PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

In Re:	)
Monongahela Power Company and The Potomac Edison Company. Application for a certificate of public convenience and necessity to construct and operate an approximate 1200 MV combined cycle gas plant at its existing Ft. Martin Power Station in Monongalia County, West Virginia and to construct 70 MW of solar generation at three sites.	))) Docket No. 26-0108-E-CN)))

Direct Testimony of
Anthony Star

On Behalf of
the Sierra Club

Public Version

May 29, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name and occupation.

A My name is Anthony Star. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts, 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q Please describe your professional and educational experience before beginning your current position at Synapse Energy Economics.

Before joining Synapse earlier this year, I spent thirteen years at a state agency, the Illinois Power Agency ("IPA") as the Director (2013-2022), Planning and Procurement Bureau Chief/Senior Advisor (2022-2024), and Senior Advisor (2024-2026). At the IPA I oversaw the development and implementation of procurement plans for electricity supply for default service customers of the investor-owned utilities in Illinois, for the support of nuclear plants, and for incentives for the development of new wind and solar resources. I also played a key role in several policy reports requested by the Illinois General Assembly including studies on energy storage, offshore wind, high-voltage direct current transmission lines, at-risk nuclear plants, and resource adequacy.

Prior to joining the IPA, I served for three years as a Policy Advisor to two Chairs of the Illinois Commerce Commission ("ICC"), Acting Chairman Flores (2010-2011) and Chairman Scott (2011-2013). In that role I provided research and analysis on a wide range of cases and proceedings that came before the Commission.

My experience in energy policy began at the Chicago-based sustainability innovator, the Center for Neighborhood Technology (and its spin-off organizations, the Community Energy Cooperative and CNT Energy) where from 2000 through 2010, I supported community-based demand response and energy efficiency programs and played a key role in researching and then developing and evaluating residential real-time pricing programs.

I hold Bachelor of Arts in History and a Master of Arts in Social Sciences from the University of Chicago. A copy of my resume is attached as Exhibit AS-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club.

Q Have you testified previously before the Public Service Commission of West Virginia or any other Commission?

A No, I have not previously testified before this Commission.

I have provided written testimony in two cases before the ICC, Docket Nos. 13-0546 and 19-1121, and substantially participated in the drafting of twenty procurement plans submitted to the ICC for review and approval.[1]

[1] The process for the approval of Illinois Power Agency procurement plans by the ICC typically does not involve testimony. Instead, the process is conducted through the submittal of objections to the proposed plan by intervenors and utilities, and then responses, and replies by all parties. In addition to contributing to the development of procurement plans, I also participated in the drafting of responses and replies for each procurement plan.

Q What is the purpose of your testimony?

A The purpose of my testimony is to assess whether the application of Monongahela Power Company and Potomac Edison Company (collectively, the "Companies") provides a sufficient evidentiary basis to justify: (1) approval of a Certificate of Public Convenience and Necessity ("CPCN") for the construction of new generation resources; and (2) establishment of a new surcharge to recover costs from existing customers.

In making that assessment, I address: (1) the updated load forecast submitted in this proceeding, which revises the load forecast filed by the Companies in Case No. 25-0857-E-IRP (the "2025 IRP") due to the purported increase in demand from a potential new large-load customer (the "data center project"); (2) the process by which the Companies developed their proposals to construct a 1,200 MW Combined Cycle Gas Turbine ("CCGT Project")[2] and 70 MW of solar ("Solar Projects") (collectively "the Projects"); (3) resource alternatives that the Companies did not adequately evaluate; (4) the risks the application creates for ratepayers; and (5) recommendations for the Commission's consideration.

While the Sierra Club was not a party in the 2025 IRP, in recognition of the Joint Stipulation and Agreement for Settlement filed by the Companies on May 5, 2026, I also take note of certain shortcomings that I identified in the 2025 IRP, which are relevant to this proceeding.

Q How is your testimony organized?

A My testimony is organized as follows:

In Section 2, I summarize my findings and recommendations for the Commission.

[2] The 1,200 MW size of the proposed CCGT Project is the gross size in MW which reflects the size of the turbines to be installed. The net size of the proposed CCGT Project is 1,050 MW. The Companies have used the gross size as the descriptor of the project and for simplicity, I will also use that size in my testimony.

In Section 3, I describe the Companies' request related to their application for a CPCN and the related Generation Projects Surcharge, and how this case connects to the 2025 IRP.

In Section 4, I explain how:

- The load for the proposed data center is not firm enough to warrant the approval of the CPCN for the CGT Project CPCN and Generation Projects Surcharge.
- The shortcomings in the IRP cascade through to the request for the CPCN for the CCGT Project.
- The CCGT Project is too large.
- There are flaws in how the self-build approach was selected and how it is too risky.
- The CCGT Project places too much burden risk on ratepayers.
- The Companies have demonstrated the need for the Solar Projects.
- The CCGT Project is inconsistent with state and federal policies.

Q Are you sponsoring any exhibits?

A Yes, I am sponsoring the following exhibits:

Exhibit Number	Description of Exhibit	Protected Status
AS-1	Resume of Anthony Star	Non-confidential
AS-2	Selected Responses to Discovery Requests	Non-confidential

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are summarized as follows:

1. The load associated with the 1,012 MW data center project is too speculative to justify the $2.476 billion investment in the CCGT Project. The Companies' process for determining that the data center project met the scoring threshold necessary to trigger resource additions was insufficient to make that level of commitment.

2. In the 2025 IRP, the Companies failed to evaluate demand-side resources and overly constrained renewable resource build options. As a result, there is uncertainty in the true shortfall identified in the planning process and thus the resources that may need to be procured to meet that forecast.

3. The load associated with the proposed data center project is 1,012 MW, 273 MW of which was included in the 2025 IRP (which forecast a small capacity shortfall, but an energy surplus), leaving 739 MW as the incremental load added to the forecast used in this proceeding. The proposed 1,200 MW CCGT Project is thus significantly larger than necessary to serve the prospective data center load and is an enormous investment for a system that currently has about 3,000 MW of demand; the CCGT Project would increase the Companies' rate base by 67 percent.

4. The Companies failed to issue an all-source Request for Proposals ("RFP") and only seriously considered a company-owned resource. By limiting the solicitation to a Build-Own-Transfer ("BOT") approach for a CCGT, the Companies were too narrow in their search for new generation. This includes not evaluating a power purchase agreement ("PPA") bid that could have offered a more flexible approach that better matched the actual generation needs of the Companies.

5. The process by which the Companies selected a self-build option for the CCGT Project raises concerns regarding the adequacy and objectivity of the competitive solicitation process, including whether the process was structured in a manner that favored the self-build option over third-party alternatives.

6. The Companies propose to finance the construction of the Projects through a tariff that would collect over $514 million from ratepayers before the CCGT

Project even produces 1 megawatt-hour of electricity.[3] This proposal would place an immediate burden on existing ratepayers.

7. The application also places excessive risk on ratepayers due to many critical components of the proposal not being finished, including the reservation of turbines, the selection of an Engineering, Procurement, and Construction firm, or a firm gas supply. The Companies could reduce these risks by exploring options such as batteries paired with renewable energy resources.

8. The Companies are requesting abandonment authority which would saddle ratepayers—rather than the developer of the data center project, or shareholders —with the sunk costs should it be abandoned.

9. The Companies have the prior experience in building solar projects. Furthermore, due to the upcoming deadline of either being in service by December 31, 2027, or starting construction by July 4, 2026, for eligibility for the 50 percent Federal Investment Tax Credit ("ITC") (inclusive of the 10 percent adder for locations in Energy Communities and 10 percent for use of domestic content) development of the Solar Projects should start as soon as practicable.

10. The proposed CCGT Project, with costs borne by ratepayers, is inconsistent with federal and state policies that (1) recognize the need to strengthen ratepayer protections in connection with large-load development and (2) obligate data center developers to shoulder the costs and risks of the resources the projects demand.[4]

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations.

[3] Derived from "RV3 CCGT Summary" provided with the Companies' response to CAG/SUN/EEWV Discovery Request 1-02.d.

[4] See: White House. *Ratepayer Protection Pledge*. March 4, 2026. https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/, and West Virginia Code, §5B-2-21b(E)(5).

1. I recommend that the Commission deny the CPCN for the proposed CCGT Project and approve the CPCN for the proposed Solar Projects. Prior to any subsequent filing for a CCGT CPCN, I recommend the Commission direct the Companies to do the following:

    a. Engage with the developer of the Data Center Project (and any other future large-load customers) to contractually ensure that other ratepayers do not bear the costs of generation associated with new data center load. This would ensure that the development of data centers in the Companies' service territories adhere to the principle that data center developers shoulder the costs and risks of the resources their projects demand. At a minimum, the Companies should develop a large-load tariff that recognizes that data center load additions are fundamentally different from other types of commercial and industrial loads that have historically been added to the grid.

    b. Provide an anonymized list of prospective large-load customers including the location, projected demand, and status in future load forecasts and IRPs to maximize transparency and to help ensure that costs created by new large loads are not allocated to other customers.

    c. Fully evaluate third-party ownership and PPA alternatives, which would not require upfront payments by ratepayers and could offer more flexibility in terms of meeting the actual load of new data center customers.

    d. Go beyond the provisions of the Joint Stipulation in the 2025 IRP and ensure that future IRPs follow industry best practices including robust upfront and ongoing stakeholder processes, thoughtful inclusion of battery storage and demand-side resources, use of consistent modeling inputs, and refinement of scenarios to be analyzed.

2. Should the Commission approve the CCGT CPCN, I recommend the Commission include the following provisions:

    a. Deny the request for abandonment authority, as it shifts too much risk onto the Companies' customers.

    b. Establish a firm cost cap for the CCGT Project at the requested Application amount of $2.476 Billion.

    c. Require the Companies to establish adequate protections for existing customers, such as a large-load tariff, which commit large-load customers to paying their full incremental cost of service before new assets are built to serve them. A large-load tariff should include exit fees, minimum billing demand provisions, and collateral requirements to ensure that existing ratepayers are held harmless from resource investments undertaken to serve the proposed data center load.

    d. Go beyond the provisions of the Joint Stipulation in the 2025 IRP and ensure that future IRPs follow industry best practices including robust upfront and ongoing stakeholder processes, thoughtful inclusion of battery storage and demand-side resources, use of consistent modeling inputs, and refinement of scenarios to be analyzed.

    e. Condition any approval on a firm commitment to close the Fort Martin coal generating units as the proposed CCGT Project comes online, rather than having excess capacity that would be sold into the market.

III. SUMMARY OF THE COMPANIES' PROPOSAL

Q What are the Companies proposing in this Case?

The Companies are requesting a CPCN to construct new generation resources, including a 1,200 or 1,350 MW CCGT project at the Fort Martin site in Monongalia County (adjacent to the two-unit 1,098 MW coal-fired Fort Martin Power Station) with a planned operating life of 30 years (through 2061). The Companies have not chosen the exact turbine for installation, proposing either a Siemens H, 1,200 MW gross, or a Siemens HL at 1,350 MW gross (which would cost an additional $100 million). The CCGT Project is expected to operate at 85 percent capacity factor and would sell excess energy and capacity into the PJM market.[5]

The Companies also propose to construct 70 MW of solar projects, Davis (11.5 MW), located adjacent to Davis; Wylie Ridge (8.4 MW) located near Weirton, and Valley Point (50 MW) located near Albright.[6] The projects are located in Energy Communities and will use domestic content to maximize the utilization of the ITC at 50 percent. The Solar Projects will build off the experience the Companies developed through three earlier solar projects at Fort Martin, Rivesville, and Marlowe.[7]

In the Application, the Companies explained that an updated load forecast identified a capacity shortfall of around 116 MW in 2029 that rises to 1,083 MW in 2045.

[5] Application for Approval of Generation Resource Construction and Related Relief ("Application") at 8.
[6] Id. at 9-10.
[7] Direct Testimony of Doug Hartman at 7-8.

Q What are the Companies' estimate for the costs of the CCGT and Solar Projects?

A As shown in Table 1, the Companies provided an estimate of the capital spending between 2026 and 2033 of $2.476 billion for the CCGT Project and $182 million for the Solar Project. For the CCGT Project, $2.359 Billion would be spent through 2031, the year the plant is projected to come online.[8]

Table 1. Estimated Capital Spend by Year, 2026-2033 (in $ millions)

Year	2026	2027	2028	2029	2030	2031	2032	2033	Total
CCGT Project Spend	$71	$241	$521	$599	$545	$382	$116	$0.6	$2,476
Solar Project Spend	$1	$73	$50	$56	$2	$0	$0	$0	$182

Source: Application at 11.

The Companies noted that the cost estimate was a high-level engineering estimate with an accuracy range of -30% to +50%. That accuracy range was only applied to the direct construction cost of $1.72 billion,[9] and thus that estimate translates to a cost between $1.207 billion and $2.586 billion**.** The Companies did not provide an accuracy range for the remaining $756 million in non-direct construction costs for the CCGT Project.

Q How do the Companies propose to recover the cost of developing the Projects?

A The Companies proposed a Generation Projects ("GP") Surcharge as a mechanism to support an Allowance for Funds Used During Construction ("AFUDC"). The surcharge was estimated by the Companies to increase

[8] These estimates are based on the smaller of the two proposed turbine sizes. Selection of the larger size would add an additional $100 million in expenditures.

[9] The difference between the $1.72 billion and $2.476 billion amounts is made up of, "[f]inancing fees, interest during construction, land, outside-the-fence infrastructure, and taxes and other `outside-the-fence' costs [which] are considered to be `Owner Costs' and were added to the EPC cost estimates to arrive at a total installed cost." Companies Response to WVEUG Discovery Request 6-19.

residential customer bills by about 2.3 percent over the next five years while the CCGT Project was being constructed, and prior to operations commencing. In addition to the GP Surcharge covering construction costs, the Companies also requested that the GP Surcharge allow recovery of any abandonment costs deemed prudent. Abandonment costs are the costs, "associated with planning, development, permitting, engineering, procurement, and construction activities for a project that ultimately does not proceed to completion."[10] These costs occur if the termination of the project is "due to circumstances outside of the Companies' control."[11]An example of such a circumstance would be if the proposed data center is not developed and thus generation designed to serve it is not needed.

Q How will the Projects impact the rate base of the Companies?

A The estimated $2.7 billion of capital investment in the Projects would increase the current rate base by 67.5 percent.[12]

Q How does this case intersect with the 2025 IRP?

A This case is separate but related to the 2025 IRP.[13] In the 2025 IRP, filed on October 1, 2025, the Companies considered several potential resource portfolios and recommended one that included continuing operation of the Fort Martin and Harrison coal plants through 2035, exploring the addition of a 1,200 MW CCGT in 2031, adding 70 MW of solar in 2028, and using short-term purchases from the wholesale market until new resources were available.[14] While the 2025 IRP

[10] Direct Testimony of Raymond Valdes at 25.
[11] Id. at 25-26.
[12] Id. at 7.
[13] Monongahela Power Company and The Potomac Edison Company, *Integrated Resource Plan* filed pursuant to the May 23, 2025 Commission Order in GO 183.15, Case No. 25-0857-E-IRP ("2025 IRP"), October 1, 2025.
[14] 2025 IRP, ES-1 to 2.

identified some capacity shortfalls during the period studied (through 2035), the Companies expected to have a positive energy position each year.

On May 5, 2026, a "Joint Stipulation and Agreement for Settlement" was filed in the 2025 IRP,[15] which seeks to resolve most of the open issues. Notably, issues addressing the CCGT Project and the 70 MW Solar Project should be considered in this proceeding rather than in the 2025 IRP, including issues related to modeling and assumptions. In their next IRP (scheduled for 2030), the Companies agreed to:

1) model a low large-load sensitivity if their base forecast includes large-load customers that have not yet committed to locate in the utility's service territory;
2) if the Companies use a capacity contingency, present a sensitivity without a capacity contingency;
3) evaluate demand-side resources and estimate the energy savings, peak load reduction, and the costs and benefits of potential utility investments in demand-side resources;
4) if the Companies impose build limits on certain resources, include a sensitivity analysis omitting those build limits; and
5) file updated yearly load forecasts, until the submission of the next IRP in 2030. The filing shall include a description of the significant changes in the forecast since the prior year (with additional interim updates if new loads over 250 MW are identified).[16]

The Sierra Club did not participate in the 2025 IRP and thus is not a signatory to the Joint Stipulation. However, in reviewing the record and discovery in the instant proceeding (and to a limited extent, the discovery in the 2025 IRP), I did

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[15] 2025 IRP, Joint Stipulation and Agreement for Settlement (May 5, 2026).
[16] *See* 2025 IRP, Joint Stipulation and Agreement for Settlement at 4-6.

identify several underlying concerns with the 2025 IRP that are germane to this proceeding.

IV. FINDINGS

A. THE PROPOSED DATA CENTER LOAD IS TOO SPECULATIVE TO JUSTIFY A $2.476 BILLION CCGT

Q How did the Companies' load forecast change between the October 2025 IRP and the February 2026 CPCN Application?

A In the 2025 IRP, the Companies projected there would be a resource shortfall of 31 MW starting in 2029, increasing to 260 MW in 2035. However, the Companies would not have an energy shortfall, with a surplus hitting 2,346 GWh in 2027 and declining to 523 GWh in 2035.[17] Just four months later, when the Companies filed the pending CPCN application for the CCGT Project and Solar Projects, the Companies projected there would be a resource shortfall of 116 MW starting in 2029, increasing to 1,083 MW in 2035, primarily due to data center growth. Rather than a surplus energy position, the Companies now state there would be a shortfall of 1,183 GWh in 2028, which would increase to 9,527 by 2035.[18] Table 2 shows how the capacity, energy, and load forecasts of the Companies have changed between the two filings.

[17] 2025 IRP, Figure ES-3 at ES-4.
[18] Direct Testimony of Chris Beam at 12.

Table 2. Changes in Load Forecast

Year	Capacity Position (MW)			Energy Position (GWH)			Load (GWH)		
	IRP	CPCN	Change	IRP	CPCN	Change	IRP	CPCN	Change
2026	210	211	1	2,039	728	(1,311)	17,726	17,520	(206)
2027	(31)	150	181	2,346	1,458	(888)	17,840	17,531	(309)
2028	(105)	28	133	1,984	(1,183)	(3,167)	17,980	19,353	1,373
2029	(112)	(116)	(4)	1,180	(1,327)	(2,507)	18,049	21,629	3,580
2030	(125)	(132)	(7)	599	(2,829)	(3,428)	18,135	22,290	4,155
2031	(156)	(348)	(192)	1,172	(3,870)	(5,042)	18,196	24,173	5,977
2032	(203)	(742)	(539)	580	(7,311)	(7,891)	18,280	27,472	9,192
2033	(188)	(824)	(636)	1,243	(7,996)	(9,239)	18,311	28,752	10,441
2034	(235)	(850)	(615)	266	(9,383)	(9,649)	18,371	28,939	10,568
2035	(260)	(867)	(607)	523	(9,527)	(10,050)	18,445	29,001	10,556

Source: Derived from 2025 IRP Figure ES-3 and the Direct Testimony of Chris Beam, Figure 1.

Q Why has the load forecast of the Companies increased?

A While the Companies broadly discuss that the updated load forecast produced in the fall of 2025 was driven by data center growth,[19] through discovery it has emerged that the triggering event was one specific data center with a projected load of 1,012 MW when fully constructed.[20] The Companies assert that the project readiness of this one data center changed between the time they filed the 2025 IRP and the filing of this proceeding.

Q How did the Companies determine that this data center should be included in the load forecast?

A The Companies used a scorecard approach with twelve criteria, as shown in Figure 1. The scores listed are the maximum points available in each category, rather than the specific scores for the proposed data center.

[19] Direct Testimony of Trenton Feasel at 6-7.
[20] Companies Response to CAG/SUN/EEWV Discovery Request 02-21. Attached in Exhibit AS-2.

Figure 1. Large Load Scoring Matrix

Question	Score
Is Customer still considering non-FE locations for this project? Are we in competition with other utilities?	-1
Does Customer own or control the land?	1
Does Customer have ALL necessary building permits? This includes environmental permits.	2
Does Customer have a development plan? This is a detailed, professional, realistic site plan.	2
Does Customer have tenants or raw materials secured?	5
Has the Customer publicly announced their project?	1
Has the Customer begun construction? Includes site clearing and grading.	3
Does the Customer have headwinds that would stop construction? For example, a lawsuit or community opposition.	-1
Has the Customer signed an interconnection, construction, or line extension agreement with FE?	5
Has the customer signed an Electric Service Agreement (ESA)?	5
Is the DLS finished?	2
Is the CLS finished?	1

Source: Companies Response to CAG/SUN/EEWV Discovery Request 2-33.b.i.

While the highest score obtainable is 27, the threshold the Companies used to include a project in its load forecast is just five points.[21] The Companies stated that the data center did not meet this five point threshold during the development of the 2025 IRP, but a refreshed scorecard, in the intervening four months, met the threshold and prompted the revised load forecast included in this filing. The updated scoring was based on adding points for “Has the Customer begun construction? Includes site clearing and grading.” [redacted][22] It appears that the Companies updated the scoring for the proposed data center based on some [redacted] at the site, not significant indicators of project maturity that would have scored points such as a [redacted] would provide sufficient points to warrant including

[21] Direct Testimony of Trenton Feasel at 6.
[22] CONFIDENTIAL Response to CAG/SUN/EEWV Discovery Request 2-19.b.

in the load forecast, which is a telling indicator of the value of [redacted]

Q What is the risk of procuring resources to serve speculative load?

A We are living through extraordinary times where the demand from data centers is transforming the electric industry. Energy use in PJM is expected to increase from 5.3 percent per year over the next ten years.[23] However, the existence of numerous proposed projects does not mean that all projected load growth will ultimately materialize. Data center developers are frequently evaluating multiple locations simultaneously (forum shopping), and many announced projects will never be constructed or will proceed at a smaller scale or on a delayed timeline. Beyond securing electric supply, data centers also need to navigate local siting and permitting requirements, financing, and transmission interconnection constraints. In addition, data center developers have no incentive to ensure that their estimated loads are accurate.[24] As a result, there is substantial uncertainty regarding which projects will ultimately proceed and at what scale.

One example of a dramatic shift in load expectations comes from Ohio where the load forecast associated with data centers in the AEP service territory fell from 30 GW to 13 GW[25] once the Public Utilities Commission approved a large-load tariff imposing certain requirements on prospective new load, such as minimum bills, contract terms, collateral, and exit fees.[26]

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[23] PJM, *2026 PJM Load Forecast Report*. January 14, 2026, available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

[24] *See* Energy and Environmental Economics, *Forecasting Large Loads in the Age of AI and Data Center,* 2025 at 3. Available at: https://www.ethree.com/wp-content/uploads/2025/12/E3Whitepaper_DataCenterForecasting.pdf.

[25] *See Manufacturers say AEP Ohio still inflating data center demand after halving forecast.* Utility Dive. February 6, 2026, available at https://www.utilitydive.com/news/aep-ohio-data-center-load-tariff-oma-manufacturers/811583/.

[26] Public Utilities Commission of Ohio, Opinion and Order, Case No. 24-508-EL-ATA, July 9, 2025, available at: https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G09B43531I00509.

Without firm commitments from potential large-load customers, the Companies are asking ratepayers to assume substantial risk that the projected load may not materialize and thus ratepayers are forced to pay for an unnecessary gas plant. As seen in Table 2, the 2025 IRP (reflective of the load forecast without the proposed data center) showed that the Companies had sufficient energy position and only needed to fill minor capacity shortfalls. The proposed 1,200 MW CCGT is far larger than the 31 MW to 260 MW capacity gap that would exist if the data center were not developed.

Q What is the risk allocation of building speculative generation between the Companies and their ratepayers?

A The risk allocation is asymmetric. The Companies stand to earn a return on their capital investments (with a rate base that increases 67.75 percent), incentivizing them to take such risks, while ratepayers stand to be saddled with the costs of any stranded assets should the load not materialize. In my view, that risk should not be placed on existing customers and strong protections are needed to ensure the costs associated with serving speculative large-load growth are borne by the customers causing those costs.

Even though the Companies could sell excess energy and capacity into wholesale markets, should the proposed data center load not materialize, using ratepayer funds to finance the construction of the CCGT Project for that purpose would involve locking in a massive increase in rate base, annual operating expenses, and relying on speculative market revenues to counteract those costs.

Q What unknowns do you see in the firmness of the proposed data center load?

A For confidentiality reasons, the Company has not disclosed the name or location of the proposed data center, which limits our understanding of who this prospective new large-load customer is. [redacted]

[redacted][27] This is troubling since the Companies' ratepayers are being asked to foot the bill for the next forty years for the development of a 1,200 MW CCGT to serve the load of an unknown company for unknown purposes.

Q Is the load profile of the proposed data center flexible, and how does flexibility have the potential to lower costs?

A No. The Companies indicated they expect the proposed data center will run at a 100 percent load factor and the data center does not plan to interrupt its use of electricity during peak demand times.[28] Several recent studies suggest that adding load flexibility to data centers is key for managing the skyrocketing cost of electricity.[29] Different types of data centers will serve different business use cases, including many that do not require inflexible load requirements. As the exact use of this proposed data center is as yet unknown, committing to develop resources to serve it, without fully exploring what options for load management might be available, is potentially creating unnecessary commitments and costs on all other customers.

Q Should the Companies procure resources to meet the full amount of load identified through the updated load forecast?

A No. The certainty of the load added to the updated load forecast is too speculative.

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[27] CONFIDENTIAL Companies Response to CAG/SUN/EEWV Discovery Request 5-28.

[28] Companies Response to CAG/SUN/EEWV Discovery Request 5-08. Attached in Exhibit AS-2.

[29] For example, a recent study of load flexibility in Nevada found that, "1 GW of data center flexibility was able to defer 600–850 MW of new firm capacity needs." See GridlaLab. *Bringing Data Center Flexibility into Resource Adequacy Planning A Case Study of NV Energy*. September 2025, available at: https://gridlab.org/datacenter_flex/. A wider overview of the literature on load center flexibility can be found at https://knowledgeproblem.substack.com/p/data-centers-flexibility-and-the

Q Is the Companies' scorecard approach sufficient for determining when to include a proposed large load in its resource procurement?

A No. The scorecard approach is useful for high-level resource planning and other preliminary resource procurement activities. But moving on to resource procurement involves creation of financial obligation to the ratepayers of a utility; therefore, a firm commitment from new load should be required. In other words, the new large load should be fully committed to coming online. A typical firm commitment is the signing of an ESA.

An ESA, or other financial commitment, will ensure that new load requests are real. Here, where the Companies would be acquiring capacity additions to serve that new load, the acquisitions made by the Companies, based on signed ESAs, would be right sized to meet that new load.

In addition, the National Association of Regulatory Utility Commissioners, in a recent report on large load tariffs, proposed a framework to set a standard for planning assumptions under which,

> "PUCs should consider explicit thresholds for inclusion of large loads, or a portion thereof, in baseline forecasts such as evidence of site control, a letter of authorization along with a financial deposit, or execution of the final ESA. Loads meeting defined commercial and financial readiness criteria may be included, while loads that fall short should be excluded or discounted from baseline forecasts and addressed through sensitivity analyses."[30]

The purpose of an ESA or other financial commitment is not to push away potential new economic development opportunities in West Virginia or to create

[30] National Association of Regulatory Utility Commissioners. *Large Load Tariffs and Load Forecasting: Reducing Uncertainty in an Era of Load Growth* at 10. April, 2026. https://pubs.naruc.org/pub/85205501-DD6C-ABD4-D8EB-B2AC6C7BD0BC?.

reliability risks. Rather it will minimize overall costs, increase transparency, and ensure that resources meet the needs of new customers**.**

B. SHORTCOMINGS IN THE 2025 IRP CASCADE THROUGH TO THE NEED FOR THE CCGT PROJECT

Q Why are you concerned about the 2025 IRP and how does it impact this case?

A The purpose of this case is to consider the public convenience and necessity of the Projects and the associated costs. Are the projects "needed?" That is the threshold question. The Companies premise the need to pursue the CCGT Project on an updated load forecast that includes additional data center load not contained in the 2025 IRP load forecast. The updated load forecast builds off the 2025 IRP load forecast and thus any shortcomings cascade through to the assumptions used in this case to justify the need for the CCGT Project.

Q Why do utilities develop Integrated Resource Plans?

A The purpose of an IRP is to provide a planning framework for a utility to determine investment decisions over a future period of time. These decisions can span a wide range of options from the retrofits of existing resources, the retirement of existing resources, the development of new resources, plans for market-based purchases, transmission investments, and demand-side management programs. An IRP involves a detailed modeling exercise of the utility's load expectations, existing resources, new demand- and supply-side options and the development and consideration of several potential portfolios. Typically, there is one "preferred plan" being submitted to the applicable regulatory agency for review and approval. Once approved, the preferred plan is in essence a roadmap for the utility to follow over the subsequent planning period.

Q Why have Integrated Resource Plans taken on increased importance in recent years?

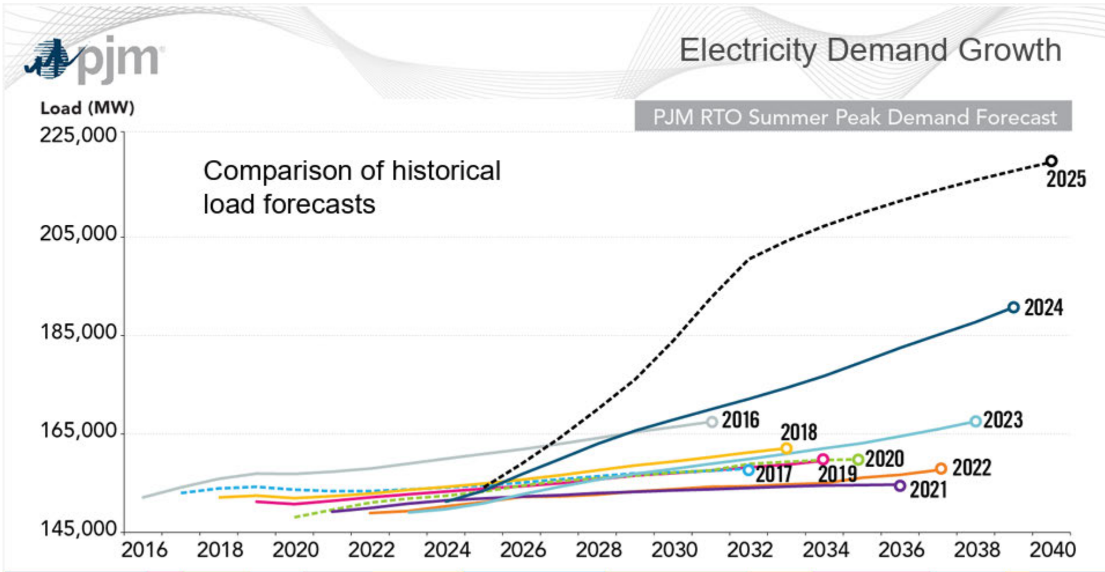
A For most of the 21st century, electricity usage in the United States was fairly stable. While there were regional differences, as some portions of the country saw decreasing usage due to deindustrialization and populations losses, other parts of the country saw increase. Meanwhile, customers became more efficient in their electricity use as older appliances were replaced and the advent of the first compact fluorescent lights, and more recently, LEDs. Since the ultimate purpose of a utility is to reliably serve the needs of its customers at reasonable rates, the overall trend was to focus utility planning on managing stable or declining electricity use against the backdrop of replacing aging and inefficient power plants with new technologies such as wind and solar.

For the Companies, this trend is manifested in the fact that they have not built any new fossil generation since the late 1970s,[31] and neither the 2015 nor 2020 IRPs included proposals to build new generation. Since 2020, a shift has occurred in electricity use in the United States, and demand has been growing. While the growth in electric vehicles and electric heat pumps has contributed to this increase, the transcendent driver has been data centers.

In the past few years, the growth in data centers has exploded into the national conversation about energy affordability. As Figure 2 illustrates, while there were early signs of a change in the electricity landscape in 2022-2023, it was really in 2024 that something radical was occurring.

[31] The Pleasants Power Station, now owned by Omnis Energy, came online in 1979/80. *See* Company's Response to WVEUG Discovery Request 1-05.

Figure 2. PJM Summer Load Forecasts 2016-2025



Source: PJM Large Load Additions Workshop Presentation, May 9, 2025 at Slide 8, available at: *https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.*

As a result, utilities, state and federal regulators, and regional transmission organizations are all grappling with what are the right planning tools, cost allocation methodologies, and environmental considerations needed to help manage this transition of the energy landscape. In this context, the IRP has new-found importance because the process is a key tool for utilities to consider how to comprehensively plan for load growth.

While the Companies' two previous IRPs did not result in any significant resource mix changes, that is likely no longer the case. The IRP process needs to be the starting point for good resource planning, which means it must be comprehensive, inclusive, flexible, and creative. As Northwestern University economist Lynne Kiesling recently wrote about the need for proper load forecasting:

> "Load forecasts are no longer technical appendices to utility plans; they are central to economic development, reliability, affordability, and decarbonization. When a forecast becomes the basis for billions of dollars of infrastructure on both sides of a transaction, the assumptions behind it

deserve scrutiny: which projects are included; how credible they are; what commitments customers have actually made; and how much projected demand is firm, flexible, speculative, or duplicative."[32]

Additionally, improving the precision needed for planning in an IRP process has increased in importance in this high load-growth era, when the next step is moving from planning to actual resource procurement, where actual ratepayer funds are committed to projects.

Q Are there best practices for IRPs?

A Different states will have different statutory and regulatory frameworks for the IRP processes conducted by the utilities. However, in 2013, Synapse developed a report on best practices for IRPs for the Regulatory Assistance Project,[33] and that report was updated in 2024 with support from the Lawrence Berkeley National Laboratory.[34]

The Report discusses fifty best practices in Integrated Resource Planning. I will not detail all of those practices, but I do want to highlight a few areas of best practices that I believe were lacking in the Companies' 2025 IRP and as a result introduced uncertainty into the load forecasting and thus the need for considering the need for the CCGT Project.

The first area is a set of best practices around modeling, in particular, demand-side resource modeling, which the Companies did not do in the 2025 IRP. The second area is how to iterate the model. The Companies appear to have only conducted limited modeling and did not adjust and update the modeling based on

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[32] Kiesling, Lynne, *You Can't Just Plug in a Data Center*. The Dispatch. May 12, 2026. https://thedispatch.com/newsletter/dispatch-energy/data-center-electricity-use-regulators-utilities/.

[33] Synapse Energy Economics. 2013. *Best Practices in Electric Utility Integrated Resource Planning*. Regulatory Assistance Project. https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf.

[34] Synapse Energy Economics, *Best Practices in Integrated Resource Planning: A Guide for Planners Developing the Electricity Resource Mix of the Future.* www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf.

initial runs. Both of these limitations in the 2025 IRP process cast uncertainty on the results and the need for the CCGT Project.

I appreciate that conducting an IRP process is a complex and expensive undertaking. The need for a better IRP process is illustrated by several provisions of the Joint Stipulation related to the next IRP cycle, notably the commitment to a wider consideration of resources, more sensitivity analysis, and increased communication on updated load forecasts. While those are a good start, to better inform resource procurement practices, such as that used for the pending CCGT Project, I recommend that the Commission instruct the Companies to utilize the Best Practices in Integrated Resource Planning report well in advance of developing the next IRP. In addition, the IRP itself should explicitly address how the Companies adhered to best practices throughout the IRP development process.

Q In addition to generally not following best practices, please describe the deficiencies you found in the 2025 IRP and how those deficiencies affect the CPCN application.

A First, the Companies only modeled the addition of supply-side resources and did not consider how they could expand demand-side resources such as energy efficiency programs. In the 2025 IRP, the Companies merely stated that, they "do not have an explicit Energy Efficiency and Conservation Plan or surcharge in effect in West Virginia."[35] In response to a discovery request, the Companies confirmed that existing demand-side resources were included in the load forecast, but "no additional selectable resources were available during the portfolio optimization phase of the analysis."[36]

The failure to consider additional demand-side resources is disappointing and a disservice to its customers. A cursory review of First Energy affiliates in other

[35] Direct Testimony of Chris Beam, Attachment CB-1 at 31.
[36] Companies' response to CAG/SUN/EEWV Discovery Request No. 1-03.h. Attached in Exhibit AS-2.

states shows that those affiliates offer a wide range of energy efficiency and demand response programs to help their customers reduce energy use and save money.[37] However, in West Virginia, the Companies only offer an online energy analyzer for homes and businesses, and some "Energy-Saving Tips."[38] By contrast, Appalachian Power offers home energy assessments and rebates, and a bring-your-own-thermostat program in West Virginia.[39]

The Companies should have considered how other utilities have offered demand-side programs to their customers and used that consideration to include demand-side programs in the development of potential portfolios for the IRP. Instead of actually considering if they could create opportunities to support the reduction of energy consumption by their customers, the Companies merely passively pointed to existing market trends on how energy use is changing. Empowering customers to better manage their energy use is low-hanging fruit and common practice around the country. The failure to include increased use of demand-side resources in portfolios modeled in the 2025 IRP is a lost opportunity. Proposing the increased use of demand-side resources could have meant that the Companies could have a smaller shortfall, potentially reducing or eliminating the speculative need driving the proposed CCGT Project.

Second, in their modeling, the Companies included annual and total build limits for wind (200 MW), solar (200 MW), and solar plus storage (150 MW).[40] The Companies claimed they had to set a build limit of 200 MW due to West Virginia

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[37] Examples include smart thermostats, in Ohio: https://www.firstenergycorp.com/save_energy/save_energy_ohio/for_your_home.html, a wide range of rebates in Pennsylvania: https://www.firstenergycorp.com/save_energy/save_energy_pennsylvania.html, rebates and thermostat programs in New Jersey: https://www.firstenergycorp.com/save_energy/save_energy_new_jersey/for_your_home_nj.html, and range of programs and demand response in Maryland: https://www.firstenergycorp.com/save_energy/save_energy_maryland.html

[38] *See*: https://www.firstenergycorp.com/save_energy/save_energy_west_virginia.html.

[39] *See*: https://takechargewv.com/programs/for-your-home. Appalachian Power also offers links to the state weatherization program that helps low-income customers reduce their energy usage; I did not find similar links on the Companies' website.

[40] Direct Testimony of Chris Beam, Attachment CB-1 at 59 and Companies response to CAG/SUN/EEWV Discovery Request 01-03.f Attachment A.

Code §24-2-1o. However, subsection (l) contains a sunset date of December 31, 2025; therefore, the limitation is inapplicable to resource planning beyond 2025.[41] The Companies also raised concerns with the ability to develop wind in West Virginia due to siting and permitting challenges which led to applying a build limit to wind.[42] Without these assumed restrictions, the modeling for the 2025 IRP may have selected different resources and/or reduced the size of any proposed CCGT.

Third, the Companies failed to consider closure of one or more of the coal plants (Fort Martin and Harrison). Instead, they modeled the coal resources as continuing to operate through the end of the 2025 IRP planning horizon, 2035. By not considering the retirement of some, or all, of its coal plants, the 2025 IRP modeling likely excluded the addition of more cost-effective resources.

As the Sierra Club has not participated in the 2025 IRP Case, these observations are not a comprehensive list of concerns with the 2025 IRP raised by other parties,[43] but they are sufficient to raise questions about whether the IRP and subsequent load forecast update demonstrate the need for the 1,200 MW CCGT. Additionally, these observations support the need for improvements in future IRP processes beyond those in the pending Joint Stipulation.

C. THE PROPOSED 1,200 MW CCGT PROJECT IS LARGER THAN NEEDED

Q Assuming the load forecasts of the Companies are correct, is the proposed 1,200 MW CCGT Project the appropriate size plant to build?

A No. The proposed CCGT Project is larger than the capacity deficit the Companies seek to fill. As shown above in Table 2, the Companies are forecasting a capacity

[41] West Virginia Code § 24-2-1o.
[42] Direct Testimony of Chris Beam, Attachment CB-1 at 58.
[43] *See generally* 2025 IRP, Direct Testimony of Chelsea Hotaling, Direct Testimony of Catherine M. Kunkel, and Direct Testimony of Jim Grevatt.

shortfall of 742 MW in 2032, growing to 867 MW in 2035. The 1,200 MW CCGT has an Unforced Capacity ("UCAP") of 936 MW.[44] Assuming the updated load forecast is correct, and the proposed data center's load fully materializes, the Companies will have excess energy and capacity of 194 MW when the CCGT Project comes online in 2031, which could increase to 311 MW if they use the larger, 1,350 MW Siemens HL turbine. While the Companies can sell the excess capacity and energy into the PJM market, ratepayers are covering the construction costs before the data center operator comes online. Any benefits from the sales of excess energy and capacity will be spread across all of the kilowatt-hours of Companies' sales to customers. Thus, the data center (which would be approximately a quarter of the Companies' sales) will be a beneficiary of the sales, after not having had to pay for the construction of the CCGT Project.

Q Should the Companies study alternatives to the 1,200 MW CCGT Proposal?

A Yes. Section B, above, describes how there were shortcomings in the 2025 IRP modeling process, which did not employ best practices in IRP development, such as consideration of demand-side resources and of alternative generation portfolios. As a result, the resulting capacity and energy positions contained in both the 2025 IRP, and in this proceeding, may not be accurate. This means that the remaining positions that would need to be filled may in fact not match the energy and capacity from the addition of the proposed CCGT Project. In other words, because of the uncertainty of the actual energy and capacity shortfalls, the solution sought by adding a 1,200 MW CCGT may be a proposed solution to the wrong problem.

As discussed in Section D, there were also deficiencies in the RFP process, which resulted in the selection of the self-build option for the 1,200 MW CCGT Project. A different resource selection process could have had more flexibility to choose

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[44] *See* Companies Response to CAG/SUN/EEWV Discovery Request 1-02(d), Attachment D. "Input_CCGT_SUN." The UCAP is derived from the gross capacity of the CCGT Project multiplied by the PJM Effective Load Carrying Capability of 78% for CCGTs.

more appropriate resources. Additionally, as discussed in Section E, battery storage paired with renewables could have been an opportunity to more closely align resource additions with supply needs.

Taken together, these issues confirm that the Companies' application does not support the conclusion that the CCGT Proposal is needed, reasonable, or in the best interests of customers.

D. THE PROCESS OF SELECTING THE SELF-BUILD 1,200 MW CCGT OPTION WAS FLAWED

Q What concerns do you have about the process leading to the decision to pursue the self-build option for the 1,200 MW CCGT Project?

A The process that led the Companies to select the self-build option was not conducted properly and included structural deficiencies that unfairly tilted the playing field towards the self-build option. The Companies did not give other options real consideration.

The 2025 IRP identified a preferred portfolio that included 70 MW of solar and a plan to "evaluate opportunities to develop a 1,200 MW natural gas CC unit with a 2031 in-service date."[45] In rebuttal testimony in the 2025 IRP, Company witness DiNicola stated that the "IRP is a strategic planning document rather than a commitment to specific resource additions or other courses of action."[46] Yet despite that statement, as shown below in Figure 3, the Companies were already actively developing a self-build CCGT option concurrent with the development of the 2025 IRP and thus appear to have had a predetermined result.

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[45] 2025 IRP, Attachment CB-1 at 16.

[46] 2025 IRP, Rebuttal Testimony of Laura DiNicola at 8. *See also* 2025 IRP, Direct Testimony of Trenton Feasel at 9-10 stating the IRP is only a planning document, "rather than serve as a commitment to implementation."

Q Were the Companies focused on pursuing a specific resource addition approach?

A It appears so. The 2025 IRP had posited that a wider net would be cast to procure resources to fill their energy/capacity shortfall:

> "this path balances affordability, reliability, and local impacts to maximize the value of the existing fleet, and keeps flexibility to adjust timing, technology, and contracting based on future market conditions and **competitive all-source Request for Proposal ("RFP") results**." [47] (emphasis added)

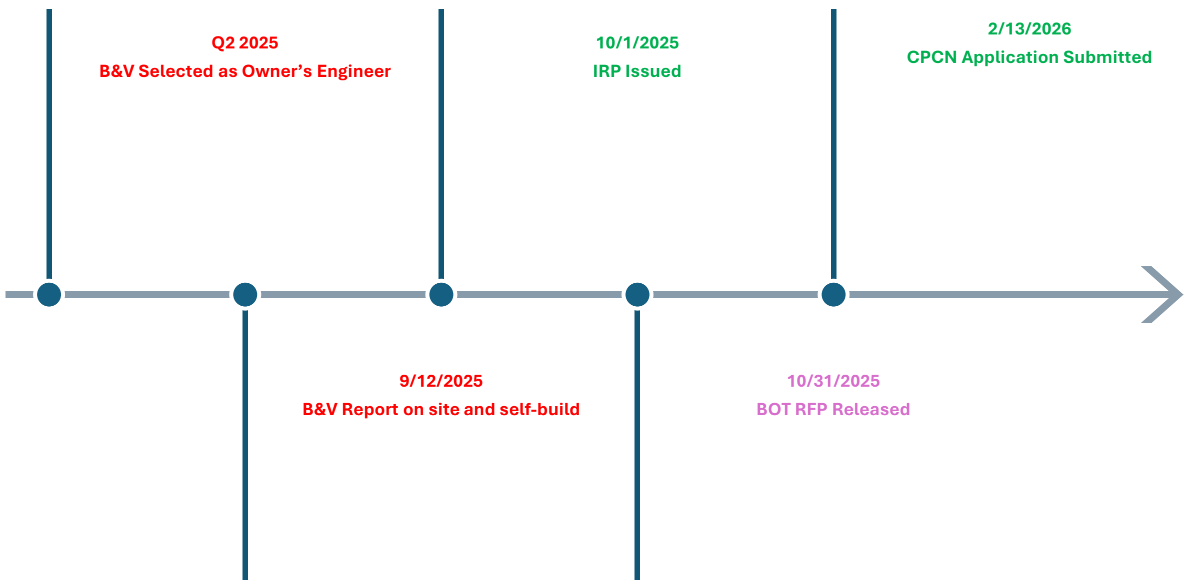
But the Companies did not pursue the all-source approach they indicated in the 2025 IRP. Instead, roughly four months earlier and before the 2025 IRP was filed, the Companies began working with the "Owners Engineer" Black and Veatch ("B&V") on the site selection and design for a self-built CCGT Plant. B&V provided a report to the Companies on September 12, 2025, a month before the 2025 IRP was filed.[48]

Rather than issue an all-source RFP to see what resources private developers would propose to meet the Companies' energy and capacity shortfalls, the Companies issued an RFP for a Build-Own-Transfer ("BOT") of a 600-1,200 MW CCGT on October, 31, 2025 (six weeks after the submittal of the preliminary report for the self-build option had been received by the Companies from B&V). The Companies received five bids in late November 2025, and rejected two as non-conforming.[49] The Companies then determined that the three remaining bids were not preferable to the self-build options developed by B&V because they were not "economically or technically preferrable" to the self-build option and

[47] 2025 IRP at 14.
[48] Direct Testimony of Phillip Carrol, Attachment PC-1 "Siting Study for Natural Gas Combined Cycle Generation Facility."
[49] Companies Response to CAD Discovery Request 1-04a.

B&V's analysis of the Levelized Cost of Energy ("LCOE") of the BOT bids were on average higher (8.27¢/kWh) than the self-build option (6.55¢/kW).[50]

Figure 3. Timeline of the development of CCGT Proposal



Q **Was this process adequate and fair for determining that the Companies' self-build option was the best solution?**

A No. The purpose of the RFP process was to determine whether there was a better option than the Companies' proposed self-build option. The entire process should have been structured differently in terms of the scope of what the RFP sought, and in how the RFP was evaluated in order to allow all options to have a fair and equal chance for consideration.

[50] Direct Testimony of Chirs Beam at 24-25.

Q How should the RFP been structured differently?

First, the Companies should have conducted an all-source RFP to allow for a broader range of resources to compete, rather than presupposing the preferred resource of a CCGT. If a third party could have proposed another resource (perhaps a peaker plant paired with energy storage) to cost-effectively meet the Companies' supply needs, then it should have been considered. The wisdom of the marketplace reflected through competitive bidding is ultimately a more powerful discovery tool than modeling. Just because the preferred portfolio contained in the 2025 IRP included *consideration* of a 1,200 MW CCGT does not mean that the 1,200 MW CCGT was a foregone conclusion.

Second, while a true all-source RFP would have been preferable to an RFP for the specific technology of a CCGT, the Companies did receive one bid that was structured as a PPA, a more flexible arrangement than a BOT. The Companies deemed that bid nonconforming and did not conduct an LCOE analysis on it; therefore, the merits of the bid could not be evaluated to determine if it provided a superior alternative. The Companies provided some terms of the PPA in a response to a discovery request, but the details provided were not sufficient to independently calculate the LCOE of the PPA bid. [redacted][51] To the extent that the Companies only have a capacity shortfall, and not an energy shortfall (as suggested by the load forecast in the IRP that does not include the proposed data center), as shown in Table 3, the PPA would be more attractive than purchasing capacity from the PJM Capacity Market.

[51] CONFIDENTIAL Response to Sierra Club Discovery Request 3-01.

Table 3. CONFIDENTAL. [redacted]

Delivery Year	IRP Capacity Price Forecast	[redacted]	[redacted]
2027	$333.44	[redacted]	[redacted]
2028	$550.00	[redacted]	[redacted]
2029	$594.03	[redacted]	[redacted]
2030	$580.01	[redacted]	[redacted]
2031	$521.72	[redacted]	[redacted]
2032	$453.71	[redacted]	[redacted]
2033	$484.89	[redacted]	[redacted]
2034	$519.04	[redacted]	[redacted]
2035	$591.32	[redacted]	[redacted]
2036	$429.59	[redacted]	[redacted]
2037	$466.58	[redacted]	[redacted]
2038	$447.22	[redacted]	[redacted]
2039	$410.95	[redacted]	[redacted]
2040	$338.32	[redacted]	[redacted]
2041	$343.64	[redacted]	[redacted]
2042	$377.59	[redacted]	[redacted]
2043	$353.18	[redacted]	[redacted]
2044	$370.08	[redacted]	[redacted]
2045	$325.25	[redacted]	[redacted]

Source: Direct Testimony of Patrick Augustine, Attachment PA-1 at 4 and [redacted]

Q Should the Companies have evaluated the RFP responses differently?

A Yes. The Companies failed to ensure that the responses to the RFP were evaluated in an objective and unbiased manner. Instead, the Companies had B&V evaluate the responses (the same company that developed the Companies' self-build option). In essence, B&V was tasked with evaluating whether third-party bids were superior to the approach it had itself developed. Ultimately, and unsurprisingly, B&V did not find the third-party bids to be superior to its own option, and B&V recommended the self-build option it developed.

This approach is inconsistent with the principles of conducting competitive procurements. If a utility is comparing self-build options against third-party alternatives for major generation investments, then the evaluation process should be conducted by an independent evaluator with no financial, strategic, or reputational interest in the outcome. The Companies did not provide any indication that there were protocols employed by either the Companies or B&V to separate duties and isolate potentially conflicting interests.[52]

Through my previous experience at the Illinois Power Agency, I have firsthand experience with the value of separation of duties in evaluating the results of competitive procurements. The Illinois Power Agency was created in 2007 in response to controversies over utility-administered procurements and has the duty of conducting competitive procurements for the customers of Illinois investor-owned utilities.[53] During my time as the Agency's Director, and Planning and Procurement Bureau Chief, I oversaw thirteen procurement events that procured Renewable Energy Credits to support the development of 5.9 GW of new projects.[54]

The procurement model in Illinois utilizes a Procurement Administrator, retained by the IPA, to conduct the procurement events and a Procurement Monitor, retained by the Illinois Commerce Commission, to monitor the events, both then issue separate reports to the Commission.[55]

There are several layers of independence contained in this process. First, utilities in Illinois do not choose which resources are selected in competitive procurements, that is the role of the IPA through its Procurement Administrator.[56] Second, the work of the Procurement Administrator is verified by the Procurement Monitor who independently runs a bid evaluation model. Third, the results are approved by a vote of the Commission. These separate and discrete layers of review and approval ensure objectivity and independence in the selection of new resources.

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[52] *See* Companies Responses to Sierra Club Discovery Requests 3-05 and 3-06. Attached in Exhibit AS-2.
[53] *See* Illinois Public Act 95-0481. Available at: https://ilga.gov/Legislation/PublicActs/View/095-0481.
[54] Derived from Competitive Procurements spreadsheet available at: https://cleanenergy.illinois.gov/download-data.html.
[55] See the Illinois Public Utilities Act, 220 ILCS 5/16-111.5(c). Available at: https://www.ilga.gov/Documents/legislation/ilcs/documents/022000050K16-111.5.htm.
[56] See: https://ipa.illinois.gov/renewable-resources/long-term-plan.html.

Illinois is not alone in having independent monitoring. A 2020 report by Energy Innovation, concluded that "[r]egulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding" (noting that there can be a bias towards self-built projects, as is seen in this proceeding) and "[c]onsidering new challenges presented by more diverse, complex, and competitive power generation markets, it is also worth revisiting regulatory practices that provide for fair, objective, and efficient procurement processes. Public Utility Commissions (PUCs) **generally require the use of an independent evaluator.**"[57] (emphasis added).

E. THE SELF-BUILD APPROACH CONTAINS TOO MANY RISKS

Q Do you have any concerns with the riskiness of the Companies' self-build option?

A Yes. I am concerned that the cost estimates are highly uncertain and the Companies lack recent experience constructing power plants, let alone gas plants. Under the Companies' proposed approach, this creates undue risks for ratepayers who would foot the bill for the CCGT Project, including any cost overruns.

Q How uncertain are the Companies' cost estimates?

A The cost estimate of $2.476 billion for the self-build option is a Class Level 4 with an accuracy range of -30% to +50% for the $1.72 billion of direct construction costs.[58] Therefore, the cost estimate for direct construction costs could range from $1.207 billion to $2.586 billion. As described in the Direct Testimony of Chris Beam, a Class 4 estimate is a high-level estimate with substantial uncertainty remaining to be resolved, as shown in Figure 4.[59]

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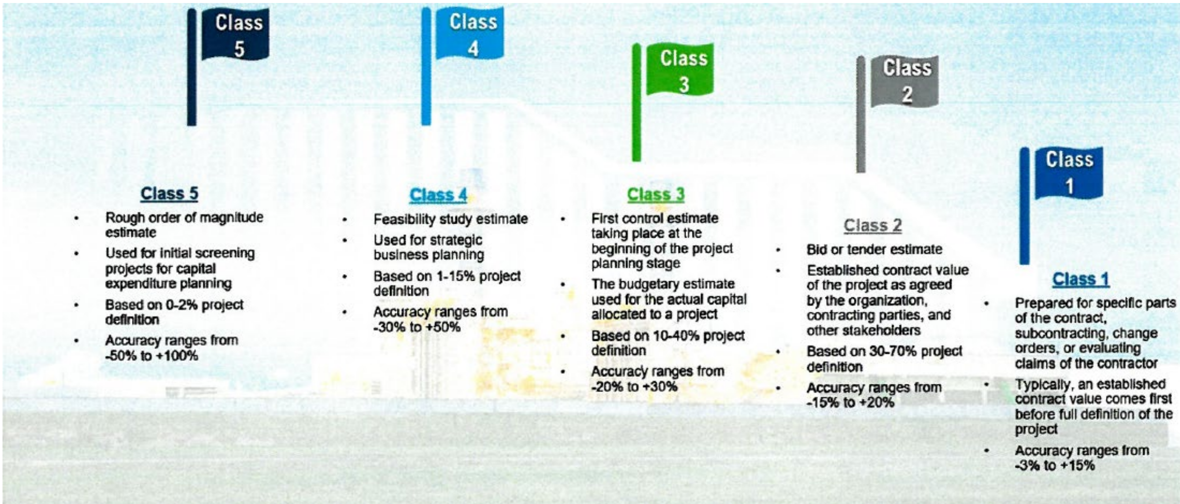
[57] Energy Innovation, *Making the Most of the Power Plant Market: Best Practice for All Source Electric Generation Procurement*. 2020, at 2-3, available at: https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf

[58] Application at 11.

[59] Direct Testimony of Chris Beam at 20 and Companies response WVEUG Discovery Request 6-19.

Figure 4. Cost Estimate Levels



Source: Direct Testimony of Chris Beam at 20.

The level of precision in a Class 4 estimate is for feasibility studies, not for a CPCN. Perhaps it would have been an acceptable level of certainty for an IRP, but in this proceeding the Companies are requesting approval of a CPCN for a specific project, with actual costs to be recovered by ratepayers. The cost estimation contained in the Application for the CPCN warranted a more refined cost estimate.

In fact, the Companies planned to use a more refined estimate, but in their rush to submit the CPCN application, they changed course. Initially B&V was supposed to provide a Class Level 5 estimate and then the selected Engineering, Procurement, and Construction ("EPC") firm would refine the costs to Class Level 3 (-20% to + 30%).[60] However, the Companies were not able to secure a Class Level 3 estimate in a timely manner and nonetheless proceeded with this application using the less certain estimate.[61] As the Companies are asking their

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[60] Direct Testimony of Chris Beam at 19.
[61] Id.

ratepayers to finance the CCGT Project, those ratepayers should know the total cost.

Q Do the Companies have recent experience with thermal power plant construction?

A No. The Companies have not built a new fossil fuel power plant since the late 1970s and have no direct experience developing natural gas plants. By pursuing a self-build option, the Companies are assuming significant risk that could have been avoided by a BOT option. Under this option, a company with more experience developing CCGTs would undertake the project and would also bear responsibility for managing the costs.

Q Have the Companies secured a firm gas supply for their proposed CCGT?

A No. The Companies planned to issue a RFP for gas supply in February 2026 but postponed it until the fourth quarter of 2026.[62] While the Companies indicated that they have had discussions with seven potential bidders who state they can meet the supply needs and development timeline, the Companies do not have firm bids, including prices for gas supply. This creates additional cost uncertainty above and beyond the uncertainties related to building the plant itself such as the timely availability of turbines, or an EPC to oversee the construction.

Q Have the Companies finalized any of the major equipment or development contracts associated with the CCGT Project?

A No. The Companies have not yet secured contracts for the actual development of the CCGT Project and thus the costs remain speculative and subject to refinement. For example, while the Companies have narrowed their choice of turbines to two models, they have not yet signed a contract for turbines nor do they have a firm reservation for said turbine.[63] Similarly, while the Companies have had

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[62] Companies Response to WVEUG Discovery Request 1-15.
[63] Companies Response to CAG/SUN/EEWV Discovery Request 9-02.

discussions with potential EPC contractors, those contractors appear to be constrained due to other project commitments.[64] As a result, the Companies also do not expect to sign a contract with an EPC contractor until the fourth quarter of 2026;[65] however, that date could slip further depending on the availability of an EPC contractor.

Q What cost trends are you seeing in the gas turbine industry more broadly?

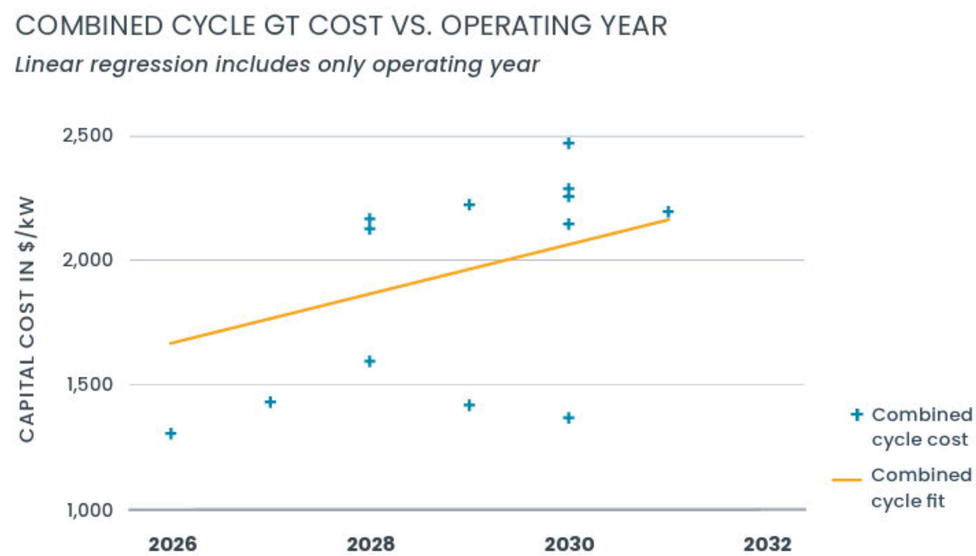
A Utilities across the country are currently facing increasing costs and lead times for combined cycle and combustion turbine units. High demand for equipment such as turbines and transformers, and also the skilled labor shortages, are driving up costs across the country.[66] These costs increases are driven primarily by load growth from data centers, manufacturing facilities, and electrification, which together have caused surging demand from utilities for gas equipment, as well as global competition for turbines and other plant components.[67] Globally and domestically, increased demand has led to equipment backlogs and has increased the market power of the three major turbine manufacturers: GE Vernova, Siemens Energy, and Mitsubishi Power. Finally, the industry is experiencing a shortage of skilled labor and qualified EPC contractors, which causes additional cost increases and delays.[68]

A recent survey of CCGT plant costs (based on year projected online) in recent utility dockets, as depicted in Figure 5, shows the increasing cost trends. The initial costs (for units coming online in 2026) are markedly higher than industry estimates from before the increase in turbine costs began. Costs continue to increase over time, and the cost of a CCGT coming online in 2031 is nearly a

[64] Direct Testimony of Chris Beam at 21.
[65] Companies Response to CAG/SUN/EEWV Discovery Request 7-31.
[66] GridLab, Energy Futures Group, and Halcyon. 2025. *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S*, available at https://gridlab.org/gas-turbine-cost-report/.
[67] Id.
[68] Id., *see also* Shenk, M. 2025. *Rush for US gas plants drives up costs, lead times*" Reuters (July 21, 2025), available at https://www.reuters.com/business/energy/rush-us-gas-plants-drives-up-costs-lead-times-2025-07-21/.

third higher in real terms than the cost of a similar resources coming online in 2026, even before including inflation. In nominal dollars (i.e., including effects of inflation), the upward trend in the data would be even more pronounced.

Figure 5. CCGT capital costs from recent utility dockets



Source: Supra note 66. Each blue data point represents the cost from a recent utility docket, and the yellow line shows a linear regression fitted to the data.

Q How does the cost of the CCGT Project compare to industry benchmarks?

The estimated cost of $2,063/kW appears to be in line with the project estimates shown in Figure 5. However, as discussed above, this is just a rough estimate at the Class 4 level and could be as much as 50 percent higher, which is out of line with industry benchmarks. In addition, there are a range of unknown costs such as the EPC contractor, gas supply, and final turbine cost based on the size selected. Due to high demand across the industry for new generation, constructing the CCGT Project now could lock ratepayers into elevated turbine and other prices, so it is particularly important to ensure that the resource is right-sized to the Companies' actual capacity needs.

Q Is there also a risk that the commercial operation date of the CCGT Project will be delayed?

A Yes. The Companies have not yet signed a contract for the turbines and thus have not locked in a delivery date. Similarly, the Companies have not yet issued an

RFP for the gas supply or selected an EPC contractor. External to those decision points, there are also external factors that could delay the operation date, such as supply chain delays and delays in the PJM interconnection approval process.

Q Will the CCGT Project increase ratepayer exposure to fuel price volatility?

A Yes. The CCGT Project is a baseload gas plant, which is designed to run at high capacity factors, thereby exposing ratepayers to fuel price volatility. [redacted][69]This significant portion of the operating cost will be subject to fuel price volatility in the natural gas market.

Q Explain the risks posed to ratepayers by fuel price volatility.

A Heavy reliance on gas resources can expose ratepayers to fuel price volatility for which they cannot plan. Because gas is a global commodity, both domestic and global market forces impact price and demand for the resource. After roughly doubling from 2019 to 2024, North American liquified natural gas ("LNG") export capacity is projected to more than double again by 2029, from current levels of 11.4 billion cubic feet (Bcf) per day to more than 28 Bcf per day in 2029.[70] To put this in perspective, U.S. total gas consumption in 2023 averaged roughly 89 Bcf per day. This leaves domestic markets exposed to global market dynamics.[71] Figure 6 illustrates that exposure to global forces as seen in the spike in prices in 2022 (Russian invasion of the Ukraine) and 2026 (Iran war).

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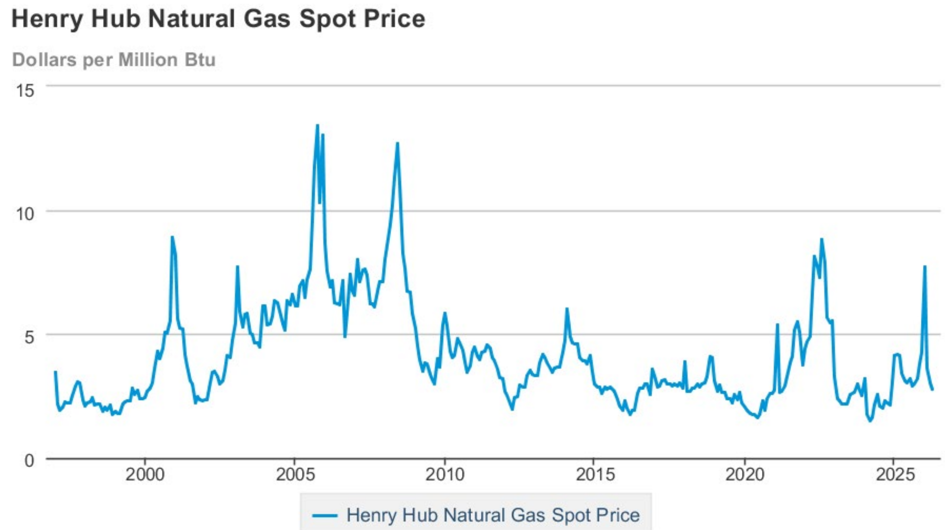
[69] CONFIDENTIAL Companies Response to CAG/SUN/EEWV Discovery Request 2-16, Attachment A Natural Gas Prices used were from August 2025.

[70] Young, J. 2025. *North America's LNG export capacity could more than double by 2029*. U.S. Energy Information Administration, available at https://www.eia.gov/todayinenergy/detail.php?id=66384.

[71] U.S. Energy Information Administration. 2025. *Natural Gas Consumption by End Use*, available at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

Figure 6. Natural Gas Price Volatility



Source: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm, accessed May 27, 2026.

Q How are volatile fuel costs passed on to ratepayers?

A Fuel costs are a direct pass-through, meaning 100 percent of the costs are passed on to customers. The Companies have little financial incentive to minimize these costs because they can recover whatever amount they spend from ratepayers. When the global market is constrained and fuel prices spike, ratepayers may face unexpected bill increases as a result of increased fuel charges. This happened in 2022 when Russia invaded Ukraine and European gas customers turned increasingly to U.S. gas. This drove up domestic gas prices, and utilities passed those high costs directly on to ratepayers.

For example, Dominion Energy South Carolina ("DESC") reported large fuel under-recoveries in 2022 following the war in Ukraine and filed for a mid-period adjustment in August 2022, due to under-recovery of $202 million in base fuel costs.[72] While fuel adjustments usually happen annually, DESC wrote that it was forced to file for a mid-period adjustment because of "significant and unforeseen

[72] *Dominion Energy South Carolina, Inc.'s Application for a Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs*, Docket No. 2022-259-E, Application at 9 (Aug. 9, 2022), available at: https://dms.psc.sc.gov/Attachments/Matter/5430373d-17df-45cd-8d08-66bee88ec69e.

market changes and commodity price increases."[73] DESC's under-recovery on base fuel costs reached $452 million by the end of year.[74] The utility stated the under-recovery was largely driven by shifts in gas markets, including "higher commodity prices, coupled with higher gas-fired generation demand driven by issues related to coal supply, interstate pipeline maintenance, an increase in natural gas export activity, and lower-than-average natural gas inventories."[75] Under-recoveries during future volatility events could be even larger after the Proposed CCGT comes online and the Companies' reliance on gas increases.

Q How does the building of the CCGT Project impact regulatory uncertainty and risk to environmental compliance?

A Gas units, such as the CCGT Project, will face uncertain regulatory and environmental compliance costs from existing federal rules, and new rules further out in the future. This regulatory uncertainty poses a substantial risk to ratepayers. Section 111 of the Clean Air Act currently requires newly built gas generators to either maintain a capacity factor below 40 percent or meet emissions standards consistent with 90 percent carbon capture and storage by January 1, 2032.[76] The current federal administration has proposed repealing this rule;[77] however, the law currently remains in effect. The Companies should have included the costs to comply with this rule in their analysis.[78] While these rules may be overturned or repealed eventually, until such time as that occurs, and that repeal has been

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[73] Id. at 4.

[74] *Annual Review of Base Rates for Fuel Costs for Dominion Energy South Carolina, Inc. (for potential increase or decrease in fuel adjustment)* ("2022 DESC Fuel"), Docket No. 2023-2-E, Corrected Direct Testimony of Allen W. Rooks at 5 (Mar. 4, 2023), available at https://dms.psc.sc.gov/Attachments/Matter/77d48784-7447-4e2d-88ea-626170570291.

[75] 2022 DESC Fuel, Direct Testimony of Rose M. Jackson at 5 (Feb. 15, 2023), available at: https://dms.psc.sc.gov/Attachments/Matter/b71532cd-457c-49a5-9d7a-8f7f26231a70.

[76] *New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,* 89 Fed. Reg. 39,798 (May 9, 2024), available at https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-09233.pdf.

[77] *Proposed Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating* Units, 90 Fed. Reg. 25752 (June 17, 2025).

[78] Companies response to CAG/SUN/EEWV Discovery Requests 9-11 and 9-12 which indicate that the Companies have not modeled CO2 emissions from the proposed CCGT Plant.

finalized by the courts, the Companies should be required to consider the substantial costs that would be added to the CCGT Project if it were to include carbon capture and storage (costs that have been estimated at $50-$120 per metric ton of CO_2).[79]

Q How can the Companies protect ratepayers from the risks posed by continued reliance on fossil resources?

A One way the Companies can reduce those risks is through the deployment of energy storage strategies. The Companies should be required to analyze whether smaller firm resources, such as Battery Energy Storage Systems ("BESS") or combustion turbines paired with renewables and BESS, could replace some or all of the capacity of the proposed CCGT Project at a lower cost and risk to ratepayers.

Q How would replacing a portion of the CCGT Project with paired BESS and renewables protect ratepayers?

A BESS resources have shorter useful lives than CCGTs (15 years for batteries compared to the 30 years for the CCs).[80] The 15-year lifetime of BESS aligns more closely with the typical large-load contract length.[81] In contrast, CCGTs have useful lives that are over twice as long and would lock ratepayers into 30 years of capital costs and fuel costs over the resource's lifetime. This makes batteries a more appropriate resource addition during a time of uncertain future load growth, when it is unclear how quickly data center load will materialize, if it will fully materialize, and how long it will last. Pairing BESS with renewables

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[79] *Carbon Capture and Storage in the United States*, Congressional Budget Office (Dec. 2023), available at: https://www.cbo.gov/system/files/2023-12/59345-carbon-capture-storage.pdf.

[80] *See* NREL Annual Technology Baselines, available at: https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

[81] For example, Santee Cooper's experimental large load tariff requires a contract length of 15 years. *See* South Carolina Public Service Authority (Santee Cooper) Large Light and Power Experimental Large Load Service Schedule L-25-LL at 10, available at https://www.santeecooper.com/Rates/ pdfs/Industrial-Wholesale/L-25-LL-FINAL.pdf.

also helps to shield ratepayers from fuel price volatility, because solar and wind have no exposure to price volatility once constructed.

Q How does the construction timeline of BESS compare to CCGT resources?

A BESS resources typically have short construction lead times of one to two years, compared to five years for the CCGT Project. BESS is also more modular than CC units, so the Companies could adjust the quantity of BESS they procure each year based on current market conditions, and the Companies could procure resources incrementally to serve load growth as it materializes. In contrast, constructing the CCGT Project will reduce the Companies' flexibility in decision-making and lock ratepayers into a $2.476 billion gas plant for the next 30 years regardless of whether the data center load fully materializes. For these reasons, BESS have the dual value of offering a more tailored approach to addressing capacity concerns and reducing risk for ratepayers.

F. THE PROPOSED COST MECHANISMS PLACE TOO MUCH BURDEN ON RATEPAYERS

Q How are the Companies proposing to recover costs associated with the development of the Projects?

A The Companies are proposing a new GP Surcharge that would recover the AFUDC from Construction Work in Progress ("CWIP") while the projects are in development. This mechanism would then transition to a recovery of the generation revenue requirement after the projects are placed into service.[82]

[82] Direct Testimony of Raymond Valdes at 2 to 3.

Figure 7 shows the revenue that would be collected through the surcharge.

Figure 7. GP Surcharge Components

MONONGAHELA POWER COMPANY
Generation Projects Surcharge (CCGT + Solar Project)

	Generation Projects Surcharge Components (CCGT and Solar Combined)				
Year	AFUDC	Capital Revenue Requirement	Property Tax	Fixed O&M	Total
[1]	[2]	[3]	[4]	[5]	[6]=sum[2] t0 [5]
2025	$ 56,216	$ -	$ -	$ -	$ 56,216
2026	$ 1,680,426	$ -	$ -	$ -	$ 1,680,426
2027	$ 18,270,407	$ -	$ -	$ -	$ 18,270,407
2028	$ 54,618,511	$ 1,613,579	$ 88,612	$ 48,473	$ 56,369,174
2029	$ 104,041,383	$ 9,474,938	$ 481,538	$ 454,313	$ 114,452,172
2030	$ 159,074,471	$ 8,975,014	$ 493,416	$ 542,914	$ 169,085,814
2031	$ 193,321,851	$ 12,898,435	$ 710,398	$ 1,556,558	$ 208,487,242
2032	$ 5,551,292	$ 286,662,266	$ 9,549,648	$ 46,470,969	$ 348,234,176
2033	$ 1,736,616	$ 302,031,103	$ 10,322,618	$ 47,391,471	$ 361,481,808
2034	$ -	$ 296,114,734	$ 10,446,703	$ 47,822,942	$ 354,384,378
2035	$ -	$ 287,557,489	$ 10,476,478	$ 48,769,765	$ 346,803,731
2036	$ -	$ 279,337,889	$ 10,506,878	$ 49,778,803	$ 339,623,570
2037	$ -	$ 271,396,327	$ 10,537,917	$ 50,808,741	$ 332,742,985
2038	$ -	$ 263,686,736	$ 10,569,608	$ 51,308,697	$ 325,565,041
2039	$ -	$ 256,191,605	$ 10,601,964	$ 52,370,166	$ 319,163,735
2040	$ -	$ 248,811,019	$ 10,634,999	$ 53,453,620	$ 312,899,638
2041	$ -	$ 241,444,987	$ 10,668,728	$ 54,559,511	$ 306,673,227
2042	$ -	$ 234,073,160	$ 10,703,166	$ 55,089,201	$ 299,865,527
2043	$ -	$ 226,694,725	$ 10,738,327	$ 56,228,793	$ 293,661,845
2044	$ -	$ 219,309,456	$ 10,774,226	$ 57,391,983	$ 287,475,665
2045	$ -	$ 211,917,297	$ 10,810,879	$ 57,941,612	$ 280,669,788

Source: Direct Testimony of Raymond Valdes, Attachment RV-7.

In addition to the GP Surcharge, ratepayers will also pay Expanded Net Energy Costs ("ENEC") which reflect the added costs and expenditures of energy and capacity sales and will reflect the volatility in future natural gas prices.

Table 4 shows the rate in cents per kilowatt of the GP Surcharge and the ENEC Costs for residential customers, as well as the incremental annual cost of the GP Surcharge and ENEC for a typical residential customer who uses 10,000 kWh per year.

Table 4. Net impact of GP Surcharge and ENEC on Residential Customers

Period	GP Surcharge (cent/kWh)	ENEC Incremental Charge (cents/kWh)	Net Charge (cents/kWh)	Incremental Annual Cost (@10,000 kWh/year)
Sep 2026-Dec 2027	0.12	-	0.12	$ 11.75
2028	0.43	0.14	0.57	$ 56.87
2029	0.86	0.12	0.98	$ 97.95
2030	1.26	0.16	1.42	$ 141.93
2031	1.54	0.12	1.66	$ 165.67
2032	2.46	(2.07)	0.39	$ 39.01
2033	2.54	(2.51)	0.02	$ 2.47
2034	2.46	(2.51)	(0.05)	$ (5.05)
2035	2.39	(2.48)	(0.09)	$ (8.69)
2036	2.32	(2.27)	0.05	$ 4.81
2037	2.25	(2.13)	0.12	$ 11.76
2038	2.18	(2.10)	0.08	$ 7.73
2039	2.12	(2.05)	0.07	$ 7.23
2040	2.06	(1.86)	0.19	$ 19.34
2041	2.00	(1.77)	0.23	$ 23.10
2042	1.93	(1.81)	0.13	$ 12.82
2043	1.88	(1.82)	0.06	$ 5.84
2044	1.82	(1.83)	(0.01)	$ (1.37)
2045	1.76	(1.83)	(0.08)	$ (7.72)

Source: Derived from Direct Testimony of Raymond Valdes, Attachment RV-15.

Q How will these surcharges impact customers' bills?

A The impacts will vary over time, growing rapidly until 2031 and then declining. As shown in Table 4, on average between 2026 and 2045, a residential customer using 10,000 kWh per year would be expected to see a bill increase of nearly $31 annually due to these charges. In some years the annual increase would be over $100.

This increase in electricity bills is what residential customers will pay to support the development of the project.

Q Who will pay this surcharge?

A All ratepayers will pay the surcharge. While the proposed data center will pay the surcharge on the electricity it consumes once it comes online, the data center's payments would only be a portion of the total cost collected, with the majority paid for by other ratepayers who are not benefiting from the addition of the 1,200 MW CCGT meant to serve the load of the data center.

Q Is there a risk that the final cost of the CCGT will escalate beyond current projections?

A Yes, as I discussed earlier in Section E, the cost estimates used in the application have a large band of uncertainty, -30% to +50% for the direct construction costs, or $1.207 billion to $2.586 billion. In addition, there is the uncertainty in costs for gas turbines (including if the Companies elect to go with a larger size at an additional $100 million cost), transformers and qualified EPC contractors (which are all in high demand), escalating prices and wait times, all of which the Companies have not yet locked in. Since the Companies are still in the early stages of contracting, as evidenced by their Level 4 cost estimates, there is a real risk that the project costs will escalate beyond the current projections.

To protect ratepayers from the impacts of future cost escalation, if the CCGT Project is approved, I recommend the Commission cap project costs at the total amount the Companies currently estimate, $2.476 billion, and require a separate demonstration of prudence for any expenditures above the cap.

Q Who shoulders the risk if the CCGT Project is abandoned and not built?

A The customers. In addition to the GP Surcharge, the Companies also requested the authority to recover expended costs if the CCGT Project is abandoned prior to or during construction, and thus not completed.[83] While a prudence standard may provide some protection to ratepayers, in that it would allow for Commission review of expenditures, it is one-sided since it focuses on expenditures related to the development of the project that will never become used and useful. This standard fails to protect customers in the case where the expected load for the proposed data center does not materialize and thus the need for the project

[83] Direct Testimony of Raymond Valdes at 26.

evaporates. It also does not protect customers if the project costs skyrocket and the continued development of the project becomes untenable.

In their Application, the Companies state that, “Abandonment Authority is integral to the Companies’ ability and willingness to construct the Projects.”[84] If the Companies are not willing to take on the risk of the CCGT Project failing, a process for which they do not have an established track record, why should its customers. The Companies have also not structured the proposal to place that risk on the proposed data center, the sole customer that will be served by this CCGT Project. Instead, the Companies are asking their ratepayers to shoulder the risk and costs of abandonment. This is not an abstract risk: South Carolina Dominion Energy and Santee Cooper customers are still paying for the failed $5.9 billion VC Summer nuclear plant, which accounts for approximately 5 percent of their monthly bill, and they will continue to pay for this failed project for another 15 years.[85]

The Commission should deny the Companies request for abandonment authority, as it places all the risk of project abandonment on the customers, with no accountability to the data center or the Companies’ shareholders.

Q How would a Large-Load Tariff help alleviate the risk and burden to ratepayers?

A Large loads, as with data centers, are unlike other commercial and industrial loads due to their enormous size and 24/7 around-the-clock operation. Therefore, traditional tariffs will not properly assign the costs associated with large loads to

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[84] Application at 19.

[85] *Here’s how much SC power customers are still paying for a failed nuclear project*, South Carolina Daily Gazette (April 5, 2024), available at: https://scdailygazette.com/2024/04/05/heres-how-much-sc-power-customers-are-still-paying-for-a-failed-nuclear-project/

that particular customer class. Large-load tariffs are an increasingly common regulatory response to this challenge, with 29 such tariffs approved in 2025.[86]

West Virginia is one of those states, having approved a large-load tariff for the Appalachian Power Company and Wheeling Power Company in Case No. 24-0611-E-T-PW.[87] That large-load tariff contains several key provisions which could be included in a large-load tariff for the Companies, including minimum contract length, collateral requirements, minimum charges that commit to at least 80 percent of the customer's demand, and exit fees.

By implementing a large-load tariff, the Companies could address the concerns I have raised regarding resource additions for new data center loads placing increased costs and risks on other ratepayers (costs that provide no benefit to those other ratepayers). The large-load tariff will reduce speculative load and, if properly developed along with cost allocation methodologies, will ensure that data centers are paying for their full cost of service.

G. THE NEED FOR THE SOLAR PROJECTS HAS BEEN DEMONSTRATED

Q Describe the proposed Solar Projects.

A The Companies propose to develop 70 MW of solar projects, Davis (11.5 MW), Wylie Ridge (8.4 MW), and Valley Point (50 MW).[88] The Solar Projects are located in Energy Communities and will use domestic content to maximize the utilization of the ITC at 50 percent. Two of the projects, Davis and Wylie Ridge,

[86] *Large load tariffs proliferate as states take more active role in data center regulation*, Utility Dive (March 31, 2026), available at: https://www.utilitydive.com/news/large-load-tariffs-proliferate-as-states-take-more-active-role-in-data-cent/816184/.
[87] *See Appalachian Power Company and Wheeling Power Company Application for approval for revisions to Schedules LCP and IP*, Case No. 24-0611-E-T-PW, Commission Order (March 25, 2025), available at: https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=638931&NotType=WebDocket.
[88] Direct Testimony of Doug Hartman at 4.

were previously considered in Case No. 210813-E-US. Valley Point is a new proposal. All three sites meet the brownfield provisions of Senate Bill 583, which is an important step forward in reclaiming blighted land and returning it to economic usage.[89]

Q Do the Companies have experience developing solar projects?

A I reviewed the site selection process used by the Companies and have no concerns about the proposed projects.[90] Furthermore, the Companies have developed the Fort Martin, Rivesville, and Marlowe solar projects prior to this Application and have demonstrated that they have the expertise needed to develop solar projects.[91]

Q Why should the Commission grant the CPCN for the 70 MW Solar Projects?

A The CPCNs for the Solar Projects should be approved because they will help diversify the resource mix serving the Companies' customers. There is no fuel cost for solar so additional use of solar reduces exposure to commodity price volatility. Additionally, time is of the essence for solar projects to be able to qualify for the ITC, to minimize costs, the CPCN should be granted now. Notwithstanding this recommendation, as I discussed in terms of the limitations of the 2025 IRP, the Companies should continue to evaluate additional solar opportunities in their IRPs to: (1) continue to diversify the Companies generation portfolio, (2) reduce customer's exposure to fuel price volatility, and (3) harness the experience and workforce the Companies have developed.

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[89] Id. at 4.
[90] See Response to CAD 1-09 including CAD-01-09 Attachment A-CONFIDENTIAL.
[91] Id. at 7-9.

H. THE PROPOSAL DOES NOT ALIGN WITH STATE AND FEDERAL POLICY

Q How does the approach the Companies have proposed to serve the data center fit into evolving policy at the state and federal levels?

A The approach proposed by the Companies is the traditional way a regulated utility would add generation to meet growing demand. As I have discussed, the load growth due to data centers does not fit into traditional utility planning paradigms. The advent of the data center era requires new thinking, not reliance on old approaches. The scale of the load requirements of data center customers is unprecedented. The approach proposed by the Companies of collecting funds from all ratepayers to finance the construction of new generation to serve one customer is not appropriate. The enormous and speculative load of data centers requires new thinking that properly isolates risk and allocates costs.

I can offer two examples for how policy is advancing at the state and national levels that show how the traditional approach utilized by the Companies is outdated and should be rejected, West Virginia HB 2014, and President Trump's Ratepayer Protection Pledge.

Q What actions has the West Virginia Legislature taken to address data center load growth?

A HB 2014, enacted in 2025, seeks to address new data center load through the creation of microgrids. While this approach is not without its flaws, it indicates that the West Virginia Legislature has shown a commitment to adopting new models to meet growing electric demand and to not simply rely on the traditional regulatory structure.[92]

[92] For example, "[i]t is the intent of the Legislature to occupy the whole field of the creation and regulation of certified microgrid districts and certified high impact data centers. The stated purpose of this section is to promote uniform and consistent application of the act within the state." West Virginia Code §5B-2-21b(a).

Q Does HB 2014 address who should pay for the costs associated with data centers?

A Yes, the data center. While I am not a lawyer, my understanding is that HB 2014 creates the High Impact Data Center Program and certifies microgrids that would consist of both large energy users and new electric generation[93] HB 2014 includes a provision stating:

> "Regulated electric utility customers shall not bear any construction, operational, ancillary services, or capacity-related costs associated with non-utility owned and operated electricity generation co-located within a microgrid district. Any costs of this nature are to be borne by the electricity consumers situated within the microgrid district that is to be co-located with onsite electricity generation. Regulated electric utility customers shall not bear any construction, operational, ancillary services, or capacity-related costs associated with any new transmission facilities built to provide electric service to any facilities within a microgrid district and owned and operated by a regulated electric utility"[94]

While I understand that the proposed data center and the proposed CCGT Project are not part of a microgrid, the vast majority of the projected need, (e.g., the 769 MW of incremental data center load included in the revised load forecast in this case), is for a single data center. Given the Legislature's intent to have data centers/microgrids pay their full costs, why should the Companies' ratepayers face increased costs for this CCGT Project that would not be incurred without the data center's construction? I urge the Commission to recognize the intent of the Legislature and apply a consistent cost allocation framework across the state regardless of whether the data center is located within a microgrid.

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[93] West Virginia Code §5B-2-21 and West Virginia Code §5B-2-21a(b).
[94] West Virginia Code §5B-2-21(f).

Q What development at the Federal level has changed how data centers play a constructive role in meeting their energy needs?

A Data centers are a complicated issue for many Americans as they explore and learn about the potential for how artificial intelligence will transform lives. Americans also have concerns about where the data centers will be built and how they impact electric bills and daily life. The set of principles agreed to by the largest data centers, in the Ratepayer Pledge announced by President Trump in March (listed below), are a step in the right direction and acknowledge that other customers should not be paying for the infrastructure necessary to meet the growing data center demand. However, a pledge is not a firm commitment. In energy policy, the translation from broad principles to actual implementation often happens at the state level, and that is where the Commission has an opportunity in this case. A clear statement that data center developers need to be responsible neighbors and not offload their risks and costs to other ratepayers is needed. As the Commission considers the myriad of issues in this proceeding, I urge the Commission to consider the terms of the affordability pledge and implement its own guardrails, such as requiring the Companies to develop a large-load tariff, to protect the Companies' customers from the impacts of data centers and the CCGT Proposal.

The Ratepayer Protection Pledge[95]

1. Building, Bringing, or Buying New Power Supply

- **WHAT**: Companies will build, bring, or buy the new generation resources and electricity needed to satisfy their new energy demands, paying the full cost of those resources whether by building, or buying from, new or otherwise additive power plants. Where possible, these companies will also add more capacity that serves the broader public by increasing supply.

[95] *See* White House, *Ratepayer Protection Pledge*, March 4,2026. Available at: https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/.

- **WHY**: This advances self-sufficiency and protects Americans from higher prices.

2. Paying for New Power Delivery Infrastructure Upgrades

- **WHAT**: Companies will pay for all new power delivery infrastructure upgrades required to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to the ordinary household.
- **WHY**: This way, data centers can benefit all ratepayers and the grid.

3. Paying Whether They Use the Power or Not

- **WHAT:** Companies will voluntarily negotiate new, separate rate structures with their utilities and relevant State governments wherever they build data centers. Importantly, they will pay these rates for the power and related infrastructure that are brought online to service their data centers, whether they use the electricity or not.
- **WHY**: This will protect the American people from increased utility bills as a result of the development of these data centers.

4. Investing in Local Job Creation and Workforce Development

- **WHAT**: Companies will invest in the local communities in which they build data centers. This includes hiring from within the local community and establishing programs to develop relevant skills.
- **WHY:** This allows all American workers to benefit from the oncoming technological boom at every step from construction to operation.

5. Contributing to Electric and Community Resilience

- **WHAT**: Companies will coordinate with grid operators to contribute to a more reliable grid and, whenever possible, make available their backup generation resources at times of scarcity to prevent blackouts and power shortages in their communities.

- **WHY**: Consumers will benefit from enhanced grid resilience from data center power resources in times of emergency.

Q What are your main takeaways from the CPCN Application in this case and your recommendations to the Commission?

A My main takeaways are that:

- The load associated with the 1,012 MW data center project is too speculative to justify the $2.476 billion investment in the CCGT Project in the 2025 IRP.
- The Companies failed to evaluate demand-side resources and overly constrained renewable resource build options.
- The proposed 1,200 MW CCGT Project is larger than what is needed to serve the load of the proposed data center.
- There were multiple flaws in how the self-build option was selected.
- The self-build option contains too many risks.
- The proposed cost recovery mechanism places too much burden on existing ratepayers.
- The companies have the experience needed to develop the Solar Projects.
- The proposed approach is inconsistent with state and federal policies.

I therefore recommend the Commission deny the CPCN for the CCGT Project and grant the CPCNs for the Solar Projects. I also recommend a number of steps the Companies should be ordered to undertake before applying for a CPCN including working with data center developers, conducting RFPs in a different manner, and improving their IRP and load forecasting process. If the Commission does chose to grant the CPCN, then I have several recommendations including that that the Companies adopt a large-load tariff and not be granted abandonment authority to ensure that data centers pay their full costs, improve their IRP process, and commit to closing the Fort Martin coal generating units when the CCGT Project comes online.

Q Does this conclude your testimony?

A Yes, it does.