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July 5, 2019

VIA ELECTRONIC FILING

Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans
Docket No. E-100, Sub 157

Dear Chief Clerk:

Pursuant to the *Order Granting Joint Motion for Extension of Time* issued on January 24, 2019, in the above-referenced docket, enclosed for filing on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (the "Company") are the Company's *Reply Comments*.

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

Very truly yours,

/s/Andrea R. Kells

ARK:mth

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2018 Integrated Resource Plans and Related 2018 REPS Compliance Plans	))))	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 the *Order Granting Joint Motion for Extension of Time* issued by the North Carolina Utilities Commission ("Commission") in the above-captioned proceeding on January 24, 2019, hereby submits these Reply Comments in response to the Comments of the Public Staff filed in this docket on May 6, 2019.

INTRODUCTION

On May 1, 2018, the Company filed its 2018 Integrated Resource Plan ("2018 Plan") pursuant to Commission Rule R8-60 in the above-captioned docket as well as with the Virginia State Corporation Commission ("VSCC"). The Company held its North Carolina stakeholder meeting on its 2018 Plan on December 7, 2018. On the same day, the VSCC issued an order directing the Company to re-file its 2018 Plan to include a least-cost plan and address implementation of Virginia Senate Bill 966, among other directives.[1]

[1] *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Order, Case No. PUR-2018-00065 (Dec. 7, 2018) ("VSCC 2018 IRP Order").

On January 22, 2019, the Company and the Public Staff filed a joint motion with the Commission requesting an extension of time to file comments on the 2018 Plan, as the Company would be filing the revised 2018 Plan with the modifications directed by the VSCC ("2018 Compliance Filing") in both North Carolina and Virginia. On January 24, 2019, the Commission granted this request and allowed interested parties 60 days to file comments from the date the Company submitted the 2018 Compliance Filing.[2]

On March 7, 2019, the Company filed the 2018 Compliance Filing with both the Commission and the VSCC. On May 6, 2019, the Public Staff filed comments on the 2018 Compliance Filing. No other parties filed comments on the 2018 Compliance Filing. On June 27, 2019, the VSCC issued its final order on the 2018 Compliance Filing, finding that the 2018 Compliance Filing met the requirements of the VSCC 2018 IRP Order and was reasonable and in the public interest for planning purposes consistent with Virginia Code § 56-597.[3] The VSCC also directed the Company to include certain information in future IRPs, as discussed further below.[4]

REPLY COMMENTS IN RESPONSE TO THE PUBLIC STAFF

A. Peak and Energy Forecasts

The Public Staff commented that in its 2018 Plan, the Company used accepted econometric and end-use analytical models to forecast its peak and energy needs. It also noted that the 2018 Compliance Filing revised DENC's peak demand forecasts to

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[2] *Order Granting Joint Motion for Extension of Time and Closing Discovery Period*, Docket No. E-100, Sub 157 (Jan. 24, 2019).
[3] *In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2018-00065 (June 27, 2019) ("VSCC Final Order").
[4] *Id*. at 11-12.

model them using the PJM DOM Zone non-coincident peak forecast, scaled down for the Dominion load serving entity, which resulted in a significant reduction of peak demand over the forecast horizon.[5] The Public Staff assessed the reasonableness of the 2018 Plan and 2018 Compliance Filing forecasts by comparing the Company's most recent weather-normalized peak loads to those forecasted in its 2017 IRP update, and compared the peak demand and energy sales predictions in the 2012 IRP to actual peak demands and energy sales.[6]

The Public Staff supported the use of the PJM peak demand forecast, and concluded that the Company's revised peak load and energy sales forecasts as contained in the 2018 Compliance Filing are reasonable for planning purposes. The Public Staff recommended that the Company's 2020 IRP also rely on the PJM coincident peak scaled down for the Company's load serving entity forecast for its baseline peak and energy forecasts, and encouraged the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.[7] The Public Staff also noted the growing dominance of morning winter peaks, which it stated appeared to represent a shift in electricity usage that warrants further examination of the Company's "econometric and statistical forecast models."[8] The Public Staff recommended that the Company continue to review its winter peak equations in order to better quantify the response of customers to low temperatures.[9]

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[5] Comments of the Public Staff at 9 (May 6, 2019) ("Public Staff Comments").
[6] *Id*.
[7] *Id*. at 12, 47 (Recommendation (1)).
[8] *Id*. at 12.
[9] *Id*. at 47 (Recommendation (2)).

The Company is not opposed to showing both the PJM and Company load forecasts for the 2020 IRP. The Company is also committed to studying the effects of the winter peak on its econometric and statistical forecast models either through its own analysis or that of an outside consultant. The Company notes that in the VSCC Final Order, the VSCC directed the Company to "[c]ontinue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Senate Bill 966, both as an energy reduction and a supply resource, and separately identify the load associated with data centers" in its 2020 IRP.[10] Therefore, the PJM load forecast is now required to be used in future full IRP[11] filings made by the Company.

B. Use of Demand-Side Management ("DSM") Resources During System Peaks

The Public Staff acknowledged that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations for the Company in determining which DSM resources to deploy, and that the use of these resources largely depends on the circumstances and cannot be prescribed in any definitive manner. The Public Staff commented that nevertheless, utilities should maximize the use of DSM to reduce fuel costs, especially when marginal energy costs are high. The Public Staff reviewed the Company's DSM activations at the time of its 15 highest hourly peaks, and noted an "ongoing concern" regarding the difference in DSM resources available in the winter and summer due in part to the fact that winter programs are typically not cost effective. It noted that

[10] VSCC Final Order at 11.
[11] The Company uses the term "full IRP" as *not* including IRP updates. The Company will file an IRP update in North Carolina and Virginia by September 1, 2019.

DENC activated its distributed generation program during the Company's 2018 winter peak and most of the other near-peaks during the winter season, but those activations led only to a 4-6 MW load reduction. The Public Staff recommended that the Company "investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands."[12] It also recommended that the Company (1) maximize the use of DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability, (2) put a renewed emphasis on designing new DSM programs to meet winter peak demands as well as summer peak demands, and (3) continue to pursue all cost-effective energy efficiency ("EE") and DSM.[13]

The Company will continue to identify and seek approval to implement DSM and EE programs that are cost effective or meet public policy goals. With respect to the design of DSM programs to meet winter as well as summer peak demands, the Company's Distributed Generation program is currently available in Virginia during winter periods to non-residential customers who meet participation requirements based upon size.[14] The Company also recently received approval for a demand response residential thermostat control program in Virginia[15] and is filing for approval of that program in North Carolina in July, 2019. In addition, the ten new EE programs approved by the VSCC in May 2019, which will be brought to the

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[12] Public Staff Comments at 13-14.
[13] *Id*. at 48, 50 (Recommendations (3), (4), and (15)).
[14] The Commission denied approval of the Company's Commercial Distributed Generation Program in North Carolina. *See Order Denying Approval of Program*, Docket No. E-22, Sub 466 (Sept. 14, 2011).
[15] *Petition of Virginia Electric and Power Company For approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Order Approving Programs and Rate Adjustment Clauses, Case No. PUR-2018-00168 (May 2, 2019) ("VSCC DSM Order").

Commission for approval in July 2019, address both summer and winter peaks as well as energy requirements. While demand response programs can be used to reduce peak periods explicitly, EE programs can also provide reductions during winter hours. However, these reductions are not dispatchable. Instead, they occur because a measure installed through the program is providing energy savings during a peak hour and thus providing a winter peak reduction. It is important to note, however, that since the actual system peak drives the need for additional resources to meet reliability requirements, it is difficult for programs that provide benefits in mainly non-peak hours to provide a meaningful amount of benefits. The Company is also participating in a stakeholder process required by the Grid Transformation and Security Act ("GTSA")[16] to help it identify potential opportunities for EE and demand response and is hopeful this effort will lead to additional DSM resources in the future that will address both summer and winter peak hours.

C. Generating Facilities

1. Subsequent License Renewals of Existing Nuclear Plants

The Public Staff discussed the Company's generation mix and the current status of its plans for obtaining subsequent license renewals ("SLR") of Surry Units 1 and 2 and North Anna Units 1 and 2. The Public Staff recommended that the Commission continue to direct DENC in future IRPs to "include a discussion and evaluation of potential subsequent license renewals for each of its existing nuclear units, including an anticipated schedule for SLR application submission and review

[16] Grid Transformation and Security Act of 2018, SB 966, 2018 Virginia Acts of Assembly Chapter 296 (enacted Mar. 9, 2018).

and an evaluation of the risks and required costs for upgrades." The Public Staff also stated the Company should continue to reflect any such relicensing plans in future IRPs.[17] The Company will continue to provide the recommended SLR information in future IRPs.

2. Planned Generation – Solar

The Public Staff discussed the solar additions contemplated in the Alternative Plans contained in the 2018 Compliance Plan, and noted the re-dispatch charge associated with higher levels of solar penetration calculated by the Company and added to the dispatch price of solar PV in DENC's model, as well as the fixed charge associated with the estimated cost for transmission and distribution integration. The Public Staff recommended that the Company continue to discuss "mitigation strategies to address the 2016 IRP comments of high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs."[18] The Company is committed to continuing and improving its efforts to analyze solar integration costs and will provide the results of that effort in the 2020 IRP.

The Public Staff also noted that, to the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar photovoltaic ("PV") generation, such as the addition of supplemental combustion turbines ("CT") to address generation volatility or ramp rates, those applicable costs should be assigned to the overall installed cost of solar.[19] In its 2015 Update and

[17] Public Staff Comments at 15-17, 48 (Recommendation (5)).
[18] *Id*. at 19.
[19] *Id*. at 19-20.

2016 IRP, the Company's model addressed the overall installed cost of solar by adding one solar-paired CT for each 1,000 MW of solar capacity in several of its plans.[20] In its 2016 IRP, however, the Company committed to evaluate the "integration costs" of solar in future IRPs and then did so in its 2017 IRP Update by determining the cost impact on generation operations at varying levels of solar penetration.[21] This impact was referred to as the "re-dispatch cost" and was used as a variable cost adder for all solar generation evaluated in the 2017 Update and 2018 IRP.[22] The Company intends to further refine its integration costs analysis in future IRPs and IRP Updates based on the methodology used in the 2017 and 2018 IRPs. As part of that analysis, the Company will consider the costs associated with any identified strategies to mitigate the aggregate effect of distributed solar PV on the Company's system.

3. Non-Utility Generation

The Public Staff summarized the non-utility generation ("NUG") information presented in the Company's original filing, and commented on the Company's inclusion of Figure 3.1.1.3 in its 2018 IRP that provides capacity resource mix by unit type, including NUGs, and Appendix 3B, which provides non-company owned generation that includes NUGs. The Public Staff noted a few concerns with the information presented in those portions of the IRP, and recommended that in future

[20] *Integrated Resource Plan of Dominion North Carolina Power*, 113, Docket No. E-100, Sub 141 (July 1, 2015); *2016 Integrated Resource Plan of Dominion North Carolina Power*, 98, Docket No. E-100, Sub 147 (Apr. 29, 2016).
[21] *2017 Integrated Resource Plan of Virginia Electric and Power Company*, 81, Docket No, E-100, Sub 147 (May 1, 2017).
[22] *2018 Integrated Resource Plan of Virginia Electric and Power Company*, 80-82, Docket No. E-100, Sub 157 (May 1, 2018).

IRPs, the Company: "(1) clarify its definition of a NUG facility and use that definition consistently through the IRP; (2) re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; (3) separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and (4) maintain consistency on references to nameplate rating or equivalent firm capacity rating throughout the document."[23] The Company discussed these recommendations with Public Staff via telephone conference on June 12, 2019. Based on this discussion, the Company will make changes to Appendix 3B and Figure 3.1.1.3 in future full IRPs that should address the concerns raised by Public Staff. In addition, the Company plans to provide an updated version of Appendix 3B as part of the 2019 IRP Update filing to the extent the information is available.

D. Reserve Margin

The Public Staff discussed the manner in which the Company assigns solar and wind resources a percentage of their nameplate capacity towards meeting summer and winter peak demand when calculating its reserve margin (the "capacity value"). Noting that DENC's proposed capacity values for solar are significantly lower than the PJM class average, the Public Staff commented that the Company should continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research. The Public Staff clarified that while it is not recommending the 2018 IRP be re-filed with revised capacity values, in future IRPs, the Company should be required to: "(1) provide PJM's capacity value for renewable

[23] Public Staff Comments at 21, 48-49 (Recommendation (8)).

resources as comparison benchmark, and (2) to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference."[24] The Company does not oppose this recommendation, and will provide that responsive information in its 2019 IRP Update. The Company notes in addition that in its VSCC Final Order, the VSCC directed the Company in future full IRPs to model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (b) 25%.[25]

The Public Staff concluded that the Company's calculation of the adjusted reserve margin and the coincidence factor in the 2018 Compliance Filing appear reasonable for planning purposes and should be maintained as filed.[26] The Public Staff recommended that in future IRPs, the Company evaluate the "feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling, more granular system performance data, probabilistic analysis, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system performance."[27] DENC will evaluate incorporating a sub-hourly analysis into the 2020 IRP. It should be noted the Company uses internal information to establish the adjusted reserve margin and coincidence factor and the use of advanced analytical techniques requires a level of detail not provided in the PJM forecast. The Company will therefore use available internal data and forecasts when

[24] *Id*. at 26, 48 (Recommendation (7)).
[25] VSCC Final Order at 11-12.
[26] Public Staff Comments at 26, 48 (Recommendation (6)).
[27] *Id*. at 27, 49 (Recommendation (9)).

evaluating the feasibility and benefits of advanced analytical techniques in the 2020 IRP.

E. DSM and EE Programs

The Public Staff noted that the Company completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period, and stated that the Company indicated that it did not incorporate any of the measures identified in the study in its 2018 IRP. The Public Staff stated that "[m]uch of the economic potential for residential and non-residential sectors lies in lighting and space heating and cooling measures, and observed from the report that (1) there are no recommendations on specific measures that would contribute toward the achievable potential going forward for either case, and (2) the achievable potential excludes the impacts of customers who are eligible to opt out of utility-sponsored EE portfolios.[28] The Public Staff also noted that the Company has initiated an EE stakeholder process as required by the GTSA, and that meetings have occurred and are likely to continue in the future with the intent of bringing interested parties, including the Public Staff, together to discuss how EE can be implemented in Virginia.[29] The Company has recently contracted for a new appliance saturation study, conditional demand analysis, and market potential study to reflect changes in stock, standards and potential for energy consumption and reductions. This is important given the exclusion of larger customers due to the passage of the GTSA in Virginia. Many of the measures reflected in the 2017 market potential study are

[28] *Id*. at 30.
[29] *Id*. at 31.

already included in current Company-sponsored programs. The most current market potential study is provided to vendors (so they are aware of potentially cost effective measures) when the Company issues a solicitation for new DSM program designs. Of note, the market potential study is performed by an outside vendor and reflects their high level screen based upon the Total Resource Cost test only. A proposed program would be analyzed by the Company for feasibility and cost-effectiveness prior to filing with a commission or implementation.

The Public Staff also acknowledged that the Company's EE efforts are largely driven by the GTSA and noted that at that time the Company had proposed 11 new DSM/EE programs that were pending before the VSCC and were not included in the 2018 IRP.[30] It noted the cancellation of several programs in Virginia that were offered on a system-wide basis and recognized that the Company has worked with the Public Staff to evaluate whether any of the cancelled programs can continue to be offered on a North Carolina-only basis and has requested approval from the Commission for programs that can be offered cost-effectively even in the short term.[31] The Public Staff recommended that the Company continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, anytime the Company denied approval by the VSCC to implement the program on a system-wide basis.[32] The Company will continue to consider North Carolina-only basis programs if the VSCC does not approve a filed program.

[30] *Id*. at 29-30.
[31] *Id*. at 29.
[32] *Id*. at 50 (Recommendation (16)).

The VSCC approved all 11 proposed DSM programs, including 10 EE programs, by order issued May 2, 2019.[33] The Company is currently developing applications to the Commission for approval of each of these programs, and plans to submit those applications in July 2019. For clarification, the Company notes that while the Public Staff comments characterized the GTSA as "requiring" the Company "to spend" $870 million over the next ten years on EE, the GTSA requirement is for the Company to *propose* programs that spend that amount on EE over the next decade.[34] The Company intends to propose programs that meet the required spending amount, but implementation of those programs would be dependent on VSCC approval.

F. Comprehensive Risk Analysis

The Public Staff found that the Company's approach of analyzing various Alternative Plan scenarios for exposure to fuel price volatility and customer rate impacts, and of utilizing a probabilistic risk assessment framework, provides insightful information to its customers and the Commission, and recommended that the Company continue to provide comprehensive risk analysis of Alternative Plans in future IRPs and IRP updates.[35] The Company plans to continue to provide comprehensive risk analyses in each full IRP filing, including for the 2020 IRP, but does not support providing this level of analysis in the IRP updates consistent with the update requirement to summarize "significant amendments or revisions to the

[33] *See generally* VSCC DSM Order.
[34] Va. Code § 56.596.2.
[35] Public Staff Comments at 39-40, 49 (Recommendation (11)).

most recently filed biennial report."[36] Moreover, the comprehensive risk analysis process is resource-intensive and requires approximately five months to complete. This is due to the need to model the entire Eastern Interconnect in the AURORA model and generating 200 simulations of the model for individual risk factors. As the 2019 IRP Update is due in less than two months, the Company does not have sufficient time to provide this analysis for that filing.

G. Plan Costs and Rate Impacts

The Public Staff noted that in the Company's original 2018 IRP, DENC demonstrated the rate impact of each alternative plan over the planning horizon, but commented that those estimates are no longer valid due to the changes in investment decisions for the planning horizon reflected in the 2018 Compliance Filing. The Public Staff recommended that the Company submit as a supplemental filing the recalculated rate impact analysis of the modified Alternative plans found in its 2018 Compliance Filing.[37] Because the data underlying the analysis of the Alternative Plans contained in the 2018 Compliance Filing is more than one year old, it would not provide an accurate snapshot of the potential rate impact of the modified Alternative Plans contained in the 2018 Compliance Filing and presented in this proceeding. Therefore, the Company respectfully requests that rather than accept the Public Staff's proposal, the Commission permit DENC to provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update that is due to be filed by September 1, 2019.

[36] North Carolina Utilities Commission Rule R8-60(h)(2).
[37] Public Staff Comments at 41, 49 (Recommendation (10)).

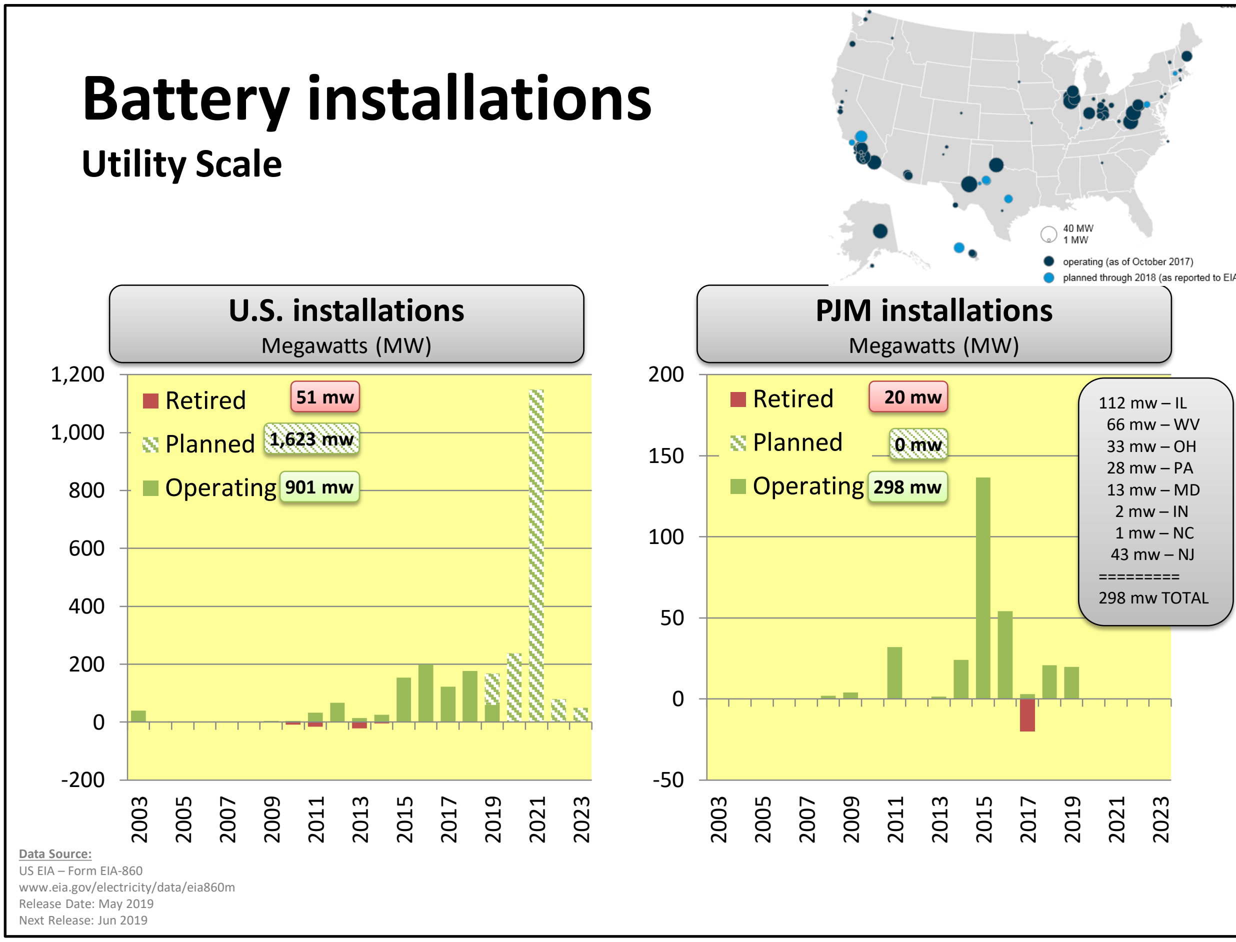
H. Energy Storage

The Public Staff noted the Commission's directive in its 2016 IRP Order that the utilities include certain information regarding the battery storage in future IRPs, and the GTSA requirement that the Company submit a proposal to deploy up to 30 MW of batteries through pilot programs. The Public Staff concluded that the Company did not comply with the Commission's 2016 IRP Order directive to provide a more complete and thorough analysis of battery storage technologies. The Public Staff therefore recommended that the Company (1) be required to make a supplemental filing to its 2018 Plan that provides a more detailed analysis of why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs, and (2) be required to address in future IRPs and IRP updates how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies.[38]

Many types of technologies can store energy, including electrical, thermal, mechanical, and electrochemical technologies. Hydroelectric pumped storage, a form of mechanical energy storage, accounts for the greatest share of large-scale energy storage power capacity in the United States. However, large-scale energy storage capacity additions since 2003 have been almost exclusively electrochemical (or battery) storage. As of May 2019, there has been limited operating experience in

[38] *Id*. at 42-44, 49 (Recommendations (12), (13)).

utility scale applications of batteries with 901 MW for the entire United States (298 MW in PJM) as seen in the Figure below.



The Company is in the early stages of battery research and has relied on publically available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. Battery storage can be a viable future option for peak shifting at a stand-alone storage facility or while co-located at a solar farm. Battery storage may also improve overall energy production at a solar facility via capturing energy that may be clipped by the inverters.[39] Overall, however, battery storage is still in its early stages of development and as a result, the estimates for a battery storage facility in the 2018 Plan were more reflective of a pilot program versus a larger utility scale facility. In addition, CTs can provide backup for periods of lower production from solar facilities, such as prolonged weather patterns or projected variations in capacity factors over the course of a year. CTs in the 2018 IRP short-term action plan were slated for deployment in 2022 and 2023, at approximately 458 MW nominal capacity per facility and an overnight installed cost of $476 per kilowatt (kW). Pricing of an equivalent battery storage facility was not cost competitive based on those 2018 estimates. As a result, based on the 2018 economics and technology, battery storage facilities were not expected to significantly displace combustion turbine facilities supplementing the solar generation profile within the next several years.

In the 2018 Plan, the Company screened out battery storage resources as part of its future resource analysis because of (1) limited utility scale operating experiences, (2) PJM was in the process of revising its tariffs for energy storage resources due to FERC Order 841, and (3) high costs.[40,41] In the 2018 Compliance Filing, a 30 MW battery storage pilot program was available as an option in the "final" PLEXOS IRP modeling based on the directive in the VSCC 2018 IRP Order.

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[39] A solar inverter converts variable direct current (DC) output of a photovoltaic (PV) panel into a utility frequency alternating current (AC) that can be fed into a commercial electric grid. Inverter clipping occurs when a solar inverter has reached maximum capacity for power output. To avoid damage, it will "clip" any additional power solar panels produce. This is a standard operating condition when designing systems with an oversized panel array.

[40] Lazard's Levelized Cost of Storage Analysis – Version 3.0 (Nov 2017) (https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf).

[41] US Energy Information Administration, "Table 2. Cost and performance characteristics of new central station electricity generating technologies." (Jan 2019) (https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf).

The 30 MW battery storage pilot was not chosen by the model as a least-cost option in Plan A. This validates the Company's decision in the 2018 Plan to screen out battery storage resources in its 2018 Plan future resource process because of their then (i.e., 2018) high cost relative to their benefits as a generating resource. The battery storage pilot was forced, however, into all other Plans (Alternative Plans B through F) as required by the VSCC 2018 IRP Order. Notwithstanding their treatment in the 2018 Plan, the Company will include battery storage and other energy storage options such as pumped storage facilities in the busbar analysis and provide the results of that revised analysis in its 2019 IRP Update.

The Company disagrees with the recommendation from Public Staff to require the Company to specifically address how its solar integration cost estimates are affected by battery storage.[42] The Company's experience with battery storage technologies is still in its early stages of development, and, as a result, the Company will not have sufficient information to analyze their effect on solar integration for the 2020 IRP. Nevertheless, the Company will also continue to assess battery storage technologies in future IRPs and IRP updates as required by prior Commission orders, and will report and incorporate the results of any relevant experience with battery storage. As part of that effort, the Company will as directed by the VSCC Final

[42] As to whether the 5,000 MW of solar has been "legislatively mandated" (Public Staff Comments at 42-44, 49 (Recommendations (12), (13)), the Company would note that the VSCC acknowledged in footnote 12 of the VSCC Final Order that "Senate Bill 966 contains numerous provisions that, when it comes time to consider a CPCN or RAC for a specific project, will be governed by the legal standard applicable to that specific proceeding and those legal standards are not all identical." The VSCC additionally noted on pages 12-13 of the VSCC Final Order that "'Code § 56-585.1:4 [A] refers to 5,000 [MW] of both solar and wind resources 'located in the Commonwealth or off the Commonwealth's Atlantic shoreline,' which would imply that the 5,000 MW total is a statewide aggregated (including offshore) total of both solar and wind.' As Dominion correctly states, the 5,000 MW is not a specific target applicable to Dominion."

Order[43] model battery storage using the most updated cost estimates available in its future full IRP filings.

I. Additional Recommendations

The Public Staff recommended that the Company continue to explain any changes of its savings projections that are more than 10% different than the previous IRP or IRP update, and that the Company should identify any changes in EE-related technologies, regulatory standards, or other trends that would impact future projections of EE savings regardless of the 10% threshold. The Public Staff recommended that these changes and trends should receive more detailed discussion in the IRPs.[44] The Company is willing to comply with these recommendations in future IRPs and updates.

The Public Staff also recommended that the Company include in future IRPs and updates a discussion of its use of data from smart meters to inform load forecasting, cost of service studies, and rate designs.[45] The Company notes that Virginia now requires the Company to evaluate "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects" in preparing its full IRPs beginning with the 2020 IRP.[46] Information about the use of smart

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[43] VSCC Final Order at 11.
[44] Public Staff Comments at 49-50 (Recommendation (14)).
[45] *Id*. at 50 (Recommendation (17)).
[46] Va. Code § 56-599 B 10. The Company further notes that, for purposes of the 2020 Plan, Requirement (8) on page 12 of the VSCC Final Order requires the Company to "[s]ystematically evaluate long-term electric distribution grid planning and proposed electric distribution gird transformation projects. For identified grid transformation projects, the Company shall include: (a) a detailed description of the existing distribution system and the identified need for each proposed grid transformation project; (b) detailed cost estimates of each proposed investment; (c) the benefits associated with each proposed investment; and (d) alternatives considered for each proposed investment."

meters will also be part of the Company's Grid Transformation Plan, which the Company intends to refile with the VSCC in 2019. The Company also notes that its ability to use smart meter data to inform load forecasting, cost of service studies, and rate designs will be limited until it can fully deploy smart meters throughout its service territory. Nevertheless, the Company intends to use data from its smart meters to inform these matters when sufficient data is available.

CONCLUSION

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission issue an order accepting these Reply Comments, approving its 2018 Plan filed on May 1, 2018, as revised by the 2018 Compliance Filing filed on March 7, 2019, consistent with the VSCC Final Order, and granting such other relief as may be appropriate. The Company notes that its 2019 IRP Update is due by September 1, 2019, and respectfully requests that any order issued by the Commission requiring *additional* information that is not already addressed in these Reply Comments for the 2019 IRP Update be issued as expeditiously as possible in order for the Company to meet this filing date.

Respectfully submitted,

/s/ Andrea R. Kells

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

July 5, 2019

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Reply Comments*, as filed in Docket No. E-100, Sub 157, were served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 5th day of July, 2019.

/s/Nicholas A. Dantonio

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