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August 8, 2023

VIA ELECTRONIC FILING

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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 2023 Integrated Resource Plan Filing Pursuant to § 56-597 et seq. of the *Code of Virginia*
Case No. PUR-2023-00066

Dear Mr. Logan:

Attached for filing in the above-referenced matter is the non-confidential Direct Testimony of Dr. Maria Roumpani, which is being submitted on behalf of Advanced Energy United. This filing is being submitted electronically, pursuant to the Commission's Electronic Document Filing System.

Thank you for your kind assistance in filing this document in the appropriate manner. Please do not hesitate to contact me should you have any questions or need anything further.

Regards,

/s/ Jasdeep S. Khaira

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Enclosures

c: All Counsel of Record (via email)

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DATED: August 8, 2023

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COMMONWEALTH OF VIRGINIA
BEFORE THE
STATE CORPORATION COMMISSION

PETITION OF VIRGINIA ELECTRIC AND POWER COMPANY *In re: Virginia Electric and Power Company s Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*	))))))))	CASE NO. PUR-2023-00066

TESTIMONY OF DR. MARIA ROUMPANI

ON BEHALF OF ADVANCED ENERGY UNITED

August 8, 2023

Summary of Direct Testimony of Dr. Maria Roumpani

My testimony focuses on Virginia Electric and Power Company's ("Dominion" or "the Company") failure to develop a least-cost plan that complies with the Virginia Clean Economy Act ("VCEA"). Based on this, I recommend that the State Corporation Commission ("Commission") not approve this 2023 Integrated Resource Plan ("IRP") in its current form and require Dominion to provide a revised IRP in this proceeding with several modifications to its modeling assumptions.

Dominion's IRP presents five Alternative Plans that are either designed as least-cost or least-VCEA-compliant portfolios but fail to demonstrate a meaningful set of options for the Commission's consideration. The Plans further fail to address the increasing costs and risks of fossil fuel generation.

In the short term, the Alternative Plans are implicitly defined by Dominion-imposed resource build constraints and forced-in resources limiting the value that an optimization model, like PLEXOS, can deliver in resource planning. Absent those limits, PLEXOS could identify cleaner portfolios with lower revenue requirements. In the long term, the Plans do not represent the possible future policy, market, and technological conditions; instead, all plans limit the model's options to today's known technologies. Therefore, the IRP presents a false dichotomy of either keeping online uneconomic thermal generation and failing to comply with the VCEA or overly relying on the capacity market.

I conclude my testimony by recommending that the Commission instruct Dominion to provide a revised IRP in this proceeding. On the supply side, this should include but is not limited to developing a least cost VCEA compliant plan, allowing additional storage options in the short term and advanced technologies in the long term, and meaningfully evaluating the alternatives to continued fossil fuel generation.

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Exhibits:

Exhibit MR-1: Dr. Maria Roumpani Resume

I. Introduction and Qualifications

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

A. My name is Maria Roumpani, and I am the Technical Director at Strategen Consulting ("Strategen"). My business address is 10265 Rockingham Dr., Suite #100-4061, Sacramento, CA 95827.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Advanced Energy United ("United"; f/k/a Virginia Advanced Energy Economy).

Q. Have you previously submitted testimony before the Virginia State Corporation Commission (the "Commission")?

A. No, I have not.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I have submitted written testimony in Docket No. UE 420, regarding PacifiCorp's Transition Adjustment Mechanism before the Oregon Public Utilities Commission. I have also testified before the Public Service Commission of South Carolina in Docket No. 2023-2-E regarding the Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc., and Docket No. 2023-1-E regarding the Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC. I have also testified before the Michigan Public Service Commission in the application of DTE Energy for the approval of its Integrated Resource Plan, before the North Carolina Utilities Commission in Duke Energy's application for approval of its Carbon Plan, and before the Colorado Public Utilities Commission in the Public Service Company of Colorado's application for approval of its 2021 Electric Resource Plan and Clean Energy Plan. Furthermore, I have supported numerous Strategen clients by providing technical support for written testimony, drafting written comments, and participating in technical workshops in a range of proceedings in Arizona, California, Colorado, Kentucky, Michigan, Nevada, North Carolina, Oregon, and South Carolina.

Q. Please describe your educational and occupational background.

A. I am a Director at Strategen Consulting. The Strategen team is globally recognized for its expertise in the electric power sector on issues relating to resource planning with a focus on decarbonization, renewable energy, energy storage, utility rate design and program design, and market entry strategy. At Strategen, I lead economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling for government clients, non-governmental organizations, and trade associations.

Before joining Strategen in 2018, I contributed to the development of analytical tools used in the European Union's energy impact assessment studies. I have a Ph.D. from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and Computer Engineering from the National Technical University of Athens, Greece.

Q. Please describe the purpose of your testimony.

A. The purpose of my direct testimony is to review and evaluate various components of the resource planning analysis and the alternative plans as outlined by Dominion in its application for approval of its IRP. I investigate the plans' compliance with the VCEA and the Company's modeling methodology and assumptions with a focus on the supply side resources, while United witness Ed Burgess reviews the Company's load forecast and Demand Side Management projections.

Q. How is your testimony organized?

A. First, I provide an overview of Dominion's IRP analysis. I outline my concerns regarding the Company's methodology and input assumptions, including the plans' compliance with VCEA, the overall design of the plans, and the inclusion of carbon costs. Next, I discuss how the

Company's analysis underestimates the role of clean resources by imposing restrictive build limits on renewable resources, ignoring available tax credits, and overstating costs for energy storage. Then, I argue that the Company's analysis overestimates the role of thermal resources by overstating their reliability contributions and ignoring future costs and risks associated with the continued operation of carbon-emitting resources. Finally, I summarize my recommendations and conclude.

II. Summary of testimony and recommendations

Q. Please summarize your findings.

A. My findings are summarized below:

- The Company did not develop a least-cost VCEA-compliant plan.
- Renewable energy is economical and consistently selected by the model to the maximum level allowed. Absent the Company-imposed build limits, the model would select higher levels of renewable energy and result in cleaner portfolios with lower revenue requirements.
- The Alternative Plans do not present a meaningful set of options. In the short term, the plans are either designed as least-cost or VCEA-compliant portfolios. However,
    - The least cost portfolios are overly restricted by exogenously chosen build limits, i.e., they are implicitly driven by Company-imposed limits and not model-selected based on least-cost principles.
    - The VCEA-compliant portfolios are again restricted by build limits and erroneous assumptions. Furthermore, they are based on the Company's single vision for VCEA compliance instead of allowing the model to find the least-cost compliant portfolio.

Finally, they include new forced-in thermal resources (i.e., exogenous fossil fuel resources, which are manually added by the Company independently of their cost and are not selected by the model as part of the least cost plan) that put their compliance into question in the first place.

- In the long term, the Alternative Plans again fail to present a meaningful set of alternatives. The different plans do not represent different future market and technological conditions; instead, all plans limit the model's options in 25 years to technologies that are commercially viable today (with the exception of small modular reactors ["SMRs"]). With an artificially limited set of options (not including additional offshore wind, longer duration storage options, or advanced technologies) the IRP presents a false dichotomy of either keeping online uneconomic thermal generation and failing to comply with the VCEA or relying on a very expensive capacity market.

- The role of thermal resources is overestimated by assuming that they are perfectly dispatchable when needed, ignoring the recent experience of Winter Storm Elliott.

- The Company's short-term action plan includes new natural gas-fired generation and a liquified natural gas storage facility. The Company has provided no analysis to justify the inclusion of either of the two.

- The Company's retirement analysis shows that the continued operation of Virginia City Hybrid Energy Center ("VCHEC") will cost customers $206 million over the next ten years. Still, the Company keeps it online despite it being non-compliant with the VCEA based on the false promise of benefits in the long term. These benefits are extremely unlikely as they depend on no future technological, market, and policy developments.

- The Good Neighbor Plan ("GNP") issued on March 15, and the new performance standards for greenhouse gas ("GHG") emissions from fossil-fuel fired electric generating units proposed in May 2023 by the U.S. Environmental Protection Agency ("EPA") (or other emissions regulations) can further exacerbate the economics and risks for portfolios that heavily rely on fossil fuels.[1] Dominion's plan of continued investment in fossil fuel energy can lock its ratepayers in extremely and unnecessarily expensive portfolios.

- All Alternative Plans assume that Virginia will exit the Regional Greenhouse Gas Initiative ("RGGI") before January 1, 2024. They further fail to incorporate the cost of climate change by not assuming a carbon price until 2036.

Q. Please summarize your recommendations.

A. First and foremost, the Commission should not approve the 2023 IRP in its current form. Instead, the Commission should instruct Dominion to provide a revised IRP to be filed in this proceeding with several modifications to its modeling assumptions. These modifications include changes to the load forecast and demand-side resource options as well as the supply-side resource options. My colleague Ed Burgess provides testimony regarding recommended changes to the demand-side resource assumptions. Regarding changes to the supply-side resource options, my recommendations is that the Company develop at least one Alternative Plan that:

- Meets VCEA requirements regarding the amount of solar, wind, and storage developed over the study period. PLEXOS should be required to meet the targets but should also be allowed to select the optimal timing for resources. It should also allow for the selection of renewable resources above the VCEA development targets on a least-cost optimization basis.

[1] On March 15, 2023, the U.S. EPA issued its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NOX) from power plants and industrial facilities in 23 states, including Virginia.

- Does not include forced-in fossil fuel resources.
- Allows PLEXOS to select additional energy storage options in the short term: hybrid resources and storage of 6 and 8 hours of duration.
- Allows PLEXOS to select from a more realistic set of resource options in the long term. These should at minimum include long duration storage or other clean peaking technology and increased limits for solar and wind.
- Allows coal units to endogenously retire (with a latest retirement date of 2045).
- Updates the storage cost assumptions to better align with public and widely used estimates.
- Complies with the GNP.
- Assumes that Virginia remains in RGGI and Dominion assumes the social cost of carbon in the resource selection and retirement step.

III. Overview of Dominion's analysis

Q. Please provide a brief overview of Dominion's analysis.

A. Dominion's 2023 Plan covers the 15-year period beginning in 2024 and continuing through 2038 (the "Planning Period"). However, in its modeling, the Company evaluates the longer 25-year period of 2024 to 2048 (the "Study Period") using 2023 as the base year. The Company's planning process begins with the development of a long-term annual peak and energy requirements forecast and a determination of demand-side resources that could be part of the Company's portfolio. The net load forecast and supply side potential resources are then incorporated into the PLEXOS model—a utility modeling and resource optimization tool—which identifies different portfolios based on the Company's assumptions and constraints.

Q. Please summarize the five Alternative Plans presented in the Company's IRP.

A. The Company presents five Alternative Plans for its 2023 IRP. Each of the plans incorporates the VCEA requirements to a different degree, as shown in Table 1. Plans B and D include an exogenously forced buildout of solar, offshore wind, and energy storage "envisioned" by the VCEA.[2] Both plans B and D also include 970 Megawatt ("MW") of exogenously forced natural gas capacity. Plans A, C, and E are least-cost plans but are overly restricted by Company-imposed limits.

Table 1: Alternative Plans

	Least Cost Plan	Company envisioned VCEA buildout	Retirement of fossil fuel resources by 2045
Portfolio A	✓		
Portfolio B		✓	
Portfolio C	✓		
Portfolio D		✓	✓
Portfolio E	✓		✓

Q. Does Dominion identify a preferred portfolio?

A. No, the Company does not identify a preferred portfolio within its 2023 IRP. According to the Company, the 2023 Plan serves as a "guide for providing customers a path to reliable, affordable, and increasingly clean power that meets public policy objectives."[3] Although no Preferred Plan is identified, the Company, presents a Short-Term Action Plan for the next five years (2024-2029) that includes elements of the presented portfolios.

Q. Did the Company model a least-cost VCEA-compliant plan?

A. No. Portfolio D meets the Renewable Portfolio Standard ("RPS") and development targets of the VCEA while it retires all fossil fuel generation by 2045. However, the Plan seems to be the result of a Company envisioned VCEA buildout without allowing any flexibility for the model to select the pace at which resources are deployed, to select additional renewable energy projects, or even the economic retirement of existing units. The Plan further forces in resources on specific years, including 970 MW of combustion turbine ("CT") capacity.

[2] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 23-24.
[3] Dominion's Response to Appalachian Voices, Set 2, Question 3.

Q. What are your key concerns regarding Dominion's modeling approach, methodology, and assumptions?

A. There are several areas that raise concerns regarding the Company's design of the Alternative Plans and the assumptions used. These concerns fall under the following categories:

- The Alternative Plans are not VCEA compliant.
- The design of the Alternative Plans does not present a broad range of portfolios that could serve as a meaningful "guide for providing customers a path to reliable, affordable, and increasingly clean power that meets public policy objectives."
- The Company's load forecast contains problematic assumptions that overstate its future capacity needs.
- The Company's analysis underestimates the role of demand-side resources, thereby leading to suboptimal resource portfolios.
- The Company's analysis overestimates the role of thermal resources and underestimates the associated risks, thereby leading to suboptimal portfolios.

Concerns surrounding the Company's load forecast and the use of demand-side resources are presented in the testimony of United witness Ed Burgess, while my testimony focuses on the design of the Alternative Plans and the assumptions for supply-side resources.

IV. The Alternative Plans do not comply with the VCEA.

Q. Please identify the requirements for Dominion set forth by the VCEA.

A. With the passage of the VCEA, Dominion is subject to certain requirements with respect to its future resource mix and the electric bills paid by Dominion's customers. Among other things, the VCEA and the State Corporation Commission's February 1, 2021 Order in Docket PUR-2020-00035 dictates:

- "By December 31, 2045, [Dominion][4] shall retire all [] electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity."[5]
- "[Dominion] shall participate in a renewable energy portfolio standard program ["RPS Program"] that establishes annual goals for the sale of renewable energy.... To comply with the RPS Program, [Dominion] shall procure and retire Renewable Energy Certificates ["RECs"] originating from renewable energy standard eligible sources."[6]
- "By December 31, 2035, [Dominion] shall petition the Commission for necessary approvals to (i) construct, acquire, or enter into agreements to purchase . . . 16,100 megawatts of generating capacity located in the Commonwealth using energy derived from sunlight or onshore wind . . . and (ii) pursuant to § 56-585.1:11, construct or purchase one or more offshore wind generation facilities located off the Commonwealth's Atlantic shoreline or in federal waters interconnected directly into the Commonwealth with an aggregate capacity of up to 5,200 megawatts."[7]
- "By December 31, 2035, [Dominion] shall petition the Commission for necessary approvals to construct or acquire 2,700 megawatts of energy storage capacity."[8]

[4] Pursuant to Code §§ 56-585.1 A and 56-585.5 A, Dominion is a Phase II Utility. Code § 56-585.1 A provides that " [f]or purposes of this section, a Phase I Utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a Phase II Utility is an investor-owned incumbent electric utility that was bound by such a settlement." *See* State Cooperation Commission Final Order Case No. PUR-20200-0035. February 1, 2021. Available at https://www.scc.virginia.gov/docketsearch/DOCS/4r%24t01!.PDF, p. 3.
[5] Code § 56-585.5 B 3. Dominion "may petition the Commission for relief from the requirements of this subsection on the basis that the requirement would threaten the reliability or security of electric service to customers." Code § 56-585.5 B 4.
[6] Code § 56-585.5 C. "The RPS Program requirements shall be a percentage of the total electric energy sold in the previous calendar year . . . ." Id For Dominion, the percentage grows over time, reaching 100% by 2045. *See* State Cooperation Commission Final Order Case No. PUR-20200-0035. February 1, 2021. Available at https://www.scc.virginia.gov/docketsearch/DOCS/4r%24t01!.PDF, p. 3.
[7] Code § 56-585.5 D 2. *See* State Cooperation Commission Final Order Case No. PUR-20200-0035. February 1, 2021. Available at https://www.scc.virginia.gov/docketsearch/DOCS/4r%24t01!.PDF, p. 3.
[8] Code § 56-585.5 E 2. As required by Code § 56-585.5 E 5, the Commission promulgated regulations to achieve the deployment of energy storage, including regulations that set interim targets, in Case No. PUR-2020-00120

- "Notwithstanding any other provision of law, each investor-owned incumbent electric utility shall implement energy efficiency programs and measures to achieve the following total annual energy savings: . . . For [Dominion]: . . . [i]n calendar year 2025, at least 5.0 percent of the average annual energy jurisdictional retail sales by that utility in 2019."[9]

Q. Are the portfolios developed by the Company compliant with the VCEA requirements?

A. No. The VCEA has set clear requirements and standards for Dominion, which Dominion fails to comply with in the development of its portfolios. Despite requirements to retire fossil-fuel facilities, Dominion invests or preserves fossil-fuel generation in all its Plans. Plan D is presented as a portfolio designed to be VCEA-compliant, but it is developed based on several flawed assumptions leading to a costly, suboptimal buildout.

Q. Has the Company provided justification why the alternative plans were not designed to be VCEA compliant?

A. No. Although VCEA allows a utility to petition the Commission for relief from the requirements on the basis that the requirement would threaten the reliability or security of electric service to customers, Dominion has not presented evidence or analysis that VCEA compliance would pose reliability risks.

Q. Is Plan D VCEA compliant?

A. It is unlikely that Plan D would be VCEA-compliant. Although the plan meets the RPS and VCEA renewable and storage development targets and retires carbon-emitting generation by 2045, it is likely not VCEA compliant. Specifically, the code notes that:

Notwithstanding any other provision of law, unless the Commission finds in its discretion

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[9] Code § 56-596.2 B. "For the time period 2026 through 2028, and for every successive three-year period thereafter, the Commission shall establish new energy efficiency savings targets." Code § 56-596.2 B 3. *See* State Cooperation Commission Final Order Case No. PUR-20200-0035. February 1, 2021. Available at https://www.scc.virginia.gov/docketsearch/DOCS/4r%24t01!.PDF, p. 4.

> 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.[10]

Plan D includes 970 MW of new utility-owned generating facilities that emit carbon dioxide as a by-product of combusting fuel to generate electricity. Other than the Company's assertion that "to address energy and capacity needs during more extreme weather scenarios, especially in the winter, the Company included 970 MW of new combustion turbine ("CT") generation as early as 2028 in Plans B and D",[11] there has been no analysis or evidence that absent those resources there would be a threat to the reliability of the electric service. Furthermore, although the Company attempts to claim that CT capacity is more cost effective than energy storage, this argument is based on several flawed assumptions (like the inflated cost of energy storage, the failure to capture all energy storage benefits, the overestimation of the CTs' reliability contribution, the non-inclusion of certain tax credits, and others) that I analyze in detail throughout my testimony. As already mentioned, this capacity was included by the Company, and not selected by the model based on economics.

Q. Do you have a recommendation with respect to modeling of VCEA requirements?

A. Both in this and future IRPs, the Company should develop plans that meet VCEA requirements regarding the amount of solar, wind, and storage developed over the study period, and should not include forced-in fossil fuel resources without proper justification and analysis of a reliability need. PLEXOS should be required to meet the targets but should also be allowed to select the

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[10] VA. CODE ANN. § 56-585.1 (2023).

[11] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 30.

optimal timing for resources. It should also allow for the selection of renewable resources above the VCEA development targets on a least-cost optimization basis.

V. The Alternative Plans assume that the Company exits the Regional Greenhouse Gas Initiative and fail to properly account for the cost of climate change.

Q. Does the Company's analysis include a carbon price?

A. To a very limited degree. First, all Alternative Plans assume that Virginia exits the RGGI before January 1, 2024, and thus assume no carbon cost or limit based on RGGI participation starting in 2024. Second, according to Appendix 4N: Base Case Price Forecast, the Company includes the federal carbon price provided to the Company by ICF Resources, LLC ("ICF"), which remains at zero up to 2035 and starts at $3.18/Ton in 2036.

Q. Is the Company required to include a carbon price in its modeling?

A. Va. Code § 56-585.1 A 6 states that

> "In any application to construct a new generating facility, the utility shall include, and the Commission shall consider, the social cost of carbon, as determined by the Commission, as a benefit or cost, whichever is appropriate. [...] The Commission may adopt any rules it deems necessary to determine the social cost of carbon and shall use the best available science and technology, including the Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, published by the Interagency Working Group on Social Cost of Greenhouse Gases from the United States Government in August 2016, as guidance. The Commission shall include a system to adjust the costs established in this section with inflation."

Based on this requirement, the Company states that the social cost of carbon will be considered in future applications for a Certificate of Public Necessity and Convenience ("CPCN").[12] Although technically not required in the IRP analysis, it seems reasonable that for consistency purposes, the Company should have explored the impacts of including a carbon price at least at

[12] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwn01!.PDFp., p. 75.

a sensitivity level, especially for the new units being proposed in the short-term action plan, if not for all its analysis including the retirement study of carbon-emitting resources. Otherwise, the Company's planning is based on assumptions inconsistent with the requirements for new resources, resulting in a disconnect between resource planning and resource procurement and ultimately undermining the value that an IRP provides as a planning document or "guide" to determine the optimal path forward.

Q. Did the Company include a carbon price in its 2020 IRP or the 2021 Update?

A. Yes. According to Figure 1.2.1 of the 2021 Update to the 2020 Integrated Resource Plan, for the first ten years of the Study Period, the Company included a carbon dispatch adder equal to the forecasted price of a direct carbon tax. Starting in 2031, the Company then blended the forecasted social cost of carbon with the direct carbon tax through 2046 (i.e., the end of the Study Period).

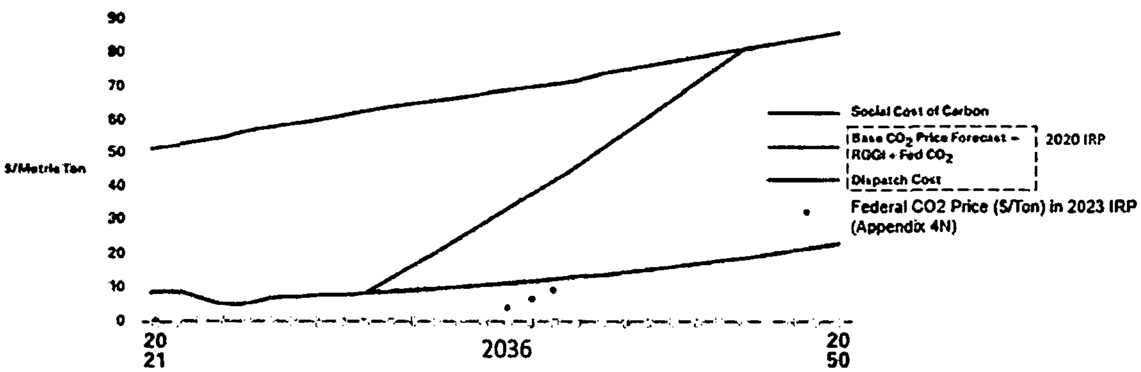
Q. How does the carbon price included in the 2023 IRP compare to the cost included in the 2021 Update or the social cost of carbon?

A. The graph below combines Figure 1.2.1 from the 2021 Update to the 2020 Integrated Resource Plan in combination with the values included in the 2023 IRP (red dots) for years prior to 2038 (as presented in Appendix 4N). In the 2021 Update, the Company also noted that:

> This 2021 Update presents the Company's initial analysis incorporating the social cost of carbon into its long-term planning process. This analysis will continue to evolve over time. For example, the 2021 Update includes the social cost of carbon only as a cost for carbon-emitting generating units—not as a benefit for carbon-free generating facilities such as solar, wind, and nuclear. That said, the Company will include the social cost of carbon as a benefit in future applications for new clean energy generating facilities, as required by the VCEA.

Still, the 2023 IRP does not include the social cost of carbon, assumes Virginia exits the RGGI, and incorporates a CO2 price that starts later than in the 2021 Update.

Figure 1: Carbon Price as included in the 2021 Update of the 2020 IRP and the 2023 IRP



Q. Do you have a recommendation with respect to the inclusion of a carbon cost in the Company's IRP analysis?

A. Yes. One overarching issue related to any IRP process is identifying how the performed analysis is used to inform specific actions taken by the utility such as new resource procurements or existing resource retirement decisions. If the analysis or assumptions between the two steps are inconsistent, then the IRP amounts to little more than an academic exercise and cannot meaningfully serve as a planning document. Based on this, and the requirement that Dominion has to include the social cost of carbon, as a cost or benefit, in any application to construct a new generating facility, I recommend that both in this and future IRPs, the Company includes the social cost of carbon at least as a sensitivity run allowing the model to optimize the investment *and* retirement of resources including their emissions costs.[13] The carbon price should be included in the Long-Term ("LT") model (i.e. the model in which resource additions and retirements are selected - capacity expansion step), incorporating the cost of climate change in planning decisions, but not in the Short Term ("ST") model (i.e. the model in which operations of the given resource fleet are simulated – production cost step), as actual operations are not

[13] Given that the social cost of carbon is also a benefit (not only as a cost for new fossil fuel resources), as determined by the Commission, new clean resources can result in quantifiable emission benefits by displacing or replacing fossil fuel generation. Thus, the social cost of carbon should also inform the retirement analysis.

currently inclusive of carbon costs. Furthermore, the issue of whether Virginia has properly withdrawn from RGGI has yet to be finalized and is still pending with the courts at the filing of this testimony.[14] Therefore, considering this litigation, Dominion should be required to conduct its planning as if Virginia has not withdrawn from RGGI.

VI. The Company's analysis underestimates the role of renewable resources and energy storage, thereby leading to suboptimal portfolios.

A. The Company's limits on renewable and energy storage resource additions are not fully justified and restrict the selection of these resources in the Alternative Plans.

Q. Has Dominion included annual resource limits in its resource modeling?

A. Yes. Dominion included resource annual limits for renewable energy resources and energy storage. In addition to build constraints, the Company has also limited the model's resource options to a narrow set of resources and did not include technologies that would reasonably be available within a 25-year period.

Q. Please describe the annual limits on energy storage that Dominion included in the model runs.

A. For the planning period, all plans were limited to 300 MW per year. Alternative Plans D and E allowed 900 MW per year after 2038. Furthermore, in terms of batteries, the model could only select lithium-ion batteries with a duration of four hours. Although the limits were not binding in the early years, they are binding every single year between 2030-2045 under Plan E, the least-cost portfolio in which carbon-emitting resources retire by 2045.

[14] Paullin, Charlie. "Virginia Enviro Groups File Notice They Will Challenge Youngkin's RGGI Withdrawal." *Virginia Mercury*, 31 July 2023, https://www.virginiamercury.com/2023/07/31/virginia-enviro-groups-file-notice-they-will-challenge-youngkins-rggi-withdrawal/. Accessed 3 Aug. 2023.

Q. Has the Company provided a reasonable explanation for the selection of those annual limits?

A. No. For the numerical limits on the MW available for selection, the Company stated that annual build limitations into the PLEXOS model "account for a realistic build scenario taking into consideration supply chain constraints, construction capacity, interconnection viability, and availability of projects."[15] With respect to modeling only four-hour batteries, the Company stated that they "limited energy storage resources in the 2023 Plan to those that are the most commercially feasible technologies available."[16] These explanations are not reasonable given the modularity and availability of lithium-ion solutions, as well as the readiness of longer-duration storage alternatives. Today, load-serving entities across the United States can attest to the viability of storage resources to provide peaking capacity and other grid services. In California, as of July 1, 2023, 5,600 MW of energy storage capacity has been brought online and is fully integrated into the electrical grid.[17] While most of these additions are four-hour resources given California's regulatory landscape, eight-hour lithium-ion solutions are feasible and have been procured.[18] Beyond lithium-ion assets, a suite of long-duration energy storage technologies, like iron-air storage systems, are commercially ready for the planning period and have been procured by entities such as Xcel in Minnesota.[19] In fact, PJM's recognition of the viability of such solutions supported the development of Effective Load Carrying Capacity ("ELCC") values for

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[15] Dominion's Response to Commission Staff Set 1, Question 65.
[16] Dominion's Response to Commission Staff Set 2, Question 93.
[17] *New Storage Milestone Reached for the California Grid; More than 5,000 MW Now Available for Dispatch*, 11 July 2023, www.caiso.com/Documents/new-storage-milestone-reached-for-the-california-grid-more-than-5000-mw-now-available-for-dispatch.pdf.
[18] Murray, Cameron. "California Utility Signs PPA with NextEra for Eight-Hour Energy Storage Project." Energy Storage News, 11 Apr. 2023, https://www.energy-storage.news/california-utility-signs-ppa-with-nextera-for-eight-hour-energy-storage-project. Accessed 3 Aug. 2023.
[19]. Howland, Ethan. "Minnesota PUC Approves Xcel's Plan to Install a 10-MW/1,000-MWh Form Energy Battery System." *Utility Dive*, 7 July 2023, https://www.utilitydive.com/news/minnesota-puc-xcel-form-energy-battery-sherco-solar/685460/. Accessed 3 Aug. 2023.

them, which were included in their December 2022 ELCC Report.[20] These experiences, coupled with the analytical work performed by PJM, show the Company could have more actively and realistically considered additional battery options within their planning approaches.

Q. Please describe the annual limits on solar resources that Dominion included in the model runs.

A. In Alternative Plans A, B, and C, the Company limited the model to select a maximum of 900 MW of utility-scale solar per year. For Plans D and E, the Company limited the model to selecting a maximum of 900 MW of utility-scale solar per year through 2038. Starting in year 2039, the Company increased this limitation to 1,200 MW per year. It is apparent from the results of plans A, C, and E in Table 2 that the limit on utility-scale solar is binding every single year. This means that utility scale solar is economic and results in benefits for Dominion's ratepayers; it is only limited due to Company imposed limits. Plans B and D include lower levels of solar up to 2030, but those values reflect the VCEA path as envisioned by the Company and were hard-coded in the model. Another point that is worth noting is that when allowed to optimize, the model selected only Power Purchase Agreements, as it found them to be more economic than Company-owned resources.

Table 2 Utility Scale Solar Resource additions under Alternative Plans A-E

UTILITY SCALE SOLAR

	A	B	C	D	E
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	900	600	900	600	900
2028	900	660	900	660	900
2029	900	660	900	660	900
2030	900	720	900	720	900
2031	900	900	900	900	900
2032	900	900	900	900	900
2033	900	900	900	900	900
2034	900	900	900	900	900

[20] *December 2022 Effective Load Carrying Capability (ELCC) Report*, 6 Jan. 2023, www.pjminterconnection.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx, p. 10.

2035	900	900	900	900	900
2036	900	900	900	900	900
2037	900	900	900	900	900
2038	900	900	900	900	900
2039	900	900	900	1,200	1,200
2040	900	900	900	1,200	1,200
2041	900	900	900	1,200	1,200
2042	900	900	900	1,200	1,200
2043	900	900	900	1,200	1,200
2044	900	900	900	1,200	1,200
2045	900	900	900	1,200	1,200
2046	900	900	900	1,200	1,200
2047	900	900	900	1,200	1,200
2048	900	900	900	1,200	1,200

Q. Has the Company provided a reasonable explanation for selecting those annual limits?

A. No. The 900 MW of utility-scale solar per year limit is based on "an assumed amount of new solar generation available each year" or "to reflect the maximum total capacity of projects that is expected to be constructed each year due to construction constraints."[21] In contrast, in the 2021 Update to the 2020 Integrated Resource Plan "the Company limited the model to selecting a maximum of 1,200 MW per year, which is based on an assumed amount of new solar generation available each year."[22] In the 2020 IRP, the Company implemented a limit of 480 MW for solar Power Purchase Agreements ("PPAs"); resulting in years that would select 480 MW of PPAs and up to 960 MW of utility-owned solar, for a total of 1,440 MW of utility-scale solar for several years within the planning period. No evidence or justification has been provided for the reduction in the availability of solar or that the utility could not still pursue 1,200 MW, 1,440 MW or more of solar resources per year. Although real life limitations exist, Dominion could pursue additional solar projects at customer sites, brownfield locations, or consider easing

[21] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 66.

[22] Virginia Electric and Power Company's Update to the 2020 Integrated Resource Plan Case No. PUR-2021-00201. September 1, 2021. Available at https://www.scc.virginia.gov/docketsearch/DOCS/5jk%2501!.PDF, p. 34.

interconnection considerations with different configurations of hybrid resources with larger sized DC components.

Q. Please describe the annual limits on wind resources that Dominion included in the model runs.

A. With respect to onshore wind, the Company made two specific projects under development in Virginia available for selection—a 120 MW and an 80 MW project. In addition to these two specific projects, the Company made an additional 60 MW generic onshore wind resource available for selection once every three years beginning in 2028.

Concerning offshore wind, the Company included the Coastal Virginia Offshore Wind project (approximately 2,600 MW) in all portfolios. In all Alternative Plans, a second 2,600 MW tranche of offshore wind was made available for selection beginning in 2033. In Alternative Plans B and D, the Company forced the model to select the second tranche of offshore wind in 2033. It is apparent from Table 3 that the limits on wind resources are again binding. This means that whenever the model was allowed to select it, wind was included in the least-cost portfolio.

Table 3: Onshore and Offshore Wind Resource additions under Alternative Plans A-E

ONSHORE AND OFFSHORE WIND

	A	B	C	D	E
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	-	-	-	-	-
2028	260	260	140	260	140
2029	-	-	-	-	-
2030	-	-	120	-	120
2031	60	60	60	60	60
2032	-	-	-	-	-
2033	-	2,600	-	2,600	-
2034	60	60	60	60	60
2035	-	-	2,600	-	2,600
2036	-	-	-	-	-
2037	2,660	60	60	60	60
2038	-	-	-	-	-
2039	-	-	-	-	-
2040	60	60	60	60	60
2041	-	-	-	-	-

2042	-	-	-	-	-
2043	60	60	60	60	60
2044	-	-	-	-	-
2045	-	-	-	-	-
2046	60	60	60	60	60
2047	-	-	-	-	-
2048	-	-	-	-	-

Q. Has the Company provided a reasonable explanation for the selection of those annual limits?

A. In the short-term, yes. Within the IRP, the Company states that the current availability of land suitable for onshore wind construction in Virginia is, and likely will continue to be, a limiting development constraint.[23] However, in the longer term it would be reasonable to assume that additional onshore and, particularly, offshore resources could be enabled with further commercial development and technological advancements, both with regard to generation and transmission. These advancements could enable further projects to be cost-effectively developed. In this context, exploring said possible futures through the modeling of scenarios or sensitivities that ease wind development constraints for later years would be informative, especially given the fact that the limits set on Alternative Plans A through E are binding.

Q. Please summarize your concerns regarding Dominion's use of build limits in the modeling?

A. I recognize that in a modeling analysis, constraints might be needed to reflect real-world limitations, and I am not arguing that an IRP should be developed without any limits. However, in cases such as this, in which the modeling constraints are binding almost every year, it becomes even more important to examine them and ensure that the model is not being precluded from selecting cleaner and lower cost plans without justification. To summarize, with respect to the Company's build limits in this IRP, I have the following concerns:

[23] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 67.

- In the short term, the Company's solar limits have significantly changed since the 2020 IRP and the 2021 Update. If the model was allowed to select more solar or wind, it would most probably select additional renewable energy and result in portfolios with lower revenue requirement.
- In the long-term, the Company's choice to limit storage resources for the next 25 years to those that are the most commercially feasible today markedly underrepresents the range of options that the Company will have in the future. The Company has further chosen to not model other advanced technologies (with the exception of SMRs). Consequently, with an artificially limited set of options (not including additional offshore wind, longer duration storage options, or other advanced technologies) the IRP presents a false dichotomy of either keeping online uneconomic thermal generation and failing to comply with the VCEA or relying on an expensive capacity market.

Q. Do you have a recommendation with respect to the set of resources available for selection in the Company's modeling and the assumed build limits?

A. Yes. In its analysis, Dominion should allow the model to select:

- In the short-term:
  - Hybrid resources of solar and storage which can provide enhanced services at a lower cost.[24, 25]

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[24] Battery storage paired with solar, hybrid resources offer greater controllability of variable resources, increasing their resource adequacy value and offering operational benefits. *See* "Hybrid Resources Enhance the Contribution of Renewables to the Grid." *Pennsylvania-New Jersey-Maryland Interconnection (PJM)*, 20 July 2023, www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/hybrid-resources-enhance-the-contribution-of-renewables-to-the-grid.ashx

[25] Furthermore the 2023 Advanced Technology Baseline from the National Renewable Energy Laboratory reports co-location cost savings of approximately 8%. *See 2023 Annual Technology Baseline (ATB)*, 2023, https://data.openei.org/files/5865/2023_v2_Workbook_07_20_23.xlsx, Tab Utility-Scale PV-Plus-Battery, Cell S44.

  - At least one scenario, in which annual resource limits are increased to the levels of the 2021 Update.
- In the long-term: additional advanced technology options after 2040. Those can include additional tranches of offshore wind, geothermal energy, long duration batteries or other storage technologies, clean peakers (including all associated costs), vehicle to grid integration, or renewable technologies with enhanced capacity factors.

B. The cost of energy storage in the Company's analysis is overstated.

Q. What cost assumptions did Dominion use to inform its resource planning analysis?

A. According to section 4.5, the Company's projected costs for solar, onshore wind, and energy storage resources are not directly based on publicly available data, but on limited cost data from Company-developed projects through 2022. The 2023 costs were then held constant through 2026, while beyond 2026 (adjusted for inflation). These values were then increased or decreased following the 2022 National Renewable Energy Laboratory ("NREL") annual technology baseline ("ATB") escalation/de-escalation rates for the moderate scenario.

Q. Do you have a recommendation with respect to cost assumptions for energy storage?

A. Yes. The Company's cost assumptions should be based on public technology baselines like the NREL ATB, with detailed justification for any adjustment due to local reasons. Although my review only focused on the energy storage assumption, my recommendation is that the Company uses the same publication for all resources for consistency and transparency. Furthermore, as already noted, I recommend that Dominion also models hybrid resources (with a number of different configurations) capturing the technologies' synergies and cost savings when paired together.

C. The flexibility and other benefits of energy storage were not included

Q. Can you provide a brief overview of energy storage's benefits and how these are included in IRP analysis?

A. Energy storage can deliver several electricity-grid services. Those can include bulk system services (capacity and energy arbitrage), ancillary services (regulation, spin/non-spin reserves, voltage support, black start, frequency response), transmission and distribution services (upgrade deferrals, congestion relief), as well as customer management services (resiliency, charge reductions).

Q. Why is the omission of the flexibility benefit important?

A. Dominion estimated generation re-dispatch costs, which according to section 4.7.5, represent costs resulting from real-time variability of load and generator availability compared to day-ahead forecasted load and generator availability. Based on Figure 4.6.3.3, which shows the re-dispatch cost on a $/ renewable MWh basis and Appendix 5G (the renewable system generation), the total cost for Plan B amounts to more than a billion. However, those re-dispatch costs which were modeled on the entire build plan output of Alternative Plan B, were not sensitized based on differing levels of storage investments.[26] However, energy storage could significantly reduce those costs, as it can flexibly and quickly respond to changing needs without the fuel usage and time required to ramp up or down thermal generation. This benefit has not been modeled, and thus, the cost of portfolios that include higher energy storage is overstated while investment in the technology is lower than the optimal level.

Q. Do you know of other utilities incorporating flexibility benefits in their IRP analysis?

[26] Dominion's Response to Advanced Energy United, Set 1, Question 20.

A. Yes. Other utilities are now approximating this flexibility value, showcasing its importance despite every system being different, and values calculated in other IRPs cannot be directly applied in the Dominion analysis.

In PacifiCorp's 2021 (as well as its preliminary 2023) IRP, they have included a "granularity" adjustment meant to capture the difference between the value that batteries (or other flexible resources) can provide in models of different time resolutions. Specifically, PacifiCorp states that:

> As detailed during the 2023 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the seven-block per month representation used in the LT model. This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.[27,28]

According to slides shared by PacifiCorp during the 2021 IRP public-input process, this undervaluation ranged between \$25/kW-year and \$50/kW-year for the second half of this decade.[29]

Furthermore, both Portland General Electric ("PGE") and Puget Sound Energy ("PSE") incorporate similar methodologies in their analyses. Using the utility's in-house, intra-hour Resource Optimization Model ("ROM"), PGE modeled its system one week at a time, stepping through three levels of granularity while preserving commitments made in previous levels: (1) Day-ahead (hourly unit commitment), (2) Hour-ahead (15-minute unit commitment), (3) Real-

[27] *PacifiCorp's 2023 Integrated Resource Plan, Volume I"*, 31 Mar. 2023, www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_February_25_2022.pdf, p. 221.

[28] "LT" refers to the long-term model, which corresponds to the capacity expansion step, while "ST" refers to the short-term model, which corresponds to the production cost step.

[29] ***Integrated Resource Plan 2021 IRP Public-Input Meeting***, 25 June 2021, www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp%202021%20IRP_PIM_July_30_%202021.pdf., p. 36.

time (15-minute unit commitment). Through this process, PGE was able to quantify a flexibility value for different resources (PGE's flexibility values seem to also reflect ancillary services values). Specifically, the flexibility value for a four-hour lithium-ion battery was estimated at \$28.20/kW-yr (in 2020 dollars). Similarly, PSE identified flexibility benefits that were used in the resource cost assumptions in each portfolio's development. In its 2021 IRP, PSE estimated the flexibility cost savings for a four-hour lithium-ion battery to be \$20.45/kW-yr.[30] DTE's 2022 IRP also modeled flexibility benefits associated with batteries reducing renewable energy integration costs; with values ranging from \$3.38/kW-yr in 2026 to \$67.85/kW-yr in 2035.[31]

Q. How did the Company calculate ancillary benefits for energy storage?

A. In order to assess the cost of regulating reserves, the Company first estimated the level of required operating reserves (which increases with the level of renewables built), then determined a market price for these reserves. Finally, the Company calculated the regulating reserve costs per Plan as the difference between the regulating costs to serve the Company's load and the revenue received from PJM for the Company units that supply this ancillary service. However, even if the ability of energy storage to provide regulating reserves was included in the final calculation of costs and thus reflected in the Net Present Revenue Requirement ("NPVRR") of the plans, it seems that this benefit that storage resources could receive was not included as an input, i.e., as a cost reduction for the technology.[32] Thus, at the time that the model optimized, it was unaware of the additional benefit of storage. Lazard calculates that PJM's regulation market revenue stream for

[30] Puget Sound Energy's Integrated Resource Plan 2021. Available at https://www.pse.com/-/media/PDFs/IRP/2021/IRP21_Chapter-Book Compressed_033021.pdf?sc_lang=en&modified=20220307225041&hash=BF3BAD39DDC31F526D46104FC523384E., 5-34 (Figure 5-17).

[31] DTE Electric Company's Integrated Resource Plan, Testimony of Laura K. Mikulan MPSC Case No. U-21193. November 3, 2023. Available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004qW9sAAE, p. LKM-65 (Table 10).

[32] Dominion specifies that renewable integration costs are a "topside" entry in the NPV calculation for each of the Alternative plans and are not included in the PLEXOS model. *See* Dominion's Response to Advanced Energy Untied, Set 2, Question 8.

energy storage far exceeds other market, with batteries in PJM seeing approximately four times the revenue from regulation ancillary services compared to other markets from February 2019-February 2020.[33] Although Lazard identified that these markets lack depth and have a risk of becoming saturated, potentially reducing future earnings, the benefit is still significant and should be included in the optimization.

Q. Do you have a recommendation with respect to modeling energy storage benefits?

A. Yes. Although, as stated before, I recognize that capturing all benefits in a single model is challenging both from a data and a computational perspective, I recommend that if the Company includes additional re-dispatch or ancillary costs driven by renewables build, then the value that energy storage can bring by mitigating those costs should also be accounted for. Specifically, for this IRP, I recommend that Dominion estimates a benefit for energy storage reflecting the reduction of renewable integration costs that each kW of storage can provide. This cost should be included in the PLEXOS optimization (either as a negative fixed operating cost, or as a reduction to the asset's capital cost).

With respect to the transmission and distribution benefits, I recommend that, in the Company's retirement analysis, the Company reduces transmission upgrade costs as appropriate when considering storage replacements.

For future IRPs, I recommend that as the models become more sophisticated, and as utilities and stakeholders gain experience, these different value streams will be increasingly integrated into utilities' modeling approaches.

[33] "Lazard's Levelized Cost of Storage Analysis—Version 7.0." Lazard.Com, 2021, www.lazard.com/media/42dnsswd/lazards-levelized-cost-of-storage-version-70-vf.pdf., p. 16.

D. Bonus tax credits that could further reduce the cost of renewable energy and energy storage were not incorporated.

Q. Has the Company incorporated the resource cost changes enabled by the passage of the Inflation Reduction Act ("IRA")?

A. Yes, to a limited degree. First, I want to clarify that the IRA includes a multitude of provisions, and I recognize that it would be challenging to model all of those. Some of the provisions, like the extended tax credits, are easier to model, while the impact of others might be more complicated to model. In its analysis, the Company included production tax credits ("PTC") for utility-scale solar, wind, and new nuclear resources and investment tax credits ("ITC") for distributed solar and storage resources.

Q. Are there provisions in the IRA that have not been incorporated into this analysis and would be material for the determination of the optimal plan?

A. Yes. Beyond the standard ITC/PTC tax extensions that the Company has already considered, many programs may also provide benefits for Dominion and its ratepayers, like the Domestic Content Bonus and Community-Based Bonuses (discussed in section 4.6 of the IRP). Bonus credits have not been incorporated in the analysis. Furthermore, the Energy Infrastructure Reinvestment Program ("EIR") provides low-interest loans to reinvest in energy communities while reducing carbon emissions. One way Dominion can apply this program is to refinance and retire existing coal plants and reinvest in new clean energy resources using the program's low-cost capital.

Q. What would the impact of incorporating the Energy Community Tax Credit in the Company's modeling be?

A. There are two potential impacts that are worth considering. First, with Chesterfield Units 5 and 6 retiring in May 2023 (approximately 1 GW of coal capacity), energy storage (or renewable energy) projects located in that site could qualify for the bonus credit i.e., an additional 10% ITC or PTC. However, the construction of the two CTs in Chesterfield County, as currently proposed by Dominion, will not benefit from any IRA credits.[34] Second, additional bonus credits could be available if the Company retired more coal capacity within the next ten years, enabling cleaner resources to come online and resulting in additional cost savings for ratepayers. This possibility was not properly considered in the Company's retirement analysis and the credits are projected to expire before the Company's planned retirement dates.

Q. Do you have a recommendation with respect to the inclusion of bonus credits?

A. According to the IRP, the Company is actively pursuing the development of projects in energy communities and expects that bonus tax credits will be available for specific future projects. My recommendation is that the Company's analysis reflects those efforts. Although these credits might be less important for modeling purposes of new resources (since the model already selects clean resources when allowed), they will be impactful when determining the replacement of existing resources. For example, the Company is considering the construction of the two CT units at a location that could potentially qualify for the energy community bonus. If the bonus were to be applied to replacement storage resources, additional savings could be achieved. Although it would fall outside of the scope of this proceeding, I recommend that, as part of the CPCN proceeding for the CT units, the Commission requires Dominion to provide a detailed narrative of whether energy storage could be constructed at the Chesterfield site as an alternative to the CT units and whether it would qualify for the bonus credits. Dominion should also be required to consider the bonus credits in the retirement analysis of its coal units.

VII. The Company's analysis overestimates the role of thermal resources and underestimates the associated risks, thereby leading to

[34] Dominion's Response to Commission Staff, Set 1, Question 23.

suboptimal portfolios

Q. One of your primary concerns is that the Company's analysis overestimates the role of thermal resources and underestimates the associated risks, thereby leading to suboptimal portfolios. Can you provide a justification for this concern?

A. Yes. Along with underestimating the role of renewable energy and energy storage, I find that the Company has overestimated the role of thermal resources in its portfolio. Thermal resources have been assigned reliability benefits beyond what has been recently experienced during Winter Storm Elliott, while the cost of keeping them in the system has been underestimated. In the case of the 2028 CT natural gas peaking capacity, thermal resources have bypassed any need for analysis and are part of the Plans of even the short-term action plan without any proper justification. Specifically, my concerns are:

- The reliability benefit of thermal resources is overstated.
- The cost of new thermal and existing resources is understated.
- Even with understated costs and risks and overstated reliability benefits, the model does not select new gas resources prior to 2032 and projects net losses over the next ten years for some of its thermal units. Still, the Company includes almost one gigawatt ("GW") of new gas-fired peaking capacity in its short-term action plan and keeps uneconomic units operating.

A. The capacity contribution of thermal resources is overstated.

Q. Please explain how the Company assesses the capacity contribution of resources within its 2023 IRP.

A. According to the 2023 IRP, the analyses contained therein use ELCC to measure the additional load a particular generator of interest can supply without a change in reliability.[35] Despite the fact that this approach can be applied to all resources, the Company only uses ELCC methods to determine the capacity contribution of solar both fixed and tracking), wind (both onshore and offshore), and four-hour energy storage.[36]

Q. Please explain how the Company assesses the capacity contribution of thermal resources within its 2023 IRP.

A. According to discovery, the Company uses ELCC values in PLEXOS to calculate firm capacity for intermittent resources; however, ELCC values do not apply to units where their firm capacity equals their summer rating.[37] This means that for thermal resources, their summer rating, or installed capacity, is the value used to approximate their firm capacity contribution. This is confirmed in Appendix 5P, which notes that a generic CT asset with a nameplate of 485 MW would contribute 485 MW of firm capacity. As stated previously, this is not unique to fossil-fueled resources; Appendix 5P also notes that a generic nuclear asset with a nameplate of 268 MW would provide 268 MW of firm capacity. This assumption equates if thermal resources provide firm capacity at 100% ELCC in both summer and winter seasons.

Q. Do you find the Company's assumption that a thermal asset's installed capacity is a viable proxy for its firm capacity contribution reasonable?

A. No, this assumption is unreasonable as it rests on the flawed assumption that fossil-fueled assets are perfectly dispatchable at their full capability at any time, an impossibility that is not met by any single resource class. This mischaracterization of fossil-fueled resources is clear within the

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[35] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 60.
[36] *Id. at* 61.
[37] Dominion's Response to Clean Virginia, Set 1, Question 9.

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Company's explanation of the ELCC methodology, which mistakenly states that ELCC can also be defined as "the equivalent MW of a traditional generator that results in the same reliability outcomes that a particular generator of interest (such as an intermittent generator) can provide."[38] This perspective is incorrect as it presumes that traditional generators would have a 100% ELCC. In reality, the dispatchability of thermal resources is also subject to several uncertainties including forced outages, correlated outages, weather dependent outages, and fuel unavailability.[39]

Q. Please explain some of the potential consequences of overestimating the capacity value.

A. Several consequences stem from this overestimation. First, for any period with a short capacity position, the planning model employed by the Company will favor solutions with a higher capacity contribution per dollar spent, given its least-cost formulation. In this context, the overestimation of thermal assets' capacity contributions will make them unduly competitive to meet capacity needs, putting them at an unjustified advantage over energy storage resources. The second consequence is that any selection of thermal resources, whether economic or forced in, will disproportionately meet capacity needs, thus artificially suppressing the additional amount of resources needed to retain reliability and ultimately yielding an unreliable portfolio. Furthermore, the overestimation of the capacity contribution of existing thermal resources inflates their perceived value in the model, making their continued operation seem more economic than it really is.

Q. Do you know of any data suggesting fossil-fueled generators in the Company's territory do not provide firm capacity equivalent to 100% ELCC?

[38] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwm01!.PDF, p. 60.

[39] Dison, Joel, et al. "Accrediting Resource Adequacy Value to Thermal Generation." *Advanced Energy United*, 30 Mar. 2022, https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf., p. 8.

A. Yes, on July 17, 2023, PJM released an update on their reliability risk modeling analyses. Included in this update were new average ELCC values by class or Class Average Accreditation Values. Notably, this update included ELCC values for thermal resources, including nuclear, coal, gas combined cycle ("CC") assets, and gas CT. As Table 5 shows, the accreditation values calculated by PJM do not equate 100% in either of the seasons analyzed. Most notable is the winter values of these resources, which demonstrate thermal assets, particularly CTs, are less dependable than the Company assumes in its 2023 IRP. Considering the hardships posed by Winter Storm Elliot, the overestimation of firm capacity contributions in the winter season should be particularly concerning for the Company.

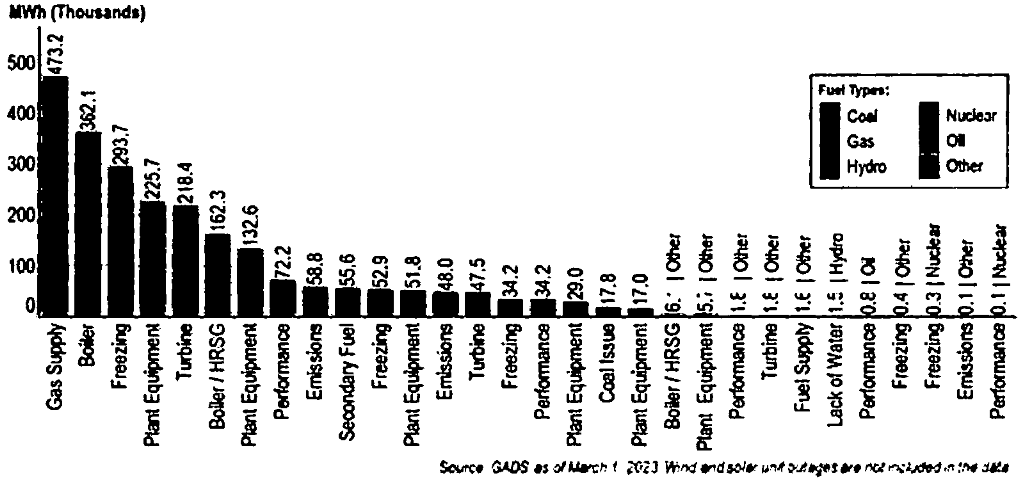
Table 5. PJM's Estimated 26/27 Class Average Accreditation Values (July 2023)[40]

Technology class	Summer	Winter
Thermal resources (overall)	95%	78%
Nuclear	98%	96%
Coal	89%	86%
Gas CC	97%	76%
Gas CT	98%	63%

Figure 39 of the Winter Storm Elliott Event Analysis and Recommendation Report (published on July 17, 2023) breaks down the outage causes, considering both fuel type and outage cause. Overall, fuel supply for natural gas and freezing, plant equipment issues – including boiler, heat recovery steam generator and turbine problems for both natural gas and coal units make up the majority of outages with 23% of natural gas generation being unavailable and 20% of coal capacity being unavailable for the duration of the event.

[40] *Update on Reliability Risk Modeling*, 17 July 2023, www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230717/20230717-item-03---reliability-risk-modeling---july-update-v2-copy.ashx., p. 8.

Figure 2: December 23, 24 and 25, 2022 Forced MWh by Fuel Type and Cause by Fuel Type in PJM[41]



Q. Do you have a recommendation with respect to the modeling of the firm capacity contribution of thermal resources?

A. Yes. Dominion should keep following the developments in PJM's accreditation methods and keep the Commission apprised of said changes through the IRP Updates. For any plan that the utility presents in its IRPs which includes either a new carbon-emitting resource or the continued operations of carbon emitting resources beyond 2045, the Company should provide documentation for the cost effectiveness and reliability analysis of the thermal resource, considering the risks explained in this session.

B. The cost of thermal resources is understated

Q. Please provide additional information on your concern about Dominion's analysis not fully incorporating all the costs associated with the continued operation of its fossil-fueled resources.

[41] *Winter Storm Elliott Event Analysis and Recommendation Report*, 17 July 2023, www.pjm.com/library/reports-notices. Fig. 39.

A. The Company's analysis incorporates the capital and some of the ongoing costs of fossil fuel resources but fails to consider several other cost components. Closely related to my concern about the reliability contribution of thermal resources is the Company's inclusion of a Liquefied Natural Gas ("LNG") in the Short-Term action plan:[42]

> The addition of an LNG facility to support Greensville Power Station and potentially others will reduce the Company's reliance on a single gas pipeline, provide backup to support at least 1,588 MW of generating capacity, and support gas supply available to the Company's fleet. This facility is vitally important to the reliability and resilience of the Company's system.

This LNG facility, which the Company claims to be critical for thermal capacity to be fully reliable, adds costs that were outside the decision-making during this IRP or even the one that the Greensville units were proposed. Thus, additional costs are needed for existing and new thermal capacity to be reliable. Those costs are not considered in the Company's investment or retirement decision-making process.

Furthermore, given all the evidence from Winter Storm Elliott, several of the Company's thermal units will be subject to additional winterization requirements to ensure that they can withstand future storms, especially as the capacity is aging, adding costs and risks for the Company and its ratepayers.

In addition to all the costs associated with ensuring that thermal capacity can be technically dispatched during critical times, the Company will need to incur additional costs to ensure that thermal capacity can keep operating based on policy requirements. Such costs are not properly accounted for in the Company's modeling and will increase the costs beyond what the Company is currently projecting if the Company keeps investing in fossil fuel resources. For example, the proposed CT capacity, which "will be capable of blending hydrogen in the future" does not

[42] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Available at https://www.scc.virginia.gov/docketsearch/DOCS/7rwn01!.PDF, p. 91.

include costs associated with hydrogen fueling, which would be an option for the unit to keep operating beyond 2045.[43]

Finally, keeping thermal capacity online exposes ratepayers to the risk associated with fluctuating fossil fuel prices. Over the last two years, the gas market has shown extreme volatility and rises in prices. This has been caused by a variety of factors, including the Russian war in Ukraine, extreme weather events, and fuel delivery and availability issues, among others.

C. The company's portfolios do not properly account for the risk of future emissions regulations

Q. Have emissions performance rules and standards been announced since the Company completed its IRP analysis?

A. Yes. On June 5, 2023, the U.S. EPA published the GNP, originally signed on March 15, 2023. The GNP aims to significantly cut smog-forming nitrogen oxide pollution from power plants and other industrial facilities in 23 states, including Virginia. According to discovery,[44] the Company has not evaluated the impact of the GNP on the operations of its thermal fleet but is aware of the rule and after studying it, it will provide the necessary analysis updates in future IRP proceedings. In addition to the GNP, on May 23, 2023, the EPA also published a proposed rule that would establish new source performance standards and existing source performance standards for greenhouse gas emissions from new, modified, reconstructed, and existing fossil-fuel fired electric generating units. Since the rule is not yet final, the Company states that it "has no plans to issue an update evaluating the impact of the proposed rule and there is no requirement for the Company to do so," and that it will model changes in regulations when those are issued as final.[45]

[43] Dominion's Response to Clean Virginia, Set 1, Question 16.
[44] Dominion's Response to Clean Virginia, Set 2, Question 23.
[45] Dominion's Response to Sierra Club, Set 3, Question 4.

Q. What do you expect the impact of the published and proposed rules to be on the Company's resource fleet?

A. Compliance with the GNP will most probably increase the costs of continuing to operate the Company's thermal fleet, especially for coal units that do not currently have Selective Catalytic Reduction ("SCR") technology (currently Mount Storm 1, 2, 3 are the only units that have SCR). GNP compliance would most likely significantly increase the cost of operating those units or limit their value by imposing operational limits. Similarly, although not yet final, the proposed performance standards provide a strong indication that the continued operation of carbon emitting resources will be subject to additional costs, with the Company's coal, as well as the natural gas combined cycle ("CC") units being most heavily impacted. Under the proposed rule, the Company will have to evaluate compliance options that include Carbon Capture and Sequestration ("CCS"), hydrogen blending, limits on capacity factors and others, all of which will again either increase the cost of operations or reduce the potential value that thermal units can provide to the grid. For example, the rule proposes emission guidelines for large (i.e., greater than 300 MW), frequently operated (i.e., with a capacity factor of greater than 50%), existing fossil fuel-fired stationary combustion turbines. These guidelines include the use of CCS by 2035 or co-firing of 30% (by volume) low-GHG hydrogen by 2032 and co-firing 96% low-GHG hydrogen by 2038. This can drastically change the economics of the Company's CC units; especially those of the Greensville plant (1,588 MW) which is projected to operate at capacity factors of approximately 86% in years 2024-2038 (with the capacity factor for years beyond 2038 not being reported).[46] Additionally, for long-term coal-fired steam generating units (those that will be in operation beyond 2040) EPA proposes the use of 90% capture CCS and that the associated standard of performance for those units is effective beginning in 2030.

[46] Virginia Electric and Power Company's Integrated Resource Plan Case No. PUR-2023-00066. May 1, 2023. Appx. 5-D.

Q. What do you conclude for the impact of the rules and their inclusion in the IRP analysis?

A. Given the timing of the announcements, I am not arguing that the Company should have conducted an analysis to evaluate the impact of the proposed performance standards in this IRP. However, whether final or not, these rules provide a very clear and strong indication that the continued operation of carbon units will be costly and risky. This highlights that the paths that the Company has presented through the Alternative Plans, to either retire the carbon-emitting resources after 2045 or keep operating them, will both carry risks, and additional costs for ratepayers – while also resulting in additional emissions. Both of those paths are suboptimal options even before considering emissions regulations. Including the rules in the analysis could show that keeping the units even until 2045 would be prohibitively expensive and possibly not allowed under the Company's current assumptions. Instead, the Company should start evaluating additional portfolios that retire fossil-fired resources well before 2045 to minimize costs for its ratepayers. With respect to the GNP, I believe that the Company had time after it was signed to at least consider it as a sensitivity. With the primary motivation being the GNP even if in draft form, the Kentucky Utilities Company and Louisville Gas and Electric Company filed a joint application for the retirement of their coal-generating units in December 2022.[47]

Q. Do you have a recommendation with respect to the emissions regulations discussed in this section?

A. Yes. Dominion should revise its IRP to comply with the GNP. My recommendation for the inclusion of a carbon price in the Company's resource selection and retirement also relates

[47] Kentucky Utilities Company and Louisville Gas and Electric Company's Certification of Public Convenience and Necessity and Site Compatibility Certificates and Approval of Demand Side Management Plan, Direct Testimony of Stuart A. Wilson, Case No. 2022-00402. December 15, 2022. Available at https://psc.ky.gov/pscecf/2022-00402/rick.lovekamp%40lge-ku.com/12152022012325/17-Wilson_Direct_Testimony_2022-00402.pdf, p. 4.

to this section, as it can serve as a general proxy for emissions regulations that are not yet final but provide a clear indication of the additional future risks and costs.

D. Dominion's retirement analysis is based on flawed assumptions.

Q. Did the Company conduct a retirement analysis for its fossil fuel resources?

A. According to the Company, they completed two analyses related to the retirement of existing units. First, the Company completed a 10-year cash flow analysis focused on coal-fired, biomass-fired, and large combined-cycle generation facilities under market conditions. Unit Net Present Values were derived by comparing the unit costs, including operations, maintenance, and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues for the next 10 years based on the snapshot in time when the analysis was conducted. Second, the Company included the same unit-specific data in PLEXOS to allow the model to optimize endogenously the timing of unit retirements.

VIII. The Alternative Plans do not reflect Dominion's full range of options.

Q. You mentioned that the design of the Alternative Plans does not present a broad range of portfolios that could serve as a meaningful "guide for providing customers a path to reliable, affordable, and increasingly clean power that meets public policy objectives." Can you provide more information about your concern?

A. Yes. Although the IRP presents five plans and several sensitivities, it unfortunately fails to consider a broad range of futures in a way that would be informative. Primarily, my concern is that the Company does not present a least cost VCEA-compliant plan. Second, in the short term, the plans do not explore how the optimal portfolio would differ if the Company assumed certain feasibility limits were eased. Third, the plans also fail to consider the breadth of long-term future market, policy, and technological scenarios, leaving the Company to prepare for a single, highly unlikely, scenario and presenting a wrong dilemma between an expensive and carbon intensive portfolio and another expensive portfolio that is overly reliant on the capacity market.

Q. The Company presents the cost associated with each portfolio, showing that VCEA compliance can be expensive. Do you have any concerns for the cost estimates?

A. Yes. These estimates are informed by flawed assumptions. With respect to the comparison of B to C, and D to E (i.e., comparing the VCEA envisioned plan with the least cost plan): First the VCEA compliant plans are not necessarily least cost. Second, the least cost portfolios consistently choose PPAs over company owned solar as the model finds them to be more economic. This cost difference, although likely and material, should not be used to differentiate between portfolios – how the utility acquires the necessary energy and capacity are a factor of interest to policymakers but Dominion would not realistically agree to the entirety of solar additions be through PPAs. Furthermore, the VCEA envisioned portfolios include forced-in resources (notably including thermal resources that run counter to the policy goals of the VCEA), that are not selected based on least-cost principles. Plans B and D also include distributed generation, but it is unclear whether the cost estimate for said generation includes the utility cost or the total resource cost.[48] With respect to the comparison between B to D, and C to E, i.e., comparing the costs of retiring the carbon emitting units, the difference can be partially explained by the lack of alternative options.

Q. How could a least cost VCEA-compliant portfolio differ from the Company's envisioned VCEA-compliant portfolio in the short term?

A. The development of a least cost VCEA-compliant portfolio would be similar to portfolio D in that it would meet the RPS and VCEA development targets and retire all carbon-emitting assets

[48] Dominion's Response to Advanced Energy United, Set 2, Question 7.

by 2045. However, it would also allow the model the flexibility to meet those targets in a least cost way, making the pacing and timing of resource additions and retirements an endogenous decision. For example, the 2,700 MW energy storage target by 2035 could be met by the least cost annual schedule of storage deployment versus the one forced by the utility (which could for example lead to either underbuilding in a year depending on other portfolio changes resulting in capacity purchases). Similarly, the selection of the second tranche of offshore wind, which is selected by the model in year 2035 in plans C and E, is forced-in in 2033 in plans B and D without any explanation as to the timing of the resource need or what the cost impact from the assumed capital cost curve for the technology is. Demand-side resources, including energy efficiency and demand response should also be allowed to meet energy and capacity needs, and be deployed at levels higher than the VCEA requirements if economic. Furthermore, Plans B and D include 970 MW of natural gas peaking capacity that is not part of the least cost plan but was forced in by the Company. The Company has not presented analysis that absent those units, the plans would have reliability issues.

Q. You also mentioned that the IRP does not explore how the optimal plan would differ if certain Company-assumed feasibility limits were eased. What would be the value of exploring such a scenario?

A. The presented plans are similar in the assumed build for solar and onshore wind resources and the preservation of carbon-emitting units within the short-term action plan window. Thus, they do not provide insights as to how system costs and emissions would be impacted from an accelerated investment in renewable energy, or an accelerated retirement schedule for the less economic carbon-emitting resources. Given how restrictive the Company's build limits for renewable energy are (a concern which is explored and documented in Section VI(A)), the Company could have modeled a plan with relaxed limits. This run would result in a different portfolio and help the Company, the Commission, and stakeholders understand what the cost of those Company-assumed limits is, i.e., the what the economic and emissions benefit would be if the Company pursued additional renewable energy in the short-term addressing some of the currently assumed "permitting, labor, and other siting and construction" considerations. This could inform whether and how much effort should be placed in overcoming those challenges instead of locking itself in a suboptimal portfolio.[49]

Q. Do you have a recommendation with respect to the Company's development of Alternative Plans that reflect a more complete set of options?

A. Yes. As already mentioned, the Company should consider modeling Alternative Plans that allow for an economical selection of a wider pool of resources. To this effect, the Company should model Alternative Plans with reduced Company-imposed deployment limitations, a focus on meeting applicable regulations while advancing cost-effective planning, and a candidate resource pool that includes long-duration energy storage technologies that can provide dispatchable power for six, eight, and ten hours. In this vein, the Company should also model Alternative Plans that revise the availability of onshore and offshore wind resources at least for the later part of the study period. Relaxing both annual constraint and overall deployment constraints could offer directional insights regarding the value of each renewable resource to the system.

IX. Recommendations and conclusions

Q. What are your key concerns regarding Dominion's modeling approach, methodology, and assumptions?

A. There are several areas that raise concerns regarding the Company's design of the Alternative Plans and the assumptions used. These concerns fall under the following categories:

- The Alternative Plans are not VCEA compliant.

[49] Dominion's Response to Advanced Energy United, Set 2, Question 4.

- The design of the Alternative Plans does not present a broad range of portfolios that could serve as a meaningful "guide for providing customers a path to reliable, affordable, and increasingly clean power that meets public policy objectives."
- The Company's load forecast contains problematic assumptions that overstate its future capacity needs.
- The Company's analysis underestimates the role of demand-side resources, thereby leading to suboptimal resource portfolios.
- The Company's analysis overestimates the role of thermal resources and underestimates the associated risks, thereby leading to suboptimal portfolios.

Concerns surrounding the Company's load forecast and the use of demand-side resources are presented in the testimony of United witness Ed Burgess, while my testimony focused on the design of the Alternative Plans and the assumptions for supply-side resources.

Q. Please summarize your recommendations.

A. In conclusion, as detailed above the Commission should not approve Dominion's current plan. Instead, the Commission should instruct Dominion to provide a revised IRP to be filed in this proceeding with several modifications to its modeling assumptions. These modifications include changes to the load forecast and demand-side resource options as well as the supply-side resource options. My colleague Ed Burgess provides testimony regarding recommended changes to the demand-side resource assumptions. Regarding changes to the supply-side resource options, my recommendations is that the Company develops at least one Alternative Plan that:

- Meets VCEA requirements regarding the amount of solar, wind, and storage developed over the study period. PLEXOS should be required to meet the targets but should also be allowed to select the optimal timing for resources. It should also allow for the selection of renewable resources above the VCEA development targets on a least-cost optimization basis.

- Does not include forced-in fossil fuel resources.
- Allows PLEXOS to select additional energy storage options in the short term: hybrid resources and storage of six and eight hours of duration.
- Allows PLEXOS to select from a more realistic set of resource options in the long term. These should at minimum include long duration storage or other clean peaking technology and increased limits for solar and wind.
- Allows coal units to endogenously retire (with a latest retirement date of 2045).
- Updates the storage cost assumptions to better align with public and widely used estimates.
- Complies with the GNP.
- Assumes that Virginia remains in RGGI and Dominion assumes the social cost of carbon in the resource selection and retirement step.

Q. What are your organization and client's overall recommendations for this Commission?

A. We recommend this Commission adopt the following recommendations based on my and my colleague's analysis that reflect the deficiencies in both the supply-side and demand-side of Dominion's current IRP.

Regarding changes to the supply-side resource options, the Company should develop a plan that:

- Meets VCEA requirements regarding the amount of solar, wind, and storage developed over the study period. PLEXOS should be required to meet the targets but should also be allowed to select the optimal timing for resources. It should also allow for selecting renewable resources above the VCEA development targets on a least-cost optimization basis.
- Does not include forced-in fossil fuel resources.
- Allows PLEXOS to select additional energy storage options in the short term: hybrid resources and storage of six and eight hours of duration.

- Allows PLEXOS to select from a more realistic set of resource options in the long term. These should at minimum, include long-duration storage or other clean peaking technology and increased limits for solar and wind.
- Allows coal units to endogenously retire (with the latest retirement date of 2045).
- Updates the storage cost assumptions to better align with public and widely used estimates.
- Complies with the GNP.
- Assumes that Virginia remains in RGGI, and Dominion assumes the social cost of carbon in the resource selection and retirement step.

On the demand-side, the Company should develop a plan that includes the following:

- A more limited forecast for data center load that accounts for the limitations and expanded EE and DR programs focused on data centers.
- A more limited forecast for EV load that fully accounts for EV TOU adoption and managed charging programs.
- Usage per customer trends for commercial and industrial consistent with recent historical trends.
- Include a scenario with an EE adjustment consistent with our alternative projections. This alternative projection should be included in the load forecast assumption used in PLEXOS.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit MR-1

Resume of Dr. Maria Roumpani

STRATEGEN

Maria Roumpani, PhD

Technical Director

Maria is the Technical Director of the Strategen Consulting practice. Maria leads the economic and technical grid modeling and analysis for the firm, including capacity planning, production cost, and energy storage dispatch modeling.

Maria has served clients including consumer advocates, public interest organizations, energy project developers, trade associations, government agencies, and foundations.

Contact

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Phone
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Education

PhD
Management Science and Engineering
Stanford University
2018

MSc
Electrical & Computer Engineering
National Technical University of Athens
2009

STRATEGEN.COM

Work Experience

Strategen

Technical Director / Berkeley, CA / 2017 - Present

+ Leads firmwide technical and economic modeling and analysis to support Strategen consulting engagements. Specializes in the use of modeling tools (capacity expansion, production cost models) to inform grid planning and decarbonization issues.

Precourt Institute for Energy, Stanford University

Research Assistant / Palo Alto, CA / 2011-2017

+ Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics. Representative projects:
    + Model for the competition in a two-settlement electricity market, capturing issues of market power and risk aversion
    + Border carbon adjustment in international trade
    + Model for electric vehicle infrastructure
    + Framework for energy efficiency measure classification to inform behavioral program design

Stanford University

Teaching Assistant / Palo Alto, CA / 2012 - 2017

+ Designed teaching material & led teaching sessions evaluated as an extremely effective teaching assistant

Energy, Economics, & Environment Modeling Laboratory, National Technical University of Athens

Researcher / Athens, Greece / 2009-2010, 2015

+ Mathematical modeler developing large scale energy planning models (focusing on capacity expansion of electricity supply)

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Maria Roumpani, PhD

Technical Director

STRATEGEN

Domain Expertise

Energy Resource Planning

Capacity Expansion and Production Cost Modeling

Storage Economics & Dispatch Optimization

Benefit Cost Analysis

Fossil Fuel Retirement Studies

Coal Plant Commitment and Dispatch Analysis

STRATEGEN.COM

Selection of Relevant Project Experience

Tech Customers

Duke Carbon Plan / 2022

+ Conducted extensive capacity expansion and production cost modeling using EnCompass and presented an alternative proposed portfolio, which results in lower emissions and significantly reduces costs and risks for Duke's ratepayers.

Testimony, Docket E-100, Sub 179

Oregon Public Utilities Commission

Idaho Power IRP Review / 2022

+ Supported the OPUC Staff and Staff Counsel in analysis of the Idaho Power 2021 IRP and crafting of
+ Conducted an in-depth investigation of the inputs, assumptions, and modeling choices in Idaho Power's IRP analysis and summarized findings to support the preparation of Staff comments.

Southwest Energy Efficiency Project

IRP Analysis and Impact Assessment / 2020 - Present

+ Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
+ Led the technical analysis and utilized a sophisticated capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRP.

Arizona Energy Rules Analysis
Summary of Alternative Resource Plan Analysis for Arizona Public Service
Summary of Alternative Resource Plan Analysis for Tucson Electric Power

California Energy Storage Alliance

Long Duration Energy Storage Special Project / 2020

- Supported the technical analysis assessing the needs and benefits of long-duration storage in California. The analysis was based on the use of capacity expansion modeling; results and recommendations were used to identify specific policy opportunities with the CPUC, CAISO, and CEC to advance long-duration storage evaluation and procurement.

Long Duration Energy Storage for California's Clean Reliable Grid

Maria Roumpani
Technical Director

[redacted]

STRATEGEN

Selection of Relevant Project Experience (continued)

Sierra Club

Alternative Resource Plan for Salt River Project's Integrated System Plan /2022 - Present

+ In anticipation of the SRP Integrated System Plan, provided technical support by preparing a comprehensive analysis of the SRP portfolio options.
+ Conducted EnCompass modeling including capacity expansion modeling to identify the least cost of resources to meet SRP's projected load, and hourly production cost modeling to assess the performance, cost, and emissions of the portfolios.

Report

PacifiCorp IRP Technical Support / 2021 - Present

+ Provided technical support for Sierra Club in analyzing issues of interest during PacifiCorp's IRP stakeholder input process.
+ Reviewed in detail PacifiCorp's IRP modeling to identify inputs and assumptions that might lead the model to deviate from a least cost solution.
+ Supported the development of technical comments before the Oregon Public Utility Commission.

Public Service of Colorado 2021 Energy Resource Plan / 2021

+ Conducted extensive EnCompass modeling including capacity expansion and production cost runs to evaluate alternative retirement dates for the utility's coal units.

Testimony

Clean Energy Group

Alternatives to a natural gas peaking unit / 2021

+ Developed an analysis of a proposed natural gas peaking unit and potential alternatives, including energy storage and market options. The analysis included an energy storage dispatch model in the energy and ancillary services markets of ISO-NE, and an economic comparison with operating the natural gas unit.

Assessment of Potential Energy Storage Alternatives for Project 2015A in Peabody, Massachusetts

Selection of Relevant Project Experience (continued)

Pennsylvania Department of Environmental Protection

Pennsylvania Energy Storage Assessment / 2021

+ Developed analysis and recommendations for measures to foster energy storage investment and integration, including convening a statewide storage issues forum, designating public funding to accelerate storage deployment, establishing incentive programs for storage projects, and accelerating microgrid deployment at critical facilities.

Report

Virginia Department of Mines, Minerals, and Energy

Virginia Energy Storage Study / 2019

+ Developed and used custom modeling tools to estimate the benefit of storage both in front of the meter and behind the meter configurations. Studied energy storage revenue streams to evaluate the technology's potential in the Commonwealth

Report

Sacramento Municipal Utility District

Virtual net metering tarriff design and analysis / 2021 – Present

+ Supported SMUD in outlining a VNEM tariff framework and constructed a financial model to evaluate the customer value proposition for the proposed tariffs, as well as a comparative look at other California IOUs' VNEM program offerings.

Maria Roumpani

Technical Director

STRATEGEN

Expert Testimony

- Public Utility Commission of Oregon, Docket UE 420 Testimony
- Public Service Commission of South Carolina, Docket No 2023-2-E Testimony
- Public Service Commission of South Carolina, Docket No 2023-1-E Testimony
- Michigan Public Utilities Commission, Case U-21193, Testimony
- North Carolina Utilities Commission, Docket E-100, Sub 179 Testimony
- Colorado Public Utilities Commission, Proceeding No. 21A-0141E, Testimony