McGuireWoods

McGuireWoods LLP
501 Fayetteville St.
Suite 500
Raleigh, NC 27601
Phone: 919.755.6600
Fax: 919.755.6699
www.mcguirewoods.com

Andrea R. Kells
Direct: 919.755.6614
akells@mcguirewoods.com

April 1, 2024

VIA Electronic Filing

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: *Reply Comments of Dominion Energy North Carolina*
Docket No. E-100, Sub 192

Dear Ms. Dunston:

On behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (the "Company"), enclosed for filing in the above-referenced proceeding is the Company's *Reply Comments*.

Please do not hesitate to contact me if you have any questions. Thank you for your assistance with this matter.

Sincerely,

/s/Andrea R. Kells

ARK:tll
Enclosure

cc: Lucy Edmondson, Public Staff—North Carolina Utilities Commission
Robert Josey, Public Staff—North Carolina Utilities Commission
Nadia L. Luhr, Public Staff—North Carolina Utilities Commission

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 192

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Dominion Energy North Carolina 2023 IRP and 2023 REPS Compliance Plan	))))	REPLY COMMENTS OF VIRGINIA ELECTRIC AND POWER COMPANY D/B/A DOMINION ENERGY NORTH CAROLINA

NOW COMES Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("DENC" or the "Company") and, pursuant to North Carolina Utilities Commission ("Commission") Rule R8-60(k), hereby submits these Reply Comments in response to the Comments of the Public Staff filed in this docket on January 29, 2024.

INTRODUCTION

On May 1, 2023, the Company filed its 2023 Integrated Resource Plan ("2023 Plan") in the above-captioned docket pursuant to N.C. Gen. Stat. §§ 62-2 and 62-110.1 and Commission Rule R8-60, as well as its 2023 Renewable Energy and Energy Efficiency Portfolio Standard Compliance Plan ("2023 REPS Plan") pursuant to Rules R8-60(h)(4) and R8-67(b). On the same date, the Company filed the 2023 Plan with the Virginia State Corporation Commission ("VSCC").[1] The Company subsequently filed with the Commission corrected pages to the 2023 Plan on May 22, May 31, June 12, July 6, August 30, and September 15, 2023.

[1] *In re: Virginia Electric and Power Company's 2023 Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2023-00066 (May 1, 2023). On February 1, 2024, the VSCC issued a notification that, "not having reached a majority decision," it would "not 'make a determination within nine months after the date of filing' as set forth in [Virginia] Code § 56-599." On February 22, 2024, the VSCC issued a Notice of Closed Status, which concluded the Virginia 2023 Plan proceeding.

The Commission granted petitions to intervene in this proceeding filed by the Carolina Utility Customers Association, Inc. and Carolina Industrial Group for Fair Utility Rates I on June 5, 2023, and June 28, 2023, respectively. On January 29, 2024, the Public Staff filed comments on the 2023 Plan. No other parties to this proceeding filed comments on the 2023 Plan. The Company and the Public Staff discussed a number of issues raised in the Public Staff's comments during conference calls on February 6, 2024, and March 7, 2024.

The Public Staff made several conclusions with respect to the Company's filed 2023 Plan and 2023 REPS Compliance Plan that the Company does not oppose. These are: (1) the 2023 Plan complied with the requirements of Rule R8-60;[2] (2) the Company's short-term action plan (5 years) is reasonable for planning purposes;[3] (3) the Company and the Town of Windsor complied with their respective REPS requirements;[4] and (4) the Company's peak load and energy sales forecasts are reasonable for planning purposes, and the Company has considerably more experience than others with data centers and has combined this knowledge with various statistical analyses to better understand its current and future energy requirements.[5]

The following reply comments will focus on the Public Staff's stated concerns about the Company's alternative plans presented in the 2023 Plan ("Alternative Plans") and their respective net present values ("NPVs"), modeling constraints (such as build limits and availability of certain generating technologies for selection by the PLEXOS model), changes in the PJM capacity market and their impact on modeling of Alternative Plans in

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[2] Comments of the Public Staff ("Public Staff") at 3.
[3] *Id.* at 61.
[4] *Id.* at 69-70.
[5] *Id.* at 43, 48, 61.

future IRPs, demand-side management ("DSM") and energy efficiency, and a number of other recommendations for the Company's next IRP and statements that the Company clarifies or provides additional context for herein. The Company will also briefly address the Public Staff's proposal for a rulemaking proceeding regarding the need for electric suppliers to receive Commission approval prior to constructing battery storage facilities in North Carolina.

Notably, the Public Staff made clear that its recommendations are for the purposes of the Company's upcoming 2024 Plan and that it is not suggesting that the Company should re-file any portion of the 2023 Plan. The 2024 Plan will be filed on or by October 15, 2024, pursuant to the Commission's February 8, 2024, *Order Amending Commission Rule R8-60* issued in Docket No. E-100, Sub 196.[6] With the upcoming October 15, 2024, filing date in both North Carolina and Virginia, the Company is well into development of the 2024 Plan at this point in time, and timing is therefore of the essence in receiving a Commission determination on the 2023 Plan. Recognizing that the Commission has scheduled the public witness hearing in this proceeding for May 6, 2024, the Company respectfully requests that the Commission issue an order in this matter within 60 days after the filing of these reply comments, or by May 31, 2024, to allow sufficient time for any conclusions impacting the development of the 2024 Plan to be implemented.

[6] *See* Order Amending Commission Rule R8-60, Docket No. E-100, Sub 196 (Feb. 8, 2024).

REPLY COMMENTS

1) The 2023 Plan is reasonable for long-term planning purposes; the Company appropriately addressed reliability considerations in the 2023 Plan and will continue to evaluate reliability considerations in future IRPs.

The Virginia Clean Economy Act of 2020 ("VCEA") became effective on July 1, 2020. The VCEA (1) establishes a mandatory renewable energy portfolio standard program ("RPS Program") for the Company;[7] (2) requires the Company to petition for necessary approvals to construct or purchase 16,100 megawatts ("MW") of renewable energy generation and 2,700 MW of energy storage resources [in Virginia] by 2035, with interim targets beginning in 2024 and 2025, respectively,[8] (3) mandates the retirement of carbon emitting generation in Virginia, except for biomass-fired units, by 2045 unless the Company petitions and the VSCC finds that a given retirement would threaten the reliability and security of electric services;[9] and (4) declares the construction or purchase of up to 5,200 MW of offshore wind energy generation by 2032 to be in the public interest.[10]

The Public Staff recommends that the Commission not accept any of the proposed Alternative Plans, arguing that the Alternative Plans fail to comply with the VCEA (Plan A), fail to demonstrate reliability concerns while not retiring all carbon-emitting resources by 2045 (Plans B and C), ignore VCEA development and procurement targets

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[7] Code of Virginia ("Va. Code") § 56-585.5 C (requiring the Company to meet annual requirements for the sale of renewable energy based on a percentage of non-nuclear electric energy sold to retail customers in the Company's service territory).
[8] Va. Code § 56-585.5 D 2, E 2, E 5; 20 VAC 5-335-30.
[9] *See* Va. Code § 56-585.5(B)(3). If such a petition is made, the Virginia SCC must "consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition." *Id.*
[10] Va. Code § 56-585.1:11. As originally enacted this provision stated a date of 2034. Virginia Senate Bill 1441, effective July 1, 2023, accelerates the time horizon of this public interest declaration from December 31, 2034 to December 31, 2032.

(Plans C and E), or strain the transmission system to meet customers' reliability expectations (Plans D and E).[11] With respect to transmission specifically, the Public Staff asserts that "Plans D and E will severely challenge the ability of the transmission system to meet [the Company's] customers' reliability expectations."[12] The Public Staff also characterizes the recent significant load growth on the Company's system as "unexpected," and contends that "[l]arge scale transmission projects typically take a decade or longer to identify need, plan, build, and become commercially operable" and expresses "…concerns as to whether the Company's proposal is least cost (much less executable) given siting uncertainty for new high-voltage transmission that will likely be needed in the northern and northwestern parts of Virginia based on the existing transmission network and the Company's participation in PJM."[13]

For purposes of the 2024 Plan, the Public Staff recommends (1) that to the extent the Company asserts that reliability would be impacted by retirement of all of its carbon-emitting resources by 2045, it provide clear evidence that a reliability concern is present or imminent,[14] and (2) that the Company include at least one plan that retires all carbon-emitting resources located in Virginia by 2045 while complying with the VCEA and other applicable law.[15]

a) The Alternative Plans included in the 2023 Plan represent an array of scenarios that are reasonable for planning purposes on their own merits and as part of the overall 2023 Plan.

[11] Public Staff at 16-17, 24-26.
[12] *Id.* at 17.
[13] *Id.* at 34-35.
[14] *Id.* at 10, 62 (Recommendation 3(i)). In a follow-up discussion with the Company conducted after filing its comments, the Public Staff clarified that their overall concern with the 2023 Plan was with reliability, and that for the 2024 Plan, the Public Staff would like the Company to clearly indicate foreseeable reliability issues and how those issues are addressed.
[15] *Id.* at 62 (Recommendation 3(h)).

Each of the Alternative Plans included in the 2023 Plan was developed with a specific objective in mind, whereas the full array of the Alternative Plans encompasses the Company's outlook on the range of future scenarios at the time of the 2023 Plan's filing. Based on those specific objectives, and considering each Alternative Plan as one of several scenarios, Plans B through E are reasonable for long-term planning purposes.

Plan A is the Company's least-cost plan, presented for cost comparison purposes only and as directed by the VSCC.[16] Thus, Plan A meets only applicable carbon regulations[17] and the mandatory Virginia RPS Program requirements. Consistent with the VSCC's directive, the Company did not force the model to select any specific resource nor exclude any reasonable resource and allowed the model to optimize the accompanying resource plan. While the Virginia RPS Program requirements of the VCEA are known, meeting the renewable development targets and executing the required retirements required by the VCEA will take time and depend on technological advancement and supportive legislative policies that are difficult to model with certainty. This is why the Company presented Alternative Plans B through E with a range of possible assumptions.

Plans B and D were provided by the Company to show two alternatives to satisfying customer demand while also meeting the development targets of the VCEA. Specifically, the VCEA development targets for solar and storage resources, as well as for offshore wind, are included in the PLEXOS model for both Plans in order to ensure compliance with those requirements. Both Plans B and D include 970 MW of natural gas

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[16] *See* Final Order, at 14, Case No. PUR-2020-00035 (Feb. 1, 2021).

[17] As discussed in section 5.2.3 of the 2023 Plan, the Company assumed Virginia will exit RGGI by December 31, 2023. The Company also presented an alternative sensitivity on Plan A that modeled Virginia's continued participation in RGGI. Thus, the Company modeled "applicable carbon regulations."

peaking capacity generation by 2028 for reliability reasons, and an additional 2,600 MW of offshore wind by 2032, consistent with Virginia law. The remaining resources for each plan are selected on a least-cost optimized basis. The difference between Plans B and D is the modeling of unit retirements. Plan B allows the PLEXOS model to select unit retirement years on a least-cost optimized basis, whereas in Plan D, unit retirement years are determined by the Company to retire all carbon-emitting units by 2045, consistent with the dates set forth in the VCEA.

The Company developed Plans C and E to comply with the stipulation approved in the 2021 VSCC proceeding concerning the Company's proposed RPS development plan.[18] Consistent with that stipulation, as relevant here, Plans C and E least-cost optimize annual additions of new RPS-eligible resources to meet the Company's need for capacity, energy, and RECs for RPS Program compliance based on the PJM Load Forecast, *without regard to the development targets* set forth in the VCEA. As directed by the stipulation, Plan C unit retirement dates match those of Plan B and Plan E unit retirement dates match those of Plan D. In summary, Plans C and E are timing- and cost-optimized versions of Plans B and D.

These Plan-specific objectives and parameters are summarized in Table 1, below.

Table 1

	Plan A	**Plan B**	**Plan C**	**Plan D**	**Plan E**
Required by the VSCC	Yes	No	No	No	No
Load Forecast	PJM	PJM	PJM	PJM	PJM

[18] Final Order, Case No. PUR-2021-00146 (Mar. 15, 2022) (approving stipulation pursuant to which the Company agreed to model two additional alternative plans that adhered to specified assumptions and constraints).

Energy Efficiency	Least-cost	VCEA Compliant	VCEA Compliant	VCEA Compliant	VCEA Compliant
Unit Selection	Least-cost optimization	VCEA development targets, then least-cost optimization	Least-cost optimization	VCEA development targets, then least-cost optimization	Least-cost optimization
Retirements	Model optimized	Model optimized	Match Plan B	Glide path to carbon free by 2045	Match Plan D

b) *Reliability implications generally are backed by unit-specific retirement analysis along with increased capacity and energy purchase assumptions supported by higher transmission investments tailored to each of the Alternative Plans.*

With regard to the Public Staff's general concerns regarding reliability implications of the five Alternative Plans, it is important to note that the further out in time in the Company's Alternative Plans, the greater the uncertainty and the greater the potential for a change in the law or technology to shift the Company's path forward. With that it mind, the Company conveyed in an informal conversation with the Public Staff that in the 2023 Plan, Alternative Plans D and E retired all carbon-emitting generators by 2045 to comply with the VCEA and the stipulation, as discussed above, and therefore had to increase capacity imports by quadrupling the Capacity Emergency Transfer Objective ("CETO")[19] limit published by PJM in 2023 for the Dominion Zone ("DOM Zone") to satisfy demand in 2037 and thereafter, along with incorporating additional transmission investments in these Plans' NPVs. Although Alternative Plans B and C retired few carbon-emitting generators by 2045 on the least-cost optimization basis, the Company still had to increase capacity imports by doubling the CETO limit for DOM Zone to

[19] *See* Planning Period Parameters for Base Residual Auction for Delivery Years 2024/2025 (Feb. 27, 2023) (available at https://www.pjm.com/markets-and-operations/rpm).

satisfy demand in 2039 and thereafter, which would also require additional transmission investments incorporated in these Plans' NPVs. The Company maintains that these assumptions were necessary for the PLEXOS model to be able to satisfy forecasted demand. The Company believes that this outlook sufficiently discloses potential reliability concerns, particularly in 2039 and thereafter.[20] Over time, as more renewable energy and energy storage resources are added to the system and as other technology advances, the Company will continue gaining knowledge about the impact of such system changes to assess the ability of a Plan D approach to maintain system reliability. That said, while the Company has presented information on the 25-year Study Period through 2048, it is important to focus on the 15-year Planning Period through 2038 in which no units are retired in any of the five Alternative Plans, and especially the Company's short-term action plan covering the next five years (2024-2029).

Importantly, the Company does consider reliability and cost as part of its annual retirement analysis for each thermal generating unit. This analysis includes projected costs for continued unit operation, fuel cost and availability, and unit performance, as well as projected benefits, including fuel savings and unit capacity value. Based on this analysis, and as stated in Section 5.2.1 of the 2023 Plan, "[t]he Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6.[21] Accordingly, the inclusion of a unit retirement in this 2023 Plan should be considered as tentative, based only on a snapshot in time. The Company's final decisions regarding any unit retirement will be made at a future date." That said, the Company is not currently seeking waiver of the VCEA requirement to

[20] *See* 2023 Plan at Sec. 2.2.
[21] These three units were retired in 2023.

retire any of its thermal units by 2045, and so presented Plans D and E that retire those units between 2039-2045, which leads to adding significantly more solar, storage, and nuclear generators, while also dramatically increasing capacity and energy purchases.

However, due to real and legitimate concerns over system reliability, it is not prudent planning to only consider plans that meet the retirement targets. The Company is cognizant of the reliability role of thermal resources, particularly during events like Winter Storm Elliott. Thermal resources, combined with market purchases, contributed almost all of the Company's generation during the peak demand of Winter Storm Elliott. Renewables like wind and solar contributed very little during that peak. This issue is not unique to the Company. There is growing consensus about the reliability risk posed by insufficient dispatchable generation. PJM has expressed concerns regarding insufficient intermittent generation resources to meet the coming load growth.[22] Plans A, B, and C, which retire no generation, therefore offer a useful comparison to Plans D and E. It should also be reiterated here the significant value to customers that the model attributed to the fossil generation units, as evidenced by the 25-year net present values for each of

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[22] *See* United States Senate Committee on Energy & Natural Resources, Testimony of Manu Asthana, President and CEO, PJM Interconnection (June 1, 2023) (available at 20230601-testimony-of-manu-asthana-us-senate-committee-energy-natural-resources.ashx (pjm.com)) ("the generation fueled by fossil fuels (mostly coal and natural gas) that we rely upon to balance the grid is retiring at a significant rate. Electrification of the transportation, industrial and building sectors is poised to create material load growth. Our region is also experiencing significant data center construction, which is creating major pockets on the system of increasing demand. New generation in the queue is largely intermittent, so we need multiple megawatts to replace one megawatt of retiring generation. And, new generation is coming online slower than anticipated. If these trends continue, our models show increased risk of having insufficient resources later in this decade to maintain the reliable electric service that consumers expect").

the units and reflected in Figure 5.2.1.2 of the 2023 IRP:

Figure 5.2.1.2: Twenty-Five-Year Cash Flow Analysis Results (NPV $ Million)

Units	2023 Plan A	2023 Plan B	Low Capacity Price	High Capacity Price
Clover 1 - 2	$423	$797	$563	$828
Mt Storm 1 - 3	$1,817	$3,763	$2,915	$3,876
VCHEC	$193	$792	$465	$835
Altavista	$104	$165	$138	$169
Hopewell	$120	$181	$157	$184
Southampton	$125	$186	$158	$190
Rosemary	$27	$35	($39)	$45
Bear Garden	$1,650	$2,440	$2,098	$2,486
Brunswick	$3,670	$5,456	$4,689	$5,559
Chesterfield 7 - 8	$989	$1,603	$1,389	$1,631
Gordonsville 1 - 2	$469	$775	$654	$791
Greensville	$4,692	$6,869	$6,007	$6,984
Possum Point 6	$1,344	$2,103	$1,788	$2,145
Warren	$4,114	$5,827	$5,068	$5,929

Regarding the Public Staff's recommendations that for the 2024 Plan the Company include at least one plan that retires all carbon-emitting resources located in Virginia by 2045 while complying with the VCEA and other applicable law and that it provide clear evidence that a reliability concern is present to support a future assertion that reliability would be impacted by retirement of all of its carbon-emitting resources by 2045, the Company does anticipate that reliability considerations will be a major focus of the 2024 Plan. The Company will monitor the impact of new ELCC values and other planning parameters provided by PJM and incorporate those into future integrated resource plans where appropriate to ensure resource adequacy. If necessary at a future time, the Company will present the analysis demonstrating the need for an exception to the retirement of carbon-emitting resources by 2045.

c) *The Company recognizes that transmission considerations are crucial to ensure reliability; the Company complies with NERC reliability standards and participates in PJM transmission planning processes.*

The Company agrees that transmission planning and investment is important for the Planning Period because of the expected load growth in the DOM Zone, due in particular to data centers and, to a lesser extent, electrification. The Company's 2023 Plan is transparent regarding the needs for additional transmission investments to address the reliability concerns.[23]

The Company also agrees that the significant increase in capacity and energy purchases required for Alternative Plans D and E raise concerns about reliability and energy independence. As noted in the 2023 Plan, there is no guarantee that other states will maintain dispatchable generation that will be available when the Company needs incremental power. As technology advances and more renewable generation and energy storage resources are added to the system, the Company will gain knowledge about the impact of such system changes and further evaluate Plans D and E and their ability to reliably meet customers' needs.[24] As part of this evaluation, the Company is conducting a new import/export transmission study to evaluate transmission-related constraints when importing power into the DOM Zone that will be considered in the development of the 2024 Plan.

Although the Company shares the Public Staff's reliability concerns, particularly for Alternative Plans D and E, it is important to note that the significant increase in capacity and energy purchases does not occur until the 2037/2039 time frame,[25] which is

[23] *See* 2023 Plan at Figure 2.4.1; *see also* 2023 Plan, Appendices 3C, 7A.
[24] 2023 Plan at 24.
[25] 2037 for capacity in Plans D and E, 2039 for energy in Plans D and E, 2039 for capacity in Plans B and C.

at the end of the current Planning Period. Nevertheless, the Company is already working diligently to address the capacity and energy purchase increases and the potential reliability concerns.

The Company is obligated to serve all customer load and ensure its transmission system is adequate to serve the load in a safe, reliable, and economic manner. The Company complies with North American Electric Reliability Corporation ("NERC") Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC Reliability Standards.[26] As a member of PJM, the Company also participates in PJM's Regional Transmission Expansion Plan ("RTEP"), which is the culmination of the FERC-approved annual transmission planning process, and competitive Open Window process.[27] In 2023, for example, the Company submitted 13 proposals through the PJM Open Window to address reliability concerns based on the latest forecast, and 8 proposals were approved by the PJM Board.[28]

In addition to investing in new infrastructure, the Company is also working with PJM to find cost-effective ways to upgrade existing infrastructure on existing rights-of-way prior to looking for any greenfield solutions. This approach has led to a significant number of 230 kV line uprates in Loudoun County that have been presented to PJM and

[26] 2023 Plan at 109.
[27] As part of the PJM RTEP development process, PJM opens competitive planning "windows" when certain needs on the system are identified. During these windows, transmission owners and non-incumbent transmission developers can submit solutions they have designed to resolve identified reliability violations. PJM Manual 14B (effective December 20, 2023) focuses on the RTEP process and can be found at https://www.pjm.com/-/media/documents/manuals/m14b.ashx.
[28] *See* Reliability Analysis Report 2022 RTEP Window 3, PJM (Dec. 8, 2022) (available at, https://pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx); *see also* Reliability Analysis Update, PJM Transmission Expansion Advisory Committee (Dec. 5, 2023) (available at https://pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-item-15---reliability-analysis-update-2022-window-3.ashx).

are in various stages of engineering and construction. The Company will continue to work closely with PJM to evaluate the transmission system and plan for the expected load growth, and will continue to incorporate the most current information regarding transmission needs in future IRPs.

2) The Company's modeling assumptions to the 2023 Plan were reasonable for long-term planning purposes and to achieve each Alternative Plan's specific objective.

The Public Staff raises concerns over modeling restrictions the Company utilized in development of the 2023 Plan and whether those restrictions were reasonable for long term planning.[29] The Public Staff recommends that the Commission not accept Plans A through E "as the modeling restrictions placed on the proposed plans raise significant concerns about their reasonableness for long term planning purposes."[30] As discussed further in this section, the Company's modeling assumptions were reasonable and appropriate based on the Company's own experience with project development and construction and information known at the time of the 2023 Plan modeling and should be accepted for long-term planning purposes.

a) Solar and battery storage modeling constraints in the 2023 Plan are appropriate and well-founded, and will be refined in future Plans.

The Public Staff states that the Company "limited the amount of solar and battery storage resources that could be selected by the model." While acknowledging that "only a certain amount of resources can be built and interconnected each year," the Public Staff posits that "this limit is unknown and theoretical," and that "[d]epending on the circumstances and assumptions made, this limit can change year to year."[31] The Public

[29] Public Staff at 8, 24-26, 38.
[30] *Id.* at 61.
[31] *Id.* at 7.

Staff contends that "[g]iven how the portfolios have maximized certain resources up to their imposed limits, the Company should relax such constraints in the next IRP filing" and recommends further that the Company "increase the annual and maximum limit of resources available to be selected in the model, gradually increasing year over year, thus mitigating concerns of the model being overly constrained."[32] The Public Staff recommends a model plan that progressively increases the number of distributed resources that can be interconnected each year[33] and that the next IRP should "increase the amount of solar and battery storage resources that can be selected by the model each year."[34]

For context, it is important to note that the Company's 900 MW annual build limit through 2038 for utility-scale solar is greater than the total capacity of solar that has been placed in service by the Company in Virginia in any year. The Company establishes the build limits for solar projects incorporated into its IRP modeling based on several practical factors. The total number and capacity of conforming project proposals that are submitted into the Company's annual Request for Proposals, routine meetings and discussions with solar developers and engineering, procurement, and construction ("EPC") contractors, and the number of and capacity of projects that are receiving local land use approval inform the Company in determining the total capacity of solar projects that can reasonably be constructed within a given year or time period. The total maximum annual build limits are based on the availability of projects, including projects that have been sited, fully developed with all environmental reviews and site studies, and

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[32] *Id.*at 32-33.
[33] *Id.* at 63 (Recommendation 3(j)). In discussion with the Company, the Public Staff clarified that by "distributed" it means utility-scale solar and storage.
[34] *Id.* at 63 (Recommendation 3(k)).

permitted by the locality. Additionally, there are construction considerations, such as the availability and cost of labor, supply chain constraints for procurement of transformers and solar modules, and the available capacity of EPC contractors.

The Company also considers the projects' ability to complete the interconnection study process and have the required interconnection facilities constructed with any necessary additional transmission upgrades completed. In recent years, the PJM transmission interconnection reform in progress has been a constraining factor. For example, if a solar developer submits an interconnection request today, the project is not expected to have an interconnection agreement in place until late 2027 or early 2028.[35] Once an interconnection agreement is executed, the transmission system upgrades and project construction could take 18 months to three years to complete, and that solar facility would only come online between 2029 and 2031.

The Company owns and operates the second largest solar fleet among utility holding companies in the U.S. and has a tremendous level of experience in constructing and placing into service utility-scale solar projects. In the last decade, and across the enterprise, Dominion Energy has successfully constructed over 3,000 megawatts ("MW") of utility-scale solar capacity. It is through this diverse experience of successfully constructing and operating solar facilities, and by taking full advantage of the lessons learned, best practices, and industry knowledge, that the Company establishes the build limits that are incorporated into its modeling.

The Company continually evaluates the build limits and updates its modeling accordingly, which is illustrated in how the build limits have adjusted over time. For

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[35]https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230828/20230828-item-05---transition-study-approach.ashx.

example, in 2017, the Company assumed only 240 MWs of utility-scale solar would be available annually. In the 2018 and 2020 IRPs, the Company doubled the prior assumption to 480 MWs. And then again, in the 2021 and 2022 IRP Updates, the Company increased the assumption by more than double the 2018 and 2020 assumption to 1,200 MWs of utility-scale solar annually.

In the 2023 Plan, however, the Company saw a need to reduce the limit to 900 MWs of utility-scale solar resources through 2038 to reflect the maximum utility-scale solar that is expected to be available in Virginia per year. The Company then increased the limit to 1,200 MWs in 2039. The reduction in the annual build limit for utility-scale solar is primarily driven by the lack of projects that are fully developed and permitted. The Company's land use discussions with localities have been revealing more and more challenges in obtaining conditional use permits or special exemption permits for solar facilities. It can take two years or more to receive a permit for a solar project due to the pace by which localities are approving projects and new conditions being incorporated in zoning ordinances, which may include density and acreage caps. There are also resource limitations in localities reviewing building permits, which is delaying the construction of projects. There are similar limitations in the U.S. Army Corps of Engineers that perform the wetland jurisdiction determination for solar projects. Furthermore, as mentioned earlier, construction constraints and PJM transmission interconnection reform slow down the solar development process. With these challenges in mind, the Company's 900 MW annual build limit through 2038 for utility-scale solar, which as noted above is greater than the total capacity of solar that has been placed in service by the Company in Virginia in any year, already represents a significant build out that eclipses previous efforts.

Notably, in 2022, the combined nameplate capacity of renewable generators placed in service across all thirteen PJM states totaled only 677 MW.

Although energy storage technology is more nascent, the Company also has experience constructing and operating energy storage resources. The Company considers similar permitting, supply chain, labor, and other siting and construction considerations in establishing the reasonable capacity of energy storage facilities that may be brought online in a given year. Energy storage near-term build limits are also influenced by technology readiness and its commercial viability. Therefore, in the 2023 IRP, the annual build limit was estimated at 300 MWs per year through 2038, increasing to 900 MWs per year in 2039 for energy storage.

Regarding small modular reactors ("SMR"), the modular components and factory fabrication of key components of SMRs will reduce the construction costs and timelines of deploying SMRs when compared to the development and construction of traditional nuclear power stations. However, given the anticipated deployment schedule in the 2023 Plan, which shows SMRs being placed in service by the end of 2033, it is not possible to predict with certainty the ultimate cost and schedule due to a number of factors, such as the final engineering of SMRs designs, changes in the commodity market, or the timing of regulatory approvals. Changes to both the construction costs and schedule are possible. As stated in Section 1.4 of the 2023 Plan, the Company will continue evaluating the costs and deployment schedule of SMRs and will update modeling assumptions related to SMRs in future IRP filings.

For the reasons outlined above, the annual solar and energy storage build limits utilized for purposes of the 2023 Plan are reasonable and supported and support acceptance of Alternative Plans B through E as reasonable for long-term planning purposes. Additionally, considering the factors discussed above, for purposes of the 2024 Plan and other future IRPs, it would not be appropriate or helpful to require a plan that progressively increases the number of distributed resources that can be interconnected or selected by the model each year as suggested by the Public Staff. As the Company has done for prior IRPs, the Company will periodically review and assess whether the annual build limit is realistic and achievable, and continue to refine its build limit assumptions based on updated information, in the 2024 Plan and other future IRPs.

b) New natural gas generation resource modeling is location neutral, and advanced class CTs will be considered in future IRPs as appropriate.

The Public Staff contends that the Company "artificially" limited the model's ability to select new natural gas generation by requiring that all be built in Virginia. For the 2024 Plan the Public Staff recommends that the Company "model new natural gas generation, applying reasonable modeling constraints such as fuel supply limitations or a maximum number of units that can be built in a year as non-designated resources that can be built in Dominion's service territory of Virginia or North Carolina."[36] Additionally, the Public Staff recommends that the Company allow the model to select advanced class CTs (H or J frames).[37]

As stated elsewhere in these Reply Comments, the 2023 Plan is a snapshot in time and is not representative of the Company seeking a CPCN or approval for a resource in any particular location. Siting of new generation resources is determined on a case-by-case basis considering many factors, including land availability, cost, and transmission

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[36] Public Staff at 62 (Recommendation 3(d)).
[37] *Id.* at 62 (Recommendation 3(e)).

interconnection. This type of analysis is presented in CPCN hearings for specific resources. In contrast, the long-term PLEXOS model is location-neutral, meaning that generation resources are not set at a particular location within the model. PLEXOS models the Company's system from a broader viewpoint of a load serving entity, balancing overall load that the Company is obligated to serve in both Virginia and North Carolina and a mix of resources built anywhere as long as they are connected to the Company's transmission network and are needed to serve the load. The Public Staff's recommendation is therefore not reasonable in that it implies that the Company overlooked opportunities for a CT development in North Carolina; as such, this recommendation is inconsistent with the location-neutral nature of the PLEXOS modeling.

With regard to advanced frame CTs, the Company is continually reviewing different types of generation resources. A number of factors may impact the decision to include advance class frames in an IRP, including air permit limitations, fuel availability, ramping and turn down capabilities, amongst others. The Company will continue to evaluate advanced frame CTs with the potential to make them available for future IRPs.

c) Offshore wind was economically selected in Plans C and E; modeling assumptions for Plans B and D were consistent with VCEA requirements.

The Public Staff raises concern with the Company "forcing" a second tranche of offshore wind into the model in 2033 and recommends that in the 2024 Plan the Company "not force undesignated resources into the capacity expansion plan."[38] The Public Staff contends that it was unreasonable to force the model to select a resource of

[38] *Id.* at 6-7, 9, 62 (Recommendation 3(g)).

this magnitude of capacity, energy, and overnight costs for purposes of an unquantified target for resource diversity.[39]

The Company clarified in a discussion with the Public Staff conducted after the Public Staff's comments were filed that the second tranche of offshore wind was selected economically two years later on a least cost basis in Plans C and E. The Company moved the commercial operation date ("COD") ahead two years in Plans B and D to comply with Virginia SB 1441, which, as discussed above, accelerated the VCEA timeline for public utility construction or purchase of one or more offshore wind facilities from 2034 to 2032. The Company thus did not force PLEXOS to select the second tranche of offshore wind, it simply pulled the COD forward by two years from when it would have been economically selected in order to comply with the legislation. As stated elsewhere in these reply comments, the IRP represents a snapshot in time; for purposes of the 2024 Plan and future IRPs the Company will therefore consider relevant planning and compliance-related changes known at the time.

3) Cost considerations: the Company's NPV results accurately reflect the full cost of the Alternative Plans; DENC will work with the Public Staff on North Carolina bill impacts.

The Public Staff discusses NPV results that the Company presented in the 2023 Plan for each Alternative Plan, and raises a concern that, due to the modeling constraints on the Alternative Plans and resulting lack of a "true least-cost plan," "the NPV results … do not accurately reflect the full costs of the plans."[40] The Public Staff also characterizes the present value of revenue requirement ("PVRR") as an economic metric presented for each Alternative Plan.

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[39] *Id.* at 6-7.
[40] *Id.* at 38.

The Public Staff also recommends specifically "that the Company provide North Carolina-specific bill impacts in future IRP filings to contextualize the residential impacts to North Carolina. The Public Staff will continue to work with [the Company] to understand the sensitivities of the various inputs to ensure that the analyses are capturing all the incremental changes to revenue requirements resulting from each plan."[41]

The Company maintains that it provided true least cost versions of its Plans B (as Plan C is its timing and cost optimized version, as discussed earlier) and D (as similarly, Plan E is its timing and cost optimized version) in which the model was allowed to select resources completely on a least-cost basis without regard for the development targets for solar, wind, and energy storage resources established through the VCEA. No proposed project was pre-programmed into modeling of either Plans C or E. Further, as discussed above, the modeling constraints (or build limits) incorporated into each Plan were based on the Company's extensive experience with project development and construction, and the Company stands by these assumptions for the maximum realistic annual build limit for each type of resource as reasonable. In other words, the pool of generation resources included in the PLEXOS model was realistic and the model did not have to resort to selecting potentially more expensive resources while cheaper options could have been available.

Additionally, the Company tied the import assumptions used for the model to two opposite scenarios for planned resource retirements in Plans C and E, such that both the low and high level of thermal resources retirements are incorporated into the Company's least cost planning.

[41]*Id.* at 40.

It is also important to note that realistic modeling requires careful balancing of the unprecedented load growth forecast for DOM Zone and multiple regulatory requirements around emissions, resource retirements, resource development, construction timelines and costs, commodity costs, and value of environmental attributes such as RECs. For this reason, the Company presented multiple Alternative Plans, two of which (Plans C and E) are least cost optimized and therefore represent a realistic least-cost range for planning purposes at the time the 2023 Plan was prepared. For purposes of the 2024 Plan, the Company will review and revise all the constraints and cost assumptions to prepare updated NPV estimates based on the best available information at that time.

Finally, the Company and the Public Staff discussed the PVRR and NPV via conference call on March 7, 2024. During this discussion, the Company explained that the NPV results shown in the 2023 IRP represented the system NPV for each Alternative Plan based on projected timeline of incurring the modeled costs by the Company. This NPV metric is different from the PVRR metric, which would have represented present value of revenue requirement collected from the Company's customers, which (by design) happens later than the costs are incurred. As such, PVRR of each Alternative Plan would necessarily differ from the NPV of incurred costs modeled for that Plan. To reflect customer costs, instead of PVRR, the Company presents bill analysis for each Alternative Plan in its IRP, which allows the projected cost of service to be tracked over time for selected customer classes, instead of its present value for all customers. The bill analysis is more useful for customers as it is tied to hypothetical energy consumption levels, as compared to PVRR, which would have presented aggregated revenues collected by the Company from all customers over time in each Alternative Plan.

Regarding the Public Staff's North Carolina-specific bill analysis recommendation, the Company does not oppose developing a North Carolina-specific bill analysis, based on system-wide plans, if the Commission determines it would be helpful. It would not, however, be reasonable to run a North Carolina bill analysis based on modeling parameters that apply only to North Carolina. The Company is open to working with Public Staff on a bill analysis specific to North Carolina and will take Public Staff's recommendations into consideration to develop feasible options for presentation of this information.

4) The IRP is a snapshot in time and the Company will consider relevant and compliance-related changes for the 2024 Plan.

a) RGGI/Federal Environmental Standards were modeled appropriately.

The Public Staff states that "policy assumptions regarding long-term planning – particularly those pertaining to carbon regulation – involve a level of uncertainty, and failure to account properly for this uncertainty can result in sub-optimal plans and create the risk of unnecessarily high rates for customers."[42] The Public Staff identifies Virginia's membership in the Regional Greenhouse Gas Initiative ("RGGI"), potential mandatory federal CO2 compliance standards, and uncertainty around the impact of the Environmental Protection Agency's ("EPA") proposed new CO2 standards for power plants under the Clean Air Act ("Section 111(d)") as examples of such policies but does not make any specific recommendation in this regard. The Public Staff acknowledges that the Company conducted an RGGI sensitivity that showed an average increase to plan implementation costs if Virginia remained in RGGI.[43]

[42] *Id.* at 8.
[43] *Id.* at 7-8, 18.

The Company continuously evaluates new and proposed environmental regulations and will continue to update its modeling as appropriate in future plans based on those evaluations. As the Commission has recognized, however, it is not appropriate in a "snapshot in time" document such as the IRP to expect the Company to continually update modeling to account for policy developments that occur subsequent to the Plan modeling and submission.[44]

Specifically with regard to Section 111(d), the Company reasonably determined not to include Section 111(d) regulations in the 2023 Plan modeling since the regulations were released on May 11, 2023, after the 2023 Plan was filed. Instead, the Company included its qualitative discussion in the 2023 Plan. The Company will give appropriate consideration to Section 111(d) for purposes of the 2024 Plan, depending on the outcome of the proposed rule.

Regarding RGGI, as the Company has reported in Docket No. E-100, Sub 194 ("2023 Avoided Cost Docket"),[45] the administrative repeal of the Virginia CO2 Budget Trading Rule ("Virginia Carbon Rule") took effect December 31, 2023 and, with that repeal, Virginia does not qualify for RGGI participation under RGGI's Model Rule, which defines a "participating state" as a "state that has established a corresponding

[44] *See* Order Adopting Initial Carbon Plan and Providing Direction for Future Planning at 48, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("While the Commission agrees with the parties that the IRA will likely significantly impact the cost of compliance with N.C.G.S. § 62-110.9, it is also cognizant that Congress passed the IRA on August 16, 2022, three months after Duke completed its initial modeling in this proceeding, less than one month before the beginning of the evidentiary hearing, and a little over four months before the Commission's deadline for adopting the 2022 Carbon Plan. Such a timeline does not allow for the incorporation of the IRA into Duke's modeling or for a full review of the potential impacts of the legislation. The Commission further agrees with the Public Staff and Duke that modeling inputs must be final at some point, lest a proceeding 'devolve into an endless cycle of updating assumptions and re-running the models.'").

[45] *See* Update to Initial Statement of Dominion Energy North Carolina, Docket No. E-100, Sub 194 (Jan. 9, 2024).

regulation as part of the $CO2$ Budget Trading Program."[46] Currently this repeal remains in effect, while the Virginia courts address challenges to the decision. As the Company noted in the 2023 Avoided Cost Docket, based on the Board's authority to repeal the Virginia Carbon Rule, the Company believes that the Board's decision, and Virginia's December 31, 2023, exit from RGGI, will stand. The Company will continue to update the Commission and the Public Staff of any further developments on the status of appeals of repeal of the RGGI rule and, if there are known changes to this situation, will consider those in preparing the 2024 Plan.

b) *PJM Reserve Margin value was incorporated appropriately at the time of the 2023 Plan filing; its updates will be included in future Plans.*

The Public Staff notes that the Company relied on the 2022 PJM Reserve Study for purposes of the 2023 Plan and that PJM updated its reserve margin "after the company filed its 2023 IRP."[47] While "recogniz[ing] that IRPs are inherently a snapshot in time and there will be some staleness to any reviewed plan," the Public Staff contends that this change "limits the planning value of the long-term portfolios as filed."[48] The Public Staff recommends that in the next IRP the Company should incorporate any updates to PJM's reserve margin.[49]

As the Public Staff acknowledges, the IRP serves as a snapshot in time and reflects market conditions at the time of modeling. As such, the Commission's findings in this proceeding should not be impacted by information that was not published *until*

[46] RGGI Model Rule Part XX, Subpart XX-1.2 (available at https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2017-Program-Review-Update/2017_Model_Rule_revised.pdf).
[47] Public Staff at 7.
[48] *Id.* at 7, 53-54.
[49] *Id.* at 63 (Recommendation 3(l)).

after the filing of the 2023 Plan. In addition, notably, PJM recommended using the updated reserve margin for the June 2024+ planning period.[50] The increased PJM reserve margin will accordingly and appropriately be addressed in the Company's 2024 Plan; it should not, however, be relied upon to reject the 2023 Plan.

c) *PJM Capacity Price Forecast is appropriate and well-supported; the Company will keep Public Staff apprised of PJM Market Rule Changes that may impact the 2024 Plan.*

The Public Staff notes the Company's forecast of a significant PJM capacity price increase over the 15-year planning period and recommends that the Company reevaluate the reasonableness of the capacity price forecast for purposes of the 2024 Plan. The Public Staff also notes the ongoing development of modifications of PJM capacity market rules and other potential changes that could affect the economics of the Fixed Resource Requirement ("FRR") that the Company currently utilizes to meet its PJM reliability requirements.[51]

The Company continually evaluates FRR versus reliability pricing model ("RPM") economics as Capacity Market reforms are approved and implemented by FERC and PJM. The Company entered FRR for the 2022/2023 Delivery Year ("DY") and its five-year commitment ends after the 2026/2027 DY. FERC has approved an early "out" for FRR entities as early as the 2025/2026 DY,[52] among other market changes, that the Company will consider. Additionally, the Critical Issue Fast Path ("CIFP") capacity

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[50] *See* 2023 PJM Reserve Requirement Study (Oct. 3, 2023) (available at https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20231025/20231025-item-02---2-2023-pjm-reserve-requirement-study-report-final.ashx).
[51] Public Staff at 29.
[52] *See Order Accepting Tariff Revisions Subject to Condition*, 186 FERC ¶ 61,080, P 252 (Jan. 30, 2024) ("FERC Order Accepting Tariff Revisions").

reform process at PJM[53] was in its infancy when the Company filed the 2023 IRP and was not approved by FERC until January 30, 2024.

The Company discussed recent PJM market changes with the Public Staff on two occasions after the Public Staff's comments were filed and has agreed to keep the Public Staff apprised of the developments that could have substantial impact on planning of Alternative Plans in the 2024 IRP, including the status of the Company's FRR election. The Company will reflect the results of the CIFP process and any other relevant market changes, as appropriate, in its 2024 Plan.

Regarding the capacity price forecast specifically, ICF provides projections for capacity, RECs, and other commodity pricing that are all correlated. Adjusting one element (such as capacity) upward or downward would impact the entire pricing complex because these commodities are inherently linked in the market. Moreover, a number of reasons can cause differences between historical pricing and price expectations including market rule uncertainty (e.g., the Minimum Offer Price Rule, public policy, the Market Seller Offer Cap ("MSOC"), administratively established Cost of New Entry, etc.), delayed unit retirements, state policy decisions, and other fundamental factors. Current markets continue to reflect a mix of subsidies and uncertainties caused by the transitional state of the energy industry. An example of this is when assets which had announced retirement move to a wait-and-see mode seeking more certainty before retiring in full (*e.g.,* the Pleasants facility, a large coal plant in West Virginia, had announced retirement and is now expected to remain online and operate on a low-carbon fuel source). The

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[53] *See Letter to PJM Stakeholders*, PJM Board of Managers (Feb. 24, 2023) (available at https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20230224-board-letter-re-initiation-of-the-critical-issue-fast-path-process-to-address-resource-adequacy-issues.ashx).

Company will continue to evaluate the reasonableness of the PJM capacity price forecast in its next IRP and will continue to work with ICF to ensure the reasonableness of capacity, and other, price forecasts for the 2024 IRP in light of the CIFP review recently completed by PJM and FERC.

d) Other ongoing developments will be appropriately incorporated in future IRPs.

The Public Staff notes additional potential changes that could impact the Company's assumptions for its future IRPs, including proposed new EPA rules for regulating GHG emissions, additional guidance from the Internal Revenue Service relating to Production Tax Credits, Investment Tax Credits, and other impacts of the Inflation Reduction Act that were not clear at the beginning of 2023, and the Company's participation in the Mid-Atlantic Hydrogen Hub, which was selected by the US Department of Energy for award negotiations in October 2023.[54]

As discussed above, the Company is always actively monitoring market and regulatory developments to inform its planning. The Company's 2023 Plan incorporates reasonable assumptions and constraints based on the Company's own experience working towards the VCEA targets as well as the best information available at the time the 2023 Plan was developed. An integrated resource plan is an iterative process, representing a snapshot in time. The Company is committed to updating and refining its modeling assumptions in future filings. This will include incorporation of the latest information on potential EPA rule changes and available IRS guidance on the IRA impacts (such as ITCs and PTCs) as well as comments on the Mid-Atlantic Hydrogen Hub, provided there is

[54] *Id*. at 29-30.

sufficient clarity on these topics at the time of the 2024 IRP development to support relying on such developments.

5) The Company will continue to review its load forecasting methodology to ensure its appropriateness for planning purposes.

As noted above, the Public Staff comments that the Company has considerably more experience than others with data centers and has combined this knowledge with various statistical analyses to better understand its current and future energy requirements. The Public Staff concludes that the Company's peak load and energy sales forecasts are reasonable for planning purposes.[55] The Public Staff recommends that the Company continue to review its load forecasting methodology to ensure that assumptions and inputs remain current and that the methodology employs appropriate models quantifying customers' responses to weather, particularly abnormally cold winter weather events.[56]

The Company will continue to review its load forecasting methodology to assure current and appropriate inputs and modeling as it has always done. In addition, the Company will continue to analyze winter weather scenarios developed through weather simulations to assess increases in load driven by abnormally cold weather.

6) It is unreasonable and unrealistic to model the Company as an island; the Company will continue to evaluate options for securing capacity.

The Public Staff identifies its concern regarding the level of capacity imports reflected in the Plan, noting for example that "the magnitude of capacity purchases is substantially larger than all other new resources in Plans A, B, and D, and exceeds 50%

[55] *Id.* at 48.
[56] *Id.* at 61 (Recommendation 3(a)).

of total resource additions in all three Plans."[57] The Public Staff also notes unit retirements appear to trigger the need for new imports and the costs needed for expansion. The Public Staff recommends: (1) limiting import capacity to the current level of 1,100 MW for future NC IRPs in at least one portfolio;[58] (2) continuing to review capacity options for addressing the winter peak;[59] and (3) "[m]odel[ing] an alternative plan that does not rely on any import capacity to solve energy or capacity needs,"[60] the latter of which would ultimately would require the Company to develop a separate alternative plan that models the Company as an island.

The Company is currently a member of PJM and operates its day-to-day business within the PJM Market to serve customers. This includes purchasing capacity and importing energy to meet the needs of its customers in both Virginia and North Carolina. Therefore, while the Company acknowledges that reliability is paramount and understands and acknowledges the Public Staff's concern, an Alternative Plan without available capacity and energy purchases would be unrealistic in both the modeling and operational spaces. This is especially the case in the wake of the recent PJM Capacity Market reform that made it more challenging for *all* market participants to satisfy their reserve requirements due to lowered ELCC values for most of generating resource classes, including thermal resources, for the first time since the ELCC concept was introduced.[61] During discussions with Public Staff, the Company wwnoted that it is waiting for PJM to publish an updated CETO limit for the DOM Zone, and that the 2024

[57] *Id.* at 27-28; *see also id.* at 6, 34.
[58] *Id.* at 33-34.
[59] *Id.* at 9, 62 (Recommendation 3(b)).
[60] *Id*. at 9, 62 (recommendation 3(f)).
[61] *See* FERC Order Accepting Tariff Revisions.

IRP will be aligned with the anticipated real-world conditions of the capacity market. In discussions with the Company, the Public Staff expressed openness to a modeling approach that incorporates the updated CETO limit rather than no capacity purchases at all or purchases limited to 1,100 MW per year. Additionally, as always, the Company will continue to review potentially available capacity options for addressing winter peaks.

7) It would not be reasonable or appropriate to require Company to incorporate all Public Staff recommendations in at least one single aggregated portfolio.

The Public Staff recommends the Company develop in its 2024 Plan a new alternative plan that "incorporate[s] all Public Staff recommendations into at least one single aggregated portfolio and provide the NPV amounts and a corresponding bill impact analysis focused on North Carolina Customers."[62] Based on the Company's review of the Public Staff's comments, the Company interprets this recommendation to include recommendations 3(a) through (m) on pages 61-63.

While the Company will incorporate all Commission requirements set forth in the final order issued in this proceeding into its future IRP modeling of individual Alternative Plans, it would not be appropriate or feasible to incorporate all modeling recommendations from the Public Staff Comments in a single, aggregated portfolio.

Importantly, the Company's system is not divided between Virginia and North Carolina; it is planned and operated as a single system that is agnostic to state border lines. As a result, the Company models the entire DOM-LSE in its IRP which includes customers in both North Carolina and Virginia and must therefore take into account all applicable laws, statutes, and Commission orders from both states when developing its IRP. Modeling just the Public Staff recommendations into a single aggregate portfolio

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[62] Public Staff at 34, 63 (Recommendation 3(m)).

would devote resources to the development of a hypothetical plan needed solely to address such recommendations, and create a portfolio that may not be reasonable or executable within the entire DOM-Zone. By contrast, consolidating VSCC and this Commission's directions to inform modeling of each of the Alternative Plans developed for the 2024 Plan, as feasible, would be grounded in both jurisdictions' precedent and more realistic.

8) Additional Topics Addressed By Public Staff

a) Subsequent License Renewal

The Public Staff recommends that the Commission continue to direct in future IRPs discussion and evaluation of subsequent license renewals ("SLRs") for each existing nuclear unit, including the anticipated schedule for SLR application submission and review, and an evaluation of risks and required costs for upgrades if required by the SLR approval, or any new industry trends.[63]

The Company will continue to provide information on SLR status as was done in the 2023 Plan.[64] In addition, the Company will provide in future plans references to VSCC dockets pertaining to Rider SLR for additional information; the Company has discussed this approach with the Public Staff and the Public Staff does not oppose it.

With regard to the Public Staff's request for a risk evaluation and required costs for SLR projects, that information is beyond the scope of IRP and will be available to the Public Staff through access to the Company's annual Rider SNA proceedings at the VSCC, which the Company has committed to provide to the Public Staff as conveyed in recent discussions.

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[63] *Id.* at 23.
[64] *See* 2023 Plan at Section 5.2.4.

b) DSM/EE

The Public Staff expresses concern regarding the long-term achievability of the VCEA's requirement that the Company reach 5% EE savings by 2025 relative to a 2019 jurisdictional baseline, which the Company incorporated as a modeling assumption to the 2023 Plan.[65] The Public Staff agrees with Recommendation #12 of the VSCC Senior Hearing Examiner in the Virginia 2023 Plan proceeding that the Company utilize only Category 1 EE Programs for future model runs, with inclusion of Category 2 appropriate for a sensitivity analysis.[66] The Public Staff also recommends that the Company identify any changes in energy efficiency ("EE") related technologies, regulatory standards, or other drivers that would impact future projections of EE savings.[67]

With regard to DSM, the Public Staff "acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the inconvenience associated with the use of DSM are all important considerations in determining which DSM resources should be deployed and how often."[68] The Public Staff recommends "[t]hat the Commission encourage Dominion to optimize use of its DSM resources to reduce fuel costs (especially when marginal costs of energy are high) and ensure reliability" and states that "utilities should seek to maximize the use of DSM to reduce fuel costs, particularly when marginal energy costs are high."[69]

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[65] Public Staff at 50 (citing IRP at 50: "The first category ("Category 1 Programs") consists of previously approved EE programs that remain effective (*i.e.*, that are still producing savings), along with programs that were approved by the SCC in Case No. PUR-2021-00247. The second category ("Category 2 Programs" or "generic" EE) represents unidentified EE programs and measures designed to meet legislative directives.").
[66] *Id.*
[67] *Id.* at 62 (Recommendation 3(c)).
[68] *Id.* at 50. *See also id.* at 51 ("Based on the evidence from Docket No. E-22, Sub 676, Dominion reasonably activated its DSM resources throughout the summer of 2022 to achieve an average demand reduction of 33.294 MW. Table 11 below summarizes Dominion's DSM activation during three seasonal peaks.").
[69] *Id.* at 11, 50-51.

The VSCC's 2022 RPS Final Order required the Company to address the load forecast, modeling, and planning implications of projecting a portion of data center load increases, and its modeling assumption for energy efficiency beginning in 2026 in its next IRP proceeding. The 2023 Plan addresses this directive as it pertains to DSM by including a generic block of energy savings that represents the future undefined EE programs necessary to meet the VCEA target. The Company also assumed a 5% energy efficiency reduction target for 2025, consistent with the VCEA, and further used that 5% reduction target for years 2026-2047. As directed, the generic block of energy savings represents future undefined EE programs necessary to meet the VCEA energy savings targets.

Currently the Company is not aware of any technologies, regulatory standards, or other drivers that would change the current projection methodology of EE savings. The Company conducts a DSM/EE potential study roughly every three years, with the next one scheduled to be completed in May 2024, and provides its latest potential study during its annual Request For Proposals ("RFP") process to seek new and cost-effective DSM program proposals. In short, the Company's 2023 Plan is based on current, verified data from the Company's DSM programs at the time the Plan was created.

With regard to the Public Staff's agreement with the VSCC Hearing Examiner that the Company utilize only Category 1 EE Programs for future model runs, with inclusion of Category 2 appropriate for a sensitivity analysis, as the Company stated in the Virginia 2023 Plan proceeding, DENC does not oppose this recommendation.

Regarding DSM specifically, the Company always looks to maximize the use of its DSM resources to reduce fuel costs. It should be noted, however, that while optimization of DSM is feasible with dispatchable DSM programs, not all DSM/EE measures are dispatchable as many programs depend on customer behavior.

c) Proposed Rulemaking on Battery Storage Approval

Due to "increasing reliance on energy storage in the Company's IRP," the Public Staff requests that the Commission initiate a generic rulemaking proceeding to evaluate whether, and under what circumstances, an electric supplier should be required to receive Commission approval prior to construction of a battery energy storage facility in North Carolina.[70]

The Company does not oppose a rulemaking to evaluate whether and under what circumstances an electric supplier should be required to receive Commission approval to construct a battery energy storage facility in North Carolina, should the Commission determine such a rulemaking to be appropriate and needed. The Company suggests that the Commission consider what the purpose of such a requirement would be when considering whether such a proceeding is required. If the Commission seeks additional information on the Company's and other electric suppliers' battery storage plans and projects, the IRP proceedings may continue to be the best forum in which to obtain such information, without the need for additional procedure.

CONCLUSION

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission issue an order on or by May 31, 2024, accepting these Reply Comments, accepting its 2023 Plan and 2023 REPS Plan filed on May 1, 2023, and granting such other relief as may be appropriate.

[70] *Id.* at 11, n.10.

Respectfully submitted,

/s/ Andrea R. Kells

Lauren W. Biskie
Dominion Energy Services, Inc.
120 Tredegar Street, Riverside 2
Richmond, VA 23219
(804) 819-2396
lauren.w.biskie@dominionenergy.com

Andrea R. Kells
Nick A. Dantonio
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
(919) 755-6614 (ARK)
(919) 755-6605 (NAD)
akells@mcguirewoods.com
ndantonio@mcguirewoods.com

Counsel for Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina

April 1, 2024

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Reply Comments*, as filed in Docket No. E-100, Sub 192, was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 1st day of April, 2023.

/s/Andrea R. Kells
Andrea R. Kells
McGuireWoods LLP
501 Fayetteville Street, Suite 500
PO Box 27507 (27611)
Raleigh, North Carolina 27601
Telephone: (919) 755.6614
akells@mcguirewoods.com

Attorney for Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina