BEING CONSIDERED IN THIS PROCESS?

A. Yes. The Companies state in response to KCA 2-46 that such a rate impact analysis is inappropriate.

> As stated in the response to KCA 1-68 (which KCA 1-69 references), the appropriate analysis in this proceeding is to determine whether the proposed projects constitute the least reasonable cost to customers of meeting their electricity needs. **The financial effect to customers of the projects in this case is measured by the present value revenue requirements the Companies have already submitted.** Revenue requirements are the first phase of a general rate case, used to determine the total amount of revenue required to cover the costs of service provided by a utility. **Rate design, or the determination of how costs should be allocated among customer classes and across components of customer rates, is the second phase of a general rate case.** The former has always been used by the Commission to assess the relative cost of investment alternatives in a CPCN proceeding. The latter is not performed outside of a general rate case and is often the product of alternative analyses presented by the Companies and intervening parties which become the subject of significant debate and is ultimately ruled on by the Commission. (**emphasis added**)

Q. WHY DO YOU BELIEVE THIS IS THE COMPANIES' POSITION?

A. The fact that the Companies have historically used a net present value of revenue requirements to assess the relative cost of investment alternatives is not a sufficient reason to not consider residential rate impacts in this case particularly given the language in SB 4. This CPCN differs from a historical CPCN with respect to the size ($2 billion plus) of capital being requested for accelerated retirements of existing capital and the amount of dollars remaining in stranded investments.

As the Companies well know, ratepayers will be paying for both the remaining capital associated with the closed plants as well as the new capital. While there may be some nuances in rate design, the bottom line is the Companies will request a significant increase in capital recovery. Producing an estimate is not an unreasonable request and is prudent given the potential size of the residential rate increases seen by other state utilities-.

Q. DID THE COMPANIES ULTIMATELY ACKNOWLEDGE THAT IN FACT RATEPAYERS WILL BE ADVERSELY AFFECTED IN THE FIRST 10 YEARS OF THE COMPANIES PLAN?

A. Yes. In response to KCA 3-23 and KCA 3-29, the Companies finally acknowledged that the proposed capital expenditures will increase rates and per their own analysis the NPV over the first 10 years is higher in the proposed case.

Q. DO YOU BELIEVE THE LONG-TERM INCENTIVES (LTI) CREATE A CONFLICT OF INTEREST FOR THE EXECUTIVE TEAM?

A. Yes. The 2022 Proxy notes the following:

> In 2022, the Compensation Committee evaluated PPL's LTI mix and considered how to further link executive compensation to its future strategy, which resulted in adding earnings growth (EG) and environmental, social and governance (ESG) metrics to the LTI mix at 20% each. Priority ESG metrics are tied to climate-related performance. TSR continues to be one of the leading performance measures among utilities and a vital metric that recognizes PPL's share performance compared with that of other utilities in the UTY. TSR-based performance unit grants will continue

> to comprise 40% of the NEO's total LTI, and RSUs will continue to comprise 20% of the NEO's total LTI.[21]

Given the LTI compensation is deliberately linked to implementation of its future strategy which includes sizable capital investments, it is hard to conclude otherwise. My personal experience is that Executive Team compensation focused on realizing the CPCN will be communicated throughout the organization.

Q. DO YOU SEE A SIMILAR EMPHASIS ON AFFORDABLE RATES?

A. No.

Q. WHAT WILL HAPPEN TO RATES ONCE THE COAL FLEET IS RETIRED AND REPLACED WITH NEW CAPACITY?

A. Rates will increase substantially as the utilities begin to generate earnings for new capital in the rate base while they continue to generate earnings from their stranded investments.

Q. WOULD YOU SAY THE COMPANIES ARE EXCITED ABOUT THE GROWTH IN EARNINGS THAT WILL BE PROVIDED BY NEW INVESTMENTS.

A. Yes. One of the major 2022 accomplishments PPL identifies in its 2023 Proxy Statement is "delivering solid financial results while strengthening our financial foundation" which PPL attributed to its commitment "to delivering on (its) near-term commitment to shareholders while further developing and refining (its) plan to drive near-term value." Prominent in its plan is to "increase planned capital investments by 20% over the previously announced capital plan … **improving annual base rate growth to over 5.5%**."[22]

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[21] 2022 PPL Proxy, Page 35. Note RSU is restricted stock unit, TSR is total shareholder return, and UTY is the PHLX Utility Sector Index, a market capitalization-weighted index composed of geographically diverse public utility stocks.

[22] www.pplweb.com/wp-content/uploads/2023/04/PPL-Corporation-2023-Proxy.pdf, page 40.

Q. DO YOU BELIEVE THAT MANAGEMENT'S REFERENCE WAS REFLECTED IN THE IRP AND THE CPCN?

A. Yes. One example of this was the omission of consideration of carbon capture retrofits on the existing coal fleet. The 2021 Climate Assessment states a key assumption is that "retrofitting coal generation facilities with CCS remains uneconomic."[23] The 2022 Resource Assessment, which provides the update to the IRP to justify the CPCN, continues to omit from consideration the retrofit of CCS on existing coal plants despite the increase in the Section 45Q tax credits for CCS in the Inflation Reduction Act ("IRA").[24] I Rather the IRA incentives were selectively applied in other areas.

A second example is the modification of the coal price forecasting methodology to link future coal prices to gas prices, which the Companies refer to Coal-to-Gas (CTG) methodology. This is not a standard methodology for forecasting coal prices. Nor did the Companies adequately justify it. As shown below, the coal price forecasts in the IRP were significantly below the contrived forecasts using the CTG methodology. It is notable that despite multiple requests for the Companies to produce support for this approach, it did not do so.[25]

Q. WHAT WAS THE COMPANIES FORECAST COAL PRICE FOR 2023?

A. The mine mouth coal price following the CTG methodology in 2023 was higher than the actual price of coal paid in the first quarter of 2023 which was $2.30 per MMBtu based upon the EIA 923 data. The magnitude of the difference varied by scenario.

[23] 2021 Climate Assessment, Page 20.

[24] In response to KCA 2-33, the Companies confirm their failure to consider the expanded Section 45Q tax credits because "such an analysis (was) not necessary at this time." If the coal is to achieve least cost solutions, it is unclear why it was not necessary.

[25] Response to KCA 2-36.

Q. DO YOU HAVE AN ISSUE WITH HOW THE COMPANIES APPROACHED THIS ANALYSIS?

A. All indications are the Companies decided to retire its coal fleet by 2035 and developed a plan to support its objective. One indication of this position is found in PPL's 2021 Climate Assessment Report which lays out the retirement plan from the 2021 IRP.[26] The opening "Message From the CEO" in the Climate Assessment, Vince Sorgi makes clear the plan is "to transition our Kentucky coal-fired generation with an expected 2,000 megawatts of coal plant retirements over the next 15 years and replace it with non-emitting generation."

Q. DID THE COMPANIES' POSITION CHANGE IN THE CPCN FILING?

A. The 2021 IRP did not consider NGCC's *without* carbon capture. The CPCN did not consider carbon capture for either the proposed NGCC's or the coal fleet.

Q. HOW DO YOU RECONCILE THE CHANGE IN POSITION?

A. It appears that the 2021 IRP was roundly considered inadequate. The Commission Staff Report stated that the "Commission Staff believes that many of the issues discussed above affected the reasonableness of the optimal, base case plant produced by the IRP. In fact, there does not appear to be a single party to this review-LGE/KU included-who is likely to support implementing the optimal base case plan at this point. Thus, LG&E/KU did not establish that the 2021 IRP produced a least cost plan to reliably serve its project load.[27]

Q. DID THE STAFF INDICATE WHAT CHANGES IT WANTED IN FUTURE IRP'S?

A. Yes. The Staff listed 27 separate recommendations.[28]

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[26] www.pplweb.com/wp-content/uploads/2021/11/PPL_Corp-2021-Climate-Assessment-FINAL.pdf
[27] Order in Case No. 2021-00393, pages 66-67.
[28] Order Case No. 2021-00393

Q. DO YOU BELIEVE THAT THE COMPANIES WERE COMMITTED TO SHUTTERING THE COAL PLANTS WHEN IT PERFORMED THE 2022 RESOURCE ASSESSMENT?

A. Yes. In my opinion, the 2022 Resource Assessment was biased toward closing the three coal units and replacing the capacity with two NGCCs.

Q. HOW WOULD THE ANALYSIS HAVE BEEN DONE DIFFERENTLY IF A SPECIFIC OUTCOME WAS NOT DESIRED?

A. The Companies would not have used the excuse of the GNR that had not been promulgated to accelerate retirement decisions, particularly for a unit that is equipped with SCR's.

The Companies would have considered the devastating impact of a $2 billion plus impact on ratepayers in the near term.

The Companies would have considered the impact of their plan on the local and state economies.

The Companies would have acknowledged the risk of the proposed overly ambitious construction plan over the next four to five years given high inflation, supply chain and labor shortages, and transmission interconnection challenges.

The Companies would have considered reasonable price outlooks for both coal and natural gas, rather than constructing an artificial connection in pricing between the two.

The Companies would have been further along in fine tuning the costs of the alternatives including the full cost of the NGCC's including Firm Transportation for natural gas in its basic economics.

The Companies would have acknowledged that replacement of coal with natural gas absent carbon capture would not achieve the desire net-zero emission objectives.

Q. DOES THE CPCN ACTUALLY SUPPORT THE STATED GOAL OF PPL?

A. No. The stated goal in 2021 was to replace the coal generation with "non-emitting" generation. The proposed NGCC plants emit carbon both during combustion and upstream. The 2022 Resource Assessment does not acknowledge that to achieve zero-emissions from gas by 2040 or 2050, the plants need to be retrofit with carbon capture or converted to green hydrogen. The costs associated with either of these options are not considered.

Q. WHY DO YOU BELIEVE THE COMPANIES DID NOT CONSIDER CARBON CAPTURE?

A. An NSPS requiring carbon capture on NGCC produced different modeling results according to the Companies' response to PSC 1-92. The Companies stated that the least cost "gas" option *with* a CCS requirement would be a single cycle combustion turbine ("SCCT"), not an NGCC. SCCT's have a lower capital cost.

Q. DO YOU BELIEVE THE COMPANIES ERRED BY NOT INCLUDING CARBON CAPTURE IN ITS 2022 RESOURCE ASSESSMENT?

A. Yes. It turns out the Companies had been correct to require carbon capture in the 2021 IRP. The Companies decision to omit carbon capture for both natural gas and coal from consideration is puzzling given the very significant tax credits for carbon capture included in the IRA which was signed into law in August 2022.[29] It is interesting to note that the 2022 Resource Assessment did not discuss in any material way carbon capture or low GHG hydrogen co-firing.

Q. HOW SHOULD THE COMPANIES HAVE CONSIDERED THIS?

[29] The expanded 45Q tax credits for carbon capture were announced after the 2022 Resource Assessment but prior to the filing of the current proceeding. It is unclear why the carbon capture option was not considered in the most recent update given the significant increase.

A. Either the Companies should have included a carbon capture retrofit or hydrogen co-firing or they should have assumed a shorter life over which to depreciate the NGCC plants.

IV. 2022 RESOURCE ASSESSMENT

Q. PLEASE SUMMARIZE THE 2022 RESOURCE ASSESSMENT

A. The Executive Summary of the 2022 Resource Assessment states its purpose is "to ensure that the Companies could continue to provide safe, reliable, and low-cost service to their customers while complying with the GNR across a variety of possible future fuel prices and carbon price scenarios."

Q. DO YOU HAVE ANY ISSUES RELATED TO THE STATED PURPOSE OF THE 2022 RESOURCE ASSESSMENT?

A. Yes. First, it is worth noting that at the time of the filing of the CPCN, the GNR had not been promulgated. Therefore, any compliance strategy identified would not necessarily be compliant. Specifically, the assertion in the 2022 Resource Assessment that the GNR "effectively require(s) two of the Companies' largest coal-fired units, the 297 MW Mill Creek Unit 2 ("Mill Creek 2" or "MC2") and the 485 MW Ghent Unit 2 ("Ghent 2" or "GH2") to cease operating during the ozone season (May through September) each year beginning in 2026 unless the Companies install SCR's was simply not known at that time. Second, the retrofit of SCR's was not adequately considered.

Q. DOES THE CPCN ACHIEVE COMPLIANCE WITH THE GNR BY THE 2026 OZONE SEASON?

A. No. The Companies' plan does not. The Companies' assumed EPA would provide them with a two year deferment[30] which was consistent with the Federal Register notice which stated "the EPA is requesting comment on potentially deferring the application of the backstop daily rate for large coal EGUs that submit written attestation to the EPA that they

[30] Exhibit SAW-1, Page 18.

make an enforceable commitment to retire by no later than the end of calendar year 2028.[31] Once again, however, the rule was not final and the two year compliance extension was not certain.

Q. ARE THERE ANY OTHER RETIREMENTS INCLUDED IN THE 2022 RESOURCE ASSESSMENT?

A. Yes. The Companies include the retirement of the 412 MW E.B. Brown Unit 3 (Brown 3 or EB3) which is unaffected by the GNR. The Companies argue for the retirement because it would allow the Companies to avoid previously scheduled (and routine) maintenance of this unit which is estimated to cost $26 million.

Q. DO HAVE ANY REASON TO BELIEVE THAT THE JUSTIFICATION WAS OTHER THAN WHAT THE COMPANIES STATED IT TO BE?

A. With respect to the overall plan, there are several possibilities.

- The proposed investments by the Companies would significantly increase rate base which by definition would increase the Companies' earnings. Based upon the Companies own numbers, the incremental compliance capital would be $246 million versus the $2.2 billion proposed.
- The sizing of the two NGCC's was tied to plant retirements. The retirement of EB3 produces a more desirable size for the NGCC's.
- PPL Corporation has a stated goal of net-zero carbon emissions by 2050. While the Companies repeatedly state in their testimony, the CPCN was not affected by the corporate objective, carbon emissions are a prominent metric. This is particularly relevant given PPL has no other carbon emitting generation.

[31] https://www.federalregister.gov/documents/2022/04/06/2022-04551/federal-implementation-plan-addressing-regional-ozone-transport-for-the-2015-ozone-national-ambient

Q. HOW ARE THE COMPANIES PROPOSING TO REPLACE THE RETIRED CAPACITY?

A. The primary replacement for the capacity is two 641 MW natural gas combined cycle (NGCC) plants, one to be located at Mill Creek and one to be located at E. B. Brown. In addition, the Companies are proposing constructing 240 MW of solar and 125 MW of energy storage and entering into 637 MW of solar PPAs.

Q. THE COMPANIES REFER TO THIS PLAN AS "A NO-REGRETS PORTFOLIO FOR SERVING CUSTOMERS NOW AND FOR DECADES TO COME." DO YOU AGREE?

A. No for several reasons.

- Spending over $2 billion on a wrong plan is likely going to result in significant regrets if the Companies' proposed plan cannot be implemented on a schedule consistent with that proposed.
- Over $2 billion is being added to the rate base based upon a flawed analysis. It is possible, if not likely, the Companies are simply building new assets that will likely be stranded before their costs are fully recovered adding yet another regulatory liability to customer bills.
- PPL announced a corporate goal to achieve net zero emissions by 2050[32] and the proposed NGCC's are not net zero absent a carbon capture retrofit or conversion to low GHG hydrogen.
- The Companies do not consider Scope 3 emissions in their calculations of net-zero. Scope 3 emissions relate to the production and transport of fuel. While today Scope 3 emissions are not reported, it is more than likely they will be included in reporting

[32] www.pplweb.com/wp-content/uploads/2021/11/PPL_Corp-2021-Climate-Assessment-FINAL.pdf

requirements at some point in the future given the significant methane leaks from natural gas production and transport.

- The proposed conventional NGCC does not reflect either a carbon capture retrofit or conversion to low GHG hydrogen. The Companies state there is not adequate storage for CO2 near Cane Run 7.[33] The Companies indicate that they have not fully explored sequestration options at existing plants.[34] The Companies indicate they have not fully explored a market outlet for CO2 that would support carbon capture without sequestration.[35] No cost estimates related to carbon capture are included.
- Equally inadequate is their discussion about conversion to low GHG hydrogen citing only a statement from an OEM that conversion is possible. The cost of conversion is not zero.[36] A full conversion is likely to result in derates.[37] There is no market analysis that demonstrates that low GHG hydrogen will not be significantly more expensive than natural gas.
- Reliance on long-term PPA's is high risk unless there is an exit ramp built in that would allow termination (even with some payment) if the resource is no longer economic. This is particularly problematic for 15 plus year PPAs.
- The Companies solicited bids during a period when prices were high due to supply chain issues as well as inflation. The Companies note that the bids they received were 30 to 40 percent higher that what the Companies paid in 2019/2020.[38] As the industry continues to mature and the supply chain issues are resolved, prices could revert to lower levels.
- The Companies argue they over-building. That is unlikely to be the case, however, as their plans are considerably optimistic on timing. The Companies have already

[33] Response to KCA 1-33
[34] Responses to KCA 1-36 and KCA 1-37
[35] Responses to KCA 1-36 and KCA 1-37
[36] Responses to KCA 1-46 through 1-48
[37] Response to KCA 1-49
[38]Exhibit SAW-1, page 12.

announced delays in the solar agreements. Further, as the Companies acknowledge there has been "poor performance by solar developers in meeting contractual deadlines and costs.[39] In addition, the Companies represent the resource additions also offset the potential closure of OVEC in 2028 despite the fact that the contract with OVEC runs through 2040.[40] Finally, the Companies confirmed that it did not consider the load associated with Blue Oval.[41]

Q. THE COMPANIES STATE THAT THE CPCN REQUEST "MAKES ONLY THE DECISIONS THAT MUST BE MADE TODAY." DO YOU AGREE?

A. No. I do not agree it was true when the Companies filed the CPCN. I know it is no longer true today. For a fraction of the cost, the Companies could continue to operate the three coal plants it is planning to retire rather than replacing them with the new NGCCs. Not only would this help to keep rates lower, this approach would provide the Companies with a five to 10 plus year window to further investigate non- or low-carbon emitting generation such as SMRs, low GHG hydrogen and carbon capture utilization on coal plants.

Q. HOW DID YOU COME TO THE CONCLUSION THAT IT WOULD BE TO CUSTOMER'S ADVANTAGE TO DELAY THE MILL CREEK. EB BROWN AND GHENT NGCC PLANTS?

A, The analysis is straightforward. Using the Companies schedule of undepreciated capital for the three coal plants proposed to be retired in the CPCN[42] the Companies estimated costs for the SCR's, a seven-year amortization period for the SCRs, an eight percent return of capital and a $1.7 billion all-in cost for the two NGCCs, I calculated an annual savings to customers as shown in Exhibit ESM-4. Note these estimates are sensitive to assumptions and not meant to provide an exact number. They are shown to illustrate the potential rate

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[39] Exhibit SAW-1, page 5.
[40] Exhibit SAW-2, pages 6 and 16.
[41] Response to KCA 2-8.
[42] Response to KCA 2-49

impacts associated with undepreciated capital in alternative resource plans. The numbers would be even more compelling with respect to costs if the Companies used a reasonable coal price assumption.

[redacted]

Q. IN ADDITION TO KEEPING RATES LOW, ARE THERE OTHER ADVANTAGES TO PRESERVING THIS CAPACITY?

A. Yes. There is growing concern about the adequacy of capacity from FERC, North American Electric Reliability Council ("NERC"), PJM and MISO. These entities are warning of a reliability crisis and citing early retirements of coal plants and delays in new plants as factors. Attachment ESM-4 contains their respective current comments on the topic.

Q. DO YOU HAVE ANY COMMENTS ABOUT THE COMPANIES' COAL PRICE FORECAST?

A. Yes. The Companies used an atypical approach to forecast coal prices by assuming coal prices are tied to the forecasted price of natural gas. They have coined this methodology coal-to-gas (CTG).

Q. WHAT PROBLEMS DO YOU HAVE WITH THIS APPROACH?

A. I have several issues. With respect to modeling, the methodology effectively ensures the same outcomes in each scenario because the relationship between the two fuels is static. More importantly, it is simply not true and misleading for this purpose.

I have been involved in coal price forecasts for decades. The forecasts consider the supply curves for each coal type, demand for coal in domestic and export markets, and the price of alternative energy sources. I recognize the prices both rise and fall below equilibrium levels as a result of such factors as weather, economic activity, and the price and availability of other sources of generation.

With respect to the utility sector in particular, coal and natural gas are procured in very different manners. Coal is procured in most cases through a portfolio strategy which typically consists of staggered contracts complemented with spot purchases. The Companies have been leaders in their coal procurement strategy which can be seen by the results. In 2022, the Companies' procurement strategy limited the impact of a jump in spot prices. As shown in Exhibit ESM-5, the average contract price was $2.06 per MMBtu; the average spot price was $3.45 per MMBtu. The blended price was $2.25 per MMBtu, 35 percent lower than the spot price. Had the portfolio not existed, the exposure would have been more significant. As of April 2023, the Companies report commitments through 2027.[43]

Exhibit ESM-5

2022 Reported Coal Purchases

Type	Tons	Average Del'd Price $/Ton	Average Del'd Price Cents/MMBtu
Contract	10,447,212	47.80	205.88
Spot	1,670,285	*80.72*	*345.09*
Total	12,117,497	52.34	225.19

Source: EIA Form 923

Natural gas on the other hand is generally purchased in real time for next or same day. While some parties hedge their purchases, hedging is not without risk or expense. Utility hedging strategies vary from none to a defined strategy in which hedges are entered in a formulaic way. The goal of hedging programs for gas is to manage volatility, not to beat the market. A non-trivial cost of hedging relates to credit calls if price volatility (up or down) diverges from market and raises performance concerns. Credit costs are not typically included in the reported delivered price. Purchases are reported on EIA 923. The Companies' reported gas procurement prices in 2022 and the first four months of 2023 are shown in Exhibit ESM-6.

Exhibit ESM-6

Reported Natural Gas Purchase Prices

Period	Volume (MCF)	Price ($/MMBtu)
2022	55,857,553	642.21
2023 (4 Months)	9,858,735	515.23

Source: EIA 923

Not surprisingly, the prices are more aligned with the prompt market.

Q. IS THERE A RELATIONSHIP BETWEEN COAL AND NATURAL GAS PRICES?

[43] https://www.eia.gov/electricity/data/eia923/

A. Yes, but not in the way the Companies suggest. A relationship developed over the last decade or so because of the addition of considerable NGCC capacity combined with increased production related to fracking and associated gas production. As a result, power sector consumption of natural gas increased but the power sector has been more or less the swing market for natural gas, accounting for only about 30 percent of the total natural gas market.

Q. PLEASE DESCRIBE THE FUEL PRICE FORECASTING METHOLODGY ASSUMED BY THE COMPANIES IN THE CPCN FILING.

A. The Companies described their methodology as a Coal to Gas Methodology in which prices for coal are determined by the gas prices.

Q. IS THIS AN ESTABLISED METHODOLGY FOR FORECASTING COAL PRICES?

A. No. The Companies were asked multiple times as to the origin and justification for this policy and confirmed it was something they developed starting with this case and could identify no other party that employs this methodology.[44]

Q. DO YOU HAVE AN OPINON AS TO WHY THE COMPANIES ADOPTED THIS METHODLOGY?

A. Yes. Consistent with its entire analysis, it is clear that the Companies were focused on achieving a specific result, closing selected coal plants and building new NGCC's. As shown in Exhibit ESM-7, the coal price forecast using the historic methodology, the coal price forecast was not helpful. The three lowest lines are based upon the coal prices used in the 2021 IRP. The higher prices are the coal prices forecast in the CPCN analysis based on the CTG methodology.[45]

[44] Response to KCA 2-36
[45] CONFIDENTIAL Response to KCA 2-10(a)

[redacted]

Q. WHAT IS THE BENEFIT OF LINKING THE COAL PRICE TO THE PRICE OF NATURAL GAS?

A. It supports the desired result for the Companies, in this case selecting a NGCC.

Q. HOW DOES THE COMPANIES FORECAST COMPARE TO THE COAL PRICE FORECAST USED IN THE UPDATED RIA ANALYSIS?

A. The IMP forecast (converted to nominal dollars per ton) is provided in **Exhibit ESM-8.** This forecast, while not provided on a regional basis, appears to be more consistent with the coal price forecast used in the 2021 IRP.

Exhibit ESM-8

COAL PRICE FORECAST IN UPDATED RIA (Nominal $/Ton)

	Year	$/MMBtu		Percent Change from Updated Baseline with LNG Update
		Updated Baseline with LNG Update	Integrated Proposal with LNG Update	Integrated Proposal with LNG Update
Minemouth	2028	$ 1.50	$ 1.51	1%
Delivered		$ 2.08	$ 2.07	-1%
Minemouth	2030	$ 1.57	$ 1.69	8%
Delivered		$ 2.02	$ 2.05	1%
Minemouth	2035	$ 1.93	$ 2.04	5%
Delivered		$ 2.15	$ 2.24	4%
Minemouth	2040	$ 2.28	$ 2.40	5%
Delivered		$ 2.40	$ 2.44	2%

Q. WHAT ARE YOUR OTHER OBJECTIONS TO THIS METHODOLOGY?

A. The methodology ignores the fact that gas is a commodity that is effectively purchased real time while coal is purchased pursuant to a portfolio strategy which limits the impact of short-term gas price volatility.

Q. WHAT ARE THE COMPANIES' GUIDELINES FOR FUEL PROCUREMENT?

A. In Case No. 2017-00284[46], the Companies identified its **minimum** coal procurement practices of **projected burn** to be as follows:

1 year out	95-100%
2 years out	80-90%
3 years out	40-90%
4 years out	30-70%
5 years out	10-50%
6 years out	0-30%

In the same proceeding, the Companies also provided for its projected gas requirement at Cane Run 7, the only combined-cycle plant in the system.

1 year out	10-50%
2 years out	0-30%
3 years out	0-10%

Note unlike coal t there is no minimum contracting requirement for natural gas.

Q. WHAT IS YOUR UNDERSTANDING AS TO THE RANGE IN TARGET PURCHASES?

A. The range recognizes the desired flexibility to address market movements. For example, if price moved to significantly higher levels, the Companies can be compliant with the plan and reduce purchases until markets normalize. Similarly, if prices were depressed, the Companies can be compliant with increased purchases.

Q. DID YOU REVIEW REPORTED COAL PROCUREMENTS FOR THE COMPANIES IN 2022 AND 2023 YEAR-TO-DATE?

[46] psc.ky.gov/pscecf/2017-00284/derek.rahn%40lge-ku.com/09132017101229/03_KU_Formatted_1st_DR_FINAL_Case__2017-00284.pdfResponse No. 3

A. Yes. The Companies are required to report their purchases monthly on EIA Form 923. As shown in Exhibit ESM-9. the Companies reported purchases of 12.1 million tons in 2022 of which 14 percent were spot and 86 percent were contract. Note the contract purchases were for a range of terms with 11.2 percent running through 2025.

Exhibit ESM-9

2022 Reported KG&E/KU Purchases by Contract Expiration Date

Plant	Spot	22-Jan	22-Dec	23-Apr	23-Dec	24-Dec	25-Dec	Total
E.W. Brown	-		-			526,222		
Ghent	694,305	9,555	853,118	41,622	100,806	2,191,368	559,253	4,450,027
Mill Creek	302,050	1,613	185,767	25,698	2,228,661	325,967	253,501	3,323,257
Trimble County	673,930	1,575	932,361	4,843	182,015	1,474,150	549,117	3,817,991
Total	**1,670,285**	**12,743**	**1,971,246**	**72,163**	**2,511,482**	**4,517,707**	**1,361,871**	**12,117,497**
Share	**13.8%**	**0.1%**	**16.3%**	**0.6%**	**20.7%**	**37.3%**	**11.2%**	**100%**

Source: EIA 923

Reported purchases in January through April 2023 show a continuation of the Companies portfolio procurement strategy. (Exhibit ESM-10). Only 2.3 percent of purchases during the first four months were reported as spot. Contract purchases have been extended through 2027.

Exhibit ESM-10

Jan- April 2023 Reported KG&E/KU Purchases by Contract Expiration Date

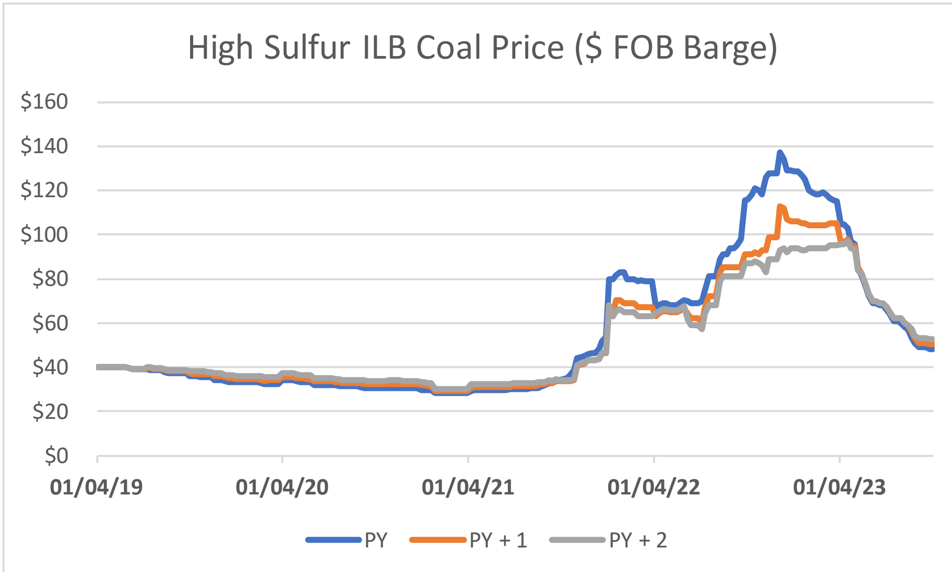
Plant	Spot	12/22	4/23	4/24	12/23	12/24	12/25	12/26	12/27	Total
E.W. Brown				-		89,680				89,680
Ghent	52,919	-	136,219	37,671	81,760	794,258	330,003	231222	27393	1,638,526
Mill Creek	5,067	-	57,330	23,956	736,585	297,949	154,588	19949	56701	1,347,058
Trimble County	32,724	832	5,303	3,320	-	517,087	490,070	82405	3403	1,101,588
Total	**90,710**	**832**	**198,852**	**64,947**	**818,345**	**1,698,974**	**974,661**	**333,576**	**87,497**	4,176,852
Share	**2.1%**	**0.0%**	**4.7%**	**1.5%**	**19.2%**	**39.8%**	**22.8%**	**7.8%**	**2.1%**	**100%**

Source: EIA 923

Q. WHY IS THIS RELEVANT TO THE PREPARATION OF THE FORECAST?

A. The bump in coal prices that occurred starting in the second half of 2021 is all but gone and therefore did not and does not reflect the prices that the Companies are likely to face long-term as shown in Exhibit ESM-11. To the extent that there is a market disturbance, the portfolio will mute the impact as it did in 2022.

Exhibit ESM-11



Source: Coaldesk

Q. WHY DID COAL PRICES JUMP?

A. To understand this correctly, one must start with the weakness in the coal price as a result of COVID. According to Coaldesk,[47] prompt year prices fell by about a third from $44.25 per ton in the beginning of 2019 to under $30.00 per ton by late 2022. The decline reflected lower coal demand due to a decline in coal generation combined with bloated stockpiles.

Prices started to increase in the second half of 2021 when it became clear that domestic demand had rebounded and the ability of the coal industry to rapidly respond was limited in part due to contraction in the industry during 2019 and 2020 and in part due to increased sales of Illinois Basin into the global market in 2021. Exports are typically sold on an indexed basis and producers receive a price based upon the netback to the mine.

The primary market for Illinois Basin coal, however, continues to be power generation. The drop in price was due largely to reduced utility demand as a result of COVID and mild

[47] https://www.coaldesk.com/

weather. Annualized utility demand for Illinois Basin coal declined from 88 million tons in January 2019 to about 61 million tons by the end of 2020. Coal stocks increased from about 16 million tons in January 2019 to about 25 million tons in April 2020 as utility generation fell.

Pricing rebounded but not until the second half of 2021. The rebound in prices lagged the rebound in burn because utilities focused on reducing their bloated stocks, thereby collectively failing to give the coal industry a signal that demand would be increasing. As a result, the supply response was delayed.

Q. WAS COVID THE ONLY FACTOR AFFECTING COAL AND NATURAL GAS GENERATION AND PRICING OVER THE LAST THREE OR SO YEARS?

A. No. While COVID was significant, its impact went well beyond electricity demand levels. COVID has also resulted in supply chain issues and inflation. Since February 2022, a major factor has been the war in Ukraine which dramatically affected global energy markets including increased gas prices and gas price volatility.

Q. WHAT WERE THE REASONS FOR THE INCREASED GAS PRICE VOLATILITY?

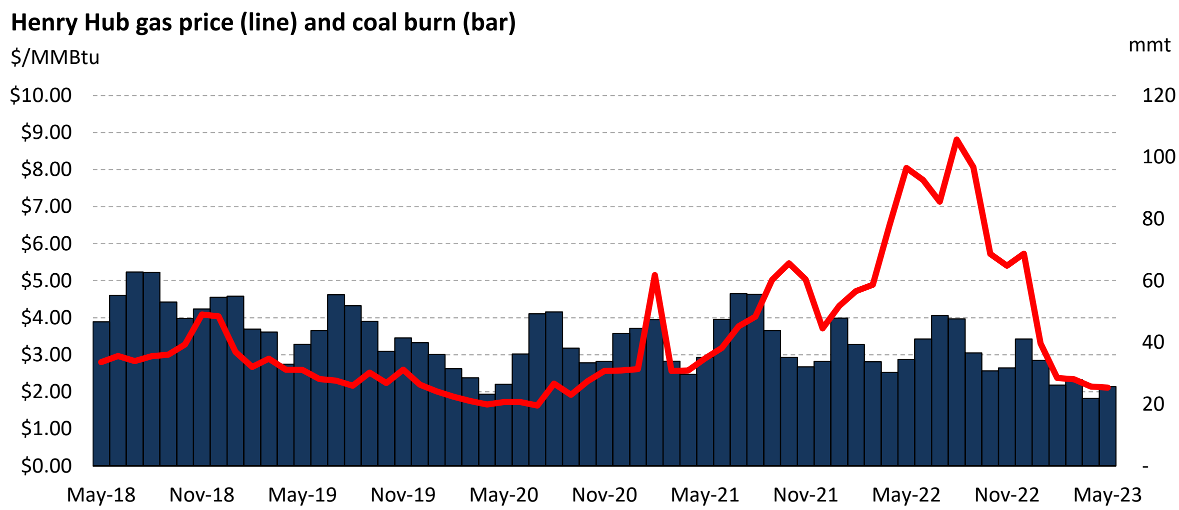
A. There are numerous factors in play. Generally, the most significant was that demand recovery outpaced the recovery in supply. Relatively low energy prices resulted in a lack of CAPEX spending as producers focused on cash flow rather than investment in new capabilities. When the post COVID demand recovery started, the industry had to play catchup.

Q. DO YOU BELIEVE THAT COAL AND GAS PRICES ARE INTERRELATED?

A. In part but not in the way the Companies represent. Since the shale revolution over a decade ago and significant construction of NGCCs, a coal gas switching relationship in the power sector developed. Coal plant dispatch would increase with high gas prices which effectively capped the increase in gas prices. Similarly, coal plant dispatch would decline with low gas prices effectively capping coal price levels. In the second half of 2021 and the first half of 2022, this relationship changed as in many regions because there was inadequate coal supply for operating power plants to cap natural gas prices. As a result, natural gas prices went unchallenged in many regions as utilities had no option but to run their gas plants regardless of the price. This can be seen in Exhibit ESM-12 which shows historically coal burn increases with higher gas prices. In 2022, coal burn barely budged despite the increase in gas prices as the coal supply was inadequate. The concern going forward is that gas prices will be unchecked by coal if coal plant retirements eliminate or diminish coal generation as an option.

Exhibit ESM-12

Henry Hub Price versus Utility Coal Burn



Source: EVA Coal Stockpile Report, May 2023

Q. HOW DO THEIR RESPECTIVE MARKETS AFFECT THE INTERRELATEDNESS OF GAS AND COAL PRICES?

A. Natural gas has a number of large non-power markets including residential, industrial, commercial and export. Coal's primary domestic market is power. Exports via LNG and pipeline shipments has been a large and growing market. As a result, natural gas prices are also affected by movements in those other markets. For example, the LNG market became very lucrative as a result of strong international demand.

Q. IS THERE A LESSON TO BE LEARNED FROM THE EXPERIENCE OF THE LAST 12 to 24 MONTHS?

A. Yes. If coal generation is retired, the remaining non-gas power generation will not be sufficient to cap natural gas prices going forward and a repeat of pricing in the second half of 2022 is likely to recur as the cap on pricing will largely be gone. In other words, gas prices could disconnect with coal prices at certain times in a manner unfavorable to the power sector.

Q. DO THE COMPANIES RECOGNIZE THIS ISSUE?

A. There is no indication they do.

Q. DO YOU HAVE THE SAME CONCERNS ABOUT LONG-TERM COAL PRICING AS YOU DO WITH RESPECT TO NATURAL GAS PRICING?

A. No, for two reasons. First, the problem in 2022 largely reflected temporary short-term supply issues which have already been resolved. Second, the ability for the U.S. to increase coal exports is limited due to terminal capacity constraints along the U.S. East Coast which unlike LNG capacity are unlikely to be resolved.

Q. HOW HAS THE WAR IN UKRAINE AFFECTED DOMESTIC ENERGY MARKETS?

A. The war in Ukraine has affected global energy markets which have in turn affected domestic energy markets. Europe is in the process of weaning itself from Russian imports of both natural gas and coal. With respect to natural gas, this is expected to accelerate the next wave of LNG development in the US. The White House and EU's agreement[48] to materially increase U.S. LNG supply for Europe is likely to accelerate a number of projects

[48] https://www.whitehouse.gov/briefing-room/statements-releases/2022/03/25/fact-sheet-united-states-and-european-commission-announce-task-force-to-reduce-europes-dependence-on-russian-fossil-fuels/

including Plaquemines, Corpus Christi Stage III, Driftwood LNG, and Freeport LNG which total over 6.5 BCFD.

V. SOLAR PPA'S

Q, DID YOUR REVIEW THE PROPOSED CONGTRACTS RAISE ISSUES?

A, Yes. I am concerned about the PPA Terms, the PPA Pricing, and the "must-take" obligations.

Q. WHAT ARE YOUR CONCERNS ABOUT TERM?

A. I am not against long-term agreements, per se. I am against long-term agreements that do not contain appropriate protections.

Q. WHAT DO YOU MEAN BY APPROPRIATE PROTECTIONS?

A. I am concerned that any long-term agreement recognizes the fundamental concern that the future is uncertain and what looks like a good deal today, may or may not look like a good deal tomorrow. Therefore, an agreement with any term as a matter of principle must have buy-out provisions of either the contract or the plant if it is solely delivering to the Companies. The agreements also must recognize and address the must-take provisions, namely it may not be possible in the future due to transmission constraints as the industry is increasingly saturated with renewables,

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT CONTRACTS THAT HAVE NO PRESPECIFIED BUY-OUT PROVISIONS.

A, Unfortunately, I have been witness to a number of term contracts where performance has become problematic for one or both of the parties despite the best intention of all parties. This includes renewable contracts, a problem that could result for the Companies occurs when the price of the product moves above market prices. In other words, the purchase price is way out of market. While consensual buyouts are always possible, an agreement should speak to how a buyout is handled, thereby eliminating or at least managing the process.

Q. WHAT IS YOUR OBJECTION TO THE MUST TAKE PROVISION?

A. A must-take provision requires with limited exceptions the Companies to accept all of the power they generate. The problem with this provision is that it does not address or excuse how transmission limitations may prevent performance.

By way of example, in 2008 and 2019, MISO began to experience significant challenges associated with non-dispatchable wind resources, with approximately four to nine GW of wind generation on its system. "MISO had to manually curtail all wind resources output to manage congestion, over-supply, or minimum load conditions, because these resources did not receive dispatch instructions." In 2011, MISO was able to revise its tariff that would allow wind to become a dispatchable intermittent resource (DIR).

In 2019, MISO requested that certain solar-resources be similarly treated noting that its analysis "predicted that, as soon as 2021, solar penetration will cause similar challenges to what was experienced with wind prior to the implementation of the DIR for wind. In June 2020, FERC accepted MISO's request[49] noting its "proposal to require certain solar resources to register as DIRs to be just and reasonable and not unduly discriminatory or preferential…, and that it is reasonable for MISO to propose these revisions without waiting until solar penetration has reached a point when its lack of dispatchability may significantly affect reliability.

While this may not be an issue today, given the growth in solar and wind, it is certainly possible to become an issue in the future. It would be imprudent to approve a contract that specifically does not "charge" the Companies when/if the solar and wind has to be dispatched. Or said differently, the PPA should address what compensation is due.

[49]www.ferc.gov/sites/default/files/2020-06/ER20-595-000_1.pdf

Q. DO YOU AGREE THAT THE COMMISSION SHOULD HAVE ON-GOING JURISDICTION OVER THESE CONTRACTS?

A. Yes. All contracts should require active management and regulatory review. To allow PPA costs to be passed through without review potentially results in the continuation of agreements which are no longer economic. If a contract is amended or bought out, it does not mean that the initial contract was imprudent. It was good when executed and good when terminated. These conclusions are not in conflict. The concern is that if the agreements are not subject to review, the parties may not focus on whether there are lower cost options to pursue.

Q, DO YOU SUPPORT APPROVAL OF THE PPAS THAT HAVE BEEN PRESENTED?

A. Not in their current form. I recommend the changes I discussed regarding buy-out options and regular review of performance be part of any approval.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, I would like to reserve the right to update this testimony if additional information becomes available.

VERIFICATION

STATE OF New York)
COUNTY OF New York)

The undersigned, Emily Medine, being duly sworn, deposes and says that she is a Principal with the firm Energy Ventures Analysis, Inc., an energy consultancy, and an expert witness on behalf of the Kentucky Coal Association, Inc, in Case No. 2022-00402 before the Commission and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the information and answers contained therein are true and correct to the best of her information, knowledge, and belief.

Emily Medine

Emily Medine

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of July 2023.

Figueroa

Notary Public

Notary Public ID No. 01FI0003719

My Commission Expires:

03/25/2027

PEDRO FIGUEROA
NOTARY PUBLIC, STATE OF NEW YORK
01FI0003719
QUALIFIED IN KINGS COUNTY
COMMISSION EXPIRES MARCH 25, 2027