BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**[PUBLIC]**
Rates for Electric Utility Purchases from	)	**NCSEA'S INITIAL**
Qualifying Facilities – 2018	)	**COMMENTS**

NCSEA'S INITIAL COMMENTS

I. <u>INTRODUCTION</u>

In its October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 148 ("*Sub 148 Order*"), the North Carolina Utilities Commission ("Commission") made significant changes to North Carolina's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), 18 U.S.C.A 824a-3. These changes were driven partially by the passage of H.B. 589, N.C. Gen. Assem., 2017 Reg. Sess., S.L. 2017-192 (N.C. 2017) ("HB 589"), and partially by the Commission's conclusion that changes to the "economic and regulatory circumstances facing qualified facilities ("QFs") and utilities in North Carolina" necessitated changes to the regulatory regime for PURPA projects in North Carolina.[1] These changes included, but were not limited to, lowering the threshold for standard-offer rates to 1 MW (with a maximum of 100 MW of project eligible); lowering the length of standard-offer contracts to 10 years; approving an 80/20% winter/summer capacity weighting; and reducing the performance adjustment factor for most QFs to 1.05.[2]

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[1] *Sub 148 Order* at 15.
[2] *See generally*, *Sub 148 Order*.

Despite making these changes, the Commission did not conclude that it would be appropriate to block all further PURPA development in the state, which would not be lawful under PURPA or consistent with Congress's intent in promoting QF development. Notably, the Commission agreed with NCSEA's witness Dr. Ben Johnson that

> in implementing PURPA, the Commission should not "slam on the brakes" in establishing rules for the development of QF resources. Rather, as the Commission's policies have resulted in North Carolina cresting the hill, it now is appropriate to moderately ease off on the regulatory accelerator and depend in part on momentum created so as to moderate the financial impact on electric rate payers.[3]

It is clear, however, that the utilities participating in this docket have no interest in further QF development of QF resources, but instead seek to shut down further QF development and also to undermine the continued economic viability of existing QFs. Rather than afford time to let the adjustments made in HB 589 and the *Sub 148 Order* play out, the utilities seek to halt independent, statutorily-mandated renewable energy[4] in the form of QF development by driving avoided energy and capacity rates so low as to make QF development financially infeasible.

As will be discussed below, the utilities' arguments constricting independent QF development are premised on several faulty assumptions, including that: (1) solar QF development in North Carolina has continued unabated even since issuance of the *Sub 148 Order*; (2) the recent trend in declining natural gas prices will continue indefinitely, such that long-term fixed-price energy contracts will never be in the interest of ratepayers; (3) increased solar generation

[3] *Sub 148 Order* at 15-16.
[4] *See* N.C. Gen. Stat. § 62-2(a)(5) and N.C. Gen. Stat. § 62-2(a)(10).

will inevitably cause costly and intractable "operational challenges"; and (4) it is incumbent on this Commission to protect ratepayers from a "distorted marketplace" for solar QF development by approving further reductions to avoided cost rates, thus providing "improved price signals" that will further discourage QF development.

NCSEA submits that these assumptions are all false, and that the far-reaching policy changes wrought by HB 589 and the *Sub 148 Order* should be given time to take effect.[5] In the meantime, the Commission should scrutinize the utilities' cost calculations closely, and not allow the practical cessation of QF development in North Carolina.

II. PROCEDURAL BACKGROUND

A. COMMISSION ORDERS AND PRIOR AVOIDED COST PROCEEDING ISSUE HOLDOVER

On June 26, 2018, in the above-captioned docket, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("*Order Establishing Biennial Proceeding*"), subsequently amended by orders dated January 4, 2019, January 25, 2019, and February 8, 2019, pursuant to the provisions of Section 210 of PURPA and the regulations of the Federal Energy Regulatory Commission ("FERC"), initiating the 2018 biennial proceeding to set avoided cost rates. The Order made Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively,

[5] It bears noting that the implementation of the two major policy components of H.B. 589 geared towards utility-scale solar – the Green Source Advantage Program and the Competitive Procurement of Renewable Energy ("CPRE") – is still ongoing. The results of the CPRE Tranche 1 have not been finalized yet, and notwithstanding the Commission's February 1 Order in Docket Nos. E-2, Sub 1170 and E-7, Sub 1169, a final Green Source Advantage Program has yet to be approved.

"Duke"), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina ("Dominion," "DNCP," or "DENC") (DEC, DEP, and DENC, collectively, the "Utilities"), Western Carolina University ("WCU"), and Appalachian State University, d/b/a, New River Light and Power Company ("New River") parties to the proceedings.

In its *Order Establishing Biennial Proceeding*, the Commission pointed out that in its October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 148 (the "*Sub 148 Order*") it had ordered DEC, DEP, and Dominion to address:

> (1) A continued evaluation of capacity benefits of qualified facility ("QF") generation;
> (2) whether the utilization of a 2.0 Performance Adjustment Factor ("PAF") as approved in the Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and NC Hydro Group ("Hydro Stipulation") should continue as provided in that agreement;
> (3) the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations;
> (4) hourly combustion turbine ("CT") operational data and marginal cost data on a season-specific basis; and
> (5) consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable.[6]

With respect to a rate design considering the characteristics of power supplied by a QF, the Commission in the *Order Establishing Biennial Proceeding* stated that it expected "DEC, DEP, and Dominion to file [in their 2018 Avoided Cost initial statements] proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more

[6] *Order Establishing Biennial Proceeding*, p. 1.

granularity than the current Option A and Option B rate schedules."[7] The Commission also stated in the *Order Establishing Biennial Proceeding* that it will:

> attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony.[8]

The Commission revisited and restated this position in its January 25, 2019 *Order on Procedural Schedule and Requiring Report* ("*January 25th Order*"),[9] wherein the Chairman indicated that he would extend the deadline for the filing of reply comments and, also, suspend the deadline for the filing of proposed orders pending the determination by the Commission as to whether an expert hearing should be scheduled in this proceeding and the scope of issues to be heard at any such expert hearing. Further, the Commission required Duke to confer with all the parties in the proceeding on or before March 8, 2019 and provide a report to the Commission summarizing the subjects at issue in this proceeding including, specifically, which issues are still in controversy and have sufficient merit to be considered at an evidentiary hearing.

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[7] *Order Establishing Biennial Proceeding*, pp. 1-2.

[8] *Order Establishing Biennial Proceeding*, p. 1.

[9] The *January 25th Order* originated from Duke's request for an evidentiary hearing made on page 2 of the *Duke Energy Carolinas, LLC and Duke Energy Progress LLC's Joint Initial Statement and Exhibits* ("*Joint Initial Statement*") wherein Duke requested an evidentiary hearing on "discrete issues". The North Carolina – Public Staff ("Public Staff") then filed the *Public Staff Motion for Extension and Modified Procedural Schedule* ("*Public Staff Procedural Motion*") regarding Duke's request for an evidentiary hearing on December 31, 2018. Then, on January 4, 2019, the North Carolina Sustainable Energy Association ("NCSEA") filed its *Response to Public Staff's Motion for Extension and Revised Procedural Schedule and NCSEA's Motion for Modified Procedural Order on Testimony* ("*NCSEA's Response and Motion*"), to which Duke then filed *Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Joint Response to NCSEA's Response* on January 10, 2019. The *January 25th Order* was issued by the Commission in response to these filings.

B. <u>THE UTILITIES' FILINGS</u>

On November 1, 2018, Duke filed its *Joint Initial Statement* pursuant to the *Order Establishing Biennial Proceeding*.[10] In their cover letter prefacing the *Joint Initial Statement*, Duke summarizes:

> [Duke's] avoided cost rates have decreased approximately 20 percent for DEC customers and 8 percent for DEP customers from those avoided cost rates approved in the 2016 avoided cost proceeding. These decreases in the Companies' future avoided costs are driven primarily by the decrease in natural gas prices. Natural gas prices have declined approximately 16 percent since the Companies' 2016 avoided cost filing. Another contributing factor is DEP's nearer-term need for avoidable new generation or purchased capacity in 2020 versus DEC's next avoidable need in 2028. Put simply, the Companies' costs to produce power are declining due to their efficient generation fleets and lower natural gas prices, and this decline is reflected in the avoided cost rates filed in this docket.[11]

On November 1, 2018, Dominion filed the *Initial Statement and Exhibits of Dominion Energy North Carolina* ("*Dominion's Initial Statement*") pursuant to the *Order Establishing Biennial Proceeding*.[12] *Dominion's Initial Statement* provided a summary of the filing as follows:

> With this filing, [Dominion] is making proposals to (1) adjust its methodology for calculating avoided energy rates to account for re-dispatch costs associated with the avoided capacity payments to reflect the intermittent nature of these resources, addition of distributed intermittent generation to its system, (2) establish a cap on annual (3) offer more granular hours and seasons for avoided cost rates and adjust the seasonal allocation factors relevant to avoided capacity rates accordingly, to recognize winter, summer, and "shoulder" seasons, and (4) adjust the PAF applicable to avoided capacity payments to 1.07. Consistent with the Commission's directives, the Company also provides updates with regard to the increased backflow occurring on its system from distributed renewable QFs, hourly operational and marginal cost data of combustion turbines, the adjustment to avoided energy rates to

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[10] *Joint Initial Statement*, p. 1.
[11] *Joint Initial Statement*, Cover Letter, p. 1, Docket No. E-100, Sub 158 (November 1, 2018).
[12] *Dominion's Initial Statement*, p. 1.

reflect the locational value of generation in its North Carolina service area as approved in the 2016 Avoided Cost Case, and responds to the Commission's other directives contained in the Procedural Order.[13]

In light of the foregoing, the North Carolina Sustainable Energy Association ("NCSEA"), having become a party to this proceeding pursuant to the *Order Granting Petition to Intervene* issued by the Commission on August 9, 2018, by and through undersigned counsel, respectfully submits these initial comments.

II. Initial Comments

A. The Utilities' Initial Statements Highlight a Bias Towards Utility-Owned Generation and Against Qualifying Facilities

DEC, DEP, and DENC are for-profit, investor-owned, vertically-integrated utilities. Their focus is on creating value for their shareholders while providing affordable, reliable service for their ratepayers. QFs are in direct competition to the Utilities' business model. Put simply, "PURPA allows renewable energy projects to compete directly with the primary portion of the Utilities' business that does make money – building rate base."[14] The investor-owned utility's business objective has been threatened in North Carolina, where PURPA has successfully encouraged investments by small firms, and to the benefit of ratepayers, that compete against the Utilities' monopoly power.[15] While PURPA and the rules adopted by the FERC to implement it attempt to hold the Utilities' bias in check, they do not eliminate the bias altogether. Thus, the biennial avoided cost

[13] *Dominion's Initial Statement*, p. 5.
[14] *Testimony of Jay Lucas*, p. 8, ll. 12-16, Docket No. E-100, Sub 101 (November 19, 2018).
[15] *Affidavit of Dr. Ben Johnson*, para. 12, included as **Attachment 1**.

proceedings and the accompanying intervenor and Commission-based scrutiny, are necessary to ensure that the Utilities' bias towards their business objective to build their rate base does not compromise the Utilities' legal obligations under PURPA to enter into PPAs at fair rates with QFs and to allow interconnection to the Utilities' grids. Due to the Commission's thoughtful, forward-thinking implementation of PURPA and the FERC rules over the years, the Commission has been able to keep the Utilities' bias in check, and has led to North Carolina becoming the national leader in QF development. As the QF industry has grown in North Carolina, the projected costs to ratepayers of complying with the Renewable Energy and Energy Efficiency Portfolio Standard have decreased dramatically. The proposals made in the Utilities' respective initial statements strongly reflect this bias, as set forth below, and the Commission must again be called upon to ensure that the Utilities' proposals comply with the legal requirements of PURPA.

This proceeding is the latest battle in the war by North Carolina's investor-owned utilities to preserve their outmoded, unjustified, and uneconomic monopoly control of competition from independent generation. Furthermore, the Utilities are attempting to use this proceeding to circumvent Congress' express intent in adopting PURPA: to place a check on monopolies by creating an opportunity for independent power producers to compete with the Utilities. In this proceeding, and in previous biennial avoided cost proceedings, the Utilities have presented inaccurate, incomplete, and misleading information in an effort to make it impossible for QFs to exercise their legal right to receive fair compensation for the value they provide the electric grid. In the crossfire, the Utilities ignore the fact that

QFs reduce the rate-based expenditures that are passed on to ratepayers and contribute to meeting the State's generation needs in a reliable and cost-effective manner – and with substantially less risk to ratepayers than utility self-built generation. The Commission should reject the Utilities' assault on PURPA, and should instead encourage innovation that can increase the reliability of the electric grid and lower costs to ratepayers by encouraging competition by independent power producers in the electric generation market.

It is important to note that while Duke claims that its "costs to produce power are declining due to their efficient generation fleets and lower natural gas prices,"[16] it is also moving these natural gas generation assets into rate-base and seeking to recover the costs from ratepayers.[17] This statement also ignores the efforts of Duke to invest as much as $13 billion of its own capital in North Carolina, rather than exploring how QFs can contribute to a modernized and more cost-efficient electric grid.[18]

B. AVOIDED COST RATES

Throughout their respective initial filings, the Utilities have made numerous, transparent attempts to artificially, and wrongfully decrease the avoided cost rates paid to QFs. NCSEA's review of *Dominion's Initial Statement* and Duke's *Joint Initial Statement* reveal that the Utilities' methods for calculating

[16] *Joint Initial Statement*, Cover Letter, p. 1.
[17] In addition to the recently-completed DEC and DEP general rate cases, in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142 respectively, both DEC and DEP are planning multiple rate cases between 2019 and 2022. *See generally*, *Duke Energy Winter Update 2019*, Slide 13, available at https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed February 11, 2019).
[18] *See generally*, Docket No. E-7, Sub 1146. See also, *Duke Energy Winter Update 2019*, Slide 7, available at https://www.duke-energy.com/_/media/pdfs/our-company/investors/winter-2019-ir-update.pdf?la=en (last accessed February 11, 2019).

avoided capacity costs and avoided energy costs are based upon faulty assumptions and studies, and ultimately underestimate the amount that QFs should be paid for their energy and the value that their capacity provides to the Utilities' grid. As set forth below, the Utilities' calculations should be rejected on that basis.

1. AVOIDED CAPACITY COSTS

Because Duke projected a capacity need in its 2018 integrated resource plan, it identified capacity need to be avoided in its *Joint Initial Statement*. Specifically Duke claims that "DEC's next avoidable capacity need is a planned 460 MW (winter rating) of combustion turbine unit ('CT') capacity in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020."[19] As set forth below, however, NCSEA disagrees with Duke's assertion that its 2018 IRPs "precisely recognize the capacity value associated with incremental non-dispatchable solar capacity additions" and, therefore, NCSEA requests that Commission reject Duke's assertions and instead consider NCSEA's position on capacity needs and values.

i. Existing QFs in the Generation Stack

It is undisputed that Duke currently has QFs with active PPAs in its existing generation stack. However, in their 2018 integrated resource plans, DEC and DEP assume that a QF will continue providing capacity in DEC and DEP's respective generation stacks even after the expiration of the QF's PPA.[20] While it is likely that these QFs will continue to provide capacity to the Utilities, they should not be

[19] *Joint Initial Statement*, p. 13.
[20] Attachment 1, para. 156.

forced to do so without compensation for the value that they provide. If these QFs were to stop providing capacity to the Utilities, then the Utilities would be forced to procure some other source of capacity, which would be paid for by ratepayers. Existing QFs that are already in the Utilities' generation stack reduce future capacity needs, and as such, when they renew their PPA or enter into a new PPA, existing QFs should continue to be paid for the capacity that they provide. In the unlikely event that they are unable to provide such capacity, an additional capacity need would exist that, if met by new QFs, should entitle them to payment for capacity.

ii. DEC's Capacity Needs

DEC has concluded that it has no avoidable capacity need prior to 2028.[21] However, DEC's 2018 IRP shows a 30 MW short-term market capacity purchase in 2020,[22] and uprates at existing units scheduled for 2021, 2022, 2023, 2024, and 2025.[23] Market purchases of power and uprates at existing generation units should all be relevant in determining an avoidable capacity need.[24] Duke has not shown whether or not these capacity expansions can be met by small power producers, much less what type of small power producers.[25]

iii. Timing of Energization

The Utilities' avoided capacity calculations include unrealistic assumptions about when QFs will begin providing capacity. DENC assumes that QFs eligible

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[21] Attachment 1, para. 135.
[22] *Id.* at para. 131.
[23] *Id*. at para. 137.
[24] *Id*.
[25] *Id*. at para. 139. See also, N.C. Gen. Stat. § 62-156(b)(3).

for the Sub 148 avoided cost rates will begin providing capacity in January 2019.[26] DEP assumes that such QFs will begin providing capacity on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[27] However, because of well-documented delays in the interconnection queue, these are entirely unrealistic assumptions. In reality, a QF entering into a Sub 158 PPA will not begin providing capacity until December 2021 or later.[28] When considering this reality, QFs eligible for a Sub 158 PPA will actually be providing capacity during more years in which the Utilities have shown needs for capacity.[29] It would therefore be more appropriate to use December 31, 2021 as the presumptive in-service date for the purpose of calculating avoided capacity costs (both the quantification of the costs and the determination of the number of years in which there is a capacity need).[30] The Commission should also direct the utilities to calculate avoided cost rates in negotiated PPAs based on the presumed in-service date of the QF subject to the negotiated PPA.

iv. Overstatement of Winter Peak

Duke's proposed avoided capacity costs are further skewed against QFs because Duke has overstated its winter peak. Duke has failed to adequately develop DSM programs for their winter peak, as they have for their summer peak, thus exaggerating the peak. The capacity of demand-side management available for DEC's summer peak is more than double that available for DEC's winter peak, and

[26] Attachment 1, para. 167.
[27] *Id*. at para. 168.
[28] *Id*. at para. 169.
[29] *Id*. at para. 165-169.
[30] Similarly, avoided energy costs should be forecast beginning on January 1, 2022.

the capacity available for DEP's summer peak is nearly double that of DEP's winter peak.[31] For example, during 2017, DEP activated its Distribution System Demand Response ("DSDR") program only three times during the winter but five times during the summer.[32] As such, the Commission should reject Duke's DSM assumptions.[33] Instead, the Commission should adopt the DSM assumptions set forth in **Attachment 1**.[34]

v. Summer/Winter Allocation

In its *Sub 148 Order*, the Commission surprisingly approved an allocation ratio of 80% winter and 20% summer for capacity costs, despite uncontroverted evidence that (i) Duke's winter peak hours are very limited, (ii) Duke's winter peaks have been due to extreme weather events, and (iii) many more of Duke's peak hours occur in the summer months.[35] In the current proceeding, Duke is proposing to extend this fiction: DEC is proposing allocation ratios of 90% winter and 10% summer for capacity costs, and DEP is proposing to allocate 100% of capacity costs to winter.[36] Duke's proposed allocations are inappropriate due to the flaws in the loss of load analysis that underlies the proposed allocations,[37] flaws regarding the DSM assumptions,[38] as discussed above, a failure to consider imports,[39] and are flawed solar modeling.[40] Given these flaws, the Commission

[31] Attachment 1, para. 117-118.
[32] *Duke Energy Progress Distribution System Demand Response Program Implementation Status Report*, p. 2, Docket No. E-2, Sub 926 (June 15, 2018).
[33] *Id*. at para. 119.
[34] *Id*. at para. 122.
[35] *Id*. at para. 123.
[36] *Id*.
[37] *Id*. at para. 124.
[38] *Id*. at para. 125.
[39] *Id*. at para. 126.
[40] *Id*. at para. 127.

should revisit the allocation ratios approved in the *Sub 148 Order* and proposed by the Utilities.

2. AVOIDED ENERGY COSTS

The Utilities have failed to provide accurate models which display the avoided energy costs that the Utilities will realize in the coming years, particularly with robust distributed energy resource integration. Namely, as set forth more fully below, Duke forecasts its natural gas usage over ten years before moving to a fundamentals forecast despite the fact that data indicates that this length of time is too long and is inappropriate. Further, the Black-Scholes approach, utilized in prior avoided cost proceedings, to evaluate hedging values does not properly ascribe the value that QFs provide to the grid now. Finally, included in **Attachment 2** is an analysis provided by R. Thomas Beach of Crossborder Energy showing that Duke should be projecting different firm pipeline capacity costs and QF capacity costs.

i. Natural Gas Forecasting

NCSEA objects to the form and methodology that Duke uses in developing its natural gas forecast. While Dominion uses a forecast that is based on gas forward market prices for the initial 18 months, then transitions to a fundamentals forecast by 36 months, Duke's gas forecast uses a full 10 years of forward market prices before moving to a fundamentals forecast. Duke's method undermines its fundamentals forecast. "Practically, this means that the fundamentals forecast does not impact the avoided energy costs for a 10-year QF power purchase agreement ("PPA")."[41]

[41] *Affidavit of R. Thomas Beach*, p. 2, included as **Attachment 2**.

Figure 1 illustrates both the current Duke and Dominion proposals, the Public Staff's proposal in Docket No. E-100, Sub 148 that the Commission adopted in that docket[42], the ICF projection used by Dominion in Dominion's Initial Filing[43], and the recently-released *2019 Annual Energy Outlook* ("*2019 AEO*") forecast from the Energy Information Administration ("EIA") – as well as an updated set of Henry Hub forward market prices from the January 10, 2019 market.[44]

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[42] *Sub 148 Order*, p. 7.
[43] *Dominion's Initial Statement*, Exhibit DENC-5.
[44] Attachment 2, p. 9.

Duke's forward market for 10 years of natural gas at fixed prices is not transparent, broadly traded, or liquid. Duke's open interest in the natural gas future prices market is almost entirely in the first two years of the ten-year window.[45] **Figure 2** shows the open interest from the natural gas future prices market on January 10, 2019 and, as shown therein, 99.0 of the open interest is in the first two years.[46] The reported prices after two years are less certain and convey far less information than the initial two years that are heavily traded.

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[45] *Id*. at p. 10.
[46] *Id*.

Duke cites to gas contracts as evidence of their forecast reasoning, but Duke's ability to purchase four small volumes of gas (a total of 10 MDth[47] per day) for 10 years at close to the published 10-year forward prices is not dispositive. As shown in **Table 1** below **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the gas that could be displaced by the amounts of solar that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Even if a liquid market for 10-year fixed-price gas supplies existed, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Under current policy, DEC hedges the price of natural gas **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and DEP hedges the price for up to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but only for volumes representing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** DEP's expected solar purchases would displace **[BEGIN CONFIDENTIAL]** [redacted]

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[47] "MDth" is a thousand decatherms, or a billion Btu, or M3Btu.
[48] Attachment 2, pp. 10-11.
[49] *Id.*

[redacted]

[END CONFIDENTIAL]

Forward prices and fundamentals forecasts each play a role in a reasonable gas price forecast: forward prices provide market-based information on short-term price trends influenced strongly by (1) current demand, by (2) near-term expected demand, and by (3) the current status of gas in physical storage.[51] While forward prices represent the future price parties are willing to contract for now, these amounts are not necessarily what the price for those future supplies will be in the future. Forward prices often track current prices, and the magnitude of the forward price curve shifts up or down largely in parallel to changes in the current spot price. While there is some evidence that short-term forward prices provide a reasonable forecast of short-term spot prices, Duke does not provide evidence that ten years of forward price data is superior to forecasts that examine the fundamentals of the supply and demand of natural gas.[52]

[50] *Id*. at p. 11.
[51] *Id*.
[52] *Id*. at pp. 11-12.

Fundamentals forecasts look at longer-term trends in the gas supply and demand balance in North America and the world market for liquified natural gas ("LNG"). For example, the *2019 AEO* provides a fundamentals forecast considering both the growing demand for U.S.-produced natural gas and the growth in production from shale gas and gas associated with tight oil production.[53] EIA expects that increases in gas demand for electric generation will be driven by retirements of coal and nuclear capacity.[54] Fundamentals forecasts tend to be higher than forward market prices in falling markets, but lag forward prices in rising markets and the trend since 2010 has been lag forward.[55] These changing trends over time also are apparent in the EIA's own analysis of the accuracy of its past AEO forecasts.

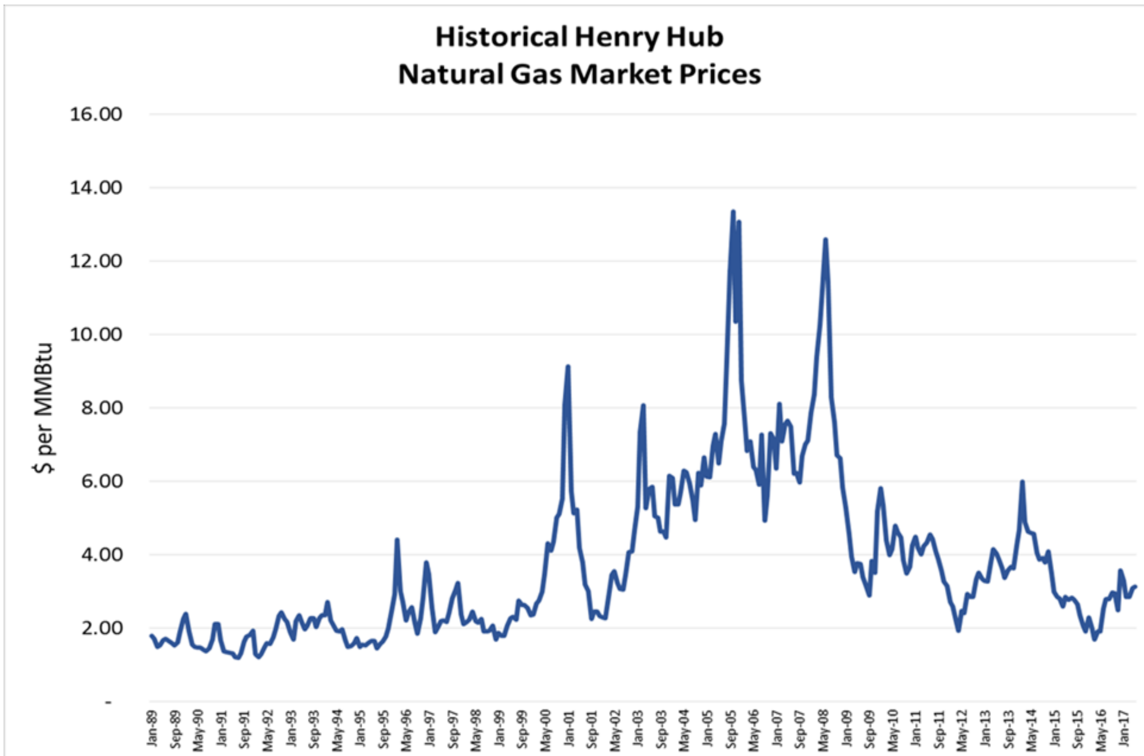
NCSEA believes that a balanced forecast that uses forward market prices for two years while the market is robust and deep, with a transition in the next three years to the average of a set of recent fundamentals forecasts, which NCSEA believes should come from (1) DNCP's forecast from ICF and (2) the new *2019 AEO* forecast from EIA, is a more appropriate forecast to use. Alternatively, NCSEA would not object to the use of Dominion's similar forecast methodology of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities.

[53] *Id*. at p. 12.
[54] *Id*.
[55] *Id*.

ii. Hedging

"Natural gas prices are volatile and uncertain, on multiple time scales. The history of Henry Hub spot price shows significant volatility over the last 30 years, as shown in **Figure 3**." [56]

Figure 3



There can also be significant price volatility on shorter time scales, as illustrated by the most recent year of Henry Hub prices shown in **Figure 4.**[57]

[56] *Id*. at p. 13.
[57] *Id*. at p. 14.

Figure 4: *2018 Henry Hub Prices*

QFs displace natural gas-fired generation and the Utilities' use of natural gas. QFs also decrease the exposure to the volatility in natural gas prices. If the avoided cost prices paid to a renewable QF are for a fixed for the term of a PPA, the renewable QF provides a long-term physical hedge for the term of the PPA by displacing market-priced gas with fixed-price renewable power. The 3,790 MW of solar coming online in the near future in Duke's territories would displace about 143,000 Dth per day of natural gas use, assuming a system heat rate of 7,250 Btu/kWh. This solar hedge extends far longer than current utility hedging programs. Moreover, renewable generation also hedges against market dislocations or generation scarcity that can occur during an energy crisis or a drought. Renewable generation provides a hedge not available in financial markets and could be utilized as financial risk management.[58]

[58] *Id*. at pp. 14-15.

In past avoided cost cases, the hedging benefit has been quantified using the Black-Scholes Model option pricing method.[59] The Black-Scholes approach assumes that the displaced gas is re-priced at the prevailing market price 5 or 10 times over a 10-year period, which is a far less effective hedge than the hedge provided by the renewable PPA that provides 10 years of prices fixed from the start of the contract's term.[60]

Several studies across the country have more adequately valued the hedge provided by renewable generation. In 2013, Xcel Energy's Public Service of Colorado unit estimated the long-term (20-year) hedging benefits of distributed solar resources on its system to be $6.60 per MWh.[61] Another method, the Maine Public Utilities Commission's *Maine Distributed Solar Valuation Study*, released in 2015, calculates the additional costs to fix the fuel costs of a marginal gas-fired generator for a long-term period, compared to purchasing gas at prevailing short-term market prices on an "as you go" basis. The difference represents the hedging benefit of fixing the cost of gas, removing the market risk that volatile gas prices could make gas-fired generation at times uneconomic.[62]

Utilizing this method to calculate the 10-year hedging benefit of renewable PPAs in North Carolina, based on NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the Utilities' weighted average costs

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[59] *See Sub 148 Order*, p. 73; *Sub 140 Order*, p. 7.
[60] Attachment 2, p. 15.
[61] *Id*.
[62] *Id.* at pp. 15-16.

of capital, and a marginal heat rate of 7,250 Btu per kWh, results in the avoided fuel hedging costs shown in **Table 2**:[63]

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As shown in Table 2, the NCSEA hedge provides substantially better values than the Utilities' hedge values and there are several methods across the country which are superior to the Utilities' current method and that have been used for several years.[64]

iii. Firm Pipeline Capacity Costs and QF Capacity Prices

In avoided cost calculations in North Carolina, the Utilities have utilized the "peaker method" where the capacity price in the calculation is based upon the fixed costs of a combustion turbine ("CT").[65] In this method, Utilities allocate much of the capacity price to winter peak hours, corresponding to periods of cold weather

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[63] *Id*. at p. 16.
[64] *See*, Attachment 2, pp. 15-16.
[65] *See, e.g., Sub 148 Order*, p. 6; *Order Setting Avoided Cost Input Parameters*, p. 48, Docket No. E-100, Sub 140 (December 31, 2014) ("*Sub 140 Phase I Order*"); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 7-8, Docket No. E-100, Sub 136 (February 21, 2014).

when gas demand peaks and gas pipeline capacity is constrained. CTs need to be served with firm pipeline capacity, to be assured of receiving gas supplies, or to have a backup supply of an alternative fuel (oil) as exhibited by the Utilities pipeline capacity and capability projections for their CTs. These two options are costly, and, as a result, a reasonable premium is added to the CT costs used to set the winter capacity price. As noted in **Attachment 2**, Duke's fuel cost data, per the calculations, indicates that Duke should project additional pipeline capacity cost and that amount should be added to the avoided winter capacity rate.[66]

iv. Duke has Recognized Natural Gas Issues in Other States

Duke Energy's subsidiaries have recognized the issues in forecasting and hedging natural gas in their other territories across the United States. In 2017, Duke Energy Ohio ("Duke Ohio") requested that the Public Utilities Commission of Ohio approve subsidization of an uneconomic coal plant on the basis that it provided a hedge against natural gas price risk.[67] Duke Ohio Witness Judah Rose presented direct testimony that (i) recent declines in natural gas prices are unsustainable and cannot continue – thus over the long term gas prices will increase[68] and (ii) it is not accurate to use the price of gas futures to project gas prices more than 1-2 years in the future.[69] Witness Rose's testimony describes at length his analysis of natural

[66] Attachment 2, p. 10.
[67] *See*, https://www.eenews.net/stories/1060082697.
[68] *Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio*, March 31, 2017, located at https://www.eenews.net/assets/2018/05/24/document_pm_01.pdf, p. 54 ("Ohio Testimony"); "Our forecast is that the recent multi-year trend (e.g., post 2008) of low 9 supply area natural gas prices will continue in the near-term, but over time, 10 natural gas prices increase in real terms and even more in nominal terms relative 11 to 2016."
[69] Ohio Testimony, p. 54.

gas prices and their recent and long-term trends. As he describes in depth, natural gas prices are currently very low, and these low prices are unsustainable. Furthermore, and perhaps most dangerously, the market for natural gas, historically, has been a volatile market amongst the commodities and susceptible to large jumps in pricing.[70]

In Florida, Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric Company ("TECO") filed a joint petition in 2016 to modify their fuel hedging programs, stating in part:

> [The] increased dependence on natural gas means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued. *While natural gas prices have trended downward in recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty.* Additionally, the recent downward trend in natural gas market prices cannot continue indefinitely. Factors such as production costs, weather, environmental regulations and exportation impact natural gas supply and demand, as well as natural gas price volatility.[71]

It's clear that Duke recognizes some of the same challenges in forecasting and hedging natural gas outlined by NCSEA as it has made some similar arguments where it suited them in Ohio and Florida. Therefore, Duke's natural gas assumptions and forecasts should be reviewed with considerable scrutiny and especially in light of NCSEA's positions set forth above.

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[70] *See generally*, Ohio Testimony at pp. 39-62.

[71] *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, Docket No. 160096-EI (Fl. Pub. Serv. Comm'm. Apr. 22, 2016), ¶ 5. (emphasis added).

C. Rate Design

1. Price Signals

The Commission recognized in its *Sub 148 Order* that stronger, more accurate price signals help market participants make better, more economically efficient decisions regarding the design, construction, and operation of QFs.[72] PURPA provides competition in power generation, even in a vertically-integrated state such as North Carolina.[73] This competition also diversifies energy supply, to the benefit of all ratepayers.[74] The Commission's role in price-setting is pivotal, because price signals can provide crucial information to QFs so that they can operate their generation assets in economically beneficial ways.[75] While HB589 reduced the availability of the standard offer PPA, this price-setting role is still important, as the standard offer PPA forms the basis of negotiated PPAs for larger QFs, as well as of critical importance in the Competitive Procurement of Renewable Energy and Green Source Advantage proceedings.[76]

i. Geographic Price Signals

Despite the Commission's guidance that the Utilities' proposals should provide more granular rate schedules, with the exception of Dominion's Schedule 19 – LMP, the utilities do not propose any rates that incorporate geographic granularity.[77] Without geographic granularity, there is no incentive for QFs to

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[72] *Sub 148 Order*, p. 56. Attachment 1, para. 9.
[73] Attachment 1, para. 14.
[74] *Id*.
[75] *Id*. at para. 15.
[76] Attachment 1, para. 25. *Sub 140 Phase I Order*, p. 21. See also, *Order of Clarification*, Docket No. E-100, Sub 140 (March 6, 2015).
[77] Attachment 1, para. 171.

locate in areas where the utilities can avoid transmission and distribution costs.[78] Without some sort of geographic price signal, QFs will continue to be incented to locate where land and interconnection costs are cheapest, which may not provide the most advantage to the grid and could exacerbate the already clogged interconnection queue.[79] The Commission should direct the Utilities to develop tariffs that incorporate geographic price signals that provide an economic incentive for QFs to locate in areas that are most advantageous to the grid.[80]

ii. Seasonal Price Signals

The Utilities' proposed rate designs fail to adequately recognize how costs vary across different seasons.[81] Duke proposes two seasons, and DENC proposes three seasons.[82] All three utilities define a Summer season of May through September.[83] DENC proposes a Winter season of December through February and define the remaining months as a Shoulder season.[84] Duke combines all non-Summer months into a single season.[85] Duke's proposal not to differentiate a Winter season ignores the distinctly different patterns of electrical usage, net system load, marginal production costs, and avoided costs that occur during winter as opposed to spring and summer.[86] As such, the Commission should reject Duke's

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78 *Id*.
79 *Id*. at para. 172.
80 *Id*. at para. 173-174.
81 *Id*. at para. 175.
82 *Id*. at para. 176.
83 *Id*.
84 *Id*.
85 *Id*.
86 *Id*. at para. 178.

proposed seasonal variations and instead should adopt the seasons proposed in **Attachment 1**.[87]

iii. Time-of-Day Price Signals

The Utilities' proposed rate designs also fail to adequately recognize how costs vary across different times of day.[88] DEC, DEP, and DENC all propose oversimplified daily on-peak and off-peak rates that average time periods with distinctly different cost characteristics.[89] These proposals are made despite the fact that the Utilities have detailed avoided cost data available for all 8,760 hours for each of the next 10 years.[90] Averaging away such important detail is inappropriate, unduly discriminatory, and inconsistent with the Commission's desire for more granular rate designs.[91] Instead, the Commission should adopt the time-of-day periods proposed in **Attachment 1**.[92] In addition, the Commission should adopt an optional, real-time pricing tariff for QFs.[93] Such a real-time pricing tariff would be consistent with the Commission's recent order authorizing Duke's proposed Green Source Advantage tariff.[94]

2. ANCILLARY SERVICES

As discussed in greater detail below, the Commission should reject the Utilities' proposed Solar Integration Charges. However, if the Commission

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[87] *Id*. at para. 187.
[88] *Id*. at para. 175.
[89] *Id*. at para. 180-183.
[90] *Id*. at para. 183.
[91] *Id*.
[92] *Id*. at para. 189-192.
[93] *Id*. at para. 194-212.
[94] *See generally*, *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, p. 55, Docket Nos. E-2, Sub 1170 & E-7, Sub 1169 (February 1, 2019).

determines that the Solar Integration Charges are appropriate, the Commission should enable a market where QFs have a meaningful opportunity to avoid charges for such ancillary services as well as the opportunity to compete to provide such ancillary services.[95] NCSEA notes that nowhere in Chapter 62 of the North Carolina General Statutes are the Utilities granted a monopoly by the General Assembly for the provision of ancillary services. Given the opportunity to compete in a market, QFs may be able to provide these ancillary services at a lower cost than the Utilities, to the benefit of all ratepayers.[96] It is distinctly possible that ratepayers are overpaying for the incumbent utilities to provide ancillary services; however the answer cannot be known without a competitive market. Furthermore, creating a competitive market for ancillary services is consistent with the "intent on the part of the General Assembly to introduce an element of competitive pricing into the procurement of renewable energy and to reduce reliance on PURPA, which contains a 'must purchase' requirement for investor-owned utilities in purchasing a QF's electric output."[97] Solar QFs that are equipped with smart inverters and energy storage are strongly positioned to provide ancillary services quicker and cheaper than the conventional generators owned by the Utilities.[98] Similarly, small hydroelectric generators would also be well positioned to provide ancillary services.[99]

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[95] *Id*. at para. 77.
[96] *Id*. at para. 78.
[97] *See generally*, *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, note 21, Docket Nos. E-2, Sub 1170 & E-7, Sub 1169 (February 1, 2019).
[98] Attachment 1, para. 79-80.
[99] *Id*. at para. 84.

In the *Sub 140 Phase II Order*, the Commission authorized the Utilities to charge QFs for VAR absorption.[100] However, the Utilities also direct QFs to generate VARs without compensation, in contravention of the Commission's direction that "To the extent that a smaller generator provides or absorbs reactive power at the utility's request, it is also appropriate for DEC and DEP to pay for such power to the extent they pay their own or affiliated generator."[101] Charging for VAR absorption but not paying for VAR generation is discriminatory and leads credence to the argument that the Commission should consider utilizing the differential revenue requirement methodology for calculating avoided cost rates, since this methodology would incorporate integration expenses.

3. PERFORMANCE ADJUSTMENT FACTOR

A performance adjustment factor ("PAF") is designed to ensure that QFs are not discriminated against in favor of rate-based generation.[102] Ratepayers pay the full cost of rate-based generation, even if that capacity is not available during critical peak hours; in contract, a QF's capacity payments are tied to the amount of energy that the QF provides during specified hours.[103] Thus, the PAF should consider the actual availability of rate-based generation during all critical peak hours.[104]

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[100] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 9, 46-48, Docket No. E-100, Sub 140 (December 17, 2015) ("*Sub 140 Phase II Order*").
[101] *Sub 140 Phase II Order*, p. 48.
[102] Attachment 1, para. 88.
[103] *Id*.
[104] *Id*.

In its *Sub 148 Order*, the Commission reaffirmed its position that the availability of a CT is not determinative for the purpose of calculating a performance adjustment factor ("PAF") and instead noted that the PAF should be developed based on a "system availability metric that represents the reliability of the system during peak demand periods."[105] In this proceeding, Duke proposes a PAF of 1.05 and DENC proposes a PAF of 1.07.[106] The difference between the two is based on the months used in analyzing generation fleet availability.[107]

Duke defines the months of January, February, July and August as "peak season" for purposes of calculating the PAF.[108] However, Duke has not claimed that these are the only months when peaks can occur.[109] Perhaps most notably, this "peak season" differs from the seasons used by Duke in developing their rate design proposals.[110] As is shown in **Attachment 1**, DEC and DEP have historically had summer peaks during all months between June and September and, although less frequent, winter peaks between December and March.[111] The historical data for both DEC and DEP does not support considering only January and February as winter peak months to the exclusion of December and March. [112] Similarly, the historical data for DEC does not support considering only July and August as summer peak months to the exclusion of June and September.[113] By systematically

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[105] *Sub 148 Order*, pp. 55-56. Attachment 1, para. 85.
[106] Attachment 1, para. 86.
[107] *Id*.
[108] *Id*. at para. 91.
[109] *Id*.
[110] *Id*. at para. 95.
[111] *Id*. at para. 96
[112] *Id.* at para. 99-100.
[113] *Id*. at para. 102.

excluding these additional months, Duke has biased their PAF calculations and, if adopted, the proposal would discriminate against QFs and understate their contribution to capacity during peak months.[114] Accordingly, NCSEA recommends that the Commission reject Duke's PAF proposal and adopt the proposal of a PAF between 1.08 and 1.10 as proposed in **Attachment 1**.[115]

D. SOLAR INTEGRATION CHARGE

In its *Joint Initial Statement*, Duke proposes a new "integration services charge for intermittent Solar QF Power" ("Solar Integration Charge") purportedly as a means "to recognize the impact on operating reserves, or generation ancillary service requirements, for new variable and non-dispatchable solar capacity."[116] Similarly, Dominion proposes a "re-dispatch charge" which "adjust[s] 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.[117] However, the Utilities' proposals are inconsistent with previous Commission decisions and do not comply with PURPA.

1. BOTH COSTS AND BENEFITS MUST BE INCLUDED

The Commission has been clear in its directives that the Utilities must consider both the costs and benefits of solar resources when conducting an integration study. Most notably, in the Sub 140 proceeding, the Commission wrote:

> The Commission agrees that integration of solar resources into a utility's generation mix results in both costs and benefits, many of

[114] *Id*. at para. 111.
[115] *Id*. at para. 112.
[116] *Joint Initial Statement*, p. 31.
[117] *Dominion's Initial Statement*, pp. 12-13.

> which may be appropriate for inclusion in a utility's avoided cost calculations. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, may require the consideration of additional factors, such as the *potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support*. The Commission is aware that several studies regarding, and methods to calculate these costs and benefits, are currently under development. For example, the Electric Power Research Institute is set to release a study, titled The Integrated Grid – Phase II: Development of a Benefit Cost Framework, in the coming months. In light of these developments and the potential for significant amounts of solar generation to be constructed in North Carolina in the next few years, the Commission determines that it is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.[118]

While Duke acknowledges in its *Joint Initial Statement* that the *Sub 140 Phase I Order* stated that "integration of solar resources into a utility's generation mix likely results in costs and/or benefits[,]" the Astrape study used by Duke in calculating its solar integration charge consider none of the benefits identified by the Commission in its *Sub 140 Phase I Order*. In that order, the Commission also noted the limited applicability of the solar integration study that was presented by Duke in that proceeding because it failed to comprehensively investigate all aspects of the integration of solar generation.

> The PNNL study included as Exhibit 1 to DEC/DEP witness Snider's testimony provides a robust evaluation of several aspects of integrating increasing amounts of solar generation into the utility's generation portfolio, including the impacts of solar PV on ancillary services and generation production cost, as well as voltage and power flows, and a limited evaluation of avoided losses in the transmission and distribution systems. The study points out, however, that it was limited in scope in order "to produce results in a timely manner using available data and analytic tools, to identify areas of concern, measure the degree of impact, and provide

[118] *Sub 140 Phase I Order*, p. 60 (emphasis added).

> guidance for further actions. As a result, the study was limited to energy production cost modeling and steady-state power flow simulations. Potential PV impacts on dynamic system characteristics, such as frequency response and dynamic and transient stabilities, were not included the study scope."[119]

Thus, Duke's proposed Solar Integration Charge is inconsistent with the Commission's previous orders because it failed to include the benefits provided by QF generation.

Similarly, Dominion admits in its initial statement that its re-dispatch charge proposal fails to comply with the Commission's previous order, stating that "At this time, the Company is not proposing to adjust avoided cost rates to specifically account for the potential *costs* or benefits related to changes in ancillary service requirements" while going on to propose a rate that QFs must pay for re-dispatch *costs* without examining the benefits of QF generation.[120]

2. SUB 148 ORDER

The Utilities have failed to comply with the Commission's clear directive to develop additional rate schedules; instead developing single rate schedules and separate penalties for intermittent QFs. In the *Sub 148 Order*, the Commission stated the following conclusion:

> As discussed in other sections of this order, the Commission concludes that an avoided cost rate based on the characteristics of the QF-supplied power may also be appropriate going forward in future proceedings, and, therefore, will require the Utilities to include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings in the next biennial avoided cost proceeding.[121]

[119] *Sub 140 Phase I Order*, p. 61.
[120] *Dominion's Initial Statement*, p. 12 (emphasis added).
[121] *Sub 148 Order*, p. 150.

As discussed further below, the Utilities have failed to propose rates based on the characteristics of QF-supplied power, but have instead proposed a punitive charge for such QFs. However, the Utilities have also failed to provide the Commission with "data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings[.]"[122] In its *Joint Initial Statement*, Duke extensively discusses two studies performed by Astrapé,[123] but notably it fails to provide those studies to the Commission.[124] Similarly, Dominion asserts that "the Company performed a simulation analysis to determine the impact on generation operations at varying levels of solar PV penetration[]"[125] but fails to provide the Commission with this analysis.

Furthermore, the Commission was clear that it intended for the Utilities to propose multiple rate schedules based on the characteristics of a QF, and not based on the generation technology used by a QF.

> The Commission further finds that it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity.[126]

However, the Utilities have proposed integration charges that are solely based on the generation technology, and not the characteristics of a QF, in direct contradiction of the Commission's previous order.

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[122] *Id.*
[123] *Joint Initial Statement*, pp. 32-33.
[124] NCSEA obtained the Astrape studies through the discovery process. Attached as **Attachment 3** to these initial comments is *Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study* (November 2018), and attached as **Attachment 4** is *Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study* (August 27, 2018).
[125] *Dominion's Initial Statement*, p. 13 (internal citations omitted).
[126] *Sub 148 Order*, p. 98.

3. THE ASTRAPE STUDY IS FLAWED

i. Astrape Inappropriately Modeled North Carolina as an Island and Did Not Account for Regional Efficiencies

As set forth above, Duke relied upon Astrape to develop a report ("Astrape Study") that provided the basis for its decision to propose the Solar Integration Charge. NCSEA believes the Astrape Study is deficient in several ways. One of the most obvious deficiencies is that the Astrape Study views Duke's service territories as an island and not connected to neighboring grid systems. This is a fundamental misunderstanding of how the electric market functions and shows an inadequate valuation of the underlying electric market dynamics in Astrape's model. Regional cooperation among utilities is a key factor in reducing integration costs and curtailment and has been successfully adopted elsewhere in the U.S. **Attachment 2** states, in part, that:

> Experience with the new Energy Imbalance Market (EIM) on the western U.S. grid is demonstrating that expanded regional cooperation among utilities is a key to reducing integration costs and renewable curtailment, as the penetration of renewable wind and solar generation grows. The EIM market in the West includes both utilities in LMP-based markets (the three California IOUs in the CAISO) and many traditional vertically-integrated utilities in the other western states (Arizona Public Service, NV Energy, PacifiCorp, Idaho Power, Portland General Electric, and Puget Sound Energy), with more utilities planning to join the EIM in the near future. The share of renewable generation is growing on the systems of all of these western utilities, but they are sufficiently diverse in loads, resources, and geography that the expanded and more efficient interchange of power facilitated by the EIM is providing significant integration cost savings and reduced renewable curtailments across the region.[127]

[127] Attachment 2, p. 18.

Attachment 2 further states that EIM is designed to fit within each of the participating utilities' traditional hourly scheduling procedures and "focuses on finding more efficient and mutually beneficial transactions in sub-hourly time frames."[128] This design has ushered quick acceptance from a diverse set of utilities "with different market structures, different state regulators, and varying resource mixes whose service territories cover most of the western U.S. grid."[129]

The results of EIM are impossible to ignore. From 2014 through the third quarter of 2018, "the benefits to the participants [in EIM] have exceeded $500 million plus 734 GWh of avoided renewables curtailment."[130] EIM also provides savings in ramping as the balancing areas with excess ramping can supply other areas that need such ramping. Obviously, these types of interstate and inter-utility efficiencies provide savings and benefits which would offset any of the underlying data in the flawed Astrape Study supporting the proposed Solar Integration Charge. Further, the Astrape Study is flawed in several other ways: Astrape developed several inappropriate metrics, data points, and accounting results, including, notably, an improperly scaled solar plant intra-hour output variability data that fails to accurately reflect geographic diversity benefits. A detailed explanation of these defects are contained in **Attachment 2**.[131]

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[128] *Id*.
[129] *Id*.
[130] *Id*.
[131] *Id*. at pp. 17-19.

ii. Astrape Incorrectly Assumes Solar is Inflexible

The Astrape study incorrectly assumes that future solar resources will not include ancillary services and will not allow the utility any flexibility in dispatching future solar resources. This is an unreasonable assumption given the nature of currently utilized negotiated solar PPAs. Further, utility-scale solar projects have demonstrated a broad range of ancillary services available on the market, which are clear benefits to the overall grid.[132] The Astrape Study fails to provide an analysis showing solar flexibility and including these clear grid benefits.

4. SOLAR PLUS STORAGE PROJECTS MUST BE ACCURATELY REFLECTED IN ANY COST BENEFIT ANALYSIS

Duke's proposed Solar Integration Charge does not even meaningfully account for the ever-increasing adoption of storage as an add-on to distributed solar projects. Storage is more cost-effective when paired with solar as it allows for incorporation of the solar investment tax credit and, when combined, the project becomes exponentially more valuable to the grid. The Astrape Study does not model the capabilities of solar plus storage projects, which is a mistake and shows that Duke's data points in preparing the Solar Integration Charge rate design are incomplete.

The use of storage substantially reduces the variability of solar output, because storage either can be dispatched by the utility or can be pre-programmed to discharge at a specific rate in certain peak hours.[133] The storage paired with solar

[132] *Id*. at p. 19.
[133] *Id*.

also offers the best opportunity to utilize ancillary services, including load following, regulation, and fast frequency response.[134] NCSEA opposes the Solar Integration Charge wholly, but, should the Commission determine that the Solar Integration Charge is appropriate, NCSEA believes that solar plus storage projects should not be subject to such as charge as their benefits clearly and easily outpace their costs.

5. SOLAR INTEGRATION PROVIDES AVOIDED TRANSMISSION AND DISTRIBUTION SYSTEM CAPACITY COSTS

Solar integration allows for utilities to avoid costs associated with transmission and distribution capacity. The Astrape Study failed to capture the benefits from integrating the distributed output of small QFs interconnected to the utilities' distribution systems. Small QF generation "can reduce peak loads on the utilities' upstream transmission and distribution systems, allowing the utilities to avoid load-related T&D capacity costs."[135]

Solar (and other distributed energy resources) interconnected directly to the distribution system produce power typically consumed on the local distribution system by the project's neighbors. This practice reduces loads on the upstream portions of the distribution system and the higher voltage transmission system.[136] Therefore, QFs displace traditional central station generation sources and makes available transmission and distribution capacity that can serve load growth and

[134] *Id.*
[135] *Id.* at p. 20.
[136] *Id.*

provide transmission capacity for future wholesale generation. This avoids avoiding the need to expand the entire transmission and distribution system.

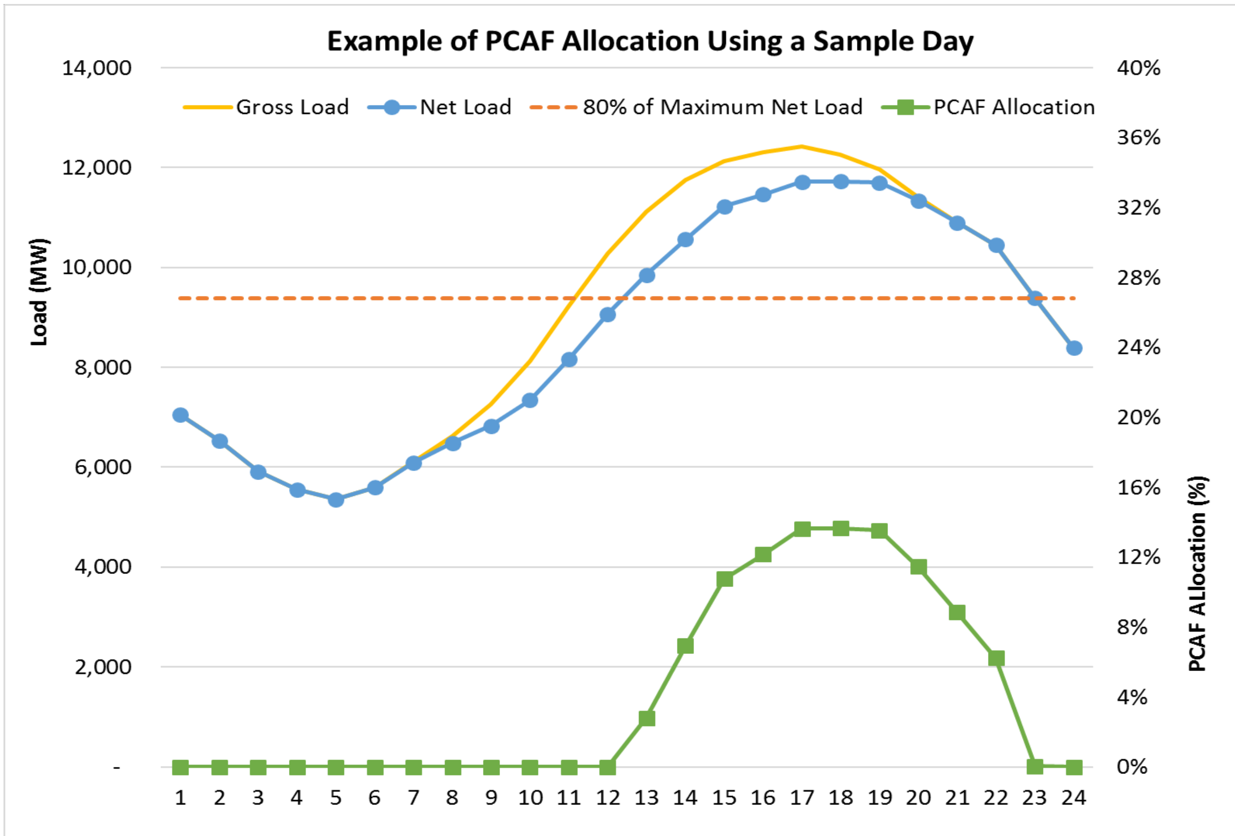
Over its 20 to 30-year useful lifespan, distributed solar can allow a utility to avoid future transmission and/or distribution costs not contained within the shorter time horizons used for transmission and distribution planning. Several areas of the U.S. are now utilizing solar and other types of distributed energy resources ("DERs") as "non-wires alternatives" that can be less expensive than grid upgrades.[137] This practice allows a utility to avoid the need to build more generation and transmission infrastructure.

Using Duke's data quantification of its avoided transmission and distribution costs, **Attachment 2** sets forth a model for avoided transmission and distribution costs resulting from solar integration. Specifically, **Attachment 2** proposes a set of "'peak capacity allocation factors' ('PCAF') based on hourly data on system net loads (for transmission) or loads at a representative sample of distribution substations (for distribution)."[138] PCAFs are hourly allocation factors that give a non-zero weight only to those system or substation loads that are within 20% of the annual peak load for the system or at each substation. All hours where the system or substation load is below 80% of the annual peak load have a PCAF of zero. The use of PCAFs is a more granular application of cost allocation methods. The threshold used to calculate PCAFs, such as 80% of the load in the system or substation peak hour, ties into planning for T&D capacity because

[137] *Id*.
[138] *Id*. at p. 21.

utilities use such thresholds to identify when to plan for possible upgrades.[139] **Figure 5** shows a simple example of how a PCAF allocation is derived.[140]

Figure 5



Attachment 2 includes hourly PCAF allocations for transmission calculated from Duke's system net loads for 2019. NCSEA believes that this method is the reasonable basis for calculating the avoided transmission and distribution rates to apply to the pricing of solar projects to be developed over the next several years.[141]

[139] *Id.* at pp. 21-22.
[140] *Id.* at p. 22.
[141] *Id.*

Figure 6 is a heat map showing the PCAF allocation for DEC's avoided transmission costs.

Figure 6: *Heat Map of DEC PCAFs for Avoided Transmission*[142]

		Hour Ending																							
	DEC	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	1	0%	0%	0%	0%	0%	0%	2%	4%	4%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	3%	2%	1%	0%	0%	0%	0%
	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	5%	6%	6%	5%	3%	1%	0%	0%	0%
	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	5%	4%	2%	0%	0%	0%	0%
	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 4 and Table 5 were developed by applying PCAF allocations and aggregating the hourly avoided transmission and distribution costs recommended in **Attachment 1**.[143] The result is the avoided transmission rates in **Table 4** and the avoided distribution rates in **Table 5**. As shown in these two tables, the integration of solar is actually a net benefit to Duke and its rate payers, and, accordingly, the owners of the QFs should receive payment.

Table 4: *Avoided Transmission Rates ($ per kWh)*[144]

Season	**Summer**			**Winter**			**Other/Shoulder**		
Period	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
DEC	0.0167	0.0016	--	0.0039	0.0006	--	--	0.0001	--
DEP East	0.0133	0.0005	--	0.0075	--	--	--	--	--
DEP West	--	--	--	0.0286	0.0068	0.0016	--	--	--
DENC	0.0104	0.0141	0.0008	0.0344	0.0152	0.0085	--	--	--

[142] *Id*. at p. 23.
[143] Attachment 1, paras. 187-194 and 204-235.
[144] Attachment 2, p. 24.

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Table 5: *Avoided Distribution Rates ($ per kWh)*[145]

Season	Summer			Winter			Other/Shoulder		
Period	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
DEC	0.0115	0.0022	0.0004	0.0163	0.0124	0.0003	0.0002	0.0001	0.0003
DEP East	0.0048	0.0008	0.0001	0.0092	0.0042	0.0015	0.0004	0.0002	0.0002
DEP West	--	--	--	0.0114	0.0081	0.0071	--	--	--

Solar integration, and its associated technologies, has further potential to benefit the grid. "If DERs – including distributed solar, storage, or energy efficiency programs – can be targeted to the parts of the system where they are most needed, i.e. where distribution avoided costs are the highest, they can produce significantly greater benefits than what are estimated using system-wide distribution avoided costs such as those presented in Table 5."[146]

In addition, as noted in **Attachment 2**, the time profiles of distribution loads matter. Solar generation will be more effective at reducing peak loads and deferring upgrade costs at a substation that peaks in mid-afternoon in the summer than at a substation serving residential loads that peaks on summer evenings and winter mornings.[147] At the substation which peaks in the evening, the more valuable resource would be solar with enough storage to shift significant output into the peak evening hours.[148]

6. MARKET PRICE SUPPRESSION

Within their avoided cost calculations, and their accompanying rate designs including the Solar Integration Charge, the Utilities have also failed to accurately capture the effect that wind and solar resources have on market prices. Namely, the

[145] *Id.*
[146] *Id.*
[147] *Id.* at p. 25.
[148] *Id.*

"zero-variable-cost output of wind and solar resources reduces market prices."[149] New renewable generation increases electricity supplies available to the utilities and displaces the most expensive fossil-fired or market resources that would have been otherwise generated or purchased in regional power markets. The addition of local renewable generation will reduce the demand which the utility places on the regional markets for electricity and natural gas.[150] The reduction in demand will cause a corresponding reduction in the price in these markets, which benefits the Utilities when each must buy power or natural gas in these markets.

This "market price response" benefit of renewable generation "is widely acknowledged and has become highly visible in markets that now have high penetrations of wind and solar resources."[151] This benefit has been quantified since 2010 when the National Renewable Energy Laboratory (NREL) and GE Consulting undertook the Western Wind and Solar Integration Study (WWSIS). The WWSIS is "a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S."[152] This model included analysis of the impact of increasing solar penetration: the "high penetration solar cases (15% to 25% penetration) in the WECC resulted in 10% to 20% reductions in spot market prices"[153] as shown below in Figure 8 from **Attachment 2**.

[149] *Id.*
[150] *Id.*
[151] *Id.*
[152] *Id.*
[153] *Id.*

Figure 8: *Impact of Solar Penetration on AZ Spot Prices, from WWSIS*[154]

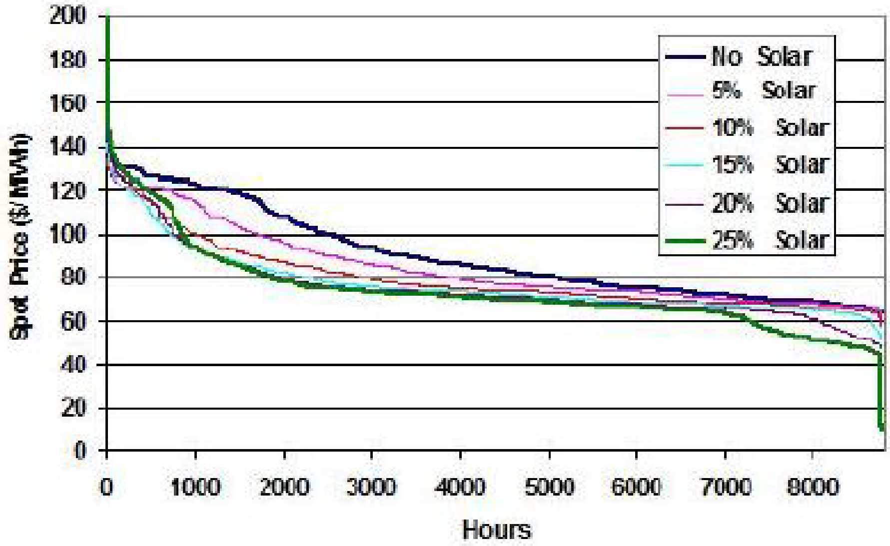

Figure 19 – Arizona Spot Price Duration Curves.

Therefore, per the results of this study, a "market price suppression benefit of about 4% of avoided energy costs has been used for distributed solar in New England."[155]

While NCSEA acknowledges that every utility is unique, and regional markets vary with regard to market price suppression to some extent, there is undoubtedly a clear economic give-and-take at play here. Namely, the introduction of distributed solar causes the prices of energy to reduce across the country, on a whole, and this practice is reflective of market economics. The Utilities in this docket have failed to account for these price benefits in their respective filings, and NCSEA requests this Commission acknowledge and require the Utilities to account for such market changes caused by distributed energy resources.

[154] *Id.* at p. 26.
[155] *Id.* at p. 26.

7. INTEGRATION CAPACITY ANALYSIS

The Utilities' proposed avoided cost plans do not call for the essential interchange of information between the Utilities, their customers, and the independent power producers. This robust interchange is integral for an efficient and least-cost methodology for determining the cost of energy. Specifically, as noted in **Attachment 2**, independent power producers and the Utilities need to exchange granular information which will allow for the most efficient and least-cost energy planning. The North Carolina interconnection queue is clogged and while HB 589 calls for thousands of megawatts of incorporated solar, the interconnection clog makes that statutory requirement difficult to timely correct. NCSEA realizes that there is no easy-fix and that issue is more appropriately addressed in the interconnection docket.[156] However, one potential repair to the interconnection queue, and also a means for the most accurate avoided cost rate, is a more robust interchange between QFs and the Utilities of granular information about the electric grid. QF developers have a strong interest in finding adequate capacity to accept their power, so they can move through the interconnection process quickly and at the lowest cost and this will benefit Utilities on a whole. "Utilities in California, Hawaii, New York, and Minnesota have completed comprehensive analyses of the ability of their systems to host distributed resources, and then have made this 'hosting capacity' data available to interested parties."[157] Hosting Capacity maps would provide developers with information necessary to

[156] *See generally*, Docket No. E-100, Sub 101, including, specifically, comments and testimony filed after the entry of the December 20, 2017 *Order Requesting Comments*.
[157] Attachment 2, p. 27.

sidestep interconnection issues and to also allow for more efficient energy production.

8. Single Issue Ratemaking

The Duke's request to implement a solar integration charge and Dominion's similar request to implement a re-dispatch charge are single-issue ratemaking and are not supported by Chapter 62 of the General Statutes or PURPA. Rates are to be set by the Commission pursuant to the requirements of N.C. Gen. Stat. § 62-133. N.C. Gen. Stat. § 62-3(24) defines "rate" to mean "every compensation, charge, fare, tariff, schedule, toll, rental and classification, or any of them, demanded, observed, charged or collected by any public utility, for any service product or commodity offered by it to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental or classification." It is uncontroverted that DEC, DEP, and Dominion are public utilities pursuant to N.C. Gen. Stat. § 62-3(23). The solar integration and re-dispatch charges are a compensation or charge, to be demanded, charged, or collected, for a service product, in this case ancillary services; as such, they are rates pursuant to N.C. Gen. Stat. § 62-3(24). As such, the solar integration and re-dispatch charges should be set during general rate cases pursuant to the requirements of N.C. Gen. Stat. § 62-133.

In addition to being inappropriate under North Carolina state law, the proposed solar integration and re-dispatch charges do not comply with PURPA and its regulations. The solar integration and re-dispatch charges are not "rates" pursuant to 18 C.F.R. 292.101(b)(5)[158] because they do not involve the sale or purchase of electric energy or capacity. Even if, for argument's sake, the solar integration and re-dispatch charges are rates pursuant to 18 C.F.R. 292.101(b)(5), they are still inappropriate; 18 C.F.R. 292.304(e)[159] lists the factors that may affect rates in determining avoided costs, and ancillary services are not listed among the factors that may be considered. NCSEA notes that Duke cites to 18 C.F.R. 292.304(e) in arguing that lower avoided capacity and energy rates may be allowed for purchases from intermittent QFs.[160] NCSEA does not dispute the plain language of 18 C.F.R. 292.304(e), which allows the listed factors that may be considered "in

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[158] "Rate means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity."

[159] "Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> > (i) The ability of the utility to dispatch the qualifying facility;
> >
> > (ii) The expected or demonstrated reliability of the qualifying facility;
> >
> > (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
> >
> > (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
> >
> > (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
> >
> > (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
> >
> > (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
>
> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
>
> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity."

[160] *Joint Initial Statement*, p. 30.

determining avoided costs[.]" However, Duke does not propose lower avoided capacity and energy rates for intermittent QFs. Instead, it proposes to pay QFs full avoided capacity energy rates and then charge the intermittent QF for ancillary services provided by the utility. Thus, despite Duke's assertion to the contrary, its proposal is not consistent with 18 C.F.R. 292.304(e).

E. PPA RENEWAL

In this proceeding, the Commission is faced with the issue of PPA renewals for solar QFs. Solar QFs that opted for a 10-year levelized avoided cost rate under the Commission's E-100, Sub 127 rates will soon reach the end of their initial PPAs.[161] While solar QFs that opted for 15-year levelized avoided cost rates as well as those subject to E-100 Sub 136 and Sub 140 rates are not yet at the end of their initial PPAs, the Commission should begin considering how to deal with the residual rights of these solar QFs to enter into new PPAs for the balance of their useful lives.

"In balancing the costs, benefits and risks to all parties and customers, the Commission recognizes that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy."[162] As a policy matter, the Commission should try to ensure regulatory continuity and certainty for existing QFs that are seeking to renew a PPA upon its expiration or enter into a new PPA. Existing QFs have an expectation of continuity for their rights after their initial PPA expires, and the Commission should recognize these residual rights.

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[161] *See generally*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 127 (July 27, 2011).
[162] *Sub 140 Phase I Order*, p. 21.

Such a recognition would avoid the risks associated with QFs choosing not to continue to provide capacity to the Utilities, as discussed above.

F. PPA TERMS AND CONDITIONS

In addition to the issues discussed above regarding the Utilities' initial statements, the Utilities propose highly problematic changes to the standard offer PPA terms and conditions.

1. CURTAILMENT

In its *Sub 148 Order*, the Commission authorized nondiscriminatory curtailment of QF generation during system emergencies.[163] However, Duke has inappropriately expanded the Commission's limited authorization of utility control over QF generation. Specifically, the redlined terms and conditions call for QF compliance with all "system operator instructions provided by [DEP or DEC], including any energy storage protocols provided if applicable[.]"[164] This proposed amendment to the conditions of service for a QF is vague and Duke has offered no valid explanation for its incorporation in each of DEC and DEP's respective proposed schedules. However, it is clear that this language could allow for an increase in curtailment decision rights held on behalf of the operating utility that would violate the "nondiscriminatory" curtailment requirement and, for that reason, NCSEA strongly objects and requests the Commission deny this amendment for both DEC and DEP.

[163] *Sub 148 Order* at p. 8: "It is appropriate for DEC, DEP, and Dominion to file procedures with the Commission stating how they would curtail QFs on a *nondiscriminatory basis* when there is a system emergency." (emphasis added).
[164] *Joint Initial Statement*, DEC Exhibit 4, p. 14 and DEP Exhibit 4, p. 13

2. Material Modification

Duke's Initial Statement discusses the company's proposed changes to the terms and conditions of the standard offer PPA that would give the utility the unilateral right to terminate a PPA if a QF makes material modifications to the generating facility.[165] As an initial matter, the current proceeding is not the appropriate venue for addressing modifications to QFs after they have been interconnected to the grid. The issue of material modification is squarely an interconnection issue, and should be addressed in the ongoing interconnection proceeding.[166] The North Carolina Interconnection Procedures already address the issue of material modification,[167] and the Commission has already ruled that, in the event of a conflict between the standard offer PPA and the interconnection agreement, the interconnection agreement controls.[168] Thus, this provision proposed by Duke is wholly unnecessary.

However, in the event that the Commission determines that the provision is necessary, as proposed by Duke the material modification language is overly broad. Duke's Initial Statement states that any increase in either the AC or DC capacity of a QF will allow them to void the standard offer PPA.[169] However, Duke has already agreed that changes to the DC capacity of a QF do not constitute a material

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[165] *Joint Initial Statement*, pp. 34-38. This proposed change is reflected in *Joint Initial Statement*, DEC Exhibit 4 at pp. 13, 15-18 and DEP Exhibit 4, pp. 12-15.
[166] *See generally*, Docket No. E-100, Sub 101.
[167] *See generally*, *Order Approving Revised Interconnection Standard*, Docket No. E-100, Sub 101 (May 15, 2015).
[168] *Sub 140 Phase II Order*, p. 9.
[169] *Joint Initial Statement*, p. 35.

modification for the purpose of interconnection.[170] In addition, Duke explicitly states that "replacing existing panels with panels with greater DC capacity[]" would constitute a material modification and allow the Utility to terminate the PPA.[171] This language is extremely problematic for solar QFs, as panels need to be replaced during the normal course of operations due to issues such as storm damage. At times, identical panels may not be available, and replacements may increase the DC capacity of the QF, even if they do not increase the AC generating capacity. Thus, if the Commission approves this provision, Duke would be allowed to terminate a QF's PPA for routine operations such as repairing storm damage.

Finally, the language proposed by Duke is likely to be discriminatory because it would allow the Utility to unilaterally terminate a PPA at its discretion, and there are insufficient safeguards proposed to protect against discriminatory use by the Utility.[172]

3. Energy Storage Protocols

Duke proposes to include in the standard offer PPA's terms and conditions a new provision that requires a QF to comply with "any energy storage protocols provided" to the QF by Duke[173] However, Duke have not provided these energy storage protocols to the Commission for review and approval. Without reviewing the protocols themselves, the Commission cannot determine that the energy storage

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[170] *See*, *Agreement and Stipulation of Partial Settlement by and between Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion Energy North Carolina, North Carolina Pork Council and the Public Staff*, Docket No. E-100, Sub 101 (January 25, 2019).
[171] *Joint Initial Statement*, p. 35.
[172] Attachment 1, para. 159-160.
[173] *Joint Initial Statement*, DEC Exhibit 4, p. 14 and DEP Exhibit 4, p. 13. Dominion does not propose a similar addition to its PPA terms and conditions.

protocols are reasonable. Without Commission oversight, Duke could adopt energy storage protocols that are discriminatory against QFs in violation of PURPA. Duke does not discuss or otherwise attempt to justify this proposed modification anywhere in the body of its filing, nor does it specify any further detail regarding the content of such potential energy storage protocols. The effect of this undefined provision will be to prevent QFs from financing energy storage, since there is no certainty as to how the expected revenue generation opportunity could be limited or eliminated due to these undefined restrictions. As such, the Commission should reject the Utilities' proposal to require QFs that include energy storage to comply with unprovided and unapproved energy storage protocols unilaterally dictated by the Utilities.

4. Definition of Nameplate Capacity

NCSEA opposes the Utilities' proposal to add the DC capacity of a QF to the definition of nameplate capacity and contract capacity in their respective PPA terms and conditions. This proposal is utterly without merit, and is not supported by any of the other definitions of nameplate capacity that are applicable to QFs. The Commission's rules for reports of proposed construction and applications for certificates of public convenience and necessity both specify that capacity is to be listed in AC.[174] Similarly, the current version of the North Carolina Interconnection Standard specifies that capacity is to be listed in AC when submitting an

[174] *See*, Commission Rules R8-64(b) and R8-65(g).

interconnection request.[175] Furthermore, FERC Form 556 does not specify whether "capacity" is AC or DC.[176]

Adding a QF's DC generating capacity to the definition of nameplate capacity and contract capacity in the PPA's terms and conditions would have detrimental impacts on QFs. The effect of such a definition would be that a QF could not make any changes to a generation facility without the utility's approval. Thus, the impact would be the same as that of the Utilities' proposed language regarding material modifications, discussed above. For the reasons discussed here and above regarding material modifications, the Commission should reject the Utilities' proposed addition of a QF's DC generating capacity to the definitions of nameplate capacity and contract capacity in the PPA terms and conditions.

5. ESTIMATED ENERGY GENERATION

Duke proposes in its PPA terms and conditions that it should have the unilateral authority to void a PPA if a QF increases its annual energy production above an estimated production number stated in the PPA.[177] Duke provides no limitation or qualification on this proposed authority and provides for no reasonable circumstance in which a QF's actual annual production might exceed its estimated production number, as occurs on a regular basis for QFs. As an initial matter, Duke's proposal ignores the fact that an estimate is just that, and annual production will necessarily vary up and down due to a variety of circumstances. It is

[175] North Carolina Interconnection Request, p. 5, as approved by the Commission's *Order Approving Revised Interconnection Standard*, Docket No. E-100, Sub 101 (May 15, 2015).
[176] *See generally*, https://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf (last accessed February 12, 2019).
[177] *See generally*, *Joint Initial Statement*, DEC Exhibit 4, pp. 15-16 and DEP Exhibit 4, p. 14.

commercially unreasonable to require that a QF never exceed its estimated annual production without risking termination of its PPA. Duke's proposal departs from its long-standing practice, required by PURPA, of purchasing all of a QF's output provided that the QF does not exceed its nameplate capacity (expressed in AC). Moreover, it is NCSEA's understanding that Duke's interconnection studies evaluate solar facilities based on the assumption that they will generate at their full nameplate capacity during all hours studied during the interconnection study process, so there is no technical problem presented where actual energy production exceeds an estimate, provided that nameplate capacity is not exceeded. Furthermore, in part due to the fact that Duke provides no explanation or justification for the proposed change in its filing, it is unclear whether an "estimated production number" would be equivalent to an estimate of maximum potential production, average anticipated production, or otherwise, and it is unclear what, if anything, would prevent QFs from simply overestimating their production to avoid potential penalty.

In practice, Duke is arguing that a QF should lose its legally enforceable obligations ("LEO") if it repowers the generation facility.[178] Duke's claim is based on the fact that the Commission utilizes the receipt of a certificate of public convenience and necessity ("CPCN") as one of the prongs for establishing a LEO,[179] and that the Commission's form for applying for a CPCN requires a QF to identify the "gross and net projected maximum dependable capacity of the facility

[178] *Id.* at pp. 37-38.
[179] *Sub 148 Order*, p. 8.

as well as the facility's nameplate capacity[]" and "projected annual sales in kilowatt-hours[.]"[180] According to Duke, "Absent the Companies' acceptance of a change in the Facility, the QF's right to sell under the pre-existing PPA and standard offer rates should be limited to the Facility that established the LEO and originally entered into the PPA."[181]

This position has no legal support and defies common sense. The reason the Commission incorporated the CPCN requirement into North Carolina's LEO test was to ensure that QFs "would be in a position to enter into a legally enforceable obligation" before a LEO can be established, "and that requires a certificate."[182] The CPCN requirement was not intended to "lock" QFs into constructing a facility exactly as described in the CPCN application. This is supported by the fact that QFs are free to make a variety of changes to the information in the CPCN application (e.g. ownership and site layout), so long as they notify the Commission of the change. Under Duke's reasoning, even those changes would result in the QF sacrificing its LEO.

Duke's suggestion that a LEO is extinguished unless the utility "accepts" a change in the QF is also antithetical to the purpose of the LEO concept, which is to prevent utilities from interfering with QFs' PURPA rights. In making this suggestion, Duke is pushing the *Sub 148 Order* further than the Commission intended. While the *Sub 148 Order* did note that "existing regulatory and legislative policies have created a 'distorted marketplace' for solar projects and that this results

[180] Commission Rule R8-64(b)(3)(iii) and (ix).
[181] *Joint Initial Statement*, pp. 37-38.
[182] *Order on Pending Motions*, p. 3, Docket No. E-100 Sub 74 (Feb. 13, 1995).

in artificially high costs being passed on to North Carolina ratepayers[,]"[183] Duke appears to infer from this that any regulatory change that decreases the aggregate amount of QF sales is appropriate. However, the *Sub 148 Order* also made clear that the Commission was not trying to discourage QF development, but was adjusting the regulatory framework, in part based on HB 589, to "balance[e] PURPA's goals with the economic and regulatory circumstances facing QFs and utilities in North Carolina."[184] The Commission concluded that the balance struck in the *Sub 148 Order* was appropriate, and Duke has not introduced any facts or arguments to show that this balance was incorrectly struck and must be further adjusted.

Furthermore, the Commission was careful in the *Sub 148 Order* to "avoid introducing regulatory uncertainty."[185] Consequently, the *Sub 148 Order* focused on prospective changes to avoided cost rates and the regulatory structure. The *Sub 148 Order* did not focus on retrospective changes that would affect QFs that had already entered into standard offer PPAs. Duke's current proposal, in contrast, would have a dramatic impact on existing QFs and would therefore "introduce regulatory uncertainty," contrary to the goals of the Commission.

III. CONCLUSION

For all the reasons set forth above, NCSEA requests that the Commission reject the Utilities' avoided cost plans and request for new rate design including the Solar Integration Charge and require the Utilities to file new avoided cost plans

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[183] *Sub 148 Order*, p. 16.
[184] *Id.* at p. 17.
[185] *Id.* at p. 18.

which provide accurate representations of the avoided cost of both energy and capacity, including highlighting the benefits of distributed generation and solar, commensurate with the findings and conclusions made in this filing and also its two attachments.

Respectfully submitted this the 12th day of February, 2019.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 12th day of February, 2019.

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