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

MCGUIREWOODS

akells@mcguirewoods.com

April 1, 2022

VIA Electronic Filing

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

Re: Docket No. E-100, Sub 175
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021

Dear Ms. Dunston:

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

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

Very truly yours,

/s/Andrea R. Kells

ARK:sjg

Enclosures

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	))))	**REPLY COMMENTS OF 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 North Carolina Utilities Commission's ("Commission") March 25, 2022, *Order Granting Motion for Extension of Time of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC* submits these Reply Comments in response to the Initial Comments of the Public Staff, the Initial Comments of the Southern Alliance for Clean Energy ("SACE"), and the Joint Initial Comments of the Carolinas Clean Energy Business Alliance ("CCEBA") and the North Carolina Sustainable Energy Association ("NCSEA" and together with CCEBA, the "Joint Intervenors") filed in this proceeding on February 24, 2022.

I. INTRODUCTION

With its Initial Statement and Exhibits submitted on November 1, 2021 in this proceeding ("Initial Filing"), DENC proposed updated avoided energy and capacity rates under its standard offer rate schedules, Schedule 19-FP and Schedule 19-LMP. In addition, the Company proposed certain revisions to its "Notice of Commitment" forms ("LEO Forms") to implement the findings and revised Federal Energy Regulatory Commission

("FERC") regulations contained in FERC Order No. 872,[1] and proposed new LEO Forms specific to qualifying facilities ("QFs") that seek to add retrofit storage equipment to their facilities. On January 7, 2022, the Company filed corrected proposed standard avoided capacity rates and supporting exhibits ("Corrected Capacity Rates").

II. REPLY COMMENTS

A. Avoided Capacity Cost Issues

a. Peaker Methodology

As it has since the 2012 biennial avoided cost proceeding (Docket No. E-100, Sub 136), the Company used the peaker method to calculate the avoided capacity cost rates for its Schedule 19-FP rate schedule for this proceeding. In its initial comments, the Public Staff supports the Company's, Duke Energy Carolinas, LLC's, and Duke Energy Progress, LLC's ("Duke Utilities" and together with the Company, the "Utilities") use of the peaker methodology to calculate avoided cost rates.[2] The Public Staff observes that there may come a time in the future when the peaker methodology is not appropriate for use in North Carolina. The Public Staff notes that the Company's 2021 Integrated Resource Plan Update filed on September 1, 2021 in Docket No. E-100, Sub 165 ("2021 IRP Update") contains two alternative plans (Plans B and C) which have no combustion turbines ("CT") built during the planning horizon.[3] SACE and the Joint Intervenors also assert that the Commission should begin to reconsider the appropriateness of the peaker methodology for avoided cost determinations.[4]

---

[1] *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (2020) ("Order No. 872").
[2] Public Staff Initial Comments at 24.
[3] *Id*. at 24-25.
[4] SACE Initial Comments at 3; Joint Intervenors Initial Comments at 17-18.

The Company acknowledges that additional factors or methods for determining avoided costs may need to be considered in the future. The Company agrees that, as the energy landscape continues to develop, there may be additional considerations to analyze in terms of the appropriate methodology to calculate avoided cost rates in North Carolina biennial proceedings. For purposes of this proceeding, the Company agrees that the peaker methodology remains reasonable and appropriate.

b. Performance Adjustment Factor ("PAF")

In the Commission's April 15, 2020, final order ("Sub 158 Order") in Docket No. E-100, Sub 158 (the "2018 Avoided Cost Case") the Commission directed that the Utilities, "with input from the Public Staff, shall evaluate appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing."[5] For purposes of the streamlined 2020 Avoided Cost Case, the Company continued to apply the PAF that was approved in the 2018 Avoided Cost Case. The Commission approved that PAF in its August 13, 2021, final order in the 2020 Avoided Cost Case ("Sub 167 Order").[6]

After engaging in multiple discussions with the Public Staff regarding this topic, the Company and the Public Staff reached consensus that DENC will use the Weighted Equivalent Unforced Outage Factor ("WEUOF") to determine the PAF. The WEUOF accounts for unit unavailability caused by maintenance and forced outages. The Company also agreed with the Public Staff to use a 5 year average, instead of the previously used 3 year average, to calculate the WEUOF. The Company and the Public Staff also agreed that DENC will have the flexibility to determine the months to be used in the overall PAF

---

[5] Sub 158 Order at Ordering Paragraph 13.
[6] Sub 167 Order at 52.

calculation, and would provide support for use of those months in its Initial Filing. As indicated in its Initial Filing, the Company calculated a PAF of 1.07 using 5 years of history for the months January, February, June, July, and August.

In its initial comments, the Public Staff agrees with DENC's proposed PAF adjustment, stating that it supports the use of the WEUOF metric, which should create a uniform calculation methodology that can be used in the future.[7] The Public Staff notes that the WEUOF is calculated using data from the Generator Availability Data System ("GADS"), which together with its reporting requirements are maintained by the North American Electric Reliability Corporation ("NERC"). At this time, GADS does not require solar generation information reporting, so the Utilities do not report outages from solar generation facilities into GADS, and solar facilities are thus excluded from the WEUOF calculation. The Public Staff states that while solar outage data is currently unlikely to impact the WEUOF and PAF, the Utilities are subject to carbon reduction legislation that explicitly directs them to build or acquire utility-owned solar assets.[8] The Public Staff expects that solar and wind outage data will be increasingly important in future PAF calculations, and recommends that the Commission direct the Utilities to address the inclusion of solar and wind generator outage data in the calculation of the PAF in each utility's next biennial avoided cost filing, including the current status of outage reporting requirements set by NERC.[9]

The Company does not oppose this recommendation, and if the Commission agrees with it, the Company will address the appropriateness of including solar and wind generator

[7] Public Staff Initial Comments at 15.
[8] *Id*. at 16.
[9] *Id*. at 15-16.

outage data in the calculation of the PAF in its initial filing for the next biennial avoided cost proceeding. The Company also does not oppose providing the status of NERC outage reporting requirements in the next biennial avoided cost proceeding, should the Commission find that to be appropriate. When the NERC reporting requirements, outage coding protocols, and any updated WEOUF calculation definitions are known, the Company will best be able to address the appropriateness of including solar outage data in the calculation of its PAF, including whether incorporating such data could be accomplished in a manner consistent with the peaker method.

c. Cost of an Installed CT

In the Sub 158 Order, the Commission directed the Utilities to "evaluate and apply … cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility."[10] The Company engaged in multiple discussions with the Public Staff on this topic throughout 2021. DENC also worked with the Duke Utilities to simplify and increase the transparency of the calculation of CT cost estimates. The common goal of the Utilities' work on this matter was to present CT cost estimates based on agreed-upon inputs such that the inputs may be updated more easily in each biennial avoided cost case as needed, but the underlying methodology for calculating the CT cost estimate would not need to be re-litigated from case to case. The Company's proposed methodology for determining the installed CT cost

[10] Sub 158 Order at Ordering Paragraph 9.

to be used in calculating the avoided capacity rate was therefore based on the consensus reached with the Duke Utilities.

With its Initial Filing, the Company utilized the 2021 EIA Annual Energy Outlook costs for an F-class turbine. The Company did not make any adjustments to the CT equipment costs, but did make adjustments to reflect economies of scale for the cost benefits associated with building four CTs at a single site. The Company's resulting cost breakdown of a new peaker facility supported a 7.5% cost reduction. The Company averaged the 7.5% cost reduction with a reduction of 6.7% estimated by the Duke Utilities, and then rounded the results to a 7.0% reduction. The Company applied the 7.0% reduction to the EIA estimate, and the resulting total cost of the Hypothetical CT (CT equipment costs plus construction and owner costs) is equal to $616/kW.

The Public Staff finds the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates to be reasonable.[11] Specifically, the Public Staff agrees with the Company's approach to evaluate, calculate, and apply an adjustment to the EIA published data and found the Company's 7.0% adjustment to published EIA data to be reasonable.[12] The Joint Intervenors do not comment on the Company's proposed installed CT cost calculation or amount.

SACE argues that the use of an F-class CT to establish avoided capacity cost is outdated and a more appropriate peaking resource would be an aeroderivative gas turbine in the "very near term" and then batteries or 100% green hydrogen-powered turbines

[11] Public Staff Initial Comments at 37.
[12] *Id*. at 14-15, 29.

"shortly thereafter."[13] These resources are not appropriate to use for purposes of determining avoided capacity cost under the peaker method, for several reasons.

First, because the peaker method provides a hypothetical exercise to value capacity, the Company reasonably and appropriately modeled capacity benefit and capacity benefit allocation using an F-class CT. An industrial frame CT is appropriate for use with the peaker method because a higher proportion of its value is derived from the capacity it provides, with less value derived from its other attributes. Aeroderivatives provide additional benefits beyond simple capacity, such as faster start-up times, faster ramping, and higher efficiency. Batteries and green hydrogen also offer benefits beyond pure capacity. These added benefits bring value to energy and ancillary markets and would need to be netted from the avoided capacity cost if any of these resources were used to model capacity for use with the peaker method.

Additionally, a primary driver in considering whether to implement aeroderivative CTs in particular is the need to effectively integrate intermittent resources, like solar, that cause a greater need for quick-start flexible units. The growing use of aeroderivatives by some Southeastern utilities with increasing solar penetration is further evidence of these utilities' need to invest in higher cost resources to manage the intermittency of the distributed solar generation. As SACE references, both TVA and Dominion Energy South Carolina ("DESC") are planning to add aeroderivative CTs to their fleets,[14] and the reason is that both utilities intend for these units to help with the integration of intermittent solar generation. TVA has stated that it expects additional gas-fired aeroderivative CTs to "improve the system's ability to effectively integrate variable renewable resources such as

[13] SACE Initial Comments at 8-13, 37.
[14] *Id*. at 10.

solar and wind,"[15] while DESC has stated that "fast starting and flexible assets" would among other things "support the continued integration of intermittent, non-dispatchable renewable resources such as solar."[16]

However, while more Southeastern utilities are looking to aeroderivative CTs to help with solar integration, that does not mean that aeroderivative CTs should be the basis for avoided capacity cost calculations in North Carolina. SACE cites the approval by the Public Service Commission of South Carolina for DESC to use aeroderivative units as the avoided resource in avoided capacity cost calculations in support of SACE's position that such units should be relied on for avoided capacity cost calculations in North Carolina.[17] DESC operates a system that is very different than DENC in terms of size (in total MW), asset mix, and RTO membership. The Company's system has approximately three times the MW capacity as DESC,[18] and the total MW of generating capacity contained within PJM is much greater. As a percentage of total generation in 2021, DESC has a significantly higher degree of solar penetration than DENC.[19] Finally, DENC enjoys more supply diversity due to being a member of PJM, and thus has not needed to install aeroderivative CTs to date and does not plan to in the near future, as evidenced by the Company's most recent IRP (on which the avoided energy rates in this filing are based). In contrast, DESC's

---

[15] See https://www.tva.com/environment/environmental-stewardship/environmental-reviews/nepadetail/johnsonville-aeroderivative-combustion-turbine-project (cited at fn. 22 of SACE Initial Comments).

[16] *See* Request for "Like Facility" Determinations Pursuant to S.C. Code Ann. § 58-33-110(1) and Waiver of Certain Requirements of Commission Order No. 2007-626, at 7, PSCSC Docket No. 2021-93-E (Mar. 10, 2021) (cited at fn. 20 of SACE Initial Comments).

[17] SACE Initial Comments at 10.

[18] *See* 2020 Integrated Resource Plan of Dominion Energy South Carolina, Inc., at 33, PSCSC Docket No. 2019-226-E (Feb. 28, 2020) ("2020 DESC IRP") (showing 6,507 MW of available summer generating capacity on DESC's system); *see* 2020 Integrated Resource Plan of Virginia Electric and Power Company, at 77, Docket No. E-100, Sub 165 (May 1, 2020) ("2020 IRP") (showing 20,063 MW of available summer generating capacity on DENC's system).

[19] Only 3.48% of DENC's available summer generating capacity is from solar resources compared to 12.7% on DESC's system. *Compare* 2020 DENC IRP at 77, *with* 2020 DESC IRP at 33.

2021 IRP update included aeroderivative CTs, due to their ability to provide "quick-start capacity, load-following capability, and voltage and VAR support that are critically necessary to maintain grid reliability, particularly on a system increasingly supplied by intermittent renewables and short-duration batteries."[20] This strategy is consistent with the testimony provided by the Company in Docket No. E-100, Sub 148 ("2016 Avoided Cost Case"), which cited the faster start-up and ramping capability of aeroderivative CTs as a potential strategy to help address the intermittency of distributed solar generation.[21]

More generally, it would be backward to pay intermittent resources higher capacity rates to account for those resources' creation of the need to add expensive quick-start units to make up for distributed solar resources' intermittency and lack of dispatchability. Such an approach would reward these QFs with the increased capacity costs caused by those same QFs. This is also consistent with the Company's discussion of aeroderivatives in the 2016 Avoided Cost Case, evidenced by DENC testimony that "additional distributed solar generation would not provide capacity value for DNCP because capacity costs are not actually avoided and may actually increase due to the need to add expensive quick-start units to the Company's fleet to make up for distributed solar resources' intermittency and lack of dispatchability."[22] Rather than paying intermittent QFs for capacity based on an aeroderivative CT, it is more appropriate to pay QFs capacity based on an industrial frame CT and then charge the intermittent QF for the need to procure quick-start flexible resources.

---

[20] Integrated Resource Plan 2021 Update of Dominion Energy South Carolina, Inc., PSCSC Docket No. 2021-9-E (Aug. 17, 2021).
[21] Testimony of Witness Bruce E. Petrie on behalf of Dominion Energy North Carolina, Docket No. E-100, Sub 148 (Feb. 21, 2017) (cited by SACE Initial Comments at 11).
[22] *See id.*

Aeroderivative CTs may be needed to integrate high levels of intermittent non-dispatchable resources in the future, though that is not currently the case for DENC. If aeroderivatives are used to value capacity in the future for purposes of these avoided cost proceedings, the energy and ancillary value of the aeroderivative will need to be netted from the avoided capacity cost, as these units are not pure capacity resources. Additionally, if aeroderivatives are used to value capacity in future avoided cost proceedings, the Company will need to reconsider the capacity value seasonal allocations and hours of capacity need according to the forward market projections at that time. This is because a future need for aeroderivatives will be to provide capacity in periods when solar generation is not available, and capacity value and rate design will need to be reevaluated based on forward projections rather than a recent historical lookback.

B. Avoided Energy Cost Issues

a. Fuel Forecast

Regarding the forward commodity prices (for fuels, power, and emission allowances) utilized in calculating avoided energy costs, consistent with past practice, in this proceeding the Company developed the avoided energy cost rates using 18 months of forward market prices, 18 months of blended prices (blend of market and ICF International, Inc. ("ICF") prices), and then ICF prices exclusively starting in month 37 of the forecast period.

The Public Staff does not object to the Company's fuel forecast. Joint Intervenors note that they have previously not objected to the Company's fuel forecast[23] and do not object to the fuel forecast approach in this case.

[23] Joint Intervenors Initial Comments at 19.

SACE states that the Company's approach is a "reasonable [one] for combining forward prices and fundamental forecast components of an overall price forecast in this proceeding," but also argues that the Company should average multiple fundamental price forecasts rather than use the Company's "private, opaquely derived" ICF fundamentals forecast to calculate its natural gas pricing forecast.[24] Specifically, similar to its proposal in the 2020 Avoided Cost Case, SACE argues that the Company should be required to average the Company's ICF fundamentals forecast with the 2021 EIA annual energy outlook reference case.[25]

As stated in the 2020 Avoided Cost Case, DENC's current approach of using the ICF fundamental forecast, on its own, continues to be appropriate for estimating avoided energy cost rates. The Company's use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136), most recently in the Sub 167 Order.[26] ICF forecasts are reputable and respected in the industry and SACE has not presented a convincing reason why continued use of the ICF forecast on its own is not reasonable, particularly given the Commission's consistent decisions accepting that approach.

In addition, SACE's concern about transparency is unfounded. Through both the IRP process and this biennial avoided cost proceeding, the Company has responded to all of SACE's requests, including questions about the ICF forecast.

[24] SACE Initial Comments at 38.
[25] *Id.*; *see also* Joint Initial Comments of the Southern Alliance for Clean Energy, North Carolina Clean Energy Business Alliance, and the North Carolina Sustainable Energy Association, Docket No. E-100, Sub 167 at 2, 18 (Jan. 25, 2021).
[26] Sub 167 Order at Finding of Fact 12.

Moreover, ICF conducts regional forecasts for electricity as well as natural gas and other commodities, which allows the Company to use relevant and correlated forecasts for system modeling purposes. In contrast, using un-correlated forecasts could distort model results. For example, mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, would skew the dispatch and economic value of the Company's natural gas-fired units.

b. Re-Dispatch Charge

In the 2018 Avoided Cost Case, the Company proposed to adjust the avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators. The Commission approved the proposed re-dispatch charge, modified pursuant to the Company's agreement with the Public Staff to be $0.78/MWh.[27] In the 2020 Avoided Cost Case, the Company proposed to continue to apply the $0.78/MWh re-dispatch charge that was approved in the Sub 158 Order for purposes of Schedule 19-FP in the Sub 167 proceeding, which the Commission approved.[28]

With its Initial Filing in this proceeding, the Company updated its proposed re-dispatch charge to accurately reflect the costs of the integration of intermittent, non-dispatchable QFs on its system. In conjunction with the development of its 2021 IRP Update, the Company utilized the Aurora planning model with a simulation topology of the Eastern Interconnection to capture the DOM Zone hourly prices interactively as well as the potential system cost impacts from intermittent resources outside the Company's service territory. This approach represents an improvement over the re-dispatch analysis

[27] Sub 158 Order at 112.
[28] Sub 167 Order at 46.

presented in the 2018 IRP and the 2018 Avoided Cost Case because, as shown below, it models solar generation across a broader geographical region, models the entire eastern interconnect, and performs a more robust simulation.

In the 2021 IRP Update, the Company took a chronological approach to modeling the re-dispatch cost, by utilizing one build plan from the 2020 IRP (Alternative Plan D) and studying 16 years that were chosen based on when resources were introduced or retired in the 2020 IRP Alternative Plan D build plan. For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applied different hourly renewable profiles from NREL's historical weather patterns studies to reoptimize the system cost.

The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, and purchase/sale of energy and power costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation. Based on these results, the Company constructed a generation re-dispatch cost curve for the entire Study Period reflected in the 2021 IRP Update. Compared to the methodology used in the 2018 IRP, the current approach models solar generation across a broader geographical region, models the entire eastern interconnect, and performs a more robust simulation.

The average RDC for the ten years 2022-2031 is $1.87/MWh. The Company proposed to use this value to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP.

The Public Staff generally finds the Company's revised RDC methodology to be an improvement over the methodology approved in the Sub 158 Order and used in the 2020 Avoided Cost Case.[29] The Public Staff states that the prior methodology focused only on a single year and utilized multiple model runs with varying solar output profiles at specific generation sites, to calculate the RDC, whereas the new model calculates the RDC in each future year by calculating the cost difference between "day ahead" and "real time" model runs. The Public Staff notes that the Aurora software models the entire Eastern Interconnection, endogenously calculating the market prices for energy in PJM and the appropriate level and optimal sources of ancillary services.[30]

SACE argues that the Company's RDC methodology is flawed and results in an RDC that does not reflect actual solar integration costs, because the methodology used to determine the RDC does not time-synchronize solar generation with power system data.[31] SACE notes that the historic solar data used to derive the RDC is from 22 locations, only three of which are within North Carolina.[32] SACE also claims that the increase in the RDC is "based at least in part on an error," because the level of uncertainty about re-dispatch should decrease due to "geographic smoothing" and the Company should have captured this effect by modeling the potential system cost impacts from intermittent resources

[29] Public Staff Initial Comments at 49-50.
[30] *Id*.
[31] SACE Initial Comments at 38. Joint Intervenors also appear to support SACE's arguments with respect to the Company's RDC. *See* Joint Intervenor Comments at 25.
[32] SACE Initial Comments at 38-39.

outside its service territory. SACE states that if the Company "interpreted the effect of geographic diversity to be to cause increased costs then modeling the broader region could have exacerbated the error."[33] SACE recommends that the Commission require DENC to recalculate the RDC using a methodology that accurately captures the system costs, if any, imposed by solar generation.[34]

The Company considers the RDC methodology to be a reasonable approximation of the re-dispatch costs that result from increased intermittent renewables on its system. SACE's critiques of the methodology overstate the relationship between solar generation output and system load, mischaracterize the impact of using a narrower geographic selection of locations, and appear to mistakenly assert that the Company applied assumptions about geographic diversity within the Aurora model, when it did not.

First, while there is some relationship between cloud cover and load, cloud cover is not the primary driver of load forecast error. The Company acknowledges that during real world system operations, if both load and renewable generation are lower than expected in a given time period, then the resultant re-dispatch charges would be lower than a situation where only the renewable generation was lower than expected, all else equal. However, load forecast error and solar generation forecast error are not perfectly correlated, and at times, they may have a negative relationship. For example, if during real world system operations load is higher than expected and renewable generation is lower than expected in a given time period, then the resultant re-dispatch charges would be greater than a situation where only the renewable generation was lower than expected, all

[33] *Id*. at 39.
[34] *Id*. at 40-41.

else equal. This could happen in the winter when cloud cover increases heating and lighting demand while also reducing solar generation output.

With regard to the modeled locations, the Company modeled 22 locations across a broad geographic region to represent the entire PJM RTO Balancing Authority. Including three locations in North Carolina is appropriate, as the DENC service territory is geographically compact. The addition of more locations within North Carolina would not have significant impacts on the model results.

Finally, the Company's statement that "[a]s more and more intermittent generation like solar PV or wind is added to the grid, the level of uncertainty about re-dispatch costs increases due to unpredictable cloud cover or changes in wind speed" referred to increased levels of intermittent generation and increased concentrations of intermittent generation, which can be expected to increase uncertainty. The Company was not commenting on geographic smoothing. The Company does not expect geographic diversity to increase re-dispatch cost, and did not "interpret[] the effect of geographic diversity to be to cause increased costs" or configure the model to increase costs due to geographic diversity. The Company simply modeled the units and load on its system without applying any inputs regarding diversity at all, and any benefits due to diversity would have showed up as an output of the model.

c. RDC Avoidance Protocol

In the Sub 158 Order, the Commission directed the Company to file a proposed protocol for avoidance of the re-dispatch charge.[35] In its initial filing in the 2020 Avoided Cost Proceeding, DENC proposed that the RDC can be reduced to the extent the QF

[35] Sub 158 Order at 113.

reduces the variability of its output through the use of an energy storage device ("ESD").[36] The output for the case without storage would be the actual metered output of the facility excluding the impact of storage. The output for the case with storage would be the actual metered output for the facility including the impact of storage. Determining the impact of storage would require that the storage device is separately metered.

For each case, on a calendar year basis, the Company proposed to calculate variability as the sum of the hourly absolute output variance from a QF-provided generation forecast. The percent reduction in variability would be calculated by subtracting the ratio of the variability of the case with storage to the variability of the case without storage from one. DENC would then calculate a credit to the RDC as follows: (1) the percent reduction multiplied by (2) the RDC rate multiplied by (3) the total calendar year output (MWh) of the case with storage. To be eligible for the RDC reduction, a QF must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date ("COD"). For subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract; if no updated forecast is provided, DENC would utilize the previously provided forecast to calculate the RDC reduction credit. Every April, DENC would calculate the RDC reduction using the prior calendar year forecast and metered data. DENC would provide the RDC reduction as a line item credit with the first payment following the April calculation. The Public Staff stated that it did not object to the protocol as proposed and that the proposal protocol is reasonable largely because the Company's QF load reduction

[36] DENC Initial Statement and Exhibits at 10-12, Docket No. E-100, Sub 167 (Nov. 2, 2020).

estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a controlled solar generator ("CSG") consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account.[37] The Public Staff recommended that DENC monitor the types of forecasts and the ESD dispatch behavior for CSGs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory, in its future avoided cost filings.[38]

In the Sub 167 Order, the Commission approved the Company's RDC Avoidance Protocol, and concluded that "if any CSGs seek to avail themselves of the RDC avoidance protocol, the information that the Public Staff requests DENC to monitor and provide may be helpful for purposes of evaluating the results of the protocol in the future."[39] The Commission encouraged DENC and the Public Staff to continue to discuss the information requested by the Public Staff with regard to the RDC avoidance and, to the extent appropriate, for the Company to address the proposed monitoring and reporting of this information in its Initial Filing in this case.[40] For purposes of this proceeding, the Company maintained the same RDC avoidance protocol that it proposed and the Commission approved in the Sub 167 case. The Company noted with respect to the proposed monitoring and reporting of CSG information that no CSGs have asked to use the RDC protocol.[41]

The Public Staff does not object to the RDC avoidance protocol, and again recommends that the Commission direct the Company to file a report on the "types of

---

[37] Public Staff Sub 167 Comments at 34.
[38] *Id*. at 37.
[39] Sub 167 Order at 48.
[40] *Id*.
[41] DENC Initial Filing at 17-18.

forecasts and the [energy storage device ("ESD")] dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs in DENC's service territory in its future avoided cost filings."[42] Additionally, the Public Staff again recommends that the Commission direct the Company to "specifically address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC."[43]

Consistent with the Company's previous statements, if the Commission adopts the Public Staff's recommendation, then if any CSGs do seek to avail themselves of the RDC protocol, the Company will monitor the information requested by the Public Staff and will report on that information in a future biennial avoided cost proceeding and fuel rider cases, as appropriate.

While it did not address the RDC avoidance protocol in the Sub 167 case, in this proceeding SACE objects to the protocol's annual output forecast requirement. SACE complains that no other type of resource is required or capable of such a forecast. SACE also argues that the annual forecast will become outdated, and that the consistency of a solar QF's actual generation over the course of a year with such a projection is not directly relevant to variability or volatility of solar output or any resulting re-dispatch the solar generator may cause.[44] SACE recommends that the Commission "require Dominion to adopt an RDC avoidance protocol that accurately reflects the solar QF's avoidance of the

---

[42] Public Staff Initial Comments at 50-51.
[43] *Id*. at 51.
[44] SACE Initial Comments at 39-40.

system costs, if any, imposed by solar generation," and requests that the Commission consider requiring review of DENC's compliance with SACE's RDC and RDC avoidance protocol recommendations by an independent technical review committee.[45]

SACE's recommendations are not justified, because they ignore the purpose of the protocol as being a proxy for variability reduction achieved with an electric storage system, and because the annual forecast is in the Company's view the lowest burden approach to achieving that proxy.

First, with respect to SACE's concern that other types of QFs are not required to provide the forecast required by the protocol, the purpose of the RDC is to account for the increased cost to dispatch the Company's system due to the addition of intermittent distributed solar generation QFs,[46] and the purpose of the protocol is to permit solar generation QFs that want to avoid the RDC through an ESD to do so. Therefore, solar generation QFs are the only facilities that must provide this forecast because they are the only facilities that impose the re-dispatch costs on the system.

Additionally, no QF is required to guarantee its hourly output over a year or more in advance. The RDC avoidance protocol is made available to intermittent QFs that choose to use electric storage systems to reduce their RDC charge. The premise of the protocol is that the QF will use an electric storage system to manage the output of the facility, not that the QF will provide a perfect forecast. The protocol is designed to allow for a proportional reduction of the RDC and does not require perfect execution.

---

[45] *Id*. at 40-41. Joint Intervenors also supported this recommendation. *See* Joint Intervenors Initial Comments at 4-17.
[46] Sub 158 Order at 112 ("DENC has proposed an adjustment to its rates to account for the characteristics of intermittent, non-dispatchable QFs.").

A year-ahead forecast allows a QF to account for the movement of the sun, the design of the QF facility, and some level of expected seasonal cloud cover. The Company expects a year-ahead forecast to be a smooth profile. The Company considered the deviation from this profile to be more reasonable than deviation from an observed mean, such as average hourly generation across a year, average hourly generation by month, average hourly generation by hour of day, or average hourly generation by hour of day by month. All of these measures of deviation to a mean or expected value would be measures of variability, but the Company considered the variability relative to the QF-provided profile (in the form of a year-ahead forecast) to be the most reasonable low-burden method to use to calculate a proxy for variability reduction achieved with an electric storage system.

While a day ahead forecast could conceivably be used, it would also be significantly more burdensome than a single annual profile, to the Company and, DENC believes, to the QF. Under a day ahead approach, a QF would need to provide, and the Company would need to verify receipt of, an hourly forecast every day at least 24 hours in advance of the beginning of the day. To protect customer interests and prevent gaming, failure to provide a forecast would by necessity nullify the protocol for the year. The work to implement, monitor, and address disputes regarding such a process would consume an unreasonable amount of DENC's time and personnel resources. An hour-ahead forecast would be even more excessively burdensome and would not be appropriate for implementing the redispatch charge, which is based on redispatch between the day ahead market and real time operations. The Company has seen no evidence that indicates that providing an annual hourly generation profile would be burdensome for a QF, and expects that the information necessary to construct such a profile is typically available as part of the development of a solar facility.

With regard to the "age" of the forecast, the Company considered the QF-provided forecast to be a proxy for a smooth profile, as the QF was in the best position to provide that profile. Considered as a smooth profile, the age of the forecast is not relevant unless new information about the movement of the sun, the design of the facility, or seasonal cloud cover becomes available.

The Company opposes SACE's recommendations that the Company be required to adopt a modified RDC avoidance protocol consistent with SACE's preferences and for an independent technical review committee with stakeholder input to "verify that [the Company's] subsequent filing meets" SACE's demands. These recommendations are unnecessary due to the appropriateness of the RDC avoidance protocol as discussed above, and an independent technical review committee would only impose additional costs on customers without any clear benefit.

C. Retrofit Storage

In its *Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations* issued on August 17, 2021, in Docket No. E-100, Sub 158 ("Retrofit Storage Order"), the Commission made several rulings on the Retrofit Storage Stakeholder Group report DENC filed jointly with the Duke Utilities in that docket in September 2020. As relevant to DENC, the Commission concluded that: (1) a new CPCN is not required for the addition of storage to an existing generating facility, but the facility must file with the Commission written notice of the amendment to either the applicable CPCN or the report of proposed construction consistent with Commission Rules

R8-64 and R8-65; (2) the addition of energy storage to an existing generating facility requires an amendment to the existing PPA and does not require execution of a new PPA; and (3) the term for retrofit energy storage shall be the same as the term that remains on the PPA for the facility.[47]

The Commission also directed the parties to address the procedure for how and the point in time at which a facility secures eligibility for a specific avoided cost rate or methodology when adding energy storage.[48] As explained in its Initial Filing, in DENC's view, a QF that desires to incorporate energy storage to an existing facility, the output of which the QF has committed to sell to the Company, would submit to the Company a new LEO Form reflecting the retrofitted facility, and the avoided cost rate and methodology that are current at the time the QF submits the LEO Form would apply to the retrofit storage component. The Company proposed new LEO Forms specific to retrofit storage additions to be available to QFs seeking to establish LEOs for such projects. No parties commented on the Company's new proposed Retrofit Storage LEO Forms[49] and the Company requests that the Commission find these forms to be reasonable for use by QFs seeking to add retrofit storage to their facilities.

D. Ancillary Services

In its initial comments, the Public Staff suggests that the Commission, Public Staff, intervenors, and customers would benefit from a more detailed understanding of the technical ability of utilities to procure ancillary services from inverter-based resources

[47] Retrofit Storage Order at 7-8, 10-11.
[48] *Id*. at 10.
[49] Public Staff stated that the Company's "non-storage" LEO forms, updated for consistency with FERC Order No. 872, are appropriate (Public Staff Initial Comments at 56) but did not specifically address the new Retrofit Storage LEO Forms. Public Staff subsequently confirmed with the Company that it does not object to the Company's Retrofit Storage LEO Forms.

(“IBR”) and the associated costs. The Public Staff solicits feedback from the Utilities and other intervenors on the potential benefit of initiating a proceeding to investigate this matter and potentially establish a pilot program to procure a small amount of ancillary services from IBRs, either through the establishment of a limited competitive solicitation from QFs, or a pilot program at one of the Company’s or the Duke Utilities’ owned solar sites.[50] The Public Staff notes that PURPA’s mandatory purchase obligation does not extend to ancillary services, although it also does not prohibit the procurement of ancillary services from QFs, and identifies spinning reserve, frequency regulation, and Volt-VAR support as the ancillary services “best suited to come from IBRs” based on its discussions with renewable energy developers.[51]

As an initial matter, in addition to not requiring utilities to purchase ancillary services from QFs, PURPA also does not require utilities to provide QFs with access to ancillary services markets. With respect to PJM, access to spinning reserves, frequency control, and voltage support (reactive power) ancillary compensation is available to QFs through direct market participation, but DENC is not required to achieve market participation on behalf of or for a QF.

Aside from the likely significant challenges and real limitations to the technical ability of QFs to provide meaningful ancillary services benefits, which alone may make including ancillary services in avoided cost rates or initiating a pilot inappropriate, for a utility such as DENC that participates in PJM, cost allocation issues make the inclusion of ancillary services in avoided cost rates truly infeasible. Ancillary services should not be

[50] Public Staff Initial Comments at 19. SACE and the Joint Intervenors made similar proposals for stakeholder processes or pilot projects, though it is not clear if those comments were directed at the Duke Utilities only. SACE Initial Comments at 31; Joint Intervenors Initial Comments at 17.
[51] Public Staff Initial Comments at 17-18.

part of the Company's avoided cost rates because the Company's customers already pay for these ancillary services obtained by PJM, and the PJM market structure does not allow for DENC's customers to avoid any ancillary costs due to a QF providing an ancillary service, even assuming that the QF had the technical ability to provide the service. Requiring payment for any ancillary services that a QF was able to provide would therefore contradict the fundamental principle of PURPA that the utility cannot be required to pay more than its avoided cost for QF output.[52]

With regard to spinning reserves specifically, PJM is obligated to maintain a certain quantity of total ten (10) minute reserves on the system, including a subset of reserves that are synchronized to the system (Synchronized Reserves). PJM provides market participants with a market-based system for the purchase and sale of the Synchronized Reserve ancillary service. To participate in the reserve market, a unit must be a PJM market participant, located in front of the PJM meter, that provides offers in Day Ahead and Real Time.[53] Any resources that do not participate in the PJM market cannot contribute to PJM's reserve requirement and do not reduce the amount of reserves that PJM must procure, and therefore do not reduce the cost of reserves to customers. It is not appropriate for customers to compensate QFs for reserves in an avoided cost rate when the QF does not avoid any reserve cost for the customers. Similarly, there would be no benefit to customers for the Company to host a pilot for ancillary reserves when QFs cannot participate in the PJM reserve market and cannot provide an avoided reserve cost benefit to customers.

[52] 16 U.S.C. § 824a-3(d); 18 C.F.R. § 292.304(a)(2).
[53] See PJM Manual 11: Energy and Ancillary Services Market Operations (Mar. 1, 2022) ("PJM Manual 11") at Section 4.1 (https://www.pjm.com/~/media/documents/manuals/m11.ashx).

It is also not appropriate for the Company to pay QFs for frequency control or for the Company to pursue a pilot for frequency control. Frequency control in DENC's service territory is managed by PJM, and for a facility to receive market-based compensation for frequency control, it must be a PJM market participant. PJM sends a bi-directional signal for frequency control to market participants for each unit, evaluates each facility's performance, and provides compensation for the service provided. The market is managed by PJM, not the Company, and as with spinning reserves is limited to facilities that are "in front of the meter" from PJM's perspective.[54] The Company has no mechanism to administer a frequency control market and compensate behind-the-meter facilities for this service, assuming a QF could provide it. If a QF were able provide any level of frequency control, the physical benefit would be socialized across PJM, but the PJM market structure would provide no compensation to the Company and its customers in exchange for the benefit.

With regard to reactive power versus real power, PJM provides two channels of cost compensation. The first is that in PJM, on an energy basis, if a unit must lower its real power output to produce reactive power, it is compensated at a "lost opportunity" level, which is essentially the same locational marginal price (LMP) that the generator is paid for its real power. In that way, the generator does not lose any revenue while producing reactive power in lieu of real power.[55] PJM therefore does not pay a premium above the energy price for units that provide reactive power. Likewise it would not be appropriate, and would violate the avoided cost principle, for the Company to pay a premium over the

[54] See PJM Manual 11 at Section 3.1.
[55] See PJM Manual 28: Operating Agreement Accounting (Sept. 1, 2021) at Section 5.2.8 (https://www.pjm.com/-/media/documents/manuals/m28.ashx).

energy cost for any reactive support provided by a QF, even assuming the QF had the technical ability to provide such support.

The second channel for reactive cost compensation is a cost of service filing with FERC for the recovery of generator plant costs associated with providing reactive capability. In short, a generator files with FERC a request for compensation for the calculated carrying cost of reactive-capable components. Once approved by FERC, PJM will accept the findings and pay the generator for this capability and charge the PJM zonal load-serving entities ("LSEs") in the PJM zone where the generator resides accordingly.[56] A stand-alone facility that is not part of the DENC fleet and is a member of PJM may pursue an independent reactive cost recovery filing at FERC and the cost would be allocated across all customers in DOM Zone. Conversely, requiring the Company to pay a QF for reactive capability under PURPA, again assuming the QF had the technical ability to provide the service, would cause the Company's customers to bear the full cost of that payment while other PJM members in DOM Zone would benefit but not be allocated any portion of the cost. There is currently considerable resistance among PJM LSEs to providing this reactive capability compensation to distribution-connected resources as the real impact is minimal. In fact, the reactive power cost recovery structure may be changing in the near term as there are initiatives at both FERC and PJM to review the structure.[57] Additionally, there is concern that generators may be compensated twice for the same plant

---

[56] See PJM Open Access Transmission Tariff, Schedule 2 (https://agreements.pjm.com/oatt/3897).
[57] FERC has published a Notice of Inquiry regarding reactive power capability compensation, which seeks comment on various aspects of American Electric Power methodology-based compensation; potential alternative methodologies; and reactive power capability compensation through transmission rates for resources that interconnect at the distribution level. *See Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021). PJM has formed the Reactive Power Compensation Task Force (RPCTF), which will evaluate the standards for the provision of reactive service and the mechanism that provides for the opportunity to be compensated for reactive service (PJM - Reactive Power Compensation Task Force). *See* www.pjm.com/committees-and-groups/task-forces/rpctf.

capability if they receive payment for capacity in the PJM capacity market as well as reactive services.[58]

Based on the foregoing, it is not appropriate at this time to devote the time and resources of a separate proceeding to investigate utility compensation of QFs for ancillary services, or to establish a pilot program at a Company owned solar generation facility. In addition to technical and cost recovery considerations discussed above for specific ancillary services, due to the Company's participation in PJM, customers would not see the full benefit of any ancillary services that a QF was able to provide, if it could provide them, but would bear the full cost of such services. Such a result would contradict the prohibition on utilities paying more than avoided cost for QF purchases and should not be pursued.

III. CONCLUSION

WHEREFORE, Dominion Energy North Carolina respectfully requests that the Commission accept these Reply Comments and issue an order accepting the Company's Initial Filing, as modified by the Corrected Capacity Rates and as discussed herein, and making such other determinations as are necessary and proper.

Respectfully submitted,

DOMINION ENERGY NORTH CAROLINA

By: *<u>/s/ Andrea R. Kells</u>*

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

[58] *See generally* FERC Docket No. RM22-2-000.

Andrea R. Kells
Nick A. Dantonio
McGuireWoods LLP
501 Fayetteville Street, Suite 500
P.O. Box 27507 (27611)
Raleigh, North Carolina 27601
(919) 755-6573 (ARK phone)
(919) 755-6605 (NAD phone)
akells@mcguirewoods.com
ndantonio@mcguirewoods.com

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

April 1, 2022

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina's *Reply Comments*, filed in Docket No. E-100, Sub 175, were served electronically or via U.S. mail, first-class postage prepaid, upon all parties of record.

This the 1st day of April, 2022.

/s/Andrea R. Kells

Andrea R. Kells
McGuireWoods LLP
501 Fayetteville Street, Suite 500
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