Virginia State Corporation Commission
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230810223

Case Number (if already assigned)	PUR-2023-00066
Case Name (if known)	Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.
Document Type	EXTE
Document Description Summary	Direct Testimony of Gregory Abbott
Total Number of Pages	95
Submission ID	28365
eFiling Date Stamp	8/8/2023 3:31:33PM

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August 8, 2023

VIA ELECTRONIC FILING

Mr. Bernard Logan, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.

Case No. PUR-2023-00066

Dear Mr. Logan,

Enclosed for filing in the above-captioned matter is the Direct Testimony of Gregory Abbott, which is being submitted on behalf of Appalachian Voices. Included with this testimony is Mr. Abbott's one-page summary and 2 attachments. This testimony is being filed electronically, pursuant to the Commission's Electronic Document Filing system.

As authorized by Rule 140 of the Commission's Rules of Practice and Procedure, Appalachian Voices is providing, and agrees to accept, service of documents in this case exclusively via email unless parties request otherwise.

If you should have any questions regarding this filing, please do not hesitate to contact me at (434) 977-4090.

Regards,

Nathaniel Benforado

Summary of the Direct Testimony of Gregory Abbott

My testimony examines Dominion Energy Virginia's ("Dominion's") 2023 IRP filing. First, I discuss the five alternative plans Dominion has proposed in this proceeding and the ways in which each plan fails to comply with the Virginia Clean Economy Act ("VCEA") in a credible, least-cost way. Second, I discuss larger problems I see in Dominion's fundamental modeling methodologies. Third, putting individual modeling assumptions aside, Dominion is using the PLEXOS model to solve for a problem that is fundamentally different from the actual issues facing the utility. Specifically, it is clear that all load growth for the DOM LSE[1] is occurring in one concentrated geographic area (northern Virginia) and is attributable to one type of customer (data centers). The model does not take either of these facts into account and instead assumes load growth is spread out over the entire system and over the entire customer base. As such, it is proposing supply-side solutions that are not focused on solving the actual problem, are likely unnecessary, and driving costs higher than they should be. This leads to one of two conclusions. Either Dominion is fundamentally failing to configure the model properly or the model itself is incapable of being configured to solve for this problem. In either event, this IRP has little to no value to the Commission in its consideration of future Renewable Portfolio Standard ("RPS") and Certificate of Public Convenience and Necessity ("CPCN") proceedings.

The primary driver in the model results for new future generation capacity to serve peak load, energy sales, and Renewable Energy Certificates ("RECs") is from data center load growth concentrated in northern Virginia. Further, future system reliability issues will also likely be concentrated in the northern Virginia area of the DOM Zone. Given that data center load growth in northern Virginia is the source of future peak load, energy sales, RECs, and reliability needs, Dominion's planning process should shift to focus on solutions that address data center load growth in that specific geographic part of the DOM Zone. It appears that Dominion's modeling in this case assumes that the load growth for the DOM LSE is more or less spread out equally across Dominion's service territory. Thus, Dominion's PLEXOS model is trying to solve for a load growth rate of 1.6% per year for Dominion's whole system. However, the rest of the system excluding data centers is ***decreasing*** about 1.4% per year. Ignoring this reality in the modeling can lead to solutions such as a gas-fired CT located in Chesterfield County or a SMR located in southwest Virginia to solve future peak load and system reliability problems that are concentrated in the northern Virginia area of the DOM Zone.

Dominion failed to adequately consider non-wires alternatives ("NWAs") and instead all IRP plans contain large amounts of supply-side, high CAPEX, generation resources that can deliver a return to stockholders. Given the unique nature of data center load, I recommend that the Commission direct Dominion to investigate the viability of developing (i) a demand response program and (ii) a time-of-use ("TOU") rate tailored to data centers. This would create a carrot (demand response payments) and stick (TOU rate) to incent large data center customers located in northern Virginia to lower usage during critical peak hours. This could reduce Dominion's PJM coincident peak load and lower Dominion's capacity reserve requirement and, therefore, replace the need to construct new supply-side peaking resources. Demand response could also be called on during extreme weather conditions such as recently experienced during Winter Storm Elliot. Thus, demand response if not just a peaking resource but can also enhance system reliability.

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[1] Load Serving Entity ("LSE").

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF VIRGINIA ELECTRIC AND POWER COMANY *In Re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to § 56-597 et seq.*	)))))))))	Case No. PUR-2023-00066

Direct Testimony of
Gregory Abbott

On Behalf of
Appalachian Voices

August 8, 2023

Q1. PLEASE STATE YOUR NAME AND ADDRESS AND YOUR ROLE WITH APPALACHIAN VOICES.

A1. My name is Gregory Abbott, and my address is 8610 Sunview Lane, North Chesterfield, VA. My expert testimony in this proceeding is on behalf of Appalachian Voices.

Q2. PLEASE SUMMARIZE YOUR EXPERIENCE IN ELECTRIC UTILITY REGULATION IN VIRGINIA.

A2. I was previously employed as a member of the Virginia State Corporation Commission ("Commission") Staff and retired in 2022 as a Deputy Director after 24 years of service in the Commission's Division of Public Utility Regulation. Over the last year I have been self-employed as a consultant. I have widespread experience in the regulation of electric, gas, water and sewer utilities located in the Commonwealth. This experience ranges from general rate increase applications, class cost of service, rate design, Integrated Resource Plans ("IRPs"), generation certificates, Renewable Portfolio Standard ("RPS") cases, coal ash disposal, rate adjustment clauses ("RACs"), Demand-Side Management, PJM matters, weather normalization adjustments, Natural Gas Conservation and Ratemaking Efficiency Act ("CARE") plans, and pole attachments.

Further, I have extensive experience in reviewing Dominion Energy Virginia ("Dominion") generation planning for IRPs, certificates of public convenience and necessity ("CPCNs") for both fossil fuel and renewable generation facilities, and RPS filings. I previously filed testimony on behalf of the Commission's Staff in Dominion's 2013 IRP, 2015 IRP, 2016 IRP, 2017 IRP, 2018 IRP, 2020 IRP, and the 2020 RPS Plan filing. I have testified before the Commission in scores of cases and a representative list of cases is provided in Attachment GLA-1.

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A3. My testimony examines Dominion's 2023 IRP filing, with a focus on the planning process, modeling, and supply-side resources.

Q4. HOW IS YOUR TESTIMONY ORGANIZED?

A4. First, I discuss the five alternative plans Dominion has proposed in this proceeding and the ways in which each plan fails to comply with the Virginia Clean Economy Act ("VCEA") in a credible, least-cost way. Second, I discuss larger problems I see in Dominion's fundamental modeling methodologies. Third, putting individual modeling assumptions aside, Dominion is using PLEXOS to solve for a problem that is fundamentally different from the actual issues facing the utility. Specifically, it is clear that all load growth for the DOM LSE[1] is occurring in one concentrated geographic area (northern Virginia) and is attributable to one type of customer (data centers). The model does not take either of these facts into account and instead assumes load growth is spread out over the entire system and over the entire customer base. As such, it is proposing supply-side solutions that are not focused on solving the actual problem, are likely unnecessary, and driving costs higher than they should be. This leads to one of two conclusions. Either Dominion is fundamentally failing to configure the model properly or the model itself is incapable of being configured to solve for this problem. In either event, this IRP has little to no value to the Commission in its consideration of future CPCN proceedings.

Q5. HOW DOES DOMINION CHARACTERIZE THE 2023 IRP?

A5. Dominion states that, overall, the 2023 IRP is meant for use as a long-term planning document based on a "snapshot in time" of current technologies, market information, and

[1] Load Serving Entity ("LSE").

projections, and should be viewed in that context.[2] This is consistent with Dominion's statements in IRPs from prior years. Dominion is generally reluctant to discuss past snapshots in time from prior IRPs deeming them as no longer relevant. I agree that the 2023 IRP is a "snapshot in time," however, when examined in the context of prior snapshots in time from prior IRPs, a more detailed picture begins to emerge. Dominion has a strong incentive to develop large CAPEX projects that can deliver a return to stockholders. The large capital improvement projects that Dominion develops based on these "snapshots in time" are long-lived resources. So, the 2023 IRP is much more than just a snapshot in time, it sets the stage for multi-billion-dollar investments that Dominion's customers will pay for decades to come. If a future snapshot in time changes, based on new public policy goals or market dynamics, ratepayers are stuck with paying for these sunk costs.

Q6. DO YOU HAVE ANY RECOMMENDATIONS ON WHETHER THE COMMISSION SHOULD APPROVE THE 2023 IRP IN THIS CASE?

A6. The Company has made numerous unreasonable assumptions, such that the resulting plans do not provide the Commission with the information specifically required by the IRP statute and regulations, as well as prior orders. As such, I do not believe the IRP modeling is reasonable, and should not be relied upon by the Commission.

[2] 2023 IRP at 1.

IRP REQUIREMENTS

Q7. PLEASE DESCRIBE THE PERTINENT IRP REQUIREMENTS AS SET FORTH IN LAW, REGULATION, AND PRIOR ORDERS.

A7. Dominion is required to file an IRP under § 56-599 of the Code of Virginia ("Code"). In preparing an IRP, each electric utility is required to systematically evaluate and may propose:

1. Entering into short-term and long-term electric power purchase contracts;
2. Owning and operating electric power generation facilities;
3. Building new generation facilities;
4. Relying on purchases from the short term or spot markets;
5. Making investments in demand-side resources, including energy efficiency and demand-side management services;
6. Taking such other actions, as the Commission may approve, to diversify its generation supply portfolio and ensure that the electric utility is able to implement an approved plan;
7. The methods by which the electric utility proposes to acquire the supply and demand resources identified in its proposed integrated resource plan;
8. The effect of current and pending state and federal environmental regulations upon the continued operation of existing electric generation facilities or options for construction of new electric generation facilities;
9. ***The most cost-effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations***;
10. Long-term electric distribution grid planning and proposed electric distribution grid transformation projects;
11. Developing a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, particularly for low-income, elderly, and disabled customers; reduction in emissions; and reduction in carbon intensity; and
12. Developing a long-term plan to integrate new energy storage facilities into existing generation and distribution assets to assist with grid transformation.

Dominion's 2020 IRP filing was the first IRP filed subsequent to passage of the 2020 Virginia Clean Economy Act ("VCEA"). The Commission issued its Final Order in Case No. PUR-2020-00035 ("2020 IRP Order") on February 1, 2021.

With regard to filing a least-cost plan, footnote 17 on page 6 of the 2020 IRP Order stated:

> …As discussed by the Company, Senate Bill 1349 passed by the 2015 General Assembly required the Commission to submit certain reports to the General Assembly addressing the impacts of federal carbon emission guidelines during the Transitional Rate Period, which has now concluded. Tr. 1229-1233. See also 2015 Acts ch. 6; Code § 56-585.1:1 F 1. As a result, as supported by the Company, the NRDC and Appalachian Voices, ***we will no longer require Dominion to file a least cost plan that does not take into consideration applicable environmental laws and regulations***. See, e.g., Ex. 44 (Levin) at 38-39; Ex. 31 (Rabago) at 9; Ex. 82 (Kelly Rebuttal) at 39. (emphasis added)

Further, on page 14 of the 2020 IRP Order, the Commission states the following:

> To address this issue, Dominion proposes that future IRPs and updates ***include a least cost VCEA plan that would meet (i) applicable carbon regulations and (ii) the mandatory RPS Program requirements of the VCEA***. For this plan, the Company proposes not to force the model to select any specific resource nor exclude any reasonable resource and allow the model to optimize the accompanying resource plan. Based on the record in this proceeding, we find this proposal to be reasonable at this time. (emphasis added) (footnotes omitted)

Further, the Commission issued its Final Order in Dominion's 2022 RPS filing (Case No. PUR-2022-00124) on April 14, 2022 ("2022 RPS Order"). Recommendation 3 on page 8 of the 2022 RPS Order states the following:

> The Commission finds reasonable Dominion's proposal to address - in its next IRP proceeding - (i) the load forecast, modeling, and planning implications of projecting (and conversely not projecting) a portion of data center load increases coming from ARBs, and (ii) its modeling assumption for energy efficiency beginning in 2026.

Q8. WHAT DID DOMINION PROPOSE IN THIS PROCEEDING?

A8. Dominion proposes five plans designated Plans A through E in the 2023 IRP. These plans are described on pages 2 and 3 of the 2023 IRP. Dominion's response to Appalachian

Voices Interrogatory 3-6[3] provided additional information on what resources were forced into the model and which resources were selected by the model on a least-cost optimization basis. Plans A through E are summarized below.

- **<u>Plan A</u>**: This Alternative Plan presents Dominion's least-cost plan that purportedly meets only applicable carbon regulations and the mandatory renewable energy portfolio standard program ("RPS Program") requirements of the Virginia Clean Economy Act ("VCEA"). Dominion states that it presents Plan A in compliance with prior SCC and NCUC orders and for cost comparison purposes only. All resources were selected by the model on a least-cost optimization basis for Plan A. Under Plan A, the model was not subject to the modeling constraint that 65% of solar and onshore wind resources be Dominion-owned and 35% be through power purchase agreements ("PPAs"). It should be recognized that Dominion allowed the model to select a significant amount of gas-fired generation resources for Plan A. Further, all of the existing fossil fuel generation units and the new gas units operate beyond the year 2045 under Plan A. Plan A does not comply with the VCEA's mandatory retirement schedule for carbon-emitting resources, nor does it include unit-specific analysis that would justify an exemption to those mandatory retirement obligations, as required by law. And, of course, such unit-specific analysis would be entirely premature. Dominion has 22 years to figure out how to transition to reliable carbon free generation and should not be permitted to plan for ***non-compliance*** with the retirement requirements.

- **<u>Plan B</u>**: This Alternative Plan forced the model to select the development targets for solar, wind, and energy storage resources that Dominion is required to petition the Commission for approval of under § 56-585.5 D of the Code.[4] Plan B also forced the model to select a single set (970 MWs) of gas-fired combustion turbines ("CTs") in 2028. Further, Plan B forced the model to select a second tranche (2,600 MWs) of offshore wind in 2033. The remaining resources contained in Plan B were selected by the model on a least-cost optimization basis. It should be noted that Plan B includes the development of six new small modular reactors ("SMRs") with the

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[3] Attachment GLA-2 contains Dominion's response to this interrogatory and all other responses to interrogatories referenced throughout my testimony.

[4] Notably, while the VCEA requires Dominion to *propose* a certain amount of resources, the VCEA does not obligate the Commission to *approve* any specific amount of resources. *Petition of Virginia Electric and Power Company for approval of its 2022 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia and related requests*, Case No. PUR-2022-00124. Final Order Apr. 14, 2023 at 9 ("VCEA does not require the Commission to approve cost recovery for all new projects *at any cost"*) (emphasis in original).

first SMR coming on-line in 2034. Plan B also preserves existing fossil fuel generation and includes several new gas CTs. As with Plan A, all of the existing fossil fuel generation units and the new gas CT units operate beyond the year 2045 under Plan B.

- **<u>Plan C</u>**: This Alternative Plan differs from Plan B in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources that Dominion is required to petition the Commission for approval of under § 56-585.5 D of the Code. Plan C differs from Plan A in that the model was subject to the modeling constraint that 65% of solar and onshore wind resources be Dominion-owned and 35% be through PPAs. The model selected a significant amount of gas-fired generation resources for Plan C. Further, as with Plans A and B, all of the existing fossil fuel generation units and the new gas units operate beyond the year 2045 under Plan C.

- **<u>Plan D</u>**: This Alternative Plan retires all existing and new Dominion-owned carbon-emitting generation by the end of 2045, resulting in zero carbon dioxide ("CO2") emissions from the Company's fleet in 2046. Plan D forced the model to select the development targets for solar, wind, and energy storage resources that Dominion is required to petition the Commission for approval of under § 56-585.5 D of the Code. Plan D also forced the model to select a single set (970 MWs) of gas-fired CTs in 2028. Further, Plan D forced the model to select a second tranche (2,600 MWs) of offshore wind in 2033. The remaining resources contained in Plan D were selected by the model on a least-cost optimization basis. In order to retire all carbon-emitting units by the end of 2045, Plan D shows the Company building over 4,500 MW of incremental energy storage and more than 3,000 MW of incremental SMRs to meet this need when compared to Plan B.

- **<u>Plan E</u>**: This Alternative Plan is like Plan D in that it retires all Dominion-owned carbon-emitting generation by the end of 2045. Plan E differs from Plan D in that all new generation resources were selected on a least-cost optimization basis without regard for the development targets for solar, wind, and energy storage resources that Dominion is required to petition the Commission for approval of under § 56-585.5 D of the Code.

Q9. WHAT DO YOU CONCLUDE ABOUT THE PLANS?

A9. None of the five plans presented in the 2023 IRP follow the Commission's express directives and should be either rejected entirely or dismissed as unreliable for informing future CPCN cases.

Q10. PLEASE DISCUSS THE COMPANY'S PLANS IN CONNECTION WITH THE VCEA REQUIREMENTS.

A10. It is clear that the main policy goal of the VCEA is to move the Commonwealth to a reliable zero-carbon energy future. This is accomplished by establishing a mandatory RPS Program in § 56-585.5 C of the Code that requires Dominion to meet a RPS Program requirement for zero carbon energy sales that begins at 14% of total electric energy sold[5] in 2021 and reaches 100% of total electric energy sold by 2045.

In addition, § 56-585.5 B 1 of the Code requires Dominion to retire all coal units by December 31, 2024 except those that are jointly owned with a cooperative utility (Clover units 1 and 2) or those that co-fire with biomass (VCHEC). Further, § 56-585.5 B 2 of the Code requires Dominion to retire ***all*** carbon emitting fossil fuel generating units (including Clover units 1 and 2 and VCHEC) that emit carbon as a by-product of combusting fuel to generate electricity by December 31, 2045. Lastly, pursuant to § 56-585.5 B 3 of the Code, Dominion may petition the Commission for relief from the requirements to retire fossil fuel generating units on the basis that the requirement would threaten the reliability or security of electric service to customers. § 56-585.5 B 3 also states that the Commission shall consider in-state and regional transmission entity resources and

[5] Total electric energy sold excludes sales to accelerated renewable energy buyers ("ARBs") and electric energy that was supplied by nuclear generating plants located in the Commonwealth.

shall evaluate the reliability of each proposed retirement on a ***case-by-case basis*** in ruling upon any such petition. The default assumption for all plans should be that all carbon-emitting fossil fuel units will retire by 2045 consistent with the zero-carbon policy goal of the VCEA, and the model should be solving to maintain reliability in a least-cost way while meeting those retirement deadlines. Existing carbon-emitting fossil fuel generating units should not be included to operate beyond 2045 in the IRP plans unless Dominion is able to demonstrate on a case-by-case, unit-by-unit, basis that the retirement of each unit would threaten the reliability or security of the system. For Plans A, B, and C, Dominion assumes that system reliability will be threatened by the retirement of its fossil fuel generation fleet as a whole, and each of these plans call for the continued operation of Dominion's entire existing fossil fuel generation fleet beyond 2045 as a consequence. Dominion has not performed any reliability analysis of retiring each carbon emitting fossil fuel unit on a case-by-case basis for the 2023 IRP. Instead, Dominion makes an assumption that the entire fossil fuel fleet is required to maintain system reliability. Such a blanket assumption for the entire fleet is at odds with the requirements pursuant to § 56-585.5 B 3 of the Code, and Dominion has not performed an adequate analysis in the 2023 IRP to show system reliability is threatened on a case-by-case, unit-by-unit, basis. Plans A, B, and C should be rejected as a result.

§ 56-585.5 D of the Code requires Dominion to petition the Commission for approval to construct, acquire, or enter into purchase agreements for 16,100 MWs of generating capacity from solar and onshore wind resources located in the Commonwealth.[6]

[6] Further, pursuant to Code § 56-585.5 G, the nameplate capacity of bundled ARB solar and wind facilities offset (lower) Dominion's nameplate development targets for solar and wind facilities under Code § 56-585.5 D

In addition, pursuant to § 56-585.5 D and § 56-585.1:11 of the Code, Dominion is required to petition the Commission for approval to construct or purchase one or more offshore wind facilities with an aggregate capacity up to 5,200 MWs.

The VCEA addresses system reliability concerns of transitioning to a zero-carbon energy future by requiring Dominion to petition the Commission for approval to construct or acquire 2,700 MWs of energy storage capacity by December 31, 2035 pursuant to § 56-585.5 E of the Code.

Q11. PLEASE DISCUSS THE COMPANY'S PLANS IN CONNECTION WITH THE REGIONAL GREENHOUSE GAS INITIATIVE.

A11. The VCEA and the Clean Energy and Community Flood Preparedness Act of 2020 ("CECFPA") required Virginia's participation in the Regional Greenhouse Gas Initiative ("RGGI"). The primary purpose of RGGI is to provide a price signal to reduce the dispatch of fossil fuel units to reduce carbon output. Dominion's default assumption for all of the Plans, A through E, is that Virginia is out of RGGI as of January 1, 2024. This is contrary to the Commission's directive in the 2020 IRP Order that Dominion is no longer required to file a least cost plan that does not take into consideration applicable environmental laws and regulations. RGGI is currently required by law in Virginia. Virginia Governor Youngkin issued an executive order to begin a regulatory process to remove Virginia from RGGI. Dominion based its modeling assumption on this regulatory process. Nevertheless, RGGI is currently required under the law and should be the default assumption for all plans proposed in the IRP. Dominion does present a set of sensitivity model runs showing the results of Virginia remaining in RGGI for each of the five plans. In my view, Dominion has it backwards. Virginia remaining in RGGI should be the default assumption for the IRP plans and Virginia exiting RGGI should have been the sensitivity. Moreover, the model should be configured so that RGGI allowance costs for fossil units affect unit dispatch. In other words, the costs of allowances should influence whether and when units dispatch rather than simply act as a ***post hoc*** cost adder.

Q12. PLEASE DISCUSS THE COMPANY'S PLANS IN CONNECTION WITH THE ENERGY EFFICIENCY RESOURCE STANDARD.

A12. The VCEA also made certain revisions to § 56-596.2 of the Code addressing energy efficiency. For Dominion, the annual energy savings targets to be achieved through energy efficiency programs were established beginning in 2022 with a target of 1.25% of average annual energy jurisdictional retail sales for calendar year 2019. By 2025, the energy savings target grows to 5% of average annual energy jurisdictional retail sales for calendar year 2019. Further, § 56-596.2 B 3 of the Code specifies that the Commission shall establish new energy efficiency savings targets for 2026 through 2028 and for every successive three-year period thereafter. For Plan A, Dominion assumed that the energy efficiency savings targets would not be met. For Plans B through E, Dominion assumed that enough generic energy efficiency programs could be implemented that would allow the Company to meet the 5% energy savings target in 2025. Dominion then held the energy savings target constant at a flat 5% for year 2026 and beyond. This assumption by Dominion is not responsive to the Commission's directive in the 2022 RPS Order. The 2022 RPS Order directed Dominion to address its modeling assumption for energy efficiency beginning in 2026. In the 2022 RPS filing, Dominion's modeling assumption was identical to the current assumption that it would implement energy efficiency programs that would achieve the energy savings target of 5% for 2025 and then held that 5% energy savings level constant for year 2026 and beyond. Utilizing the exact same modeling assumption for the energy savings targets beginning in 2026 in the 2023 IRP as Dominion used in the 2022 RPS filing is not responsive to the Commission's directive in the 2022 RPS Order that Dominion address the modeling assumption for energy efficiency. It would be more reasonable to assume that the Commission will approve a modest growth rate in the energy savings targets for year 2026 and beyond.

The VCEA also made certain revisions to § 56-585.1 A 5 c of the Code that prevents the Commission from approving the construction of any new utility-owned generating facilities that emit carbon as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § 56-596.2 of the Code.[7] All five of the IRP Plans A through E call for the construction of new gas-fired generation units. Dominion admits that Plan A will not achieve the energy savings goals, so the inclusion of new gas-fired generation in Plan A is not allowed under the law and, consequently, Plan A should be rejected on that basis.[8] For Plans B through E, Dominion assumes that it will hit the energy savings goals through generic (unspecified) energy efficiency programs and meeting those goals would allow for the construction of new gas-fired generation. However, Dominion assumes a flat energy savings goal for 2026 and beyond which may artificially lower the bar below what the Commission may deem acceptable and it relies on generic energy efficiency programs rather than on actual

[7] A similar restriction was also added to § 56-585.1 A 6.

[8] The VCEA does technically allow the Commission to approve new carbon-emitting facilities even if Dominion has failed to meet its energy efficiency targets, but such approval can only happen if "the Commission finds in its discretion and *after consideration of all in-state and regional transmission entity resources* that there is a threat to the reliability or security of electric service to the utility's customers," and "that supply-side resources are more cost-effective than demand-side or energy storage resources." Va. Code § 56-585.1 A 5 c. There is nothing in this IRP even approaching an analysis that would meet all these requirements.

programs that can potentially deliver the energy savings required. Including the construction of new gas-fired generation units in all five of the IRP plans seems overly optimistic and inconsistent with proper planning that would also examine plans on the basis that the energy savings goals are not actually achieved and that new construction of carbon emitting fossil fuel units would be prevented by law. For example, failing to achieve the energy savings goals would preclude Dominion from constructing new Dominion-owned gas-fired units, however, it would not preclude Dominion from entering into a PPA with a gas-fired generation unit owned by a third-party. It does not appear that Dominion has performed any analysis of alternative plans for the very real possibility that it does not achieve the energy savings goals.

Q13. DID DOMINION IDENTIFY A LEAST-COST VCEA-COMPLIANT PLAN THAT MEETS APPLICABLE CARBON REGULATIONS AND THE MANDATORY RPS PROGRAM REQUIREMENTS?

A13. No. Plan A is Dominion's least-cost plan, but it is not compliant with the VCEA because it (i) does not retire all carbon emitting fossil fuel generating units by December 31, 2045, (ii) does not achieve the energy savings goals, (iii) constructs new gas-fired resources despite not achieving the energy savings goals, and (iv) assumed that Virginia exits RGGI on December 31, 2023. Therefore, Dominion has failed to comply with the Commission's directive to identify a least-cost VCEA-compliant plan.

MODEL ASSUMPTIONS AND RESULTS

Q14. IN ADDITION TO DOMINION'S FAILURE TO PROPERLY MODEL THE VCEA, AS REQUIRED BY THE COMMISSION, DO YOU HAVE ANY OTHER CONCERNS ABOUT DOMINION'S MODELING?

A14. Yes. In addition to the concerns already discussed for Plans A through E, there are a number of modeling assumptions and constraints used by Dominion that also draw into question the usefulness of the model results for each plan.

The results that are obtained from running the PLEXOS model are only as good and reliable as the modeling assumptions that are used as inputs into the model. Developing long-term forecasts of peak load, energy consumption, commodity prices, on-peak and off-peak energy prices, capacity prices and renewable energy certificate ("REC") prices is inherently uncertain and difficult to forecast. In addition to these forecasts, a number of other model constraints are included in the modeling. I do not present a comprehensive critique of every modeling assumption and constraint used in the model, but there are several assumptions that Dominion used that are problematic and may render the model results unreliable. At a minimum, further refinement of the modeling assumptions and inputs will better inform future Dominion filings. I find the following model assumptions, constraints, and inputs problematic:

- Dominion's transmission constraint of 5,200 MWs for importing/exporting power from/to PJM's energy markets;
- Dominion does not include the energy produced from Dominion-owned Ring-Fence facilities in the model;
- Dominion does not include the energy produced from renewable facilities under PPAs with bundled Accelerated Renewable Energy Buyers ("ARBs") in the model;
- Dominion's capacity assumption of future data center load that will be bundled ARBs is not realistic;

- Dominion's peak load forecast appears to be biased to the high side and is subject to a high level of uncertainty;
- Dominion's capacity price forecast appears to be biased to the high side and is subject to a high level of uncertainty; and
- Dominion's model assumption for coal unit dispatch may not fully capture the costs associated with actual coal unit dispatch.

Q15. HOW DID DOMINION DETERMINE THE 5,200 MW IMPORT/EXPORT TRANSMISSION CONSTRAINT USED IN THE MODEL?

A15. Dominion's response to Appalachian Voices Interrogatory No. 10-1 states that it studied the import limits utilized in previous IRP studies and that this import/export limit was not changed in the 2023 IRP since it would have similar results. Further, Dominion stated that the limits of the external tie lines have not been updated significantly since this initial study.

Q16. DOES THIS 5,200 MW IMPORT/EXPORT TRANSMISSION CONSTRAINT IN THE MODEL ACCURATELY REFLECT DOMINION'S ABILITY TO PURCHASE ENERGY FROM THE PJM MARKETS?

A16. No. The 5,200 MW transmission constraint applies to imports to and exports from the DOM Zone from/to the rest of the PJM RTO. Dominion's modeling in the 2023 IRP is for the DOM LSE and not the entire DOM Zone. There are a number of merchant generating plants located inside the DOM Zone. These merchant plants sell energy into the PJM wholesale energy markets. Thus, there is energy available inside the DOM Zone that would not be subject to the 5,200 MW import transmission constraint that the model does not consider.

Q17. IS THE ENERGY FROM A MERCHANT GENERATOR LOCATED IN THE DOM ZONE AVAILABLE FOR LOCAL CONSUMPTION IF IT IS UNDER CONTRACT WITH AN OUT OF STATE UTILITY?

A17. It is important to realize that there is a difference between a paper transaction for energy sales/purchases and the actual flow of electrons on the grid. Assuming that the merchant plant is located in the DOM Zone, the electrons produced will flow onto the grid and intermingle with the electrons of all other generating units. These electrons will flow to load centers according to the laws of physics. So, on paper, a generator may have a sales contract to deliver energy to a utility in New Jersey, but the actual energy produced is consumed by load centers closer to the plant. Thus, for a Dominion purchase of energy from the PJM market, the actual energy delivered could be from a merchant generator located in the DOM Zone even though that energy, on paper, is delivered to New Jersey.

Q18. ARE THERE MANY MERCHANT PLANTS LOCATED IN THE DOM ZONE?

A18. Yes. Some of the merchant renewable facilities under PPAs with bundled ARBs are located in the DOM Zone. Further, there are some rather large merchant gas-fired generating plants located in the DOM Zone as shown below.

Tenaska Energy Partners	1,011 MW
LS Power Doswell Energy Center	1,313 MW
Panda Stonewall Power Project	802 MW

Over 3,000 MWs of existing dispatchable generation from merchant generators are located in the DOM Zone. To the extent that energy from these plants is sold into the PJM wholesale energy market, it would be available to be purchased by Dominion through those same energy markets without passing through the external tie lines. Dominion's modeling assumes that such energy purchases from these merchant plants located inside the DOM

Zone would be subject to the 5,200 MW import limit based on the limits of the external tie lines between the DOM Zone and the rest of the PJM RTO. This is clearly an incorrect assumption.

Q19. ARE DOMINION-OWNED UNITS LOCATED OUTSIDE OF THE DOM ZONE SUBJECT TO THE 5,200 MW IMPORT LIMIT?

A19. No. Even though the VCHEC coal unit and the Bath County pumped storage units are located in the AEP Zone and energy produced from these plants has to be physically imported into the DOM Zone through the external tie lines, Dominion's response to Appalachian Voices Interrogatory No. 6-12 states that "The import/export constraint is applied to MWhs being sold or purchased from the PJM market, not to Company-owned generation units."

Q20. WHAT IS YOUR RECOMMENDATION ON THE USE OF THE 5,200 MW IMPORT/EXPORT TRANSMISSION CONSTRAINT IN THE MODELING?

A20. Dominion is using a modeling constraint of a 5,200 MW import/export limit that was apparently from an internal study performed for a prior IRP many years ago. It is not clear how many years back the original study was performed. There have undoubtedly been a number of changes in load growth, the emergence of data center load growth concentrated in northern Virginia, Dominion-owned generation units coming on line, merchant generation units coming on line, generation unit retirements, Ring-Fence facilities coming online, bundled ARBs, transmission line upgrades, etc. that could impact the results of such a study. Further, Dominion is using a physical import transmission constraint for the DOM Zone to model energy purchases of the DOM LSE from the PJM energy market. Not all non-Dominion-owned generation is located outside of the DOM Zone, but Dominion's modeling treats it as if it is. The continued use of a transmission import/export constraint of 5,200 MWs without a more recent study to support it appears to be too low for purposes of purchases/sales from/to the PJM energy market given the amount of merchant gas generation and renewable generation located inside the DOM Zone. Nevertheless, it is important to include an import/export constraint in the model because otherwise the model may seek to build an unlimited amount of generation to serve the PJM RTO if projected PJM energy prices are relatively high or, conversely, try to purchase all of Dominion's forecasted energy needs from PJM if projected energy prices are relatively low.

I recommend that the Commission direct Dominion to conduct a new study to set a more realistic import/export constraint in future IRP filings and to file this study as part of its next IRP filing. Further, I recommend that this study be updated on a regular basis given the ongoing transformation of the energy grid in Virginia and the other PJM states.

Q21. WHAT ARE THE IMPLICATIONS OF USING AN IMPORT/EXPORT ENERGY SALES CONSTRAINT THAT IS TOO LOW IN THE MODEL?

A21. This constraint can skew the net present value ("NPV") results of the various plans, perhaps significantly. Also, ignoring the energy produced and sold into the PJM wholesale energy market by existing merchant generating units located inside the DOM Zone could exaggerate potential system reliability needs and the timing of those needs.

Q22. WHAT ARE YOUR CONCERNS WITH DOMINION'S MODELING ASSUMPTIONS FOR DOMINION-OWNED RING-FENCE FACILITIES?

A22. Dominion's response to Appalachian Voices Interrogatory No. 11-5 states that Ring-Fence solar and wind facilities are modeled as capacity resources in the PLEXOS model. However, Dominion further states that the energy produced by these units is sold into the

PJM market and is not used to serve retail customers. Thus, these units are not modeled as energy producers in the PLEXOS model.

My concern here is similar to the concern that I have with merchant generators located in the DOM Zone. These Dominion-owned Ring-Fence facilities are physically located in the DOM Zone. The energy that is produced is sold into PJM's wholesale energy market. Dominion's modeling treats this energy production as being subject to the 5,200 MW import constraint. In reality, this energy is available for purchase by Dominion from the PJM energy market without having to pass through the external tie lines between the DOM Zone and the rest of the PJM RTO. To the extent that a Dominion-owned Ring-Fence facility is used in a PPA arrangement with a bundled ARB, the energy produced by the Ring-Fence facility is sold into the PJM wholesale energy market on behalf of the bundled ARB and is not directly used to serve the retail load of the bundled ARB customer.[9] Thus, the energy produced from a Dominion-owned Ring-Fence facility located in Virginia that is sold to a bundled ARB customer also located in Virginia through a PPA is subject to the 5,200 MW import constraint as if it came from out of the DOM Zone.

Q23. WHAT ARE YOUR CONCERNS WITH DOMINION'S MODELING ASSUMPTIONS FOR RENEWABLE FACILITIES USED TO SERVE BUNDLED ARBS?

A23. My concerns are identical to the concerns I identified for merchant plants located in the DOM Zone and Dominion-owned Ring-Fence facilities. Although some bundled ARBs are served by Dominion-owned Ring-Fence renewable facilities, there are other bundled ARBs that have PPAs with merchant renewable resources located in the DOM Zone. Dominion's

[9] Dominion's response to Appalachian Voices Interrogatory No. 11-4 (a).

modeling treats the energy production from these bundled ARB merchant plants as being subject to the 5,200 MW import constraint. In reality, this energy is available for purchase by Dominion from the PJM wholesale energy market without having to pass through the external tie lines between the DOM Zone and the rest of the PJM RTO.

Q24. HAS THE COMMISSION PREVIOUSLY DIRECTED DOMINION TO ADDRESS THE ASSUMPTION OF DATA CENTER LOAD INCREASES COMING FROM ARBS?

A24. Yes. In the Commission's April 14, 2023 Final Order in Case No. PUR-2022-00124, the Commission directed the following:

> The Commission finds reasonable Dominion's proposal to address - in its next IRP proceeding - (i) the load forecast, modeling, and planning implications of projecting (and conversely not projecting) a portion of data center load increases coming from ARBs, and (ii) its modeling assumption for energy efficiency beginning in 2026.[10]

Given that the load growth forecast is driven by data center load growth, the amount of this data center growth that becomes bundled ARBs and REC-only ARBs can have a profound impact on the modeling results. The nameplate capacity of bundled ARB solar and wind facilities offset Dominion's nameplate development targets for solar and wind facilities under Code § 56-585.5 D. Further, the number of RECs produced from bundled ARB renewable facilities and REC-only ARB renewable facilities reduce the number of RECs that Dominion is required to procure to comply with the mandatory RPS requirements under Code § 56-585.5 C.

[10] Case No. PUR-2022-00124. See April 14, 2023 Final Order at 8.

Q25. HAVE YOU EXAMINED THE ASSUMPTIONS THAT DOMINION USED IN THE MODEL FOR DATA CENTER LOAD COMING FROM ARBS?

A25. Yes. I examined Dominion's assumptions for the nameplate capacity, energy produced, and RECs produced from bundled ARBs and REC-only ARBs under contract with data centers. Dominion's model makes growth assumptions for the nameplate capacity of bundled ARB renewable facilities under contract with data centers and for the energy produced by bundled ARB renewable facilities, but those growth assumptions are inconsistent with each other.

Q26. WHAT DID DOMINION ASSUME FOR THE NAMEPLATE CAPACITY FOR RENEWABLE FACILITIES UNDER CONTRACT WITH BUNDLED ARBS?

A26. Dominion's response to Appalachian Voices Interrogatory No. 11-1 stated that: "The aggregate nameplate capacity for facilities under bundled contracts with ARBs that were used in the Plexos modeling was 1,074 MW for 2024-2038."

Q27. IS THAT A REASONABLE ASSUMPTION?

A27. No, not in my opinion. The technology companies that own these data centers typically have zero-carbon corporate policies. Given the size of the projected data center load and technology companies' zero-carbon corporate policies, many of these customers will likely become ARBs pursuant to § 56-585.5 G of the Code.

Dominion's response to Appalachian Voices Interrogatory No. 7-5 indicates that there was a total of 9,900,020 MWhs of ARB-certified load based on 2022 production from ARB-qualifying facilities. Of this total, 9,774,225 MWhs or 98.7%, was associated with companies that operate data centers.

It is not a reasonable assumption to use in the model that the nameplate capacity of renewable facilities under contract with bundled ARBs will remain a constant 1,074 MWs over the entire study period through 2038 given the fact that data center coincident summer peak load is forecasted to grow at an average annual rate of 13.71% over the next five years. This would imply that data centers' desire for zero-carbon energy is decreasing as shown in the table below.

	Total DOM LSE Data Center Peak Load	ARB Nameplate Capacity	ARB Nameplate Capacity As a Percentage of Peak Load
2022	2,627	1,074	40.88%
2023	3,127	1,074	34.35%
2024	3,627	1,074	29.61%
2025	3,889	1,074	27.62%
2026	4,620	1,074	23.25%
2027	4,994	1,074	21.51%
Average Annual Growth Rate	**13.71%**		

Dominion's assumption of a flat 1,074 MWs of ARB nameplate capacity through the planning period means that the percentage of nameplate capacity compared to forecasted data center peak load from ARB facilities would decrease from about 40.9% in 2022 to 21.5% in 2027. This percentage would continue to decline rapidly beyond 2027. In my opinion, it would be more reasonable to assume that the bundled ARB nameplate capacity would grow at about the same rate as data center peak load growth.

Q28. WHAT DID DOMINION ASSUME FOR THE AMOUNT OF ENERGY PRODUCED BY ARB-CERTIFIED FACILITIES USED TO OFFSET THE MANDATORY RPS LOAD REQUIREMENTS?

A28. This is discussed on pages 124-125 of the 2023 IRP. Dominion states that: "For purposes of this 2023 Plan, the Company used the 2022 production for (i) all Company facilities that are under contract with a customer seeking certification as an ARB in the 2023 certification process, and (ii) all facilities that were submitted by the customer seeking certification as an ARB in the 2023 certification process to calculate the percentage of each customer's load covered by its renewable energy facilities The Company then maintained the calculated percentage to project that customer's load over the 25-year Study Period of this 2023 Plan, which assumes customer growth and that each facility maintains its 2022 production during the life of the contract."

Q29. DO YOU AGREE WITH THIS APPROACH?

A29. Dominion's assumption for forecasting energy (*i.e.*, MWh production) from ARB-certified facilities for purposes of determining the mandatory RPS compliance requirements in the model appears to be reasonable.

Dominion's response to Appalachian Voices Interrogatory No. 11-2 (Attachment APV Set 11-02 (KES)) provided the aggregate annual energy production (MWhs) for facilities under bundled contracts with ARBs used in modeling for 2024-2038. This energy assumption, however, is in conflict with Dominion's assumption regarding aggregate nameplate capacity for facilities under bundled contracts with ARBs that were used in the modeling of a flat 1,074 MW for 2024-2038.

Q30. PLEASE EXPLAIN THIS CONFLICT BETWEEN THE TWO ASSUMPTIONS.

A30. Dominion appears to assume a reasonable forecast for the amount of energy (MWhs) produced from bundled ARB facilities, but it is actually impossible to achieve this forecasted energy production from Dominion's assumed forecasted growth of renewable capacity under contract with bundled ARBs. The amount of energy produced in a year from solar facilities with a nameplate capacity of 1,074 MWs at a 100% capacity factor would be 9,408,240 MWhs, which is an impossibility since the sun doesn't shine at night. Dominion's model assumption for the aggregate annual energy production from ARB-certified facilities exceed this level by 2027. The table below shows the suggested capacity factors that would have to be realized from 1,074 MWs of solar resources to achieve the energy assumption for the period 2023-2035.

Compliance Year	ARB Bundled Facility Production	Capacity Factor 1,074 MW Solar Capacity	Equivalent Solar Capacity (MW) at 22.2% CF
2023	4,661,113	49.54%	2,397
2024	6,024,206	64.03%	3,098
2025	7,452,079	79.21%	3,832
2026	8,207,683	87.24%	4,220
2027	10,059,501	106.92%	5,173
2028	11,201,290	119.06%	5,760
2029	12,499,885	132.86%	6,428
2030	13,874,879	147.48%	7,135
2031	15,353,614	163.19%	7,895
2032	16,840,277	178.99%	8,659
2033	18,636,353	198.09%	9,583
2034	20,418,209	217.02%	10,499
2035	22,481,574	238.96%	11,560

By 2027, Dominion's assumption of energy production from ARB-certified facilities would result in a capacity factor of about 107% for the 1,074 MW capacity of ARB-certified facilities assumed in the model. By 2035, the 1,074 MWs of solar facilities would have to perform at a 239% capacity factor to produce the energy assumption used in the model.

In the last column of the table, I have calculated the equivalent nameplate capacity of solar facilities (using the three-year average CF of 22.2%) required to produce the ARB-certified energy assumed in the model. By 2027, 5,173 MW of ARB-certified solar facilities would be required. This grows to 11,560 MWs by 2035.

This level of ARB capacity offsets would reduce Dominion's nameplate capacity development targets for solar and wind facilities under Code § 56-585.5 D from 6,000 MWs to 827 MWs in 2027 and from 16,100 MWs to 4,540 MWs by 2035.

Q31. WHAT IS YOUR RECOMMENDATION FOR THE DATA CENTER ARB MODEL ASSUMPTION?

A31. The assumption used in the 2023 IRP of a constant ARB-certified nameplate capacity is in conflict with the extremely high growth forecast of data center load and is not realistic. Therefore, the model results are of dubious value, and the Commission could reject the IRP on that basis. At a minimum, I recommend that the Commission direct Dominion, in its next IRP filing and its 2023 RPS filing, to use a projected ARB-certified nameplate capacity that corresponds to its forecast of the energy produced from ARB-certified facilities used to offset Dominion's load for purposes of its mandatory RPS compliance requirements. The actual nameplate capacity from ARB-certified facilities under bundled contracts with data center companies for the most recent year should be forecasted to grow at the same rate as Dominion's forecast of data center load growth.

Q32. WHAT IS YOUR CONCERN WITH DOMINION'S PEAK LOAD FORECAST?

A32. My testimony does not address the accuracy of Dominion's load forecasts used in the 2023 IRP. Appalachian Voices witness Wilson discusses the reasonableness of Dominion's load forecast in his testimony. I am more concerned with planning based on a highly uncertain peak load forecast. Given the particular uncertainties around the data center market in Virginia and northern Virginia—which as I understand, the Company has failed to study or investigate—there is a very real possibility that the forecast is significantly overstated in the mid and long-term.

Q33. HOW DO INACCURATE LOAD FORECASTS ERODE THE UTILITY OF THE MODELING OUTPUTS?

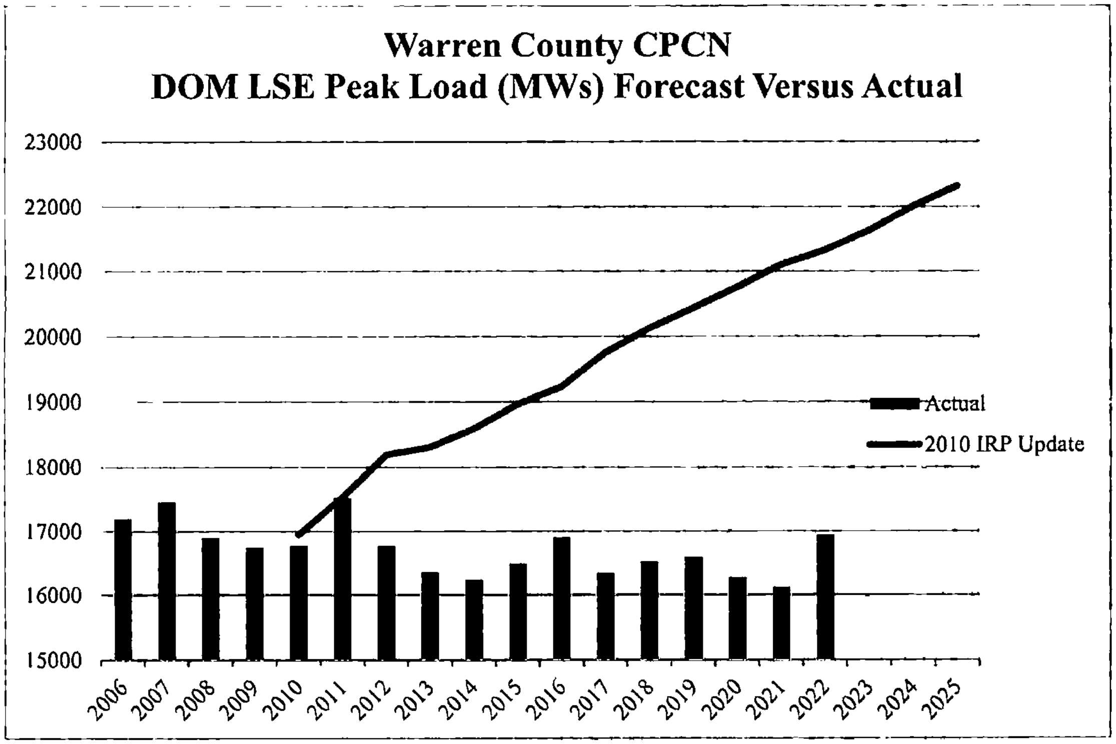
A33. It is instructive to examine the historic track record and the risk of error in the forecast that may subject Dominion's customers to undue risk. The load forecast drives the need for future resources to serve peak load, energy sales, and meet the REC requirements. All of Dominion's IRP plans meet these projected needs exclusively with new Dominion-owned resources[11] and only include third-party PPAs and non-wires alternatives ("NWAs") to the extent required by law. Given this, a load forecast that is biased to the high side can lead to an excessive build out of expensive Dominion-owned generation resources. All of these new generation resources will be included in rate base and recovered from customers, with a guaranteed return for shareholders, whether it turns out that the resources are actually needed to serve load or not.

Q34. CAN YOU PROVIDE AN EXAMPLE OF THE IMPACT OF THIS LOAD FORECAST INACCURACY?

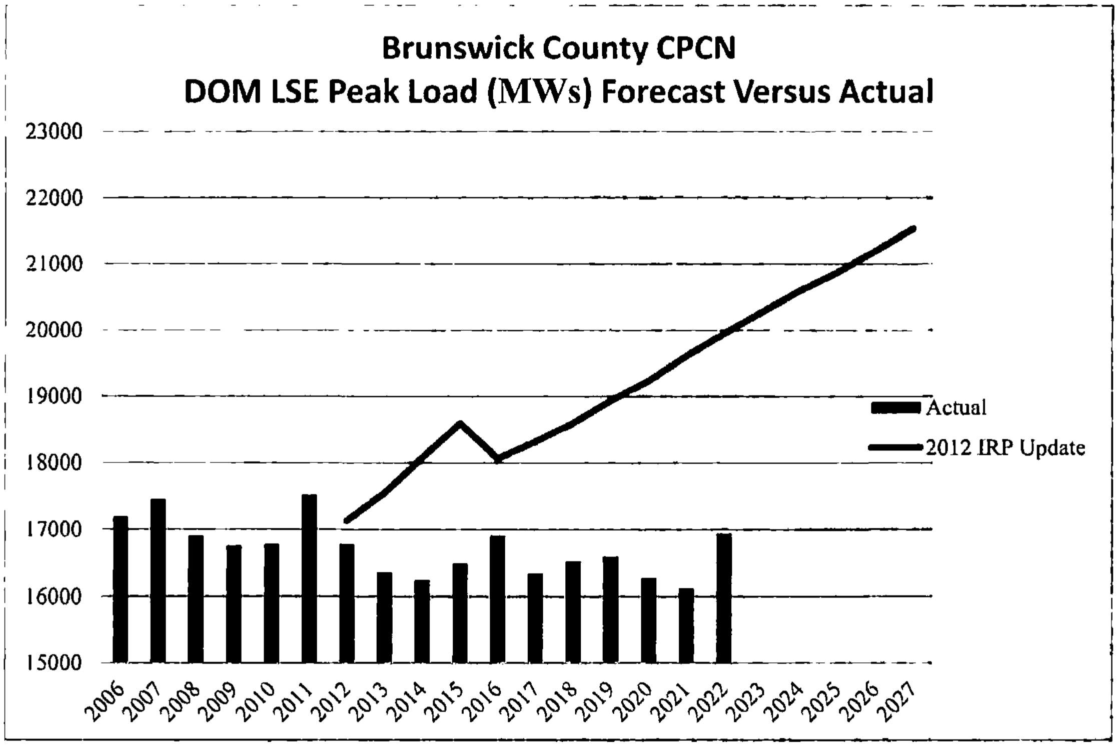
A34. Yes by looking at how prior "snapshots in time" for the load forecast from the time of approval for prior generation units have played out. The CPCNs for the Warren, Brunswick, and Greensville plants used peak load forecasts from Dominion's most recent

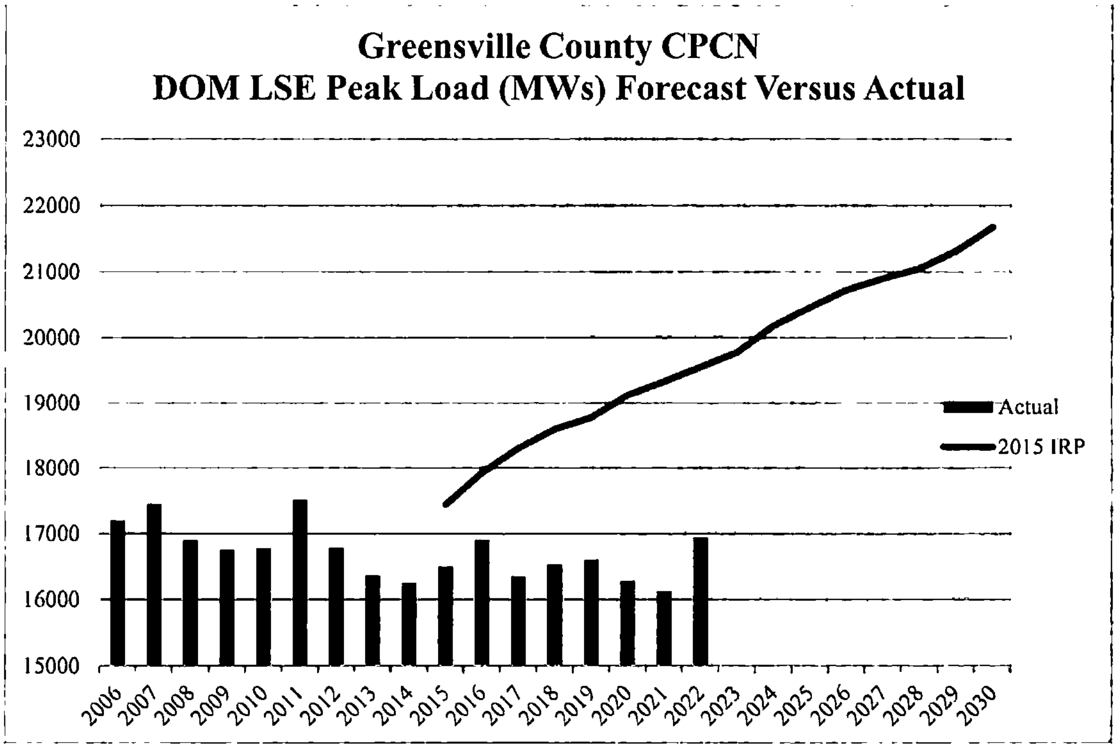
[11] All of the 2023 IRP Plans A through E also include various amounts of market capacity purchases that are generally higher in the latter years of the study period and are higher for Plans D and E. It does not appear that Dominion has any clearly defined plans to make future capacity purchases from the market at this time. Rather, Dominion made a modeling assumption that capacity would be available for purchase within PJM.

IRP filing at the time. The charts below show how well Dominion's peak load forecast in those prior CPCN cases did in predicting actual peak load growth.[12]



[12] The actual peak load data is not weather normalized.

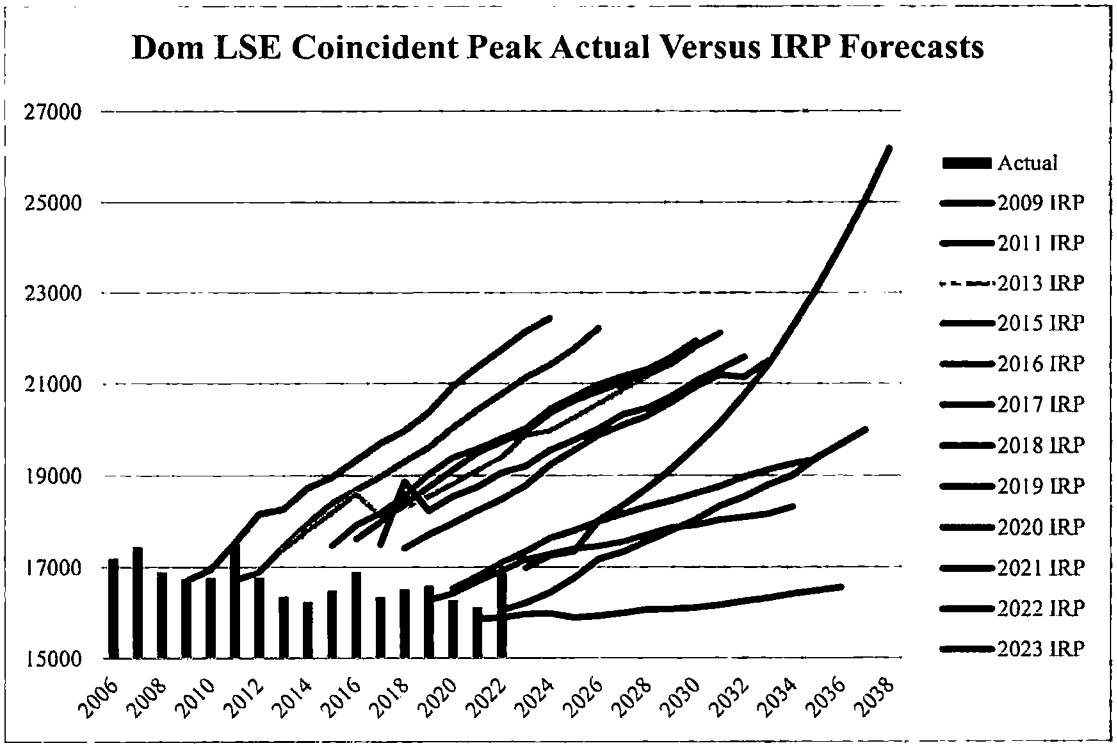

Brunswick County CPCN
DOM LSE Peak Load (MWs) Forecast Versus Actual
23000
22000
21000
20000
19000
18000
17000
16000
15000
Actual
2012 IRP Update
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027


Greensville County CPCN
DOM LSE Peak Load (MWs) Forecast Versus Actual
23000
22000
21000
20000
19000
18000
17000
16000
15000
Actual
2015 IRP
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

The load forecasts used to justify the need for these plants have proven to be inaccurate, at least so far. More concerning, however, is that this inaccuracy is consistently in one direction – to the high side.

Q35. DOES DOMINION'S TRACK RECORD FROM PRIOR IRP PEAK LOAD FORECASTS EXHIBIT THIS SAME BIAS?

A35. The historic record of Dominion's peak load forecast from prior IRPs is depicted in the chart below.



The peak load forecasts used for all IRPs through 2018 were Dominion's internal peak load forecasts. All of the Dominion internal peak load forecasts from 2009 through 2018 were consistently inaccurate to the high side.

Beginning with the 2019 IRP Update, as directed by the Commission, Dominion began using the PJM coincident peak load forecast for the DOM Zone to derive the DOM LSE peak load forecast. As I understand it, PJM incorporates a Dominion generated data center forecast into its forecast. Moreover, as I understand it, Mr. Wilson has identified significant issues with the data center forecast, including a potential double-counting issue and significant market uncertainties in the mid and long-term, which the Company has failed to investigate or study. Given the steep trajectory of the 2023 IRP peak load forecast, driven by projected data center growth, and the concerns identified by Mr. Wilson in the data center forecast, I believe that Dominion's customers are at risk of a significant over build of Dominion-owned resources should that forecast not materialize.

Q36. CAN YOU RECOMMEND A STRATEGY TO ADDRESS THE RISKS POSED TO CAPTIVE CUSTOMERS FROM UNCERTAINTY IN THE PEAK LOAD AND ENERGY SALES FORECASTS?

A36. Yes. The best way to avoid ratepayer risk of over building is to incorporate more PPAs with third-party generators rather than relying solely on brand new Dominion-owned generation resources. That way, Dominion could plan to meet the forecasted peak load, but if the forecast does not materialize, then the PPAs could be allowed to expire and Dominion's captive customers would not be burdened with paying for Dominion-owned resources that are not needed. A reasonable strategy would utilize a diverse mix of Dominion-owned new construction and PPAs with new or existing merchant plants to serve forecasted peak loads. Dominion's IRP plans assume that nearly all resources will be from construction of new Dominion-owned resources.[13]

[13] Dominion currently incorporates 35% of the capacity of Code § 56-585.5 D solar and on-shore wind resources to be from PPAs with third-party resources. Similarly, Code § 56-585.5 E requires that at least 35% of energy storage resources placed into service shall be from third-party owned resources and Dominion also incorporated this percentage into its modeling.

Q37. WHAT IS YOUR CONCERN WITH DOMINION'S CAPACITY PRICE FORECAST?

A37. My testimony addresses the accuracy of Dominion's PJM capacity price forecast. However, I am more concerned with the uncertainty and risk of using a capacity price forecast in the model that is potentially biased to the high side.

Q38. HOW DO INACCURATE CAPACITY PRICE FORECASTS ERODE THE UTILITY OF THE MODELING OUTPUTS?

A38. Forecasts of PJM market capacity prices are a key component in measuring the NPVs of IRP plans and for specific generation resources in CPCN filings.

For IRPs, the NPV cost is calculated for all plans. Typically, the NPV costs of the various plans under consideration are compared to the NPV cost of the least cost plan to measure the cost delta of each of the plans. Forecasted capacity prices are a key component of this analysis. A relatively higher capacity price forecast will favor the selection of new Dominion-owned generation resources by the model as these resources allow Dominion to avoid future capacity purchases from the market at relatively high forecasted capacity prices. A lower forecast of capacity prices will make construction of new Dominion-owned generation resources lower in value and less attractive. Instead, the PLEXOS model will select capacity purchases from the market rather than constructing a new generation unit.[14]

When Dominion files a CPCN for a new generation resource, in addition to establishing need through the load forecast, Dominion must also demonstrate that it is reasonable and prudent. This is accomplished through the economic analysis. The proposed

[14] In addition, forecasted capacity prices impact the retirement analysis for existing fossil fuel units. Higher forecasted capacity prices will increase the cost of replacement capacity in the analysis.

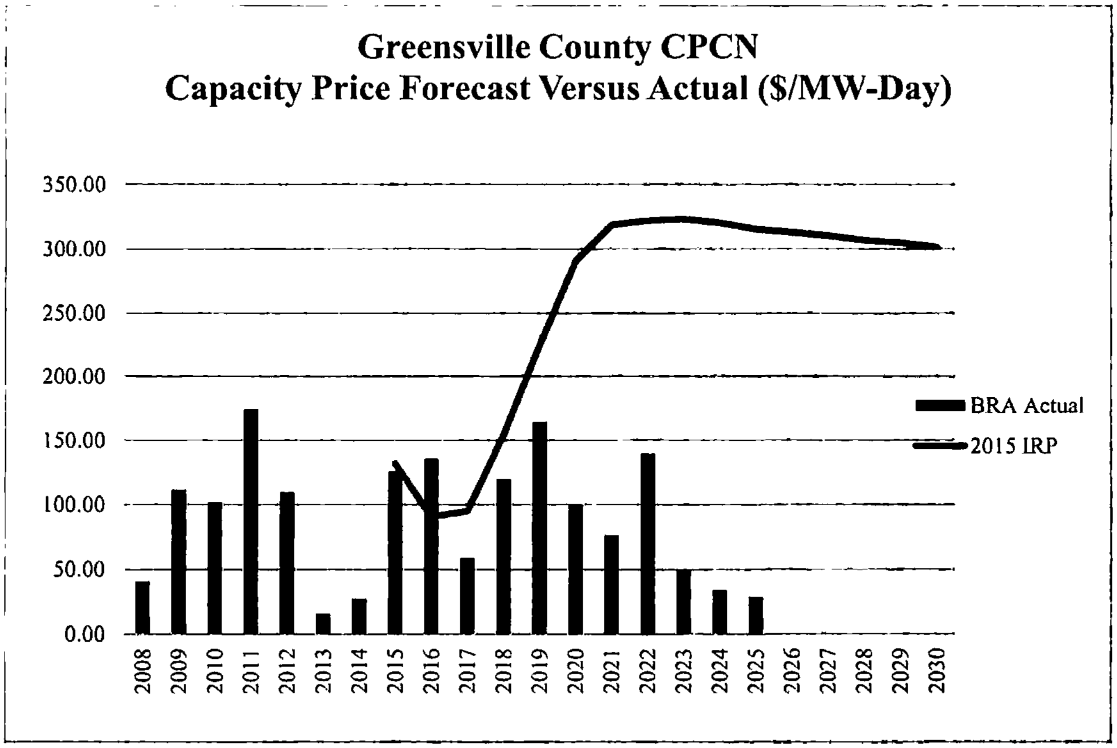
Dominion-owned generation resource is compared to the market alternative. For a traditional dispatchable resource like a gas-fired unit, the value of the energy produced and the capacity of the unit is compared to the projected price of energy purchases from the PJM energy markets and the projected capacity prices for PJM's base residual auction ("BRA"). If the net present value of the energy and the capacity of the proposed Dominion-owned resource is lower than market purchases over the service life of the unit, then the generation resource is deemed to have a positive NPV and customers would realize a net benefit.[15]

Thus, the capacity price forecast is a key driver in both the PLEXOS model results for build plans for the 2023 IRP and for the economic analysis used to justify CPCNs for specific generation resources. To the extent that Dominion's capacity price forecast is too high, this increases the risk that Dominion will construct generation resources that do not deliver the best value for customers.

Q39. CAN YOU PROVIDE AN EXAMPLE OF THE IMPACT OF THIS CAPACITY PRICE FORECAST INACCURACY?

A39. Prior to the 2015 IRP, Dominion deemed its capacity price forecast as confidential and redacted that information from the public record. Nevertheless, it is instructive to look at the "snapshot in time" for the capacity price forecast from the 2015 IRP used to support the approval of the Greensville gas plant and see how that snapshot has subsequently played out. The chart below shows how well Dominion's capacity price forecast in the Greensville CPCN case did in predicting actual capacity prices realized in the market.

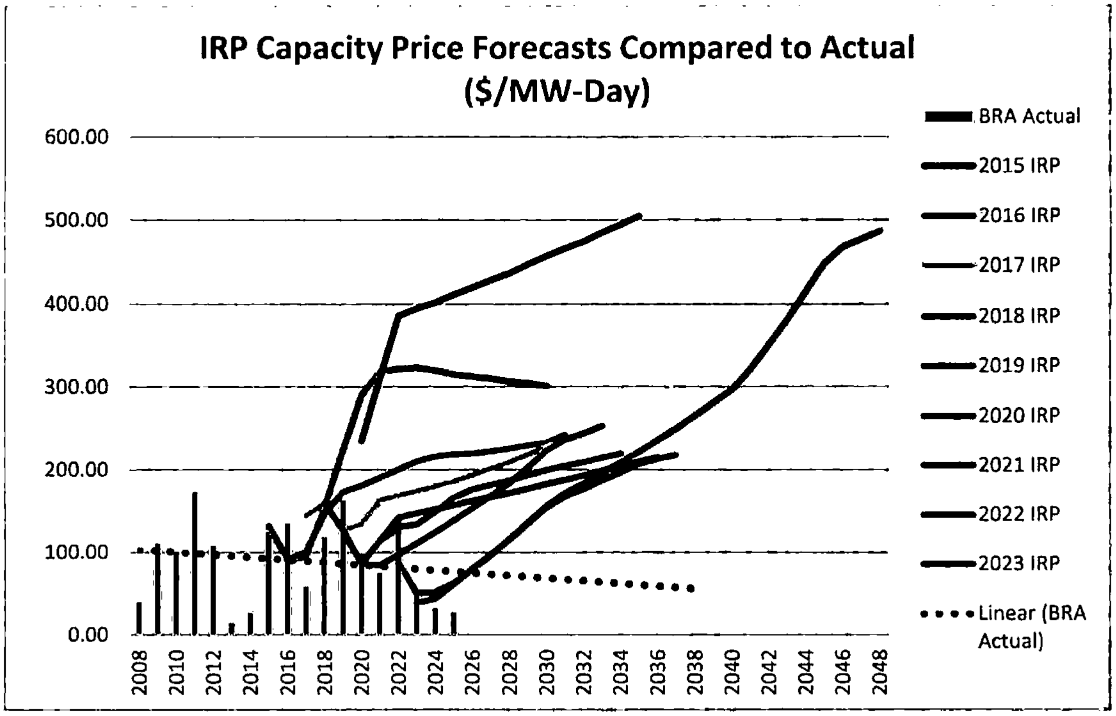
[15] For renewable generation resources, a third consideration is included. In addition to market purchases of energy and capacity, renewable resources also include market purchases of RECs in the NPV analysis.



In the case of the Greensville plant, the plant has thus far failed to deliver the avoided capacity purchase benefits projected in the CPCN case. For example, for the delivery year of 2025, the most recent BRA yielded a price of $28.92 per MW-Day. This compares to a projected price of $314.96 per MW-Day for 2025 used in the economic analysis to justify approval of the CPCN for the Greensville plant. Clearly, Dominion's capacity price forecast has missed the mark, at least so far.

Q40. DOES DOMINION'S TRACK RECORD FROM PRIOR IRP CAPACITY PRICE FORECASTS EXHIBIT A SIMILAR BIAS TO THE HIGH SIDE?

A40. The historic record of Dominion's capacity price forecasts from prior IRPs back to the 2015 IRP is depicted in the chart below.



There appears to be a bias in the forecast methodology to the high side.[16] This bias in the forecast would tend to support the economic case for large capital investment generation solutions such as the Greensville plant.

Q41. HAVE YOU EXAMINED DOMINION'S CAPACITY PRICE FORECAST METHODOLOGY?

A41. Yes. Dominion's response to Appalachian Voices Interrogatory No. 3-19 states that: "Long term PJM RTO capacity price forecasts reflect a make-whole price, net of electricity

[16] When I say "bias" I don't necessarily mean that Dominion is deliberately inflating its capacity price forecast. I simply mean that it is more or less always higher than the actual results.

market revenues, for the marginal capacity resource required to meet target demand and reserve requirements in a given year."

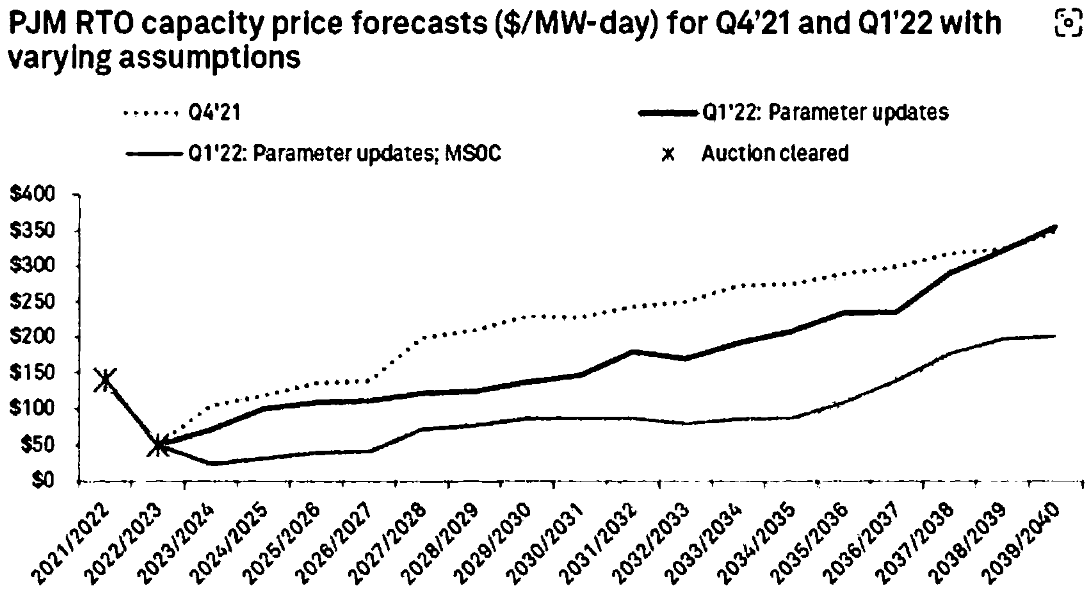
To the extent that the peak load forecast contains a bias to the high side, then the target demand and reserve requirements in a given year will also be too high and this can skew the capacity price forecast. Assuming that Dominion's capacity price forecast relies on Dominion's peak load forecast which has a track record of being biased to the high side, then the target demand and reserve requirements used to forecast capacity prices will also likely be biased to the high side. Whatever the underlying reason may be, Dominion's historic track record for forecasting PJM capacity prices appears to have a bias to the high side.

Q42. ARE YOU AWARE OF ANY OTHER INDEPENDENT FORECASTS OF PJM CAPACITY PRICES?

A42. Yes. S&P Global Market Intelligence ("S&P Global") also publishes PJM capacity price forecasts. S&P Global's most recent forecast of future PJM capacity prices is significantly lower than the Dominion 2023 IRP forecast. A key observation from the S&P Global report:

> Ahead of the 2023-24 Base Residual Auction taking place in June, PJM published its updated load forecast and auction parameters, including the final rates for implementation of the impactful Market Seller Offer Cap. Lower peak demand, installed reserve margin requirement and forced outage rates, offset by a higher net cost of new entry, lowered forecast prices marginally, while the market seller offer cap significantly limits the bid potential for generators, resulting in 62%-77% lower forecast capacity prices in the next 10 years compared to previous forecasts.

The chart below is reproduced from the S&P Global report.



Dominion's 2023 IRP forecast of capacity prices is generally consistent with the S&P Global forecast that reflects PJM's updated load forecast and auction parameters but does not reflect the Market Seller Offer Cap ("MSOC") (blue line). However, the S&P Global forecast that reflects the impact of the MSOC is much lower (gold line). It should be noted that the S&P Global forecast that reflects the impact of the MSOC (gold line) was generally in line with the actual capacity price results of the BRA price for capacity for both the 2023/2024 and the 2024/2025 delivery years.

Q43. DO YOU HAVE ANY FINAL COMMENTS ON PJM CAPACITY PRICE FORECASTS?

A43. Yes. The capacity market is not a truly competitive market, and PJM often adjusts the rules in an attempt to mimic a competitive market while at the same time trying to ensure system reliability. For example, on September 2, 2021, the U.S. Federal Energy Regulatory Commission ("FERC") issued an Order that removed the expanded Minimum Offer Price

Rule ("MOPR") and also approved a rule change for the MSOC both of which have had an impact on the PJM capacity price market. More recently, FERC approved PJM's request to delay capacity auctions for 2025-2026, originally scheduled for June 2023, to accommodate an upcoming market enhancement filing to fix potential reliability problems.

FERC Commissioner, and former SCC Commissioner, Christie recently stated the following about capacity markets:

> "Just don't pretend, however, that what's at work in capacity markets is Adam Smith's invisible hand efficiently allocating capital through a single-clearing price mechanism. And that raises the following question: How can this administrative pricing mechanism used in capacity markets -- with the complexities and subjectivity of an administratively set demand curve, administratively set local deliverability areas used to calculate zonal prices to load, administrative determination of CONE, administrative judgments about effective load carrying capabilities, offer caps, etc. -- possibly be described as the "market" alternative to the "regulated" construct of paying for needed generation through rate base, or purchasing needed power through bilateral contracts? To the honest observer RTO capacity markets and state IRP processes are both planning constructs, just in different forms."[17]

Q44. WHAT IS YOUR RECOMMENDATION FOR THE PJM CAPACITY PRICE FORECAST?

A44. I recommend that the Commission direct Dominion to perform sensitivity model runs utilizing the most recent S&P Global PJM capacity price forecast in Dominion's next IRP filing and for any future filing for approval of CPCNs for generation or energy storage resources. S&P Global is a reputable company, which operates independently of Dominion, and these sensitivity model runs will provide an important reality check on Dominion's capacity price forecast and provide an estimate of the magnitude of the

[17] *It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets*, Mark C. Christie, Energy Bar Association, May 2, 2023 at 16.

potential inaccuracy and costs to Dominion's customers from Dominion's forecast potentially being biased to the high side.

Q45. WHAT ARE YOUR CONCERNS WITH DOMINION'S ASSUMPTION FOR COAL UNIT DISPATCH?

A45. In prior cases, Dominion has represented that its coal units are assumed to be dispatched under economic dispatch in its modeling. However, in actual practice, it has been revealed that these units are frequently self-scheduled by Dominion under must-run dispatch and that often this must-run dispatch is uneconomic.[18] Thus, an assumption of economic dispatch in the IRP modeling will understate the NPV costs of the IRP plans.

This is an example where the model is capable of capturing the complexities of actual coal unit dispatch but Dominion does not allow it to do so.

Q46. HAS DOMINION PREVIOUSLY PROVIDED AN EXPLANATION FOR THIS DISCREPANCY?

A46. Dominion witness Drummond addressed this in her rebuttal testimony in Case No. PUR-2022-00124. Ms. Drummond indicated that there are minimum capacity factors in the modeling on some units to reflect limitations such as required testing and environmental requirements. Ms. Drummond also stated that "VCHEC has a minimum capacity factor that would cover any required testing as well as maintaining the biomass requirements."[19]

Apparently, to the extent that the model does not dispatch these coal units economically above the minimum capacity factor constraint used in the model, then the

[18] Case No. PUR-2022-00064, Case No. PUR-2023-00070, and Case No. PUR-2022-00124.

[19] Case No. PUR-2022-00124, Drummond Rebuttal at 18.

model would then dispatch the units uneconomically as must-run for purposes of covering any remaining hours required for testing and maintaining biomass requirements.

Q47. DO YOU SEE ANY PROBLEMS WITH THIS APPROACH?

A47. Yes. Dominion's approach of including a minimum capacity factor for the coal units as a model constraint is overly simplistic. This approach ignores the fact that testing is scheduled in advance. For example, if a coal unit is scheduled for testing that will require 72 hours of continuous operation, Dominion's minimum capacity factor model constraint would assume that the testing occurred during any 72 hours when the unit is dispatched economically regardless of whether the hours are continuous or not.

Similarly, in actual practice, Dominion schedules VCHEC as must-run for maintaining biomass requirements during times when it is more likely to be economic. Dominion's model assumption assumes "perfect" dispatch meaning that somehow testing and maintaining biomass requirements occur only during those hours that the model dispatched the units under economic dispatch. In my opinion, this will understate the true costs of dispatching the coal units, especially VCHEC.

Q48. CAN YOU PROVIDE AN EXAMPLE?

A48. Yes. In Case No. 2022-PUR-00070, it was discovered that VCHEC was self-scheduled by Dominion under must-run dispatch for 540 hours over a six-month period for purposes of maintaining the biomass requirements. Dominion lost money in 539 of those hours and only a single hour of must-run dispatch for meeting biomass requirements was actually "economic."[20]

[20] Case No. PUR-2020-00070. Transcript at 141.

Q49. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION ON COAL UNIT DISPATCH IN THE MODEL?

A49. Yes. Given that the testing schedule and the frequency and duration of testing is known in advance, Dominion could designate certain hours in the model as must-run for that purpose based on observed actual testing dispatch hours from prior years. Those hours may turn out to be either economic or uneconomic in the model simulations. Similarly, for VCHEC biomass compliance, Dominion could review its must-run dispatch scheduling from prior years for biomass compliance and designate those same hours as must-run in the model. I believe this approach would yield more accurate model results.

DATA CENTER LOAD GROWTH AND THE PLANNING PROCESS

Q50. HAVE THERE BEEN ANY MAJOR CHANGES SINCE DOMINION'S LAST IRP FILING THAT COMPLICATE LONG-TERM GENERATION PLANNING IN VIRGINIA?

A50. Yes. PJM is forecasting dramatic increases in load growth in the DOM Zone compared to the 2020 IRP, which is due almost entirely to Dominion's data center forecast. Moreover, the forecasted growth of data centers is overwhelmingly concentrated in Northern Virginia. The VCEA represented a fundamental shift in energy policy in Virginia, and required a fundamental change in modeling that Dominion has yet to fully implement. But the forecasted growth of data centers in one geographic area reflects another fundamental issue that Dominion has yet to grapple with in the planning space.

Q51. WHAT ARE THE IMPLICATIONS OF THE DATA CENTER LOAD FORECAST FOR THE PLANNING PROCESS AND MODELING?

A51. It is clear that the primary driver in the model results for new future generation capacity to serve peak load, energy sales, and RECs is from one type of customer (data centers) concentrated in one geographic area (northern Virginia). Further, future system reliability issues will also likely be concentrated in the northern Virginia area of the DOM Zone. Given that data center load growth in northern Virginia is the source of future peak load, energy sales, RECs, and reliability needs, Dominion's planning process should shift to focus on solutions for the actual problem - data center load growth in that specific geographic part of the DOM Zone.

Q52. DID THE MODELING PERFORMED IN THE DEVELOPMENT OF THE 2023 IRP RECOGNIZE THE DISPARITY IN LOAD GROWTH RATES?

A52. No. It appears that Dominion's modeling in this case assumes that the load growth for the DOM LSE is more or less spread out equally across Dominion's service territory. Thus, Dominion's PLEXOS model is trying to solve for a load growth rate of 1.6% per year for Dominion's whole system. However, the rest of the system excluding data centers is ***decreasing*** about 1.4% per year. Ignoring this reality in the modeling can lead to solutions such as a gas-fired CT located in Chesterfield County or a SMR located in southwest Virginia to solve future peak load and system reliability problems that are concentrated in the northern Virginia area of the DOM Zone. Even assuming the northern Virginia load growth materializes, and assuming it creates a reliability concern in northern Virginia, it seems unlikely an SMR in southwest Virginia is the best solution to that problem given the transmission issues involved. The PLEXOS model is not solving the actual problem the data center forecast is presenting.

Q53. WHAT ARE THE IMPLICATIONS OF DATA CENTER LOAD GROWTH FOR MODELING THE SYSTEM?

A53. Assuming the PJM load forecast is accurate, it's highly problematic because it is caused by only one type of customer in one concentrated geographic location. Dominion has not configured the model to solve for that specific issue. Dominion should be required to explore modeling solutions – whether in PLEXOS or alternative software – for this important location-specific issue. Until it does so, this IRP is failing to provide the Commission with reliable planning information, and certainly should not be referred to or relied on for CPCNs.

Notwithstanding the fact that the model is not configured to solve for this unique problem, I believe that NWAs could be a useful option to address forecasted data center load concentrated in northern Virginia and Dominion has not attempted to develop NWA options for the model to select.

NON-WIRES ALTERNATIVES

Q54. DOES THE CURRENT ENERGY PLANNING LANDSCAPE IN VIRGINIA CREATE OPPORTUNITIES FOR GREATER DEPLOYMENT OF NWA SOLUTIONS?

A54. Yes. There are two recent developments that open the door for greater deployment of NWAs. First, Dominion's load forecast is substantially higher for the 2023 IRP and almost all of the forecasted increase in the DOM LSE coincident summer peak load is due to data center growth. Further, almost all of the data center growth is concentrated in northern

Virginia which creates potential opportunities for the deployment of NWAs such as developing a demand response program tailored specifically to data centers, exploring incentives and/or disincentives for new data centers to locate in less congested areas in the DOM Zone, and performing locational analysis for siting new generation and storage resources to alleviate transmission congestion caused by the clustering of data centers in northern Virginia.

Secondly, Dominion is well underway with its distribution grid modernization improvements. The 2018 Grid Transformation and Security Act ("GTSA") created a public policy goal for the transformation of the distribution grid into a "smart" grid capable of seamlessly incorporating large amounts of DERs such as rooftop solar and battery storage resources into the distribution system. The development of the smart grid opens up opportunities for greater deployment of DERs. I believe that Dominion could be more proactive in encouraging greater deployment of DERs that could extract the potential benefits of the smart grid sooner and could lower the amount and associated costs of traditional resources required to serve load.

Q55. PLEASE DISCUSS THE POTENTIAL FOR A DEMAND RESPONSE PROGRAM DESIGNED SPECIFICALLY FOR DATA CENTERS.

A55. Demand response and peak-shaving programs are normally targeted to traditional residential, commercial, and industrial customers to either incent the shifting of load from peak hours to lower demand hours (such as AC cycling or water heater switch programs) or transferring the customer's demand during the peak hours to a standby generator located on-site for commercial and industrial customers.

Data centers, however, are a different type of customer, and there are likely opportunities for demand response for these customers that are not available to more traditional customers. In particular, those data center customers that are in the cloud segment of the market (*e.g.*, Amazon, Google, Microsoft, Meta, etc.) may be in a unique position to take advantage of a demand response program tailored specifically to those customers.

These technology companies have an extensive national and global network of data centers serving their customers. It is likely possible for these companies to shift their data processing requirements, and consequently lower energy demand, away from their northern Virginia data centers during peak hours to servers and data centers located in different geographic areas of the country or in the world that are not experiencing peak load electricity demand conditions.

I do not know if any of these technology companies currently have the capability to shift data processing load during peak hours to different data center locations or not. I am confident, however, that these technology companies have the expertise to develop such capabilities if incented to do so by a well-designed demand response program.

Q56. WHAT ARE THE ADVANTAGES OF DEVELOPING A DEMAND RESPONSE PROGRAM FOR DATA CENTERS?

A56. Demand response resources are considered capacity resources by PJM and are eligible to receive capacity payments. Demand response resources participating in the PJM capacity market must reduce load when requested by PJM or be subject to a significant financial penalty.

A demand response program designed for data centers could reduce Dominion's PJM coincident peak load and lower Dominion's capacity reserve requirement and, therefore, replace the need to construct new supply-side peaking resources such as a gas-fired CT unit.

In addition, since most of the data center load is located in northern Virginia, a demand response program that reduces peak load in that congested segment of the DOM Zone could eliminate or delay the need for additional transmission lines into northern Virginia.

Q57. HOW COULD A DEMAND RESPONSE PROGRAM DESIGNED FOR DATA CENTERS BE STRUCTURED?

A57. First, any proposed demand response program should be voluntary and open to all GS-3 and GS-4 customers. Data center customers, however, are uniquely capable of participating. Secondly, any proposed demand response program should be available across Dominion's service territory and not limited to northern Virginia.

The technology companies that own data centers would likely require a financial incentive to develop the capability to shift load to different geographical locations. Since demand response resources would eliminate the need to construct new capacity resources or to procure capacity from the market, such a program could be based on the capacity prices observed in PJM's BRA. A portion of the avoided capacity payments realized through demand response could be directly paid to participating data centers and the remainder retained for the benefit of the general body of ratepayers.

Participation in a demand response program by northern Virginia data centers can lower peak load generation costs and also would likely reduce the need for new transmission line costs as well. Further, the critical hours subject to demand response would not be limited to the summer coincident peak hours but could also be called on during extreme weather conditions such as Dominion experienced during Winter Storm Elliot. Thus, demand response if not just a peaking resource but can also enhance system reliability.

Q58. IS DOMINION EXPLORING DEMAND RESPONSE WITH THESE TECHNOLOGY COMPANIES?

A58. It is not clear to what extent this has been considered by Dominion. Dominion's response to Appalachian Voices Interrogatory No. 3-17 indicates that Dominion has not examined any NWAs, including demand response, for serving data center load. However, Dominion's response to Appalachian Voices Interrogatory No. 7-7 states that "the Company has had both group and individual confidential customer conversations. The following topics have been discussed: demand response, load shedding possibilities, customer self-supplied generation solutions, shifting testing peaks, and other potential generation options."

Q59. WHAT IS YOUR RECOMMENDATION?

A59. I recommend that the Commission direct Dominion to investigate the viability of developing a demand response program tailored to data centers and to report its findings in Dominion's next IRP filing. To that end, the Commission may want to also direct Dominion to initiate a stakeholder process with the major players in the data center space to design a workable demand response program.

Q60. PLEASE DISCUSS A POSSIBLE NWA TO INCENT DATA CENTERS TO LOCATE IN LESS CONGESTED AREAS OF THE DOM ZONE?

A60. The high energy load consumed by data centers combined with the fact that data center load is concentrated in northern Virginia has led to the construction of many high-voltage transmission lines into northern Virginia to serve this load. Further, given the projected data center load growth for northern Virginia for both Dominion and NOVEC, additional large expensive transmission projects will be required in the future.

I believe it may be possible to create a mandatory time-of-use ("TOU") rate for customers with a load of 20 MWs or greater applicable to customers located in severely congested LMP nodal points such as northern Virginia. This TOU rate could identify certain critical hours and charge a punitive rate for usage during those hours. This would incent new data center load to locate in a less congested area of the Dominion system. Further, in combination with a demand response program, it would create a carrot (demand response payments) and stick (TOU rate) to incent large data center customers that do locate in northern Virginia to lower usage during critical peak hours.

I recommend that the Commission direct Dominion to explore the feasibility of designing a locational TOU rate aimed at data centers located in northern Virginia that would also create a disincentive for new data center load to locate in northern Virginia or other congested DOM Zone nodal points.

Q61. PLEASE EXPLAIN HOW THE DEVELOPMENT OF THE SMART GRID OPENS UP OPPORTUNITIES FOR GREATER DEPLOYMENT OF NWAS.

A61. The development of the smart grid is currently part of Dominion's distribution grid modernization that is currently underway as envisioned by the GTSA. The smart grid enables two types of NWAs. First, the smart grid should open up greater opportunities for new demand-side management ("DSM") programs that were not possible with the old grid. Secondly, the smart grid enables a greater deployment of DERs to be developed.

Given the major grid-mod investments currently being made in the system, I believe that Dominion should be more proactive rather than reactive in the development of new DSM programs and the deployment of DERs in order to extract the benefits made possible by the smart grid.

In particular, given the proliferation of smart appliances and smart thermostats in customers' homes and places of business, the smart grid could be leveraged to proactively design some creative demand response options for those customers. Dominion currently has a stakeholder process in place for DSM program development that should be exploring new DSM programs that can take advantage of these new distribution grid capabilities. So, I will not discuss that further here other than to encourage Dominion to engage in a robust stakeholder process in this regard.

I believe Dominion could develop alternative incentive programs to proactively encourage wider adoption of rooftop and behind the meter ("BTM") distributed solar systems that is now enabled by the smart grid.

Q62. DO YOU HAVE ANY SUGGESTIONS TO ENCOURAGE A WIDER ADOPTION OF BTM DISTRIBUTED SOLAR RESOURCES?

A62. I do not have any specific suggestions or proposals. However, a well-designed rebate program and/or utility financing program might hasten the adoption of BTM distributed solar resources.

Currently, net metering is available to customers that install BTM distributed solar resources. Although net metering is an attractive alternative, there are financial barriers that discourage wider adoption of BTM distributed solar by customers.

Dominion is currently well underway with rebuilding, at considerable cost, its distribution grid into a smart grid capable of integrating DERs into the system. Developing a program to encourage a wider and faster deployment of BTM solar resources would (i) allow customers to extract the full benefits made available from the rebuilt distribution grid and (ii) could be an attractive generation resource option available to the model in future IRP filings.

I recommend that the Commission direct Dominion to examine the viability of a customer rebate and/or utility financing program to incent deployment of BTM solar resources. Engaging in a stakeholder process may help to design a workable program.

FUTURE CPCN FILINGS

Q63. DID DOMINION IDENTIFY A PREFERRED PLAN IN ITS 2023 IRP?

A63. No, Dominion did not identify a preferred plan. Dominion's recent announcement[21] of its plans for the development of a set of new gas CT units to be located in Chesterfield, VA, however, suggests that Dominion prefers either Plan B or Plan D since both of these plans show 970 MWs of gas-fired CT coming on line in 2028.

Further, Dominion's response to Staff Interrogatory No. 1-23 indicates that Dominion anticipates applying for an air permit and local permits in 2023 and applying for approval of a CPCN for the Chesterfield plant with the Commission in 2024.

Q64. DID DOMINION'S PLEXOS MODEL SELECT A SET OF GAS CT UNITS IN 2028 ON A LEAST COST OPTIMIZATION BASIS?

A64. No. Dominion's response to Appalachian Voices Interrogatory No. 3-6 indicates that Dominion instructed the PLEXOS model to select a single set of CTs in 2028 for both Plan B and Plan D.

Plan B modeled Dominion's carbon emitting fossil fuel generation fleet operating beyond 2045 whereas Plan D modeled the carbon emitting fossil fuel generation fleet to be completely retired by 2045. Since Dominion forced the model to select the CTs in 2028, the actual economics of a 2045 retirement or continued operation doesn't come into play in the IRP. However, the economic analysis should be scrutinized in the future CPCN case.

[21] Dominion reviving plans to build a natural gas peaker plant in Chesterfield - Virginia Mercury

Q65. DID DOMINION OFFER ANY EXPLANATION FOR FORCING THE MODEL TO SELECT THE GAS CT UNITS IN 2028?

A65. No, Dominion did not offer any explanation for why it was necessary to specifically instruct the model to select 970 MWs of gas CT capacity in 2028 in Plans B and D.

Staff Interrogatory No. 1-61 (d) requested "The Company's rationale for developing the 970 MW of gas-fired CTs (e.g., reliability concerns, additional capacity requirements, etc.)." Dominion's response stated "The Company needs dispatchable generation to reliably meet growing energy and capacity needs. See Sections 1.1, 1.3, 5.4.2, and 7.5 of the 2023 Plan." Those sections of the IRP generally discuss system reliability needs but there is no specific discussion of why 970 MWs of gas CT capacity is needed in 2028.

Further, Appalachian Voices Interrogatory No. 7-8 asked Dominion to "explain why Dominion is seeking a new gas-fired CT unit in Chesterfield County to address system reliability. Has Dominion performed reliability analysis to support this project? If so, please provide such analysis. If not, please explain why not." Dominion's response did not provide any specific reliability analysis to support the project but instead stated "see Sections 1.3, 2.3, and 5.4.2 of the 2023 Plan regarding the need for dispatchable generation supporting system reliability." Those sections of the IRP generally discuss system reliability needs but there is no specific discussion of why 970 MWs of gas CT capacity is needed in 2028.

Q66. ARE NEW GAS CT UNITS ALLOWED UNDER THE CODE?

A66. New Dominion-owned carbon emitting generation units are allowed under the Code only under a specific set of conditions. Those conditions are delineated in § 56-585.1 A 5 of the Code which states the following:

> Notwithstanding any other provision of law, ***unless the Commission finds*** in its discretion and ***after consideration of all in-state and regional transmission entity resources*** that there is a ***threat*** to the reliability or security of electric service to the utility's customers, the Commission shall not approve construction of any new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity unless the utility has already met the energy savings goals identified in § 56-596.2 and the Commission finds that ***supply-side resources are more cost-effective than demand-side or energy storage resources.***

Q67. HAS DOMINION MET THE ENERGY SAVINGS GOALS THAT WOULD ALLOW THE COMMISSION TO APPROVE A NEW SET OF GAS CT UNITS?

A67. There has not yet been a finding by the Commission that Dominion has met, or is likely to meet in the future, the energy savings goals contained in the VCEA. The Commission's August 4, 2023 Final Order in Case No. PUR-2022-00210 states the following:

> The Commission continues to be mindful of the total energy savings targets set forth in the Virginia Clean Economy Act ("VCEA") and that under current projections. Dominion does not anticipate achieving such targets as soon as 2023-2025 if measured on a net basis.[22]

It is doubtful that Dominion would meet the energy savings goals before its stated timetable of 2024 for filing for approval of a CPCN for the Chesterfield CT units. Based on this observation, it appears that Dominion will rely on the reliability exception to justify the need for new gas CT capacity in 2028.

[22] Case No. PUR-2022-00210, Final Order at 10.

Q68. DID THE RETIREMENT OF CHESTERFIELD COAL UNITS 5 AND 6 CREATE A THREAT TO SYSTEM RELIABILITY?

A68. No. Dominion's response to Appalachian Voices Interrogatory No. 10-6 indicated that Dominion filed a deactivation request for Chesterfield units 5 and 6 on February 20, 2020. PJM's letter in response to this deactivation request was provided by Dominion as Attachment APV Set 10-06 (JEC). PJM did not identify any system reliability violations that would require system upgrades to correct.

Q69. DID WINTER STORM ELLIOT DEMONSTRATE A RELIABILITY NEED FOR ADDITIONAL DOMINION-OWNED DISPATCHABLE FOSSIL FUEL GENERATION?

A69. Winter Storm Elliot was an extreme weather event that occurred over December 23-25, 2022. The entire PJM RTO was impacted as well as much of the rest of the country. PJM is responsible for system reliability of the PJM RTO including the Dom Zone. It is my understanding that PJM has performed a detailed analysis of the Winter Storm Elliot event. In fact, as a result of this analysis, PJM made a request to FERC to delay capacity auctions for 2025-2026, originally scheduled for June 2023, to accommodate an upcoming market enhancement filing to fix potential reliability problems.

I have examined the performance of Dominion's generation fleet over the 72-hours beginning with hour ending 1 on December 23, 2022 through hour ending 24 on December 25, 2022. Dominion provided the actual hourly energy production of Dominion's regulated generation fleet in response to Staff Interrogatory No. 1-42, Attachment Staff Set 01-42(2) (WAH). The data provided did not include Chesterfield units 5 and 6. Since these units were operational during this time period, I requested the hourly energy production for

Chesterfield units 5 and 6 in Appalachian Voices Interrogatory No. 10-3. Dominion provided this data as Attachment APV Set 10-03 (WAH) SUPP. Dominion provided its hourly load (energy consumed) data for the DOM LSE in response to Appalachian Voices Interrogatory No. 10-2 and Staff Interrogatory No. 1-41, Attachment Staff Set 01-41 (KS).

Based on this data for Winter Storm Elliot, it appears that Dominion had to import the most energy from the PJM energy markets in hour ending 8 on December 24, 2022. Dominion's regulated fleet, including Chesterfield Units 5 and 6, generated a total of 15,167 MWs during this hour. Dominion's load, or energy consumed, during this hour was 17,813 MWs. Thus, Dominion was required to import 2,646 MWs from the PJM energy markets to serve load during the worst hour of Winter Storm Elliot. This is far below the 5,200 MW import constraint that Dominion uses in its modeling.

Since Chesterfield units 5 and 6 are now retired, I removed the generation from these two units for hour ending 8 on December 24, 2022 to see how that would have impacted energy imports from the PJM energy market during that hour. Had Chesterfield units 5 and 6 not been operating, this would have increased the energy imports from 2,646 MWs to 3,530 MWs. This is still far below Dominion's 5,200 MW import constraint.

Q70. DO YOU HAVE RECOMMENDATIONS REGARDING A FUTURE CPCN FILING FOR GAS CT UNITS?

A70. This is an IRP and Dominion is not seeking approval of any specific resource in this proceeding. The appropriate time to analyze the merits of the specific proposed gas CT units in Chesterfield is in a future CPCN proceeding. However, it is Dominion's practice to rely on the IRP model inputs and results to support CPCN and RPS filings. Further, Dominion's announcement of its plans for the new Chesterfield gas CT units and its plans to obtain the air permit and local permits later this year is a clear indication that this is not simply a planning exercise for generic gas CT capacity shown in 2028 for Plans B and D. This draws into question how Dominion is using the IRP and the extent to which the Commission can rely on the information in the IRP. Given that Dominion is clearly moving forward with the gas CT unit in Chesterfield, it begs the question of what is Dominion's preferred plan and why.

I recommend that the Commission give Dominion instructions on what the Commission deems should be included in the anticipated 2024 CPCN application. I offer the following suggestions in this regard.

- First, I recommend that the Commission instruct Dominion to include a comprehensive reliability analysis that demonstrates the reliability need of the project including the timing of this need and the location of any projected system reliability violations identified in the DOM Zone. This reliability analysis should be coordinated with and verified by PJM.
- Second, I recommend that the Commission instruct Dominion to conduct an RFP open to both new and existing peaking generation and storage resources and present the results in the 2024 CPCN application. Given the potential bias to the high side in both Dominion's peak load forecast and capacity price forecast combined with the current Code requirement that all carbon emitting resources must be retired by 2045, the risk of customers being burdened with stranded costs for a set of new Dominion-owned gas CT units is quite high. This risk can be completely eliminated through a PPA arrangement with a new or existing third-party peaking generation or storage resource.
- Third, I recommend that the Commission instruct Dominion to perform the economic analysis for the proposed CTs under two scenarios: (i) assume that the CTs retire in 2045 as the base assumption consistent with IRP Plan D, and (ii) assume that the CTs operate over the expected useful life as a sensitivity consistent with IRP Plan B.
- Lastly, I recommend that the Commission direct Dominion to evaluate the viability of a demand response program tailored specifically to data centers as an NWA peaking resource and to report on its findings in the 2024 CPCN application.

Q70. DOES THIS CONCLUDE YOUR TESTIMONY?

A70. Yes.

Attachment GLA-1

23081023

Gregory Abbott Testimonies/Reports

Proceeding	Case/Docket No.	On Behalf of:
Dale Service Corporation For General Increase in Rates	Virginia SCC Case No. PUE-2001-00200	Virginia SCC Staff
CPV Cunningham Creek LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2001-00477	Virginia SCC Staff
CPV Warren LLC For Approval of a Generation Certificate	Virginia SCC Case No. PUE-2002-00075	Virginia SCC Staff
Dale Service Corporation For Review of Changes to Terms and Conditions	Virginia SCC Case No. PUE-2002-00092	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Weather Normalization Adjustment Rider	Virginia SCC Case No. PUE-2002-00237	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2002-00375	Virginia SCC Staff
Community Electric Cooperative For Approval of Retail Access Tariffs and Terms and Conditions of Service for Retail Access	Virginia SCC Case No. PUE-2003-00007	Virginia SCC Staff
A&N Electric Cooperative For Review of Tariffs and Terms and Conditions of Service for Retail Service	Virginia SCC Case No. PUE-2003-00279	Virginia SCC Staff
Central Virginia Electric Cooperative For Approval of Its Plan to Implement Retail Access	Virginia SCC Case No. PUE-2003-00327	Virginia SCC Staff
Atmos Energy Corporation For an Increase in Rates	Virginia SCC Case No. PUE-2003-00507	Virginia SCC Staff
Virginia-American Water Company For General Increase in Rates	Virginia SCC Case No. PUE-2003-00539	Virginia SCC Staff
Washington Gas Light Company For Approval of an Experimental Weather Normalization Adjustment	Virginia SCC Case No. PUE-2001-00010	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case No. PUE-2005-00012	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of a Performance Based Rate Regulation Methodology	Virginia SCC Case No. PUE-2005-00057	Virginia SCC Staff

Virginia Natural Gas, Inc. For Investigation of Justness and Reasonableness of Current Rates, Charges, and Terms and Conditions of Service	Virginia SCC Case No. PUE-2005-00062	Virginia SCC Staff
Roanoke Gas Company For and Expedited Increase in Rates	Virginia SCC Case. No. PUE-2005-00075	Virginia SCC Staff
Highland New Wind Development, LLC For Approval to Construct, Own and Operate an Electric Generation Facility	Virginia SCC Case. No. PUE-2005-00101	Virginia SCC Staff
Dale Service Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00070	Virginia SCC Staff
Virginia Natural Gas, Inc. For Approval of an Experimental Weather Normalization Adjustment for General Service Customers	Virginia SCC Case. No. PUE-2006-00095	Virginia SCC Staff
Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2006-00099	Virginia SCC Staff
CPV Warren, LLC For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2007-00018	Virginia SCC Staff
Appalachian Power Company For Adjustment to Capped Electric Rates	Virginia SCC Case. No. PUE-2007-00069	Virginia SCC Staff
Old Dominion Electric Coop. & Columbia Gas of Virginia For Approval of a Certificate to Acquire Ownership Interest	Virginia SCC Case. No. PUE-2007-00088	Virginia SCC Staff
James River Cogeneration Company For a Certificate to Operate as an Electric Generating Facility	Virginia SCC Case. No. PUE-2007-00092	Virginia SCC Staff
Spectra Energy Virginia Pipeline Co. For Cancellation of Certificates	Virginia SCC Case. No. PUE-2007-00106	Virginia SCC Staff
Appalachian Power Company For Approval to Participate in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2008-00003	Virginia SCC Staff
Atmos Energy Corporation For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00007	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Generation Certificate	Virginia SCC Case. No. PUE-2008-00014	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Approval of an Experimental Weather Normalization Adjustment Mechanism	Virginia SCC Case. No. PUE-2008-00074	Virginia SCC Staff

Roanoke Gas Company For an Expedited Increase in Rates	Virginia SCC Case. No. PUE-2008-00088	Virginia SCC Staff
Mecklenburg Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00006	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Annual Filing of Rider S	Virginia SCC Case. No. PUE-2000-00011	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station	Virginia SCC Case. No. PUE-2009-00017	Virginia SCC Staff
Washington Gas Light Company For Approval of Natural Gas Conservation and Ratemaking Efficiency Plan including a Decoupling Mechanism	Virginia SCC Case. No. PUE-2009-00064	Virginia SCC Staff
Craig-Botetourt Electric Cooperative For a General Increase in Electric Rates	Virginia SCC Case. No. PUE-2009-00065	Virginia SCC Staff
Appalachian Power Company For Approval of Purchase Power Agreements as Part of Its Participation in the Virginia Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2009-00102	Virginia SCC Staff
Columbia Gas of Virginia, Inc. For Authority to Increase Rates and Charges and to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00017	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Continue Two Rate Adjustment Clauses, Riders C1 and C2	Virginia SCC Case. No. PUE-2010-00084	Virginia SCC Staff
Appalachian Power Company Proposed Pilot Programs on Dynamic Rate Structures for Renewable Generation Facilities	Virginia SCC Case. No. PUE-2010-00134	Virginia SCC Staff
Virginia Natural Gas, Inc. For an Increase in Base Rates and Authority to Revise the Terms and Conditions	Virginia SCC Case. No. PUE-2010-00142	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish an Electric Vehicle Pilot Program	Virginia SCC Case. No. PUE-2011-00014	Virginia SCC Staff
Appalachian Power Company For Approval of a Rate Adjustment Clause, RPS-RAC, to Recover the Incremental Costs of Participation in the Virginia Renewable Energy Portfolio Standard Program	Virginia SCC Case. No. PUE-2010-00034	Virginia SCC Staff

Virginia Electric and Power Company For Approval to Implement New Demand-Side Management Programs and For Approval of Two Updated Rate Adjustment Clauses	Virginia SCC Case. No. PUE-2011-00093	Virginia SCC Staff
Virginia-American Water Company For a General Increase in Rates	Virginia SCC Case. No. PUE-2011-00127	Virginia SCC Staff
Virginia Electric and Power Company To Revise a Rate Adjustment Clause: Rider R	Virginia SCC Case. No. PUE-2012-00068	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider B	Virginia SCC Case. No. PUE-2012-00072	Virginia SCC Staff
Appalachian Power Company For Approval of the Recovery of Incremental Costs of Participation in the Renewable Energy Portfolio Program	Virginia SCC Case. No. PUE-2012-00094	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed Brunswick Co. Power Station	Virginia SCC Case. No. PUE-2012-00128	Virginia SCC Staff
Atmos Energy Corporation For Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2013-00038	Virginia SCC Staff
Northern Virginia Electric Cooperative For Approval of Pole Attachment Rates and Terms and Conditions	Virginia SCC Case. No. PUE-2013-00055	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2013-00088	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider BW	Virginia SCC Case. No. PUE-2013-00122	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rat Adjustment Clause	Virginia SCC Case. No. PUE-2014-00007	Virginia SCC Staff
Appalachian Power Company Application for a 2014 Biennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services	Virginia SCC Case. No. PUE-2014-00026	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2014-00089	Virginia SCC Staff
Appalachian Power Company Petition for Approval of Rate Adjustment Clause Related to its Participation in the Renewable Portfolio Energy Portfolio Program	Virginia SCC Case. No. PUE-2015-00034	Virginia SCC Staff

Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2015-00035	Virginia SCC Staff
Washington Gas Light Company Application for Approval of a Natural Gas Supply Investment Plan	Virginia SCC Case. No. PUE-2015-00055	Virginia SCC Staff
Virginia Electric and Power Company For Approval of Special Rates, Terms and Conditions	Virginia SCC Case. No. PUE-2015-00103	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Rates Designated Rate Schedule MBR - GS-3 and Rate Schedule MBR - GS-4	Virginia SCC Case. No. PUE-2015-00108	Virginia SCC Staff
Virginia Electric and Power Company For Establishment of a Rate Adjustment Clause: Rider U, New Underground Distribution Facilities	Virginia SCC Case. No. PUE-2015-00114	Virginia SCC Staff
Atmos Energy Corporation Application for Expedited Approval of a Special Contract for Gas Transportation Service	Virginia SCC Case. No. PUE-2015-00125	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUE-2016-00049	Virginia SCC Staff
Virginia Electric and Power Company For Revision of a Rate Adjustment Clause: Rider U	Virginia SCC Case. No. PUE-2016-00136	Virginia SCC Staff
Appalachian Power Company For Approval of a Wind G Rate Adjustment Clause	Virginia SCC Case. No. PUR-2017-00031	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2017-00051	Virginia SCC Staff
Virginia Electric and Power Company For Approval to Establish Experimental Companion Tariff, Designated Schedule RF	Virginia SCC Case. No. PUR-2017-00137	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2018-00065	Virginia SCC Staff
Virginia Electric and Power Company For Approval of a Rate Adjustment Clause, Designated Rider E	Virginia SCC Case. No. PUR-2018-00195	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed US-3 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-3	Virginia SCC Case. No. PUR-2018-00101	Virginia SCC Staff

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Virginia Electric and Power Company For Prudency Determination with Respect to the Coastal Virginia Offshore Wind Project	Virginia SCC Case. No. PUR-2018-00121	Virginia SCC Staff
Virginia Electric and Power Company For Revision of Rate Adjustment Clause: Rider US-3	Virginia SCC Case. No. PUR-2019-00104	Virginia SCC Staff
Virginia Electric and Power Company For Approval & Certification of Proposed US-4 Solar Projects and for Approval of a Rate Adjustment Clause, Designated Rider US-4	Virginia SCC Case. No. PUR-2019-00105	Virginia SCC Staff
Virginia Electric and Power Company For a Prudency Determination with Respect to the Westmoreland Solar Power Purchase Agreement	Virginia SCC Case. No. PUR-2019-00133	Virginia SCC Staff
Virginia Electric and Power Company Integrated Resource Plan	Virginia SCC Case. No. PUR-2020-00035	Virginia SCC Staff
Virginia Electric and Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00134	Virginia SCC Staff
Appalachian Power Company Establishing 2020 RPS Proceeding	Virginia SCC Case. No. PUR-2020-00135	Virginia SCC Staff
Virginia Electric and Power Company Allocating RPS Costs to Certain Customers of Virginia Electric and Power Company	Virginia SCC Case. No. PUR-2020-00164	Virginia SCC Staff
Virginia Electric and Power Company To Revise Its Fuel Factor	Virginia SCC Case. No. PUR-2022-00064	Appalachian Voices
Appalachian Power Company 2022 Integrated Resource Plan Filing	Virginia SCC Case. No. PUR-2022-00051	Appalachian Voices
Roanoke Gas Company For an Expedited Rate Increase	Virginia SCC Case. No. PUR-2022-00205	Roanoke Gas Company
Virginia Electric and Power Company For Approval of its 2022 RPS Development Plan	Virginia SCC Case. No. PUR-2022-00124	Appalachian Voices
Virginia Electric and Power Company For Reinstatement and Revision of a Rate Adjustment Clause Designated Rider RGGI	Virginia SCC Case. No. PUR-2022-00070	Appalachian Voices

Attachment GLA-2

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 3

The following response to Question No. 6 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on May 19, 2023, was prepared by or under the supervision of:

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 6

For each plan contained in the 2023 IRP (Plans A through E), please provide the following:
(a) identify for each generation and storage resource whether the resource was selected by the PLEXOS model on a least cost optimization basis in the model simulations; and
(b) identify those energy or storage resources that Dominion instructed the model to select.

Response:

Plan A: Unit selection is selected or least-cost optimized but this Plan meets only applicable carbon regulations and mandatory RPS program requirements of the VCEA.
Plan B: VCEA development targets required through 2038. A single set of combustion turbines ("CTs") included in 2028. A second tranche of offshore wind is included in 2033. The remaining plan is selected or least-cost optimized.
Plan C: This plan is entirely selected or least-cost optimized.
Plan D: VCEA development targets required through 2038. A single set of CTs included in 2028. A second tranche of offshore wind is included in 2033. All unit retirements are included. The remaining plan is selected or least-cost optimized.
Plan E: Fossil generation retirements are required in this plan. The remaining plan is selected or least-cost optimized.

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Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 10

The following response to Question No. 1 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Katelynn A. Vance
Manager Electric Transmission Planning & Strategic Initiatives
Dominion Energy Virginia

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

As it pertains to legal matters, the following response to Question No. 1 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 1

Please reference Dominion's response to APV 3-8 which indicates that Dominion includes a 5,200 MW transmission import/export constraint in the PLEXOS model simulations for all plans through 2038. Please provide a narrative description of how Dominion arrived at the 5,200 MW import/export transmission constraint assumption. Please provide all workpapers used to support this assumption as an executable excel spreadsheet with all formulas intact. If this model assumption is based on Dominion's judgment, please so state.

Response:

The Company objects to this request as overly broad, unduly burdensome, and potentially voluminous to the extent it seeks "all workpapers used to support" the transmission import/export constraint assumption. Subject to and notwithstanding this objection, the Company provides the following response.

There are no executable spreadsheets to provide. The Company evaluated the import limits utilized in previous IRP studies. This import/export limit was not changed since it would have similar results. The limits of the external tie lines have not been updated significantly since this initial study. See Attachment APV Set 10-01 (KAV).

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 6

The following response to Question No. 12 of the Sixth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 12, 2023, was prepared by or under the supervision of:

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 12

Please reference Dominion's response to APV 3-8. Is energy generated from Dominion's units located outside of the DOM Zone, such as VCHEC or Bath County Pumped Storage, subject to this transmission import constraint?

Response:

The Company interprets "Dominion" to be Dominion Energy Virginia. The import/export transmission constraint is applied to MWhs being sold or purchased from the PJM market, not to Company-owned generation units.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 11

The following response to Question No. 5 of the Eleventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on July 5, 2023, was prepared by or under the supervision of:

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 5

Please reference Appendix 5I of the 2023 IRP. Please further reference Dominion's response to APV 10-5 that states that "Energy from the Company's ring-fenced solar facilities are not modeled as part of the 2023 Plan." Is it correct that neither the energy nor the capacity of the Ring-Fence solar and wind facilities displayed in Appendix 5I were included in the PLEXOS modeling of the 2023 IRP plans?

Response:

No. Ring-fenced solar and wind are modeled as capacity resources in the PLEXOS model. With the move to FRR, the firm capacity of ring-fenced resources is required to be included in the Company's FRR plan to meet PJM reserve requirements. However, energy produced by these units is sold into the PJM market and is not used to serve retail customers. Thus, these units are not modeled as energy producers in the PLEXOS model.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 11

The following response to Question No. 1 of the Eleventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on July 5, 2023, was prepared by or under the supervision of:

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 1

Please reference pages 124-125 of the 2023 IRP. Please identify the annual aggregate nameplate capacity of facilities under contract with Bundled ARBs that Dominion assumed in its modeling for the planning period of 2023-2038. Please provide this by year.

Response:

The aggregate nameplate capacity for facilities under bundled contracts with ARBs that were used in the Plexos modeling was 1,074 MW for 2024-2038.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 7

The following response to Question No. 5 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 21, 2023, was prepared by or under the supervision of:

Kourtnie Sunkins
Regulatory Analyst III
Virginia Electric and Power Company

Question No. 5

Please reference pages 124-25 of the 2023 IRP. Please identify the aggregate total ARB-certified load based on the 2022 production from ARB-qualifying facilities (both Company-owned and submitted by customers). How much of this total load is associated with data centers that are ARBs or are seeking certification as ARBs? To be clear, this question is only seeking total aggregate information and is not seeking any customer-specific information.

Response:

There is 9,900,020 MWhs of total aggregate ARB-certified load based on the 2022 production from ARB-qualifying facilities, in which 9,774,225 MWhs of the total ARB-certified load is associated with companies that operate data centers.

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Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 11

The following response to Question No. 2 of the Eleventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on July 5, 2023, was prepared by or under the supervision of:

Kourtnie E Sunkins
Regulatory Analyst III
Dominion Energy Virginia

Jarad L. Morton
Manager – Integrated Strategic Planning
Dominion Energy Services, Inc.

Question No. 2

Please reference pages 124-125 of the 2023 IRP. Please identify the annual aggregate energy production (MWhs) from facilities under contract with Bundled ARBs that Dominion assumed in its modeling for the planning period of 2023-2038. Please provide this by year.

Response:

The Plexos model did not include the energy production from the wholesale ARB PPAs because the energy is not used to serve retail customer load. For the purposes of calculating the Company's RPS annual requirement, see Attachment APV Set 11-02 (KES).

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 3

The following response to Question No. 19 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on May 19, 2023, was prepared by or under the supervision of:

Whitney W. Johnson
Manager – Energy Market Analysis
Dominion Energy Services, Inc.

Question No. 19

Please provide a narrative description of the methodology used to forecast PJM RTO Capacity prices. Is this the same methodology used in prior IRP filings? If not, please describe any modifications that were included in the 2023 IRP methodology.

Response:

Yes, the analysis is consistent with the Company's prior IRP filings. Long term PJM RTO capacity price forecasts reflect a make-whole price, net of electricity market revenues, for the marginal capacity resource required to meet target demand and reserve requirements in a given year.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 3

The following response to Question No. 17 of the Third Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on May 19, 2023, was prepared by or under the supervision of:

Edmund J. Hall
Energy Market & Demand Side Planning Strategic Advisor
Dominion Energy Services, Inc.

Question No. 17

Has Dominion examined any non-wires alternatives for serving data center load such as potential participation of data centers as demand response resources in the PJM wholesale electricity market?

Response:

No.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 7

The following response to Question No. 7 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 21, 2023, was prepared by or under the supervision of:

Stan Blackwell
Director – Customer Service & Strategic Partnerships
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 7 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 21, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 7

Given the Company's projected data center load growth in Northern Virginia, has Dominion sought input from the major players in the data center space, such as Google, Facebook (Meta), Amazon, Microsoft, and the Data Center Coalition to identify potential non-wires alternatives to address reliability concerns, such as incentives to locate new data centers in less congested LMP nodes in the DOM Zone, load shedding possibilities, demand-response, etc? If so, please explain what alternatives have been discussed. If not, please explain why not.

Response:

The Company objects to the premise of this request to the extent it implies the Company has control over the location of data centers. The Company does not construct, own, or operate data centers, but the Company has an obligation to serve when a request for service is received. The Company also objects to this request to the extent it seeks confidential customer information for which the Company does not have authorization to provide. Consistent with Dominion Energy Virginia's Privacy Policy, the Company is committed to protecting customers' personal data while providing safe, reliable, and affordable services. See https://www.dominionenergy.com/privacy. Subject to and notwithstanding these objections, the Company provides the following response.

Yes, the Company has had both group and individual confidential customer conversations. The following topics have been discussed: demand response, load shedding possibilities, customer self-supplied generation solutions, shifting testing peaks, and other potential generation options.

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Virginia Electric and Power Company
Case No. PUR-2023-00066
Virginia State Corporation Commission Staff
Set 1

The following **revised** response (dated June 14, 2023) to Question No. 23 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Kelsi C. Jewell
Business Development Manager
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 23 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 23

Is the Company currently pursuing the development of any gas-fired combustion turbine ("CT") units in Virginia, such as seeking air permits and/or local permits? If so, please identify the expected location(s) of these units and when the Company anticipates filing an application or applications with the Commission for certificates of public convenience and necessity for these CT units.

Response (dated June 14, 2023):

The Company objects to this request as not relevant or reasonably likely to lead to the production of admissible evidence in this proceeding as the IRP is not a request for a certificate of public convenience and necessity, nor a request for cost approval of any particular resource. Such documentation will be provided at the time the Company seeks such approvals. Subject to and notwithstanding this objection, the Company provides the following response.

This response is now public. No changes have been made to the substance of this response.

~~This response contains confidential information as indicated and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information dated May 23, 2023, any additional protective order or protective ruling that may be issued for confidential or~~

~~extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to such orders or rulings.~~

See Section 5.4.2 of the 2023 Plan. The Company is currently evaluating and in the development phase of gas-fired combustion turbines. ~~**[BEGIN CONFIDENTIAL INFORMATION]**~~ The project is in Chesterfield County and the Company anticipates applying for an air permit and local permits in 2023. The Company anticipates filing for approval with the Commission in 2024 ~~**[END CONFIDENTIAL INFORMATION]**~~.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Virginia State Corporation Commission Staff
Set 1

The following **revised** response (dated June 14, 2023) to Question No. 61 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Corey J. Riordan
Project Construction Controls Consultant
Dominion Energy Services, Inc.

As it pertains to legal matters, the following response to Question No. 61 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 61

Please refer to Section 3.1 on page 37 of the IRP, specifically the statement, "Continue development work for 970 MW of new gas-fired CTs." Please provide a narrative explanation of what actions or communications the Company has undertaken or is currently undertaking to develop 970 MW of new gas-fired CTs. Please include the following information, at a minimum:

(a) The expected timeframe the Company plans to request approval of the 970 MW of additions;

(b) Nameplate capacity of each CT comprising the 970 MW of additions; and

(c) The location or locations the 970 MW of new gas-fired CTs are going to be installed, planned to be installed, or may be installed.

(d) The Company's rationale for developing the 970 Mw of gas-fired CTs (e.g., reliability concerns, additional capacity requirements, etc.).

Response (dated June 14, 2023):

The Company objects to this request as not relevant or reasonably likely to lead to the production of admissible evidence in this integrated resource plan proceeding as the Company is not seeking approval of any specific resource in this proceeding. Subject to and notwithstanding this objection, the Company provides the following response.

This response is now public. No changes have been made to the substance of this response.

~~This response contains confidential information as indicated and is being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information dated May 23, 2023, any additional protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.~~

The development of the new gas-fired generation plant was paused several years ago due to the VCEA. Prior to pausing the development process, the Company acquired the real estate, held county meetings, conducted an open house within the community, and has had a publicly available website with initial project details. Due to the increased reliability risks noted in Section 5.4.2 of the 2023 Plan, the Company restarted the development of the project and is ~~**[BEGIN CONFIDENTIAL INFORMATION]**~~ actively working with the locality on future open houses and local permitting. The Company will proceed in seeking the local permitting in 2023 as well as submitting an air permit application in 2023. ~~**[END CONFIDENTIAL INFORMATION]**~~

(a) The Company plans to seek approval of additional gas fired CTs in ~~**[BEGIN CONFIDENTIAL INFORMATION]**~~ 2024. ~~**[END CONFIDENTIAL INFORMATION]**~~

(b) The Company has not yet contracted with a specific technology vendor.

(c) The Company is currently developing new gas fired CTs in ~~**[BEGIN CONFIDENTIAL INFORMATION]**~~ Chesterfield County in the James River Industrial Center. ~~**[END CONFIDENTIAL INFORMATION]**~~

(d) The Company needs dispatchable generation to reliably meet growing energy and capacity needs. See Sections 1.1, 1.3, 5.4.2, and 7.5 of the 2023 Plan.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 7

The following response to Question No. 8 of the Seventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 21, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 8

Please explain why Dominion is seeking a new gas-fired CT unit in Chesterfield County to address system reliability. Has Dominion performed reliability analysis to support this project? If so, please provide such analysis. If not, please explain why not.

Response:

The Company objects to this request as not relevant or reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to this request to the extent it mischaracterizes the Company's filing in this proceeding as "seeking a new gas-fired CT unit in Chesterfield County..." This proceeding is about the Company's 2023 Integrated Resource Plan filed pursuant to Va. Code Section 56-599 et seq., and it is not a proceeding seeking a certificate of public convenience and necessity for any particular resource. Subject to and notwithstanding these objections, please see Sections 1.3, 2.3, and 5.4.2 of the 2023 Plan regarding the need for dispatchable generation supporting system reliability.

2750 Monroe Blvd.
Audubon, PA 19403-2497

David W. Souder
Sr. Director, System Planning

March 18, 2020

Joshua J. Bennett
Vice President, Technical Services
Dominion Energy Virginia
600 East Canal Street
Richmond, VA 23219

Re: Deactivation Notice for Chesterfield 5 & 6 Generating Units

Dear Mr. Bennett,

This letter is submitted by PJM Interconnection, L.L.C. ("PJM"), in response to the notice submitted by Dominion Energy Virginia dated February 20, 2020 requesting to deactivate Chesterfield 5 & 6 generating units located in the PJM Region, effective May 31, 2023.

In accordance with Section 113.2 of the PJM Open Access Transmission Tariff (PJM Tariff), this letter will serve to notify you that the deactivation of Chesterfield 5 & 6 generating units can occur on the requested date, May 31, 2023, and will not adversely affect the reliability of the PJM Transmission System. Any revisions to the requested deactivation Date shall require the Generator Owner to provide PJM with a revised notice in accordance with section 113.2 of the PJM Tariff.

PJM's System Modeling Department and the affected Transmission Owner performed a study of the Transmission System and found reliability concerns (contingency thermal overloads of transmission lines) resulting from the deactivation of Chesterfield 5 & 6 generating units. However, there are operational measures in place to keep the transmission system reliable.

Please be advised that PJM's deactivation analysis does not supersede any outstanding contractual obligations between Chesterfield 5 or 6 generating unit and any other parties that must be resolved before deactivating this generator.

Also please note that in accordance with the PJM Tariff Part VI, Subpart C, a Generation Owner will lose the Capacity Interconnection Rights associated with a deactivated generating unit one year from the actual Deactivation Date unless the holder of such rights submits a new Generation Interconnection Request within one year after the Deactivation Date.

pjm

In addition, if a generating unit is receiving Schedule 2 payments for Reactive Supply and Voltage Control, the generating unit owner must notify PJM in writing when the unit is deactivated. Moreover, in accordance with the requirements of Schedule 2 of the PJM Tariff, the generation unit owner must: (1) submit a filing to the Federal Energy Regulatory Commission ("FERC") to terminate or adjust its cost-based rate schedule to account for the deactivated or transferred unit; or (2) submit an informational filing to the FERC explaining the basis for the decision not to terminate or revise its cost-based rate schedule.

Please contact Chibuzor Ofoegbu (610-666-2375) (chibuzor.ofoegbu@pjm.com) in PJM's Infrastructure Coordination Department if you have any questions about the PJM analysis.

Very truly yours,

DocuSigned by:
David W. Souder
9127829DF1DB44B...

David W. Souder,
Sr. Director, System Planning

cc:
Joseph Bowring, MMU {Joseph.Bowring@monitoringanalytics.com}
Jeffrey Currier, Dominion Energy, {jeffrey.currier@dominionenergy.com}

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 10

The following response to Question No. 6 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Jeffrey E. Currier
Energy Supply Planning & Operations Strategic Advisor
Virginia Electric and Power Company

As it pertains to legal matters, the following response to Question No. 6 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 6

a) Please confirm that Dominion filed deactivation requests with PJM for Chesterfield Units 5 and 6.

b) If the above is confirmed, please provide the date the deactivation requests were made and provide any and all communications Dominion received from PJM in response to its deactivation requests for Chesterfield Units 5 and 6.

c) Did PJM identify any reliability violations associated with the unit retirements that would require system upgrades to correct?

Response:

a) Yes.

b) The Company objects to this request as overly broad, unduly burdensome, and potentially voluminous to the extent it seeks "all communications [the Company] received from PJM in response to its deactivation requests for Chesterfield Units 5 and 6." Subject to and notwithstanding this objection, the Company provides the following response.

As indicated by the letter in Appendix 2B (vi) of the 2023 Plan, Chesterfield Units 5 and 6 deactivation requests were made on February 20, 2020. See Attachment APV Set 10-06 (JEC) for PJM's response.

c) No.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Virginia State Corporation Commission Staff
Set 1

As it pertains to energy production and unavailability, the following response to Question No. 42 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Wesley A. Hudson
Manager – Electric Market Operations
Virginia Electric and Power Company

As it pertains to capacity, the following response to Question No. 42 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Jeffrey E. Currier
Energy Supply Strategic Advisor
Virginia Electric and Power Company

As it pertains to availability, the following response to Question No. 42 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Jorge Serrano
Manager – Power Generation Operations
Dominion Energy Virginia

Question No. 42

For each of the Company's owned and contracted generating resources, please provide the hourly performance, including the actual energy production, in MWh; installed capacity ("ICAP"), in MW, available for dispatch; and unforced capacity ("UCAP"), in MW, available for dispatch during the period of December 20, 2022 through December 30, 2022. To the extent one or more generating units was less than fully available, including completely unavailable, please provide a narrative explanation identifying the cause or causes of such unavailability.

Response:

See Attachment Staff Set 01-42(1) (JEC) CONF for the capacity data for the Company's regulated fleet.

See Attachment Staff Set 01-42(2) (WAH) for the actual energy production for the Company's regulated fleet.

See Attachment Staff Set 01-42(3) (WAH) CONF for the requested list of unavailable units from the Company's solar regulated fleet.

See Attachment Staff Set 01-42(4) (JLS) for the requested narrative on generating units that were less than fully available or completely unavailable.

Attachment Staff Set 01-42(1) (JEC) CONF and Attachment Staff Set 01-42(3) (WAH) CONF contain confidential information as indicated and are being provided pursuant to the protections set forth in 5 VAC 5-20-170, the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information dated May 23, 2023, any additional protective order or ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and the Agreements to Adhere executed pursuant to any such orders or rulings.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 10

The following response to Question No. 3 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Wesley A. Hudson
Manager – Electric Market Operations
Virginia Electric and Power Company

As it pertains to legal matters, the following response to Question No. 3 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 3

Please reference Dominion's response to APV 6-1(b). Dominion references its response to Attachment Staff Set 01-42(2) (WAH) for the data for Dominion's regulated fleet. However, there are a number of generation units missing from Attachment Staff Set 01-42(2) (WAH). The following units are missing:

Chesterfield Unit 5 (coal)
Chesterfield Unit 6 (coal)
Altavista (biomass)
Hopewell (biomass)
Southampton (biomass)
Scott (solar)
Whitehouse (solar)
Woodland (solar)

Public generation and emissions data indicate that Chesterfield units 5 and 6 were online and generating during winter storm Elliot. Please update Dominion's response to APV 6-1 (b) to reflect the generation (MWhs) from Chesterfield units 5 and 6 and the other missing units listed above. If any of the units were not generating during the requested timeframe, please indicate the reason the unit was not dispatched or was unavailable for dispatch.

Response:

The Company objects to this request as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding to the extent it seeks information on Chesterfield Units 5 and 6. These units were retired May 31, 2023, and are not included in the Company's 2023 Plan. Subject to and notwithstanding this objection, the Company provides the following response.

In Attachment Staff Set 01-42(2) (WAH), Altavista (biomass) was included using the name Hallbranch, Hopewell (biomass) was included using the name Polyester, and Southampton (biomass) was included using the name Southampton. Scott (solar), Whitehouse (solar), and Woodland (solar) are behind-the-meter resources and are considered load reducers.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 10

The following response to Question No. 2 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Karim Siamer
Lead Economist
Dominion Energy Virginia

As it pertains to legal matters, the following response to Question No. 2 of the Tenth Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on June 23, 2023, was prepared by or under the supervision of:

Vishwa B. Link
McGuireWoods LLP

Question No. 2

Please reference Dominion's response to APV 6-1 (a). "Energy sales to serve native load" refers to Dominion's total metered sales to Dominion's jurisdictional and Virginia non-jurisdictional customers. Please update the response to APV 6-1 (a) to reflect this clarification. Is Dominion's response to Staff Set 1-41 that provided hourly load data for the DOM-LSE equivalent to metered sales to Dominion's jurisdictional and Virginia non-jurisdictional customers?

Response:

The Company objects to this request because it would require original work. The Company does not have the hourly metered sales at the customer meter for all customers. Subject to and notwithstanding this objection, the Company provides the following response.

See the Company's response to Staff Set 01-41. The hourly load (energy) data for the DOM LSE provided by the Company in response to Staff Set 01-41, represents all the Company's Virginia and North Carolina, jurisdictional and non-jurisdictional customer (including VMEA, CBEC and Town of Windsor) sales at the generator level, *i.e.*, grossed up for line losses.

Virginia Electric and Power Company
Case No. PUR-2023-00066
Virginia State Corporation Commission Staff
Set 1

The following response to Question No. 41 of the First Set of Interrogatories and Requests for Production of Documents propounded by Virginia State Corporation Commission Staff received on June 2, 2023, was prepared by or under the supervision of:

Karim Siamer
Lead Economist
Dominion Energy Virginia

Question No. 41

Please provide the hourly load data for the Dom-LSE for the period January 1, 2016 through the most-recently available date. Provide this data in an executable Microsoft Excel format with all underlying formulae intact.

Response:

See Attachment Staff Set 01-41 (KS).

Virginia Electric and Power Company
Case No. PUR-2023-00066
Appalachian Voices
Set 11

The following response to Question No. 4 of the Eleventh Set of Interrogatories and Requests for Production of Documents propounded by Appalachian Voices received on July 5, 2023, was prepared by or under the supervision of:

Scott Gaskill
General Manager – Regulatory Affairs
Dominion Energy Services, Inc.

Question No. 4

Please reference page 125 of the 2023 IRP that states "In other words, the Company's load forecast and planning obligations do not change if a portion of forecasted non-residential load increases come from customers who may certify as ARBs. These customers must be provided electric supply service regardless."

(a) Please confirm that some Bundled ARBs have PPA agreements with Company-owned renewable Ring-Fence facilities where Dominion is the maker of the PPA and the ARB is the taker of the energy, capacity and RECs from the qualifying Company-owned Ring-Fence facility.

(b) Does Dominion have energy management agreements in place with these Bundled ARB customers to provide wholesale energy scheduling and settlement services to sell the energy from the Company-owned Ring-Fence facilities into the PJM energy markets on behalf of the ARB customers?

(c) If Dominion is selling energy to these ARB customers through a PPA from a Company-owned Ring-Fence facility and this energy is not being re-sold into the PJM wholesale energy market on behalf of the ARB customer, please explain why Dominion also represents that it must "provide electric supply service regardless" without regard to the ARB status of the customer and the energy that was delivered under the PPA agreement.

(d) Bundled ARBs that have PPA agreements with Company-owned renewable Ring-Fence facilities are also required to purchase the capacity from the qualifying Company-owned Ring-Fence facility. Please explain why Dominion believes it must procure additional capacity to serve these ARB customers if Dominion has already sold the capacity of the qualifying Ring-Fence facility to the ARB customer.

(e) Could Dominion enter into bilateral contracts with Bundled ARB customers to buy back the capacity of the Ring-Fence facilities to meet Dominion's capacity obligation?

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Response:

(a) Some, but not all, bundled ARBs have ring-fenced PPAs with the Company. However, these are wholesale contracts; the energy and capacity of these PPAs are committed to PJM and not directly used to serve the retail load of the customer.

(b) The Company does not utilize separate energy management agreements with the ARBs. However, for those ARBs with Company-owned ring-fenced contracts, the PPAs are structured such that the Company commits the energy and capacity into the PJM market on behalf of the ARB customer.

(c) See the Company's answers to subparts (a) and (b). The energy and capacity from these ring-fenced resources are sold into PJM. The Company is obligated to provide electric supply services to all customers unless the customers are purchasing electricity from a competitive service provider in accordance with the laws.

(d) Under the Fixed Resource Requirement ("FRR") capacity construct, the capacity of Company-owned ring-fenced facilities is included in the Company's FRR plan. See the Company's response to APV Set 11-05, which shows that the Company also includes this capacity in the 2023 Plan modeling.

(e) No. See the Company's response to subpart (d).

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing via electronic mail:

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DATED: August 8, 2023