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	:	CASE NO. 2025-00045

TESTIMONY OF EMILY MEDINE

ON BEHALF OF

THE KENTUCKY COAL ASSOCIATION, INC.

Filed: June 16, 2025

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. On February 28, 2025, Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) (collectively 'the Companies') filed an application with the Kentucky Public Service Commission ('Commission') for Certificates of Public Convenience and Necessity ('CPCN') for the construction of two approximately 645 megawatt (MW) net summer rating natural gas combined cycle combustion turbine ('NGCC') facilities, one at KU's E.W. Brown Generating Station (Brown 12) and the other at LG&E's Mill Creek Generating Station (Mill Creek 6), including on-site natural gas and electric transmission construction associated with those facilities. The Companies also applied for a CPCN to construct a 400 MW, 4-hour (1600 megawatt-hour (MWh)) lithium-ion battery energy storage system (BESS') facility at LG&E's Cane Run Generation Station (Cane Run BESS) and for a selective catalytic reduction (SCR) facility at its Ghent Generating Station. Following up on a CPCN Data Request by KCA regarding whether Companies should extend the life of Mill Creek 2 given the change in market conditions, the Companies prepared an "Analysis of Mill Creek Unit 2 Life Extension as an Option to Support Economic Development While Managing Tariff, ITC, Gas Transport Availability and Load

Risk"[1] which discussed whether the change in the market, new regulations being considered by the Trump administration, and other factors continued operation of Mill Creek 2 should be considered.

In October 2024, the Companies filed an Integrated Resource Plan ('IRP"). The Commission had not yet opined on the IRP prior to the submission of the CPCN.

The purpose of my testimony is to review whether (1) the IRP supporting this CPCN proposal reached appropriate conclusions, (2) the CPCN filing itself supports the CPCN, (3) changes in market conditions and the regulatory regime following the election of Donald Trump warrant a resource review before a decision on the CPCN is rendered, and (4) whether the supplemental CPCN June 2025 filing listed above provides sufficient basis for a critical review of the CPCN.

Q. PLEASE SUMMARIZE YOUR FINDINGS?

A. The Companies' IRP assumptions cannot be relied upon for supporting the CPCN for the following reasons:

- The forecast load growth is not firm as while there are Data Center prospects, the Companies indicated they have not entered into any firm agreements to provide electrical service.
- The Companies are just beginning to negotiate a Data Center rate with the Commission. The filing made by the Companies on May 30, 2025 does not adequately protect traditional ratepayers if there is a default.
- The outlook for CCGT's has changed since the filing of the CPCN due to many factors including cost inflation, tariffs, supply chain constraints, and increased CCGT demand. The Companies acknowledged they will be challenged to meet the construction dates put forward in their IRP. The Companies need to re-evaluate the cost and timing of the preferred plan given these changes.

[1] https://psc.ky.gov/pscecf/2025-00045/rick.lovekamp%40lge-ku.com/06062025040225/07-PSC_DR3_LGE_KU_Attach_to_Q8_%28b%29_-_Att_1_Further_Analysis_of_MC2_Retirement.pdf

- The Companies continue to rely on a correlation between coal and natural gas prices as the basis for future fuel prices despite (1) having never provided justification for this methodology and (2) ignoring the differences between coal and natural gas procurements that affect the price of natural gas as a result of weather, LNG demand, and associated gas supply related to oil production, and
- The Companies acknowledge that their parent, PPL Inc., is committed to net-zero carbon emissions by 2050. The Companies have not incorporated this commitment in their analyses. The analyses for carbon emitting sources should address the 2050 net-zero commitment by assuming closure of carbon emitting assets, the purchase/cost of carbon offsets beyond 2050, and/or PPL's commitment to not seek recovery of stranded costs.

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

A. I reviewed the following:

- Filings in Cases No. 2024-00326 and 2025-00045;
- PPL Corporation 2024 Annual Report and Proxy Statements;
- Industry periodicals and data;
- 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;
- Energy Information Administration Form 923 filings;
- Energy Information Administration Annual Energy Report for 2023 and 2025; and
- Fuel Contracts filed with the Kentucky Public Service Commission.

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 the two NGCC plants and a BESS system at Cane Run for the following reasons:

- The Companies' recent analysis regarding continued operations at Mill Creek 2 indicate that continued operation may be attractive,
- The bullish load growth assumption is uncertain at this time as the Companies have yet to enter into an agreement for a Data Center which is the basis for much of the forecast load growth and the prospect of an economic recession is looming,
- The Companies do not have an approved regulatory framework to support a Data Center contract,
- The Data Center rate that the Companies are seeking has not yet been approved by the Commission,
- The Data Center rate that the Companies are seeking would not provide adequate protections to the Companies traditional ratepayers,
- The future of renewables is uncertain given a possible phase out and end to investment tax credits (ITCs) and production tax credits (PTCs),
- While the magnitude of the expected trade tariffs is uncertain, they have already affected pricing and the supply chain and there are concerns regarding a recession,
- The Environmental Protection Agency (EPA) has proposed significant changes to the Greenhouse Gas (GHG) Rule and the Mercury and Air Toxics (MATS) Rule which are likely to affect at a minimum the timing of future requirements as well as the costs associated with compliance,
- The analyses performed by the Companies are inadequate with respect to how fuel prices are forecast, and

- The Companies do not properly evaluate ratepayer impacts by focusing on the present value of revenue requirements and ignore the potential impact of stranded costs.

Q. THE COMPANIES SUGGEST THEIR STRATEGY IS A "NO REGRETS" STRATEGY. DO YOU AGREE WITH THIS CONCEPT?

A. I agree that "no regrets" should consider both the upside benefits and downside risks of any plan. In this case, downside risks include the risk of insufficient capacity to meet customer load and over-building resulting in excess capacity and increased rates to existing customers. Upside benefits include a growing customer base that hopefully will result in reducing rates or at minimum reduce the rate of increase of the rates.

Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

A. The next section provides a review of potential regulatory changes since the filing of the CPCN. The third section discusses the flaws in the Companies' fuel price assumptions regarding coal and natural gas. The final section provides a review of the analysis supporting the CPCN.

SECTION II

REGULATORY CHANGES

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

A. On June 11, 2025, the EPA announced its efforts to repeal the 2024 MATS rule amendments, the 2015 New Source Performance Standards (NSPS) for new coal plants, and the 2024 Carbon Pollution Standards (GHG Rule). In the proposal to repeal the 2015 NSPS and 2024 GHG rule, the agency presents two alternative proposals for repealing the rules, seeking public comment on both. The primary proposal eliminates all federal GHG requirements for fossil power plants by asserting these sources do not "significantly contribute" to harmful air pollution. The alternative proposal reinterprets what qualifies as the "best system of emission reduction" (BSER), revoking many elements of the 2024 rule while retaining the 2015 NSPS. Legal challenges are expected under both proposals, and a final rule is anticipated by year-end. However, compliance with the 2024 GHG rule timelines is unlikely since both proposals repeal the rule.

Feature	Primary Proposal	Alternative Proposal
2015 Coal GHG NSPS	Repealed	Retained
2024 GHG Rule	Fully repealed	Mostly repealed
BSER definitions	Not required; no significant contribution finding (SCF) for EGUs	CCS deemed not adequately demonstrated cost-effective; 40% co-firing deemed Illegal "generation shifting", inefficient, and infrastructure-limited
2009 Endangerment Finding	Reinterpreted to exclude stationary sources like EGUs	Not addressed
Regulatory Implications	No replacement needed unless a new sector-specific SCF is issued	Future rulemaking under Section 111(d) is still likely required for existing EGUs

The 2024 Mercury and Air Toxics (MATS) proposed rolls back (1) the stricter filterable particulate matter (fPM) limit (0.010 → 0.030 lbs/MMBtu), (2) the lower mercury (Hg) limit for lignite-fired EGUs (1.2 → 4.0 lbs/TBtu), and (3) the PM Continuous Emission Monitoring System (CEMS)-only compliance requirement, restoring monitoring flexibility. The EPA justifies the repeal under Clean Air Act Section 112(d)(6), citing cost-effectiveness concerns, limited environmental benefit, and unrepresentative data supporting the 2024 standards. If finalized, the rule would re-establish the more flexible and less stringent 2012 MATS framework, aligning with recent deregulatory efforts.

Requirement	2024 MATS Amendment (To Be Repealed)	2012 MATS Standard (To Be Reinstated)
fPM Limit (Coal EGUs)	0.010 lbs/MMBtu	0.030 lbs/MMBtu
Hg Limit (Lignite-Fired EGUs)	1.2 lbs/TBtu	4.0 lbs/TBtu
fPM Monitoring Method	PM CEMS only	Quarterly stack tests, CPMS, or PM CEMS
Low Emitting EGU (LEE) Program	Eliminated	Reinstated

Both rules will have a 45-day comment period following their publication in the Federal Register. In both instances, the EPA indicated it plans to publish final rules before the end of the year. The rules cannot be appealed until after the final rule is published in the Federal Register. Given the proposed time frame, irreversible decisions should consider their uncertainty until they have been fully litigated.

Q. WHAT IS THE STATUS OF THE GOOD NEIGHBOR PLAN?

A. In March 2025, the EPA stated its intention to reconsider the Good Neighbor Plan. The EPA framed this reconsideration as a commitment to "cooperative federalism," suggesting a desire to devolve more regulatory authority to individual states. In the meantime, the D.C. Circuit Court of Appeals placed the Good Neighbor Plan litigation in abeyance, meaning the legal challenges to the plan were temporarily suspended. Until the EPA or the courts take further action, states' obligations under the Good Neighbor Plan are stayed. For reference, in Case 2022-00402 the Companies requested and the Commission approved the retirement of Mill Creek 2 based on economic analysis that included the cost to comply with this rule.

Q. ARE THERE OTHER CHANGES THAT HAVE OCCURRED SINCE THE CPCN FILING THAT COULD ALSO BE RELEVANT?

A. Yes, the Trump Administration announced a number of Executive Orders regarding nuclear plants.

While mentioned as a future potential resource, a number of factors have suggested the timetable for Small Modular Reactors (SMRs) may be shorter than what the Companies considered in its IRP. Notably (1) SMR costs are increasingly competitive with new Combined Cycle Gas Turbines (CCGT) given the increase in costs for CCGT's particularly if as a result of environmental regulations they are not able to operate at high capacity factors, (2) the time frames for SMR's could be similar to the time frames now expected for new CCGT's due to the Executive Orders (EO) regarding nuclear power that were issued in May 2025, and (3) SMR's would be compliant with PPL's commitment to net-zero carbon emissions by 2050.

NuScale announced its Standard Design Approval Application for an uprated 77 Mwe design remains on schedule for anticipated July 2025 approval by the Nuclear Regulatory Commission (NRC). In addition, NuScale announced it has 12 modules already in the manufacturing process in order to achieve its 2030 delivery target.[2] The Tennessee Valley

[2] https://www.nuscalepower.com/press-releases/2025/nuscale-power-reports-first-quarter-2025-results

Authority (TVA) submitted a SMR construction permit at its Clinch River site with a hoped-for commission by 2032. In addition, a number of retired nuclear plants being brought back to service load.[3]

The Executive Orders (EO) regarding Nuclear Power are summarized below:

Reform the Nuclear Regulatory Commission (NRC)

The EO requires an overhaul the NRC to accelerate U.S. nuclear energy development with mandates to streamline licensing timelines. The EO sets a national goal of expanding nuclear capacity from 100 GW to 400 GW by 2050. It emphasizes advanced technologies like modular and microreactors, and facilitates expedited approval for designs tested by DOE or Department of Defense (DOD). Key reforms include limiting regulatory delays, reducing public hearing burdens, and revising environmental review processes. The EO positions nuclear energy as central to U.S. energy security and economic competitiveness.

The EO builds on the Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy Act (ADVANCE Act) of 2024, a bipartisan U.S. law signed into effect in July 2024 as part of the Fire Grants and Safety Act.

Key provisions of this law include:

- The NRC is directed to expedite licensing processes,
- The Act also authorizes price competitions covering NRC licensing fees for first movers in various categories,
- The Act reduces regulatory costs by limiting specific NRC fees and eliminating some DOE pre-application costs, and
- The legislation seeks to strengthen the domestic nuclear fuel cycle by directing the NRC to enhance its capacity to qualify and license accident-tolerant and advanced nuclear fuels.

[3] Three Mile Island https://www.world-nuclear-news.org/articles/constellation-to-restart-three-mile-island-unit-powering-microsoft and Palisades https://holtecinternational.com/2025/04/07/hh-40-08/.

Reinvigorate the Nuclear Industrial Base

The EO requires reinvigorating the U.S. nuclear industrial base by rebuilding the domestic fuel cycle, expanding reactor deployment, and strengthening the workforce. The EO directs the DOE to develop a national policy for nuclear fuel recycling and reprocessing and to restart or repurpose closed nuclear facilities. The EO calls for rapid expansion of uranium conversion and enrichment, and use of the Defense Production Act to establish voluntary industry agreements for domestic fuel procurement. It also prioritizes financing for restarting or building nuclear plants and targets 10 new large reactors under construction by 2030. Finally, it mandates investments in nuclear workforce development, apprenticeships, and education to support the long-term growth of the sector.

Reforming Nuclear Reactor Testing at the Department of Energy

The EO mandates a transformation of DOE's strategy for nuclear reactor testing, aiming to speed up the advancement of cutting-edge nuclear technologies. The EO instructs the DOE to prioritize and accelerate the testing of advanced reactors, such as microreactors and small modular reactors, at national laboratories and through a new pilot initiative separate from these labs. The objective is to have at least three new reactors operational by July 4, 2026. Furthermore, the order reaffirms DOE's authority over non-commercial test reactors and requires expedited approvals with coordinated internal review teams. It also directs the DOE to optimize its environmental review process under NEPA to avoid delays. In summary, the EO Order seeks to rejuvenate U.S. nuclear innovation and reclaim global leadership in reactor technology.

Deploying Advanced Nuclear Reactor Technologies for National Security

The EO mandates the swift implementation of advanced nuclear reactor technologies to enhance national security and energy resilience at military and DOE facilities. The EO requires that a nuclear reactor be operational at a domestic military base by 2028 and specifies DOE locations for powering artificial intelligence and other critical defense infrastructure. The EO mobilizes federal resources for uranium and plutonium, creating a

fuel bank for sanctioned projects. It simplifies regulatory and environmental reviews and promotes the establishment of nuclear fuel processing facilities.

Q. ARE THERE ANY OTHER CHANGES THAT AFFECT THE OUTLOOK FOR NUCLEAR?

A. Yes. On May 22, 2025, the House of Representatives approved the One Big Beautiful Bill Act (OBBBA), which limits the scope of various credits, especially for non-nuclear entities involved in the tech-neutral electricity incentive. The OBBBA, however, retains the 45U production tax credit for existing nuclear facilities through 2031 and includes a specific carve-out for new advanced nuclear projects to qualify for the tech-neutral 45Y/48E tax credits, as long as construction starts before 2029, with subsequent credit phase-out based on in-service years. It is unclear whether these provisions will be retained in the final legislation. To the extent that they are, the cost differences between SMR's and natural gas CCGTs may be considerably narrowed.

Q. WHY IS THE CHANGE IN OUTLOOK FOR SMR'S RELEVANT TO THE CPCN?

A. The relevance is to what technologies do the Companies look to for the future. The Companies along with other utilities have expressed interest in SMR's for the future. With the potential incentives combined with forward movement in the industry and the supply chain and cost issues related to CCGT's, the Companies would be well advised to pause on new CCGTs that would have a similar timetable to an SMR. Also, the timing and cost of SMR's are relevant to the Companies planned life of its coal fleet. Extending the life of the Companies' coal units provides more time for SMR or other novel technologies to develop which may prove more cost effective than CCGT. This is why I strongly support continued investment in Ghent 2 and perhaps Mill Creek 2 as these investments will extend the life and utilization of these coal units, while having the benefit of being the least cost incremental generation source in the proposed plan.

Q. WHAT IS THE STATUS OF INVESTMENT TAX CREDITS (ITC) AND PRODUCTION TAX CREDITS (PTC)?

A. The budget bill passed by the U.S. House of Representatives proposes significant changes to clean energy tax credits. The bill would end the 30 percent solar tax credit for homeowners after December 31, 2025 and phase down commercial ITC and PTC credits starting in 2029, eliminating them by 2032 unless projects meet certain construction deadlines. Additionally, the bill includes restrictions that could make it difficult to claim credits if any part of a project is linked to entities from China, Iran, North Korea, or Russia. If the House bill is enacted without changes, it would increase the cost of renewables, including the cost of batteries.

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

A. Yes. The CPCN plan incorporates renewables energy. To the extent, the competitiveness of renewables is affected, the least cost strategies could also be affected.

SECTION III

CORRELATED COAL PRICE FORECASTS

Q. PLEASE REVIEW THE ISSUE RELATED TO THE COMPANIES' FUEL PRICE FORECASTS.

A. The Companies adopted a fuel price forecast methodology that is inconsistent with industry practice.

Q. WHAT IS THE METHODOLOGY?

A. The Companies correlate their coal price forecast to the forecast price of natural gas.

Q. WHAT IS THE PROBLEM WITH THIS METHODOLOGY?

A. While coal and gas prices can affect prompt dispatch decisions, it is not industry practice to tie long-term pricing to each other. This is because the fundamentals for both fuels are different. Natural gas moves into multiple markets including residential, commercial, industrial, power, and exports both of LNG and pipeline gas to Mexico. Coal markets are more limited with the domestic power market being the most significant. Relatively small quantities of U.S. coals are exported into the steam coal market. U.S. metallurgical coals, which are largely not related to the steam coal market, move in the metallurgical coal markets both domestic and international. The problem with the Companies' alleged linkage is that the respective current prices of fuels do not set long-term pricing.

Q. HAVE YOU ASKED THE COMPANIES TO PROVIDE INDUSTRY SUPPORT FOR ITS POSITION?

A. Yes. On multiple occasions, I have asked for such. Information has not been provided.

Q. DID THE COMPANIES AGREE TO CONSIDER SCENARIOS USING A DIFFERENT FUEL PRICE METHODOLOGY?

A. Not to my knowledge.

Q. HOW HAVE THE COMPANIES RESPONDED TO YOUR CONCERNS?

A. The Companies have taken the position that because at one point the Commission accepted the Companies' methodology, they have no obligation to reconsider the methodology.

Q. HAVE THE COMPANIES OFFERED ANY OTHER JUSTIFICATIONS?

A. Yes. In the current IRP, Company Witness Schram argued that coal and natural gas prices are correlated because the escalators in the coal contracts are tied to the price of natural gas. [4]

Q. DID YOU AGREE WITH THEIR POSITION?

A. No. I conducted a complete review of the Companies' coal procurements in 2020 through 2024 that show that this is not the case. The Companies buy coal on both a spot and contract basis. The spot purchases are defined as a purchase for a year or less. While the spot purchases typically are quality adjusted based upon actual delivered quality, they are at a fixed price with no escalation. The contract purchases range from over one year typically with volumes and prices set for the entire contract period. All contract purchases are adjusted for delivered quality based upon the quality specifications in the agreement. Term contracts also provide for recovery of costs related to governmental impositions. In Kentucky, utilities which recover their fuel costs through a fuel adjustment clause are required to submit copies of each fossil fuel purchase contract.[5] These contracts are available on the Commission website.[6]

Q. WHAT DID YOUR REVIEW FIND?

A. The contracts have standard terms and conditions with some variation presumably as a result of negotiations between the Companies and the producers. For example, some contracts state tonnage as a specific amount per year while others provide a range. Another example relates to pricing. In some contracts, pricing is established per year while in other contracts pricing is tied to cumulative tons shipped under the contract.

[4] Witness Schram, VR, IRP Hearing, 5/14/2025, 9:42 AM, 44:50.
[5] https://apps.legislature.ky.gov/law/kar/titles/807/005/056/
[6] https://psc.ky.gov/WebNet/FuelContracts

The coal contract commitments made between 2020 and YTD 2025 are summarized below for the years 2021 through 2030. This table does not include spot purchases which are under contracts one year or less, deliveries under contracts made in 2019 or earlier, or subsequent contract amendments changing volumes. Regardless, there is sufficient information in this exhibit that confirms the portfolio procurement strategy. The spot purchases including one-year contracts are not relevant to the position the Companies have adopted regarding escalators as the prices in the spot purchases are not adjusted directly or indirectly by the prevailing price of natural gas.

	Quantity (000 Tons)									
Contract	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
J20006	330	330	330	330						
J21002	250	250	250	750	750					
J21004	2,500-3,000	3,000-3,500	3,000-3,500	1,000-2,500						
J21009	240-560	360-840	360-840	0-540						
J21010	500-600	500-700	500-700	1,000-2,000	200-1,000					
J21011	300	500-600	2000-2500	2000-2500	1100-2200					
J23001			500-600	500-600	500-600	0-300				
J23002			250	500	500	1,000	1,000			
J23003			500	500						
J23004			500	500	1,000	1,000				
J23005		0-150	550-850	550-850	550-850					
J24007				150	500-600	750-950	1,000-1.200	500-1000		
J25001					2,000-2,400	2,000-2,400	2,000-2,400	2,000-2,400	2,000-2,400	0-2,000
J26001						350	600	600	600	
Range	4120-5040	4940-6370	10820-13700	7230-10870	6,100-9,900	5,100-6,000	3,600-4,200	3,100-4,000	2,600-3000	0-2,000

Notably, the volume ranges in the contracts provide significant protection for ratepayers should markets change.

The contract pricing in almost all coal procurements is fixed in the contracts for the entire term of the contract which effectively eliminates natural gas pricing as the basis for the escalated prices in the vast majority of contracts. KCA's review found only a few contracts that had prices tied to escalators. As discussed below, there was no material impact of natural gas pricing in the escalators.

In J20006 and J23002, there are adjustments for changes in the price of # 2 Diesel Fuel related to trucking obligations in those agreements, the base cost of which is laid out in the agreement. According to EIA, the price of diesel fuel is tied to the cost of purchasing

crude oil, refining costs, distribution and marketing costs, and taxed, not the price of natural gas.[7]

In J23003, most of the price is tied to changes in the Producer Price Index (PPI) for Bituminous UG Coal (PCU21211221212110). The PPI for underground bituminous coal is tied primarily to equipment costs, not natural gas prices. If the PPI for Surface Mining had been used, there would be a greater connection as the use of natural gas in explosives is substantial in surface mines. Further this agreement is only for two years and accounts for less than five percent of the purchases and burn.

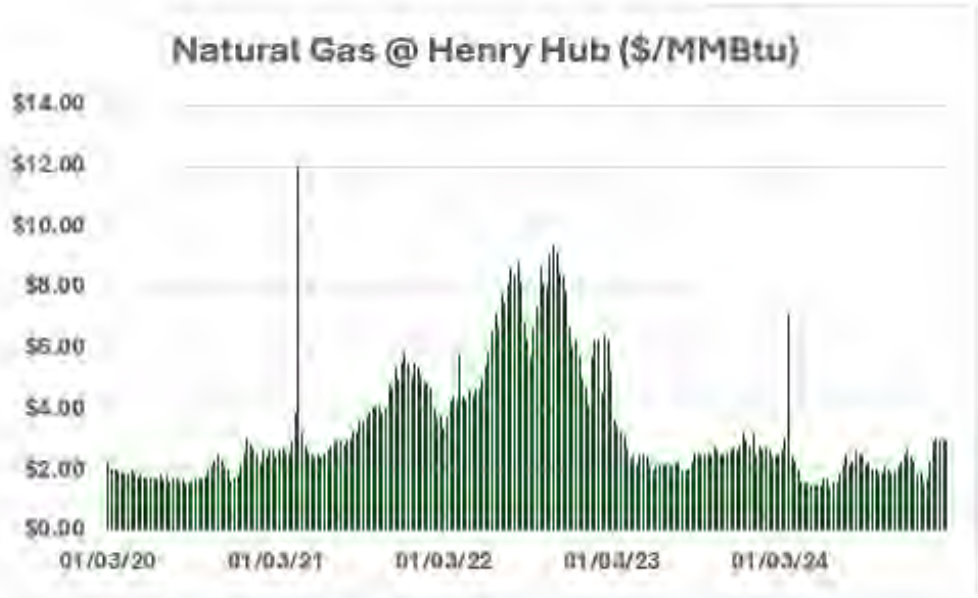
Finally in J25001, only the last three years of the six-year contract provides for price adjustments based upon changes in labor and benefit costs. While the indices and procedures for determining the adjustments are laid out in the agreement, it is worth noting that the adjustments can move in either direction and most importantly are capped at $2.50 per year or about five percent of the contract price. About 75 percent of the indices are tied to labor and equipment costs. Less than 20 percent are tied to power and commodity costs. Therefore, even if power and commodity costs doubled, the impact on pricing would be less than $0.50 per ton and would not materially influence the actual price of the coal.

The review I conducted confirmed that the Companies do an excellent job in procuring coal using a consistent hedging strategy that has proven to ensure price stability and available supply. The Companies' ability to do that same with respect to natural gas is uncertain, particularly as their demand for natural gas increases.

Another way to confirm that natural gas prices and coal prices are not linked in the manner suggested by the Companies is to review historic pricing for natural gas and coal.

[7] https://www.eia.gov/energyexplained/diesel-fuel/factors-affecting-diesel-prices.php

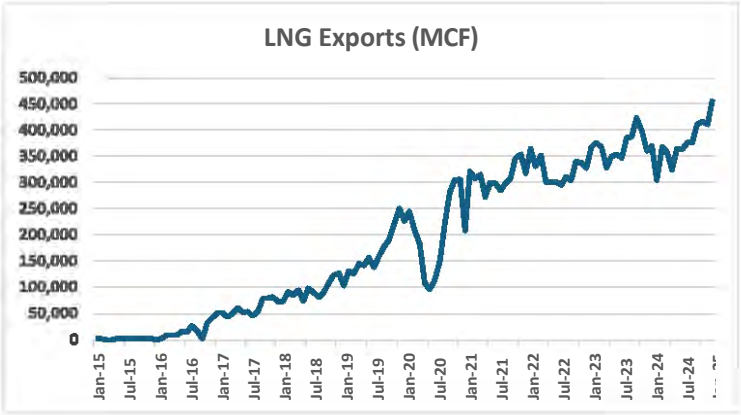
Henry Hub natural gas prices for the 2020-2024 period compared to the purchase price of coal delivered to the Companies' stations. Henry Hub refers to the spot price of natural gas at the Henry Hub in Erath, Louisiana. Henry Hub is the official delivery location for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The prices set at Henry Hub are considered the benchmark for the entire North American natural gas market.



As can be seen, natural gas prices are more volatile than coal prices. In fact, gas prices are often affected daily by weather conditions and delivery issues. As seen above, there was an extended period during COVID and post-COVID when prices soared. The increase was due to growth in demand for liquefied natural gas (LNG) due in part to the war in Ukraine, natural gas supply shortages, and coal supply shortages as coal companies did not initially resume coal production post-COVID as utilities were living off of high inventory levels.

In recent years, natural gas prices have been increasingly influenced by LNG exports which as shown below soared post-COVID.[8] Significant growth continues to be forecast.

[8] Despite repeated requests, the Companies provided no indications that the growth in natural gas by other sectors such as LNG was considered in developing coal prices for the CPCN.



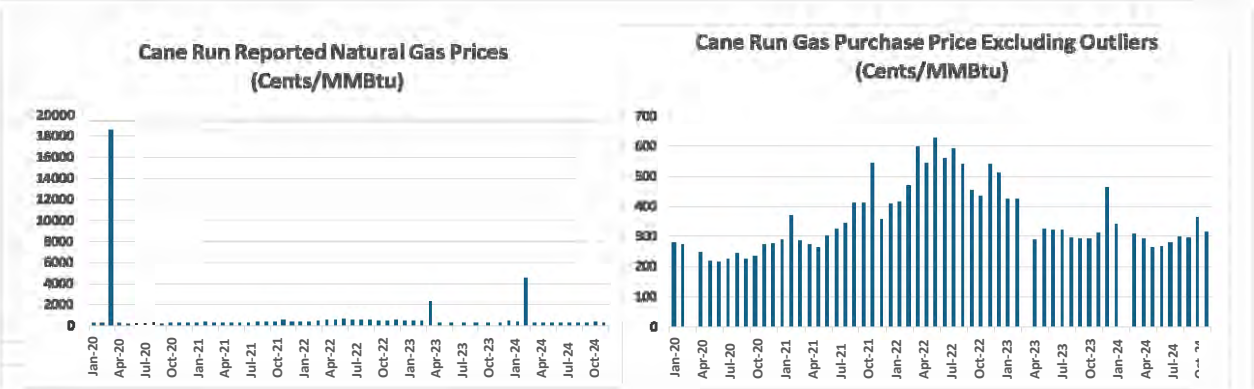
Source: EIA https://www.eia.gov/dnav/ng/hist/n9133us2m.htm

The volatility in the prices for natural gas can be seen in the purchases for Cane Run.

I reviewed the natural gas filings for the Companies for the period 2020 and beyond. As can be seen from Attachment ESM-2, my review of the Commission website produced no purchase agreements during the referenced period although some NAESB agreements[9] which do not have specific volumes or pricing were filed for some of the suppliers. I could not verify the Companies' assertions that gas was purchased through a portfolio strategy akin to how coal was purchased. As the data was not available, I focused on the gas purchase prices filed on a monthly basis with EIA on Form 923.

Reported purchases for Cane Run are summarized below. The first chart includes all months during the 2020 to 2024 period in which there were reported purchases. The second chart excludes the three outlier months in which prices were orders of magnitude greater thereby masking the significant volatility. To state the obvious, using a forecast of the monthly purchase prices for natural gas would be very difficult because of the volatility.

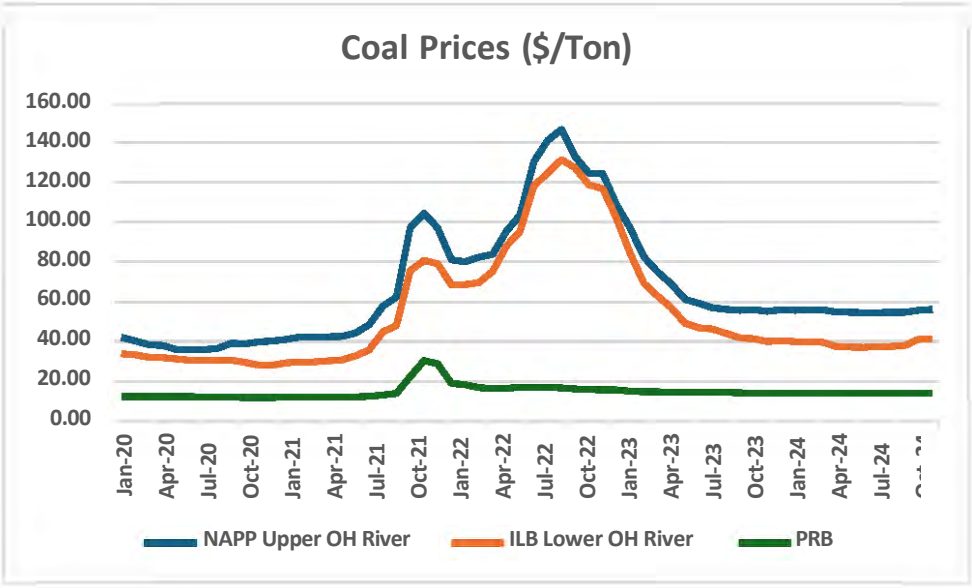
[9] The NAESB Base Contract is a widely used standardized agreement for the physical purchase and sale of natural gas in North America. It was developed by the North American Energy Standards Board (NAESB).



Source: EIA Form 923

Coal demand has declined over the last 20 years as a considerable number of domestic coal power plants were closed and very few new ones were built. That being said, coal production has not disappeared with over 200 million tons being produced east of the Mississippi and about 400 million produced in the west. Further, there are ample coal reserves should demand increase.

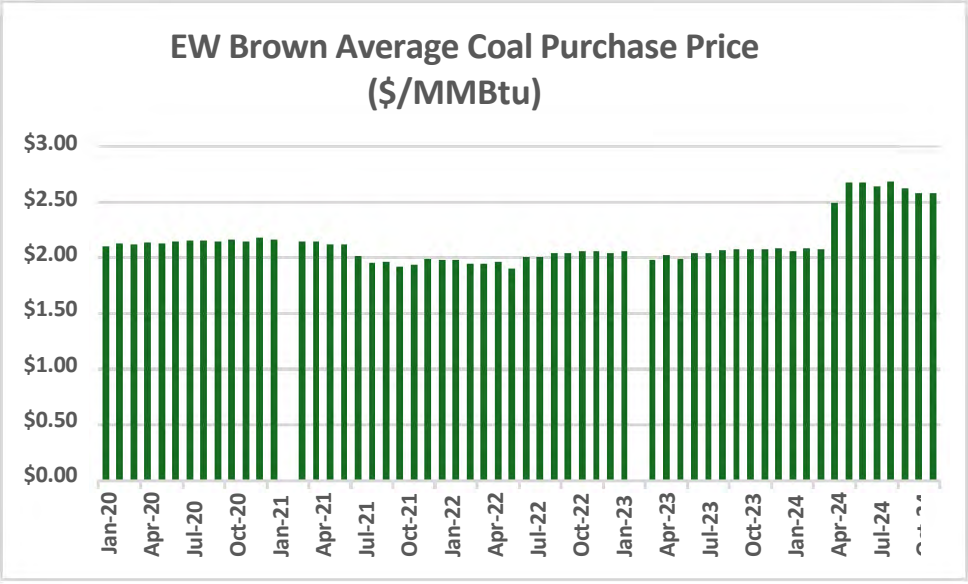
The Companies burn three types of coal: Illinois Basin High Sulfur, Northern App High Sulfur, and Powder River Basin. Market prompt year pricing for these coals over the 2020 to 2024 period are shown below.

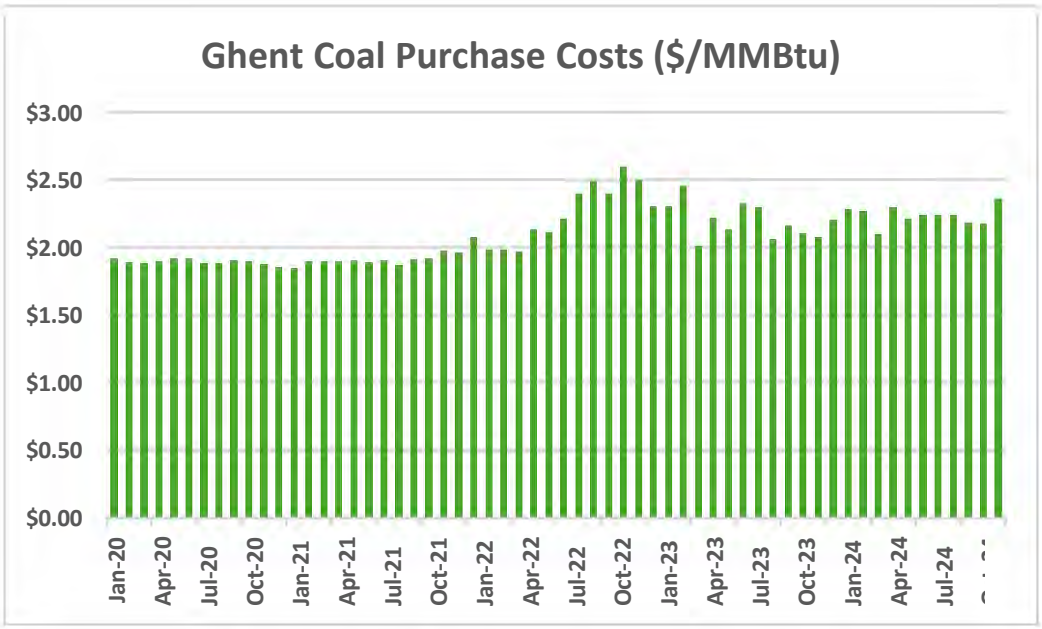


Source: Coaldesk

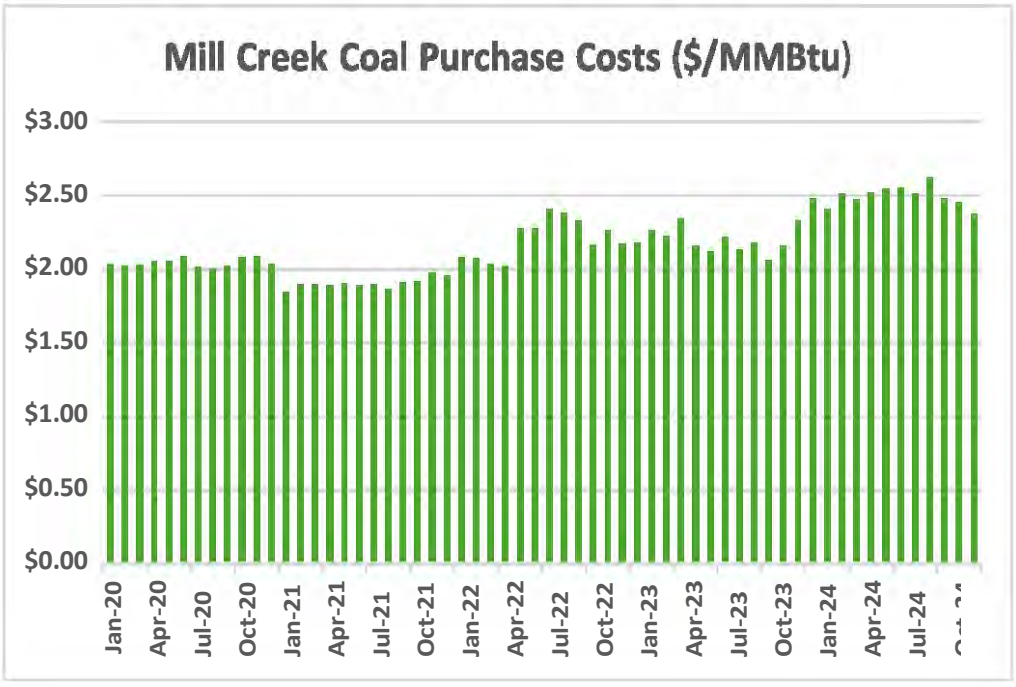
Prompt year coal prices from these regions going into COVID had been relatively flat. There was an initial bump in pricing during early COVID which was not sustained and then a significant increase in pricing from mid-2022 through the first half of 2023. The reasons for the significant bump were increased demand due to COVID recovery, a delayed response from the coal industry in restarting idled production, and higher gas prices due to strong global pricing resulting in part from the war in Ukraine. Once demand and supply were balanced in the market, coal prices fell albeit not to pre-COVID levels.

The benefits of the Companies coal procurement strategy can be seen in their reported coal purchase costs during this period from EIA Form 923 compared to the market price for each of the coal types shown above. Pricing at EW Brown was flat during the 2020 to H1 2024. Pricing at Ghent, Mill Creek, and Mill Creek was also relatively flat with a slight increase in the second half of 2022 and modest increases in price compared to 2020 and 2021 in 2023 and YTD 2024. Pricing at all four plants increased modestly during this period consistent with the post-COVID recovery prices which were slightly higher than the pre-COVID numbers.




Ghent Coal Purchase Costs ($/MMBtu)
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
Jan-22
Apr-22
Jul-22
Oct-22
Jan-23
Apr-23
Jul-23
Oct-23
Jan-24
Apr-24
Jul-24

1


Mill Creek Coal Purchase Costs ($/MMBtu)
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
Jan-22
Apr-22
Jul-22
Oct-22
Jan-23
Apr-23
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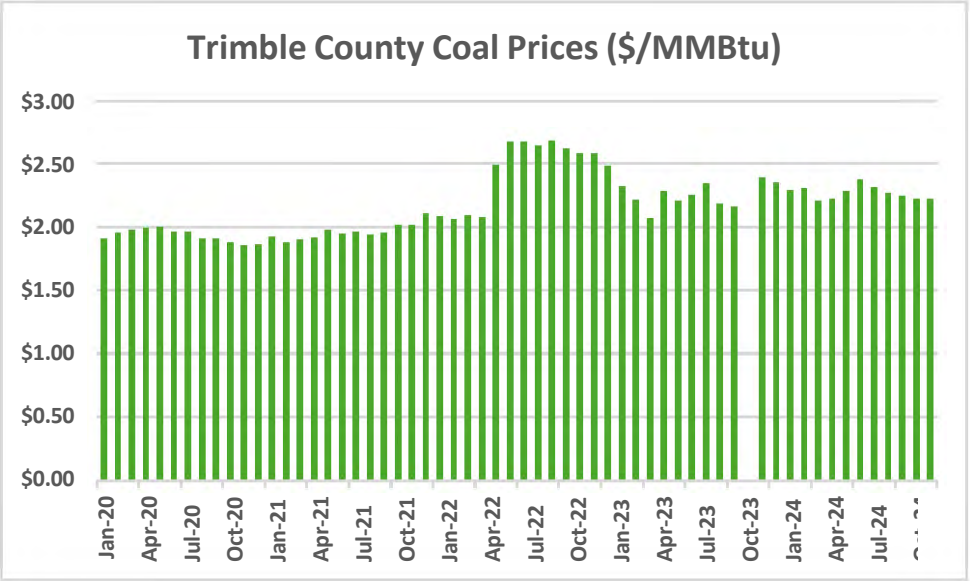
Oct-23
Jan-24
Apr-24
Jul-24

2



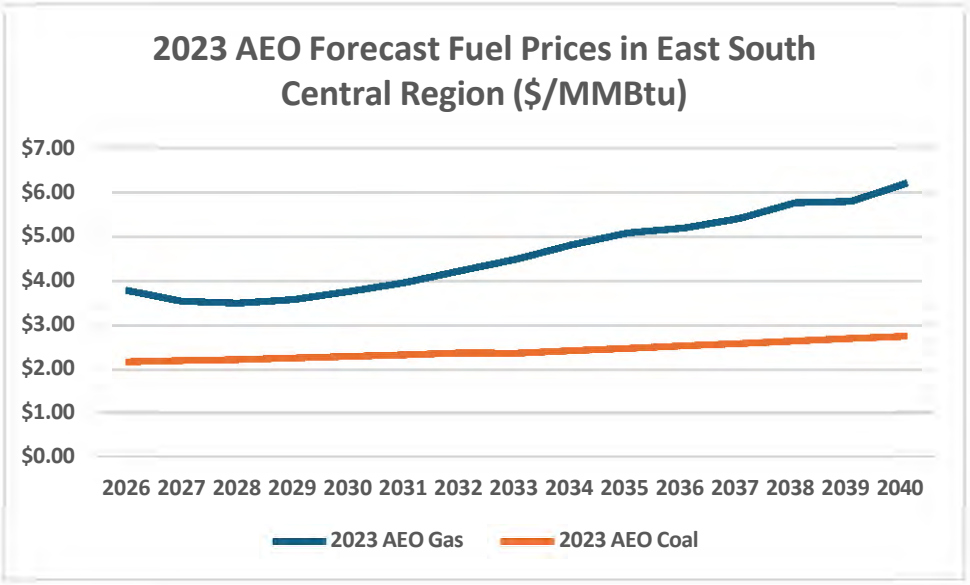
Source: EIA Form 923

Q. DO THE MONTHLY COAL PURCHASE COSTS ALIGN WITH THE GAS PURCHASE COST AT CANE RUN?

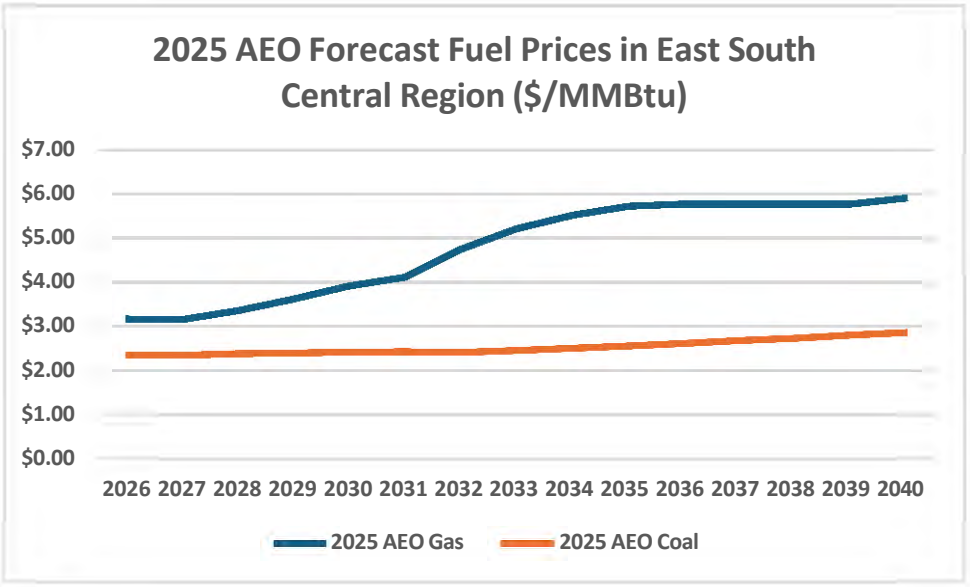
A. No. The natural gas prices at Cane Run more than doubled during the height of COVID. The coal prices experienced a slight bump, about 20 percent.

The forecasts prepared by EIA support the lack of linkage between coal and natural gas prices.

The region most relevant to the Companies is the East South Central Region. The annual forecasts in 2023 and 2025 show changes in the Reference Case outlook for natural gas prices during the period 2029 through 2037 period. Both the 2023 and 2025 AEO forecasts shown natural gas prices to be considerable higher than coal prices. That being said, the 2025 AEO has considerably higher gas prices during the 2029 to 2037 period reflecting increased natural gas demand from Data Centers and exports of both LNG overseas and pipeline gas to Mexico. The coal price outlook is effectively the same in both cases. It is obvious EIA does not correlate its coal price forecast to its natural gas price forecast.


2023 AEO Forecast Fuel Prices in East South Central Region ($/MMBtu)
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040
2023 AEO Gas
2023 AEO Coal

1


2025 AEO Forecast Fuel Prices in East South Central Region ($/MMBtu)
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040
2025 AEO Gas
2025 AEO Coal

2

SECTION IV

REVIEW OF THE CPCN ANALYSIS

Q. WHAT OTHER ISSUES DO YOU HAVE WITH THE COMPANIES' CPCN FILING?

A. As mentioned above, the forecast load growth in the CPCN is in sharp contrast to the Companies' prior CPCN. The current CPCN Filing reflects expected load growth of 2,000 MW between 2025 and 2032 of which 1,750 MW is "high load factor, energy-intensive data centers". The Filing also refers to over 8,000 MW of economic development load potential based upon their current list of potential customers. The Companies indicate it is their obligation to plan for this load growth.

Q. DO YOU DISAGREE?

A. I believe that the Companies have an obligation to serve load in their territory but not at any cost and not without adequately protecting existing rate payers. Also, as I pointed out in my explanation of the flaws in the Companies' fuel forecasting, generation from Companies' coal units is likely understated in the supporting analyses given the fuel price methodology based upon correlations, not supply.

Q. PLEASE REVIEW WHAT YOU CONSIDER TO BE THE RISKS OF THE COMPANIES' PLAN.

A. Ultimately, the Companies are required to meet the requirements of their existing customers through owned-generation or purchased power at the lowest reasonable cost. The risks of the plan put forward in the CPCN are twofold. First, there is a risk that under the proposed plan, there will be insufficient capacity as a result of supply chain delays and less renewable generation. Second, there is a risk that if the Companies move forward with their plan, the buildout for Data Centers and the like could create excess capacity that is not needed to support demand.

Q. DO YOU BELIEVE THAT THE COMPANIES HAVE ADEQUATELY ADDRESSED THESE RISKS?

A. No.

Q. WHAT ARE THE SPECIFIC RISKS OF CONCERN?

A. The risks of concern are as follows:

- Undervaluing the existing coal fleet,
- An economic recession,
- The regulatory environment,
- The cost of the new generation,
- The timing of the new generation,
- The need for the new generation, and
- The impact of the new generation on affordability.

Q. WHAT IS THE BASIS FOR YOUR CONCERN ABOUT AN ECONOMIC RECESSION?

A. The tariff proposals have sparked concerns related to the fact that the tariffs are likely to result in higher prices for many goods leading to an economic recession and lower economic growth. Several financial institutions and economists are projecting a potential economic recession in the near future, with varying probabilities and timelines.

Q. ARE THE OTHER RISKS ALSO TIED TO CONCERNS ABOUT A RECESSION?

A. Many of the other risks are tied to the recession to the extent the recession is caused by higher costs, supply chain constraints, and lower load growth.

Q. WHAT ARE YOUR CONCERNS ABOUT AFFORDABILITY?

A. The Companies use a present value of revenue requirements to determine affordability. This calculation is a metric used to compare resource plans. It is not a metric to determine affordability which is tied to customer bills. In recognition of the difference, utilities are increasingly looking at both a PV calculation and a ratepayer impact analysis. The Companies should do the same.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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

Attachment ESM-1

RESUME OF EMILY S. MEDINE

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. Her experience includes forecasting, integrated resource plans, bankruptcy support, market strategy development, fuel procurement audits, fuel procurement, acquisition and investment analyses, and strategic studies. She has also provided expert testimony on utility fuel procurement practices and coal contract disputes. The types of projects in which she is involved are described below:

Fuel and Power Purchase Procurement Audits

Ms. Medine manages and performs fuel procurement audits on behalf of regulatory commissions, utility management, and third-party interveners. She has performed over 25 audits of utilities regulated by the Public Utilities Commission of Ohio and testified in a number of proceedings. She also managed two major audits of the fuel procurement practices of PacifiCorp. Recent audits include Puerto Rico Electric Power Authority, Appalachian Power (2006, 2007, 2015, 2016, 2018, 2021, 2022, 2023, and 2024) and Monongahela Power (2007, 2015, 2016, 2018, 2021, and 2022) on behalf of the Consumer Advocate of the State of West Virginia, Tucson Electric Power in 2007/2008 and 2012 and Arizona Public Service in 2021 on behalf of the Arizona Corporation Commission.

Procurement

Ms. Medine develops and implements fuel procurement strategies for U.S. and foreign coal consumers. Fuel procurement assistance has ranged from determining an appropriate strategy to soliciting bids and negotiating purchase agreements. Ms. Medine has advised several international coal consumers of their fuel procurement activities. Ms. Medine continues to advise numerous U.S. and international coal consumers on their coal and petroleum coke procurements. In recent years, Ms. Medine has worked on natural gas and REC procurement evaluations.

Bankruptcy Support

Ms. Medine was an advisor to the Horizon Natural Resource companies which operated as a debtor-in-possession in the development of a plan to accomplish reclamation on all permits not sold and transferred as part of the plan of reorganization. For a period of 15 months, Ms. Medine served as Executive Vice President of Centennial Resources, Inc., a debtor-in-possession, as part of EVA's contract to manage this company post-petition. In this capacity, she managed the day-to-day operations of the company as well as serving as the liaison between the company, state and county regulatory agencies, the bankruptcy court, and the lenders. This assignment ended upon the filing of Centennial's plan of reorganization. Ms. Medine was engaged by the Department of Justice in the Alpha Natural Resource and Arch Coal bankruptcies.

Forecasting

Ms. Medine develops forecasts of U.S. and global solid fuel demand and prices for alternative coal types, coke and market segments. These forecasts are provided to individual clients and are documented in various FUELCAST/COALCAST reports.

Integrated Resource Planning

Ms. Medine works with utilities and/or stakeholders on the development and evaluation of Integrated Resource Plans (IRP). Ms. Medine focuses on validation of all assumptions including fuel, emission allowances, carbon, and renewable energy credits (RECs) and on methodology and modelling.

Acquisition and Investment

Ms. Medine was the agent for Lexington Coal Company in the sale of its assets in Indiana and Illinois. As part of this engagement, Ms. Medine was responsible for the sale of three mines to Peabody Energy. Ms. Medine also routinely evaluates the economics of potential projects or acquisitions for producers, developers, and industrials. For coal projects, this includes market and financial forecasts. In addition to the above, Ms. Medine has completed the sale of multiple mine assets. Ms. Medine was an advisor to and on the board of The Elk Horn Coal Company until its sale to Rhino Energy in June 2011. Ms. Medine managed the sale of a number of distress assets including JWR Resources, Piney Creek Resources, and Rhino Resources.

Market Strategy Development

Ms. Medine assists clients in the development of marketing strategies on behalf of coal suppliers and transporters. She has helped to identify the high value markets and strategies for obtaining these accounts.

Forecasting

Ms. Medine develops forecasts of U.S. and global solid fuel demand and prices for alternative coal types, coke and market segments. These forecasts are provided to individual clients and are documented in various FUELCAST/COALCAST reports.

Expert Testimony and Presentations

Ms. Medine prepares analyses and testimony in support of clients involved in regulatory and legal proceedings. She provides testimony in commission hearings on fuel procurement issues and arbitration proceedings on contract disputes and damages. Ms. Medine regularly speaks at industry meetings.

Prior Experience

Prior to joining EVA, Ms. Medine held various positions at CONSOL including Assistant District Sales Manager – Chicago Sales Office and Strategic Studies Coordinator. Prior to CONSOL, Ms. Medine was a Project Manager at Energy and Environmental Analysis, Inc. where she directed two large government studies. For the Environmental Protection Agency, Ms. Medine directed an evaluation of the energy, environmental and economic impacts of New Source Performance Standards on Industrial Boilers. For the Department of Energy, Ms. Medine directed an evaluation of the financial impacts of requiring utilities with coal capable boilers to reconvert to coal. Ms. Medine worked as a Research Assistant at Brookhaven National Laboratory while she attended graduate school.

EDUCATION

M.P.A.	Princeton School of Public and International Affairs, Princeton University, 1978
B.A.	Geography, Clark University, 1976 (magna cum laude, Phi Beta Kappa)

ATTACHMENT ESM-2.

Reported Purchases of Natural Gas by Vendor[10]

	Natural Gas Purchases 1/1/24-5/28/25	Agreements Filed with KYPSC between 1/1/17 and YTD		
Vendor	Total Volume (MMBtu)	Kentucky Utilities	Louisville Gas & Electric	
BP Energy Company	537,570	0	0	
CIMA ENERGY, LP	42,500	0	0	
Castleton Commodities Merchant Trading L.P.	137,398	0	0	
Chesapeake Energy Marketing, L.L.C.	40,462	0	0	
Colonial Energy, Inc.	306,113	0	0	
Columbia Gas of Kentucky, Inc.	2,441	0	0	
Concord Energy LLC	6,448	0	0	
ConocoPhillips Company	60,133	0	0	
Constellation Energy Generation, LLC	112,942	NAESB 5/26/13	0	
DTE Energy Trading, Inc.	4,532,898	0	0	
EDF Trading North America, LLC	37,300	0	0	
Eco-Energy Natural Gas, LLC	243,297	0	0	
Expand Energy Marketing LLC	20,000	0	0	
Hartree Partners, LP	39,600	NAESB 2/1/19	NAESB 2/1/19	
J. Aron & Company LLC	26,500	0	0	
Koch Energy Services, LLC	516,697	NAESB 3/29/21*	NAESB 3/29/21*	Amended 5/1/22
MIECO LLC	56,200	0	0	
Macquarie Energy LLC	19,931	0	0	
NJR Energy Services Company, LLC	127,100	NAESB 4/1/09	NAESB 4/1/09	
NRG Business Marketing LLC	20,600	0	0	
NextEra Energy Marketing, LLC	1,444,277	0	0	
Ovintiv Marketing Inc.	57,600	NAESB 5/15/20	NAESB 5/15/20	
Radiate Energy LLC	78,802	NAESB 2/28/22	NAESB 2/28/22	
Sequent Energy Management LLC	478,878	0	0	
Shell Energy North America (US), L.P.	554,200	0	0	
Southwest Energy, L.P.	3,775,812	NAESB 3/29/18	NAESB 3/29/18	
Spire Marketing Inc.	131,300	0	0	
Spotlight Energy, LLC	354,094	NAESB 11/4/20	NAESB 11/4/20	
Symmetry Energy Solutions, LLC	48,600	0	0	
Tenaska Marketing Ventures	28,831,400	0	0	
Tennessee Valley Authority	18,761	0	0	
TotalEnergies Gas & Power North America, Inc.	92,300	0	0	
Twin Eagle Resource Management, LLC	607,539	0	0	
Uniper Global Commodities North America LLC	196,300	0	0	
United Energy Trading, LLC	38,921	0	0	
Vitol Inc.	2,296,460	0	0	
Wells Fargo Commodities, LLC	27,000	NAESB 6/14/17	NAESB 6/14/17	
Grand Total	45,918,374			

[10] https://psc.ky.gov/WebNet/FuelContracts

VERIFICATION

STATE OF Pennsylvania)
COUNTY OF Allegheny)

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. 2025-00045 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 16th day of June 2025.

Commonwealth of Pennsylvania - Notary Seal
AARON GIBSON JR, Notary Public
Allegheny County
My Commission Expires August 12, 2028
Commission Number 1376972

Notary Public

Notary Public ID No. 1376972

My Commission Expires:

August 12, 2028