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

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

NCSEA'S REPLY COMMENTS

The North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in the above-captioned proceeding, files these reply comments pursuant to the *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing Biennial Proceeding") issued by the North Carolina Utilities Commission ("Commission") on June 26, 2018, and as subsequently modified by orders dated January 4, 2019, January 25, 2019, February 8, 2019, February 22, 2019, and March 19, 2019.

I. BACKGROUND

On November 1, 2018, Western Carolina University ("WCU") and New River Light and Power ("New River"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("Dominion" or "DENC"), and Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (DEC and DEP, collectively, "Duke") made their initial substantive filings in this docket (Duke and Dominion, collectively, the "Utilities").

On February 8, 2019, NC WARN, Inc. ("NC Warn") filed initial comments. On February 12, 2019, the NC Small Hydro Group ("Hydro Group" or "NC Small Hydro"), Cube Yadkin Generation LLC ("Cube Yadkin"), NCSEA, and the Southern Alliance for Clean Energy ("SACE") filed their respective initial comments. On February 13, 2019, the

North Carolina – Public Staff ("Public Staff") filed the Initial Statement of the Public Staff ("Public Staff Initial Statement") and, also, a Motion to Deem Comments as Timely Filed, seeking for the Commission to accept the Public Staff Initial Statement as timely filed.

NCSEA stands by the positions taken in NCSEA's Initial Comments, and, as set forth more fully below, supports many positions taken by other intervenors in this docket. NCSEA also rejects some of the positions taken by intervenors in this docket and, in particular, those positions which are highlighted below.

II. Avoided Energy Costs

A. Natural Gas Forecasting

NCSEA agrees with the Public Staff and SACE that Duke's reliance on ten-year forward pricing for natural gas forwards is inappropriate. NCSEA particularly finds Public Staff's argument regarding other utilities' forecasting methods, including some which fall under the Duke Energy umbrella, compelling:

> the Public Staff's research has found a significant number of utilities, Duke Energy Florida, Duke Energy Kentucky, Duke Energy Indiana, TVA, DENC, Georgia, Power Company, Southwestern Public Service Company, Entergy Louisiana, Entergy Arkansas, PacifiCorp, and Puget Sound Energy, using a methodology with a much narrower window for the use of forwards than the ten years proposed in this proceeding by Duke. Further, DEC and DEP have been unable to provide the Public Staff with the name of any utility that incorporates the use of forward natural gas prices greater than five years for IRP or similar long-term planning purposes.[1]

NCSEA further agrees that "DEC's and DEP's proposed use of 10-years of forward prices will not be representative of Duke's actual fuel prices, thereby sending the wrong price signals to the market,"[2] and, "[t]he fact that Duke has been able to purchase ten-year

[1] *Initial Statement of the Public Staff*, p. 25, Docket No. E-100, Sub 158 (February 13, 2019) ("Public Staff Initial Statement").
[2] *Id.* at 25.

forwards on five occasions in the last three years should not be determinative as to whether the use of ten-year forwards is appropriate. It is clearly not Duke's standard operating procedure in its fuel procurement practices to purchase ten-year forwards."[3]

While NCSEA agrees with the Public Staff regarding Duke's ten-year request, the Public Staff's proposal of allowing for up to "five years of forward market data before appropriately transitioning to the Company's fundamental forecast"[4] still inadequately captures accurate price signals. NCSEA believes that the forecast should use forward prices for up to two-years, with a three-year transition to the average of a set of recent fundamentals forecasts from either Dominion's forecast from ICF International, Inc. ("ICF") or the new *2019 AEO* forecast from the U.S. Energy Information Administration ("EIA").[5] SACE similarly believes that the Commission should "require Duke to rely on no more than two to three years of forward market price forecasts, before transitioning to a blended price forecast, and then a fundamental price forecast."[6] Also, as noted by SACE and the Public Staff, the Commission's October 11, 2017 Order in Docket No. E-100 Sub 148 ("E-100 Sub 148 Order") specifically states that a ten-year forwards forecast, as requested by Duke here, is inappropriate.[7] NCSEA believes that, especially given the spectrum of arguments against such long-term forecasting, the Commission should reject Duke's proposal to rely upon ten-year forecast and, instead, require Duke to rely upon a much shorter-in-time forward forecast before transitioning into a fundamentals forecast analysis in the current avoided cost calculation. Specifically, as stated in NCSEA's Initial

[3] Public Staff Initial Statement, p. 27.
[4] *Id.* at 28.
[5] *NCSEA's Initial Comments*, p. 19, Docket No. E-100, Sub 158 (February 12, 2019) ("NCSEA's Initial Comments").
[6] *Initial Comments of the Southern Alliance for Clean Energy*, p. 6, Docket No. E-100, Sub 158 (February 12, 2019) ("SACE's Initial Comments").
[7] SACE's Initial Comments, p. 6; Public Staff Initial Statement, pp. 21-22.

Comments, a two-year forwards forecast transitioning for three-years into a fundamentals forecast would be more appropriate and accurately reflect pertinent price signals.

B. HEDGING VALUES

Like NCSEA, the Public Staff is concerned about Duke's removal of the hedging value:

> The Public Staff reiterates its prior support for inclusion of a hedging value for renewables found to be appropriate by the Commission in the Phase One Order, and recommends that the Commission require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing model or similar method."[8]

As the Public Staff outlines, Duke contends that PURPA provides for a "Put Option" and the associated rights to Qualified Facilities ("QF") and this obligation is being within the QF's sole discretion is the equivalent to the QF owning a "Put Option."[9] Like the Public Staff, NCSEA disagrees with this position which would, as the Public Staff puts it "require QFs to compensate utilities for the right to sell their generation."[10] NCSEA agrees with the Public Staff that the removal of any hedging benefits of renewable generation is not justified despite Duke's claims that a "risk of overpayment from extending" the put-option right to QFs needs to be offset and doing do by removing hedging benefits is appropriate.[11] As noted by the Public Staff, "[t]he risk of overpayment was directly addressed by this Commission in the 2016 Proceeding through the elimination of

[8] Public Staff Initial Statement, p. 29.
[9] *Id.* at 28.
[10] *Id.*
[11] *Id.*

capacity payments when capacity is not needed, the reduction in the PAF from 1.20 to 1.05, and the reduction of the MW threshold to be eligible to receive a Standard Contract."[12]

SACE similarly argues that Duke has improperly sought to eliminate hedging value. NCSEA agrees with SACE that Duke bears the burden in this proceeding and has failed to meet the necessary burden to eliminate fuel price hedge value.[13] NCSEA also agrees that:

> Duke attempts to obfuscate the [put-option] issue by repeatedly claiming that it is not 'recommending applying this charge to QFs at the time' while simultaneously recommending the removal of the 0.028 cents per kWh hedging value from avoided energy rates. Regardless of how Duke characterizes it, the removal of the existing hedging value would reduce the avoided energy costs paid to QFs by 0.028 cents per kWh. Duke may not circumvent its obligation to include hedging benefits in its avoided energy rates by assuming that the alleged and unsupported option premium, based on the yet-to-be calculated value of the Put Option, is identical to the existing hedging value.[14]

Duke's work-around to eliminate hedging is improper. SACE makes a further instrumental point: "Duke is not entitled to compensation for the legal right PURPA grants QFs to sell energy and capacity to the Companies at avoided cost rates. […] a QF is not required to purchase the right to sell energy and capacity under PURPA. Congress and FERC have expressly granted QFs the right to sell energy and capacity to the Utilities at a price that is determined at the time the legally enforceable obligation is created." This argument is capped with a relevant assumption: "[i]f Congress or FERC had intended for utilities to receive compensation for a QF's right to sell energy and capacity, they could have expressly included this requirement in statute or regulations, but they did not."[15]

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[12] Public Staff Initial Statement, pp. 28-29; See Section VI below for a more in-depth review of PAF allocation.
[13] SACE Initial Comments, p. 8.
[14] *Id.* at 8-9.
[15] *Id.* at 9.

NCSEA agrees with SACE and the Public Staff and believes that the Commission should disallow Duke's intended elimination of hedging benefits. For these reasons, the Commission should direct Duke to reinstate hedging benefits in a revised avoided cost proposal.

III. AVOIDED CAPACITY COSTS

A. PEAKER METHODOLOGY

NCSEA disagrees with the Public Staff on their analysis of the costs of a hypothetical new Duke peaker plant. Namely, the Public Staff suggests that the use of brownfield costs, rather than greenfield costs, for new peaker plants is a more accurate way to determine the avoided capacity.[16] The Public Staff bases this argument on the assumption that "DEC and DEP have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several "brownfield" sites for potential future use for both baseload and peaking needs."[17] The Public Staff goes on to state that the brownfield sites "referenced above" are "available for use to construct future generation and represent *potential* value to customers that is not reflected in the costs of a greenfield site."[18]

The Public Staff does not provide specific brownfield sites, but rather relies on recent history to make the determination that Duke should adjust its EIA formula to utilize brownfield site costs in peaker plant calculations necessary for an avoided cost calculation.

> DEC and DEP have already utilized brownfield sites for new generation construction. In fact, the last five Duke generating plants built have been at a brownfield site or in the proximity of an existing generating station, utilizing on-site infrastructure. Examples include the Sutton Combined Cycle (DEP), Sutton Black Start CT (DEP), Lee Combined Cycle (DEC),

[16] Public Staff Initial Statement, p. 67.
[17] *Id*.
[18] *Id*.

Asheville Combined Cycle (DEP), and Lincoln County CT (DEC). It is reasonable to assume that some portion of the capacity need demonstrated over the planning period in each Utilities' 2018 IRP will be constructed on brownfield sites."[19]

The issue with the Public Staff's suggestion that Duke rely upon brownfield rather than greenfield costs is that Duke has not projected enough open brownfield locations for capacity additions. As the Public Staff notes – Duke has not proscribed the use of brownfield sites in their avoided cost calculation in their next avoided cost proposal.[20] Therefore, the Public Staff is, on its own accord, changing the avoided cost calculus in such a way that will cause it to suppress installed costs and lower the capacity payments in the next filing. To this point, in the 2018 Integrated Resource Plan filings, Duke only identified two future capacity additions that will occur at brownfield locations, and both of these facilities have already received certificates of public convenience and necessity ("CPCNs") from the Commission: in DEC, the "402 MW Lincoln CT 17 included in December 2024[;]"[21] and, in DEP, the "560 MW Asheville combined cycle addition in November 2019."[22] Given that Duke predicts only two capacity additions which may be brownfield sites, and that neither site is incorporated into its avoided cost peaker plant calculations, Duke does not appear to intend to utilize numerous brownfield sites and, instead, may have used the EIA-formula utilizing greenfield sites for good reason.

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[19] *Id.* at 68.

[20] Public Staff Initial Statement, p. 67; "DEC and DEP relied on EIA data for hypothetical overnight costs and made certain adjustments to reflect the expected economies of scale associated with the gas interconnection costs for the Carolinas service areas. The EIA costs are representative of a "greenfield" site, meaning a site with no existing infrastructure." *Id*.

[21] *Duke Energy Carolinas, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, p. 63, Docket No. E-100, Sub 157 (September 5, 2018) ("DEC IRP"). *See also*, *Order Issuing Certificate of Public Convenience and Necessity with Conditions*, Docket No. E-7, Sub 1134 (December 7, 2017).

[22] *Duke Energy Progress, LLC 2018 Integrated Resource Plan and 2018 REPS Compliance Plan*, p. 65, Docket No. E-100, Sub 157 (September 5, 2018) ("DEP IRP"). *See also*, *Order Granting Application in Part, with Conditions, and Denying Application in Part*, Docket No. E-2, Sub 1089 (March 28, 2016).

For all these reasons, NCSEA opposes the Public Staff's suggestion that Duke utilize more brownfield site data. NCSEA does not oppose Duke's utilization of brownfield sites in their next avoided cost filing but believes that such input only be utilized if Duke does plan to utilize it and will be reflective of true cost data.

B. SUMMER CAPACITY VALUES

NCSEA agrees with SACE that Duke has devalued the capacity contributions of solar QFs and eliminated the capacity benefits solar QFs can provide by overstating winter effects and undervaluing summer capacity values:

> Duke has designed its avoided capacity rates using a 100% winter / 0% summer allocation for DEP, and 90% winter / 10% summer allocation for DEC, meaning that Duke has assigned 100% of its loss of load risk in DEP to the winter months and 90% of its loss of load risk in DEC to the winter months. As a result, DEP's new rates pay all of its annual capacity value in the winter and DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer. These changes are significant because by allocating all or nearly all loss of load risk in the winter, Duke devalues the capacity contributions of solar QFs and almost completely eliminates consideration of the capacity benefits solar QFs provide during summer demand peaks.[23]

SACE's argument outlines how Duke has changed allocations in such a way as to totally undermine the value of solar QFs on the grid. Furthermore, SACE's expert found that the Duke studies related to this are flawed:

> Mr. Wilson concludes that the RA Studies and Capacity Value Study contain a number of methodological flaws that have caused Duke to over-estimate the risk of very high loads in the winter and unnecessarily inflate the winter and summer planning reserve margins. Applied to the avoided cost proceeding, these flaws have caused the Companies to greatly overstate winter resource adequacy risk compared to summer, and to inappropriately allocate 100% and 90% of winter loss of load risk in DEP and DEC, respectively.[24]

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[23] SACE Initial Comments, pp. 11-12 (internal citations omitted).
[24] *Id.* at 13.

NCSEA agrees that the methodologies used in this report are flawed.

Furthermore, NCSEA wishes to highlight the following passage of SACE's Initial Comments which outlines how the Duke reports substantially overrate winter:

> This report shows that the risk of very high loads under extreme cold was substantially overstated in the 2016 RA [Resource Adequacy] Studies, primarily due to the faulty approach to extrapolating the increase in load due to very low temperatures. Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Overall, the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year. Accordingly, the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights developed and approved.[25]

NCSEA completely agrees with SACE – Duke's flawed methodologies result in an overstatement of winter risk, and, accordingly, an unnecessary and unfair reallocation of capacity values resulted in Duke's analysis. NCSEA agrees that Schedule PP should be rejected and that more balanced seasonal weights need to be developed and approved. To that end, NCSEA disagrees with the Public Staff's assertion that "Duke's seasonal allocation of capacity payments greatly reduces the risk that ratepayers would overpay for capacity from QFs due to high solar output in the summer."[26] This is simply not the case as Duke's methodologies are flawed and should be corrected to provide true capacity values.

[25] SACE Initial Comments, Attachment B, p. 4.
[26] Public Staff Initial Statement, p. 63.

C. PPA RENEWAL AND CAPACITY DETERMINATIONS

In its Initial Comments, NCSEA requested the Commission consider how to deal with the residual rights of QFs whose power purchase agreement ("PPA") is expiring and who seek to enter new PPAs for the balance of their useful lives.[27] NCSEA further stated that "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."[28] NCSEA's argument for continuity and predictability while PPAs expired was further explored by NC Small Hydro.

In the *Hydro Group's Initial Comments*, the NC Small Hydro made a compelling legal argument for a QF to have an expectation of a renewal of capacity from their old, expiring PPA to their new PPA. The NC Small Hydro relied upon a decision made by the Idaho Utilities Commission ("Idaho Commission"). Specifically, the Idaho Commission found that

> [i]t is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the utility's load and resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal.[29]

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[27] NCSEA's Initial Comments, p. 48.
[28] *Id.* at 49.
[29] *Hydro Group's Initial Comments*, pp. 8-9, Docket No. E-100, Sub 158 (February 12, 2019) ("Hydro Group's Initial Comments"), quoting *In the Matter of the Commission's Review of PURPA QF Contract Provisions Including the Surrogate Avoided Resource (SAR) and Integrated Resource Planning (IRP) Methodologies For Calculating Avoided Cost Rates*, Case No. GNR-E-11-03, Order No. 32697, dated Order to Clarify Commission Final Order, Order No. 32871, dated August 9, 2013.

The Idaho Commission created an exception to the IRP capacity deficit in computing avoided cost rates under the IRP methodology and, recently, restated its position: ""[i]f a QF renews its contract with a utility, the capacity deficit date is still determined as of the date the original contract was executed."[30]

Ultimately, the NC Small Hydro requested the Commission to recognize that "renewal and extensions of QF contracts establish the need for their capacity as of the date the original contract was executed and that the Commission subject capacity deficiencies in the IRP proceeding to additional scrutiny."[31] NCSEA finds the NC Small Hydro's legal argument compelling and agrees with the requested relief. Given that the matter of the renewal of QF PPAs has not yet been mined out by the Commission and the parties involved, particularly with regard the tangential contracting factors made into law by HB589, a determination needs to be made with regard to how to handle renewal of PPAs. On that matter, the guidance brought by the Idaho docket seems a fair and reasonable way to help determine this matter. Therefore, NCSEA supports the NC Small Hydro's request that the Commission recognize the capacity need as relating back to the date of the original contract for QFs and in the manner consistent with the NC Small Hydro's request.

IV. PERFORMANCE ADJUSTMENT FACTOR

The Public Staff believes that the calculation to determine performance adjustment factor ("PAF") should look at both historical data and future projections of reliability that incorporate planned improvements.

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[30] Hydro Group's Initial Comments, p. 10 quoting *In the Matter of Application of Idaho Power Company for Approval or Rejection of an Energy Sales Agreement with McCollum Enterprises, Limited Partnership, for the Sale and Purchase of Electric Energy from the Canyon Springs Hydro Project*, Case No. IPC-E-18-12, Order No. 34200, dated December 4, 2018, p. 2.
[31] Hydro Group's Initial Comments, p. 11.

> As avoided cost proceedings continue to evolve, it may be appropriate for the Utilities to use new and different techniques and assumptions, such as applying prospective, forward-looking EFOR components to the PAF calculation. Because avoided cost rates are inherently forward-looking, it is also appropriate to take a forward-looking approach when determining each Utility's overall EFOR for use in avoided cost calculations, taking into consideration future capital that is, or will be, invested in generating assets, as well as, but not limited to, new or modified O&M costs, preventive maintenance costs and protocols, and newer generation technologies.[32]

NCSEA agrees that the calculation of PAF, which accounts for potential generation reliability hiccups from QFs in the avoided cost calculation, should be forward-facing as technology improves and, hopefully, to reflect the continued upgrades to the grid accommodating more technologies which utilize smart technologies to implement distributed generation. However, NCSEA believes that the Public Staff could take a more determinative step in requesting a true reflection of the current PAF calculation. The Public Staff merely requests the Commission require the Utilities to recalculate the PAF with new inputs:

> The Public Staff recommends that the Commission direct the Utilities to perform a revised PAF calculation, including June and December EFOR data. The Public Staff believes using a critical peak load analysis to determine the critical peak period(s) of the Utilities' systems is consistent with the Commission's guidance in the *2016 Order*.[33]

NCSEA believes that Duke, at least, has biased its current PAF calculations and that the Duke avoided cost proposal discriminates against QFs and understate their contribution to capacity during peak months, but rather than recalculating on its own, NCSEA "recommends that the Commission reject Duke's PAF proposal and adopt the proposal of a PAF between 1.08 and 1.10" in NCSEA's Initial Comments.[34] Further, as

[32] Public Staff Initial Statement, p. 70.
[33] *Id*. at 72.
[34] NCSEA's Initial Comments, pp. 31-32.

stated above, NCSEA agrees with the Public Staff's position that PAF mitigates the Utilities' risk of overpayment to QFs and no further actions are necessary to offset potential overpayment such as the removal of hedging values.[35]

V. Solar Integration Charge

NCSEA restates its fundamental opposition to the solar integration charge. While NCSEA understands and agrees with some of the positions of the Public Staff, NCSEA disagrees with the Public Staff's conclusion that utilities incur costs related to intermittent generation from QFs. As set forth below, the Public Staff's position (along with Utilities' positions) do not account for the benefits incurred on the grid due to distributed generation and, accordingly, blindly attributing a fixed charge to QFs for their generation but not accounting for benefits to the grid, including specifically ancillary benefits, which can offset intermittency and upgrade generation in other ways, is bad policy and should be denied as such.

A. If a Solar Integration Charge is mandated, then NCSEA supports some of the other intervenor's positions.

1. Analysis of QF Benefits to the Grid and the Refresh Proposal

NCSEA generally agrees with the Public Staff that the Commission needs to hear evidence about other known costs and benefits that should be included in an integration charge: "it may be appropriate for the Commission to consider evidence from other parties as to what additional costs or benefits can be sufficiently known and verifiable at this time such that they should be included in avoided cost rates."[36] NCSEA also agrees with the

[35] Public Staff Initial Statement, pp. 28-29.
[36] *Id.* at 33.

Public Staff that Duke lacks support to seek to refresh an integration "charge" every two years, this issue was discussed in Commission Docket No. E-100, Sub 148, and that such a frequent refresh would make financing for QFs difficult.[37]

The Public Staff goes on to state that if a charge were implemented, either there is no two-year refresh or, alternatively, if the Commission finds a refresh is appropriate then that there is a cap on the upper limit for the solar integration charge.[38] While NCSEA strongly opposes any solar integration charge, particularly one which does not identify the benefits brought to the grid by each individual interconnecting facility, if such a charge is mandated by the Commission, then NCSEA agrees that there should be no two-year refresh. If the Commission determines a refresh (of any type) is appropriate, NCSEA agrees with the Public Staff that there should be an upper limit as to any fixed charge proscribed by Duke against facilities looking to interconnect.

2. THE ASTRAPÉ STUDY INCORRECTLY MODELED DUKE'S SERVICE TERRITORIES

NCSEA and the Public Staff concur on the shortcoming of the Astrapé Study with regard to the islanding of utility territories: "[t]he Astrapé Study models DEC and DEP as load islands with no ability to rely on each other or on the larger Eastern Interconnection to meet intra-hour load variations."[39] NCSEA and the Public Staff also both agree that this practice does not reflect how a grid is operated:

> Practical realities of the operation of the electric grid challenge the merits of [the islanding assumption], which may result in a solar integration charge greater than the costs that are actually being incurred […] As reflected in their IRPs, DEC and DEP are able to utilize synergies between each other's

[37] Public Staff Initial Statement, p. 37.
[38] *Id.* at 38.
[39] *Id.* at 36.

balancing areas such as coordinating outages and more economically dispatching the combined systems on a non-firm basis.[40]

NCSEA and the Public Staff have a similar belief on this matter and, accordingly, NCSEA requests that the Commission require Duke to correct their model so as to eliminate the islanding which may cause a potential integration charge to be higher than appropriate.

3. Utility-Owned Solar Facilities Should be Included in the Baseline for Setting the Integration Charge

NCSEA also agrees with the Public Staff that, if the Commission implements a solar integration charges, there is concern that the effect may be that Duke-owned qualified facility costs are shifted to third-party solar QFs.

> The Public Staff is concerned that this methodology could have the effect of assigning the costs that result from the integration of utility-owned solar to solar QFs. It is important that the calculations of avoided energy rates reflect the same solar integration charge-related costs for utility-owned intermittent generation that will be recognized for non-utility-owned intermittent generation. While utility customers currently pay these costs in the form of additional fuel and other ancillary services costs, the determination of these solar integration charge-related costs and the resulting avoided energy rates should incorporate the impacts from similar utility-owned intermittent generation."[41]

NCSEA echoes these concerns, and requests that the Commission, should it approve the solar integration charge in any form, require that the underlying modeling for such a charge include inputs that incorporate the impacts from utility-owned solar generation so as to show that Duke is paying its fair share for its own solar resources.

[40] *Id.* at 39.
[41] *Id.* at 40.

4. NCSEA AND THE PUBLIC STAFF AGREE ON OTHER FLAWS IN THE ASTRAPÉ STUDY

Like NCSEA, the Public Staff is concerned about the use of a short amount of historical data in Astrapé's modeling: "[b]ecause solar volatility was modeled using only one year of historical data, assumptions made regarding solar fleet diversity could result in an inaccurate solar integration charge."[42] NCSEA agrees with the Public Staff that the short amount of historical data in the model may result in an inaccurate charge and, like above, NCSEA believes the Commission should, if it determines a solar integration charge is appropriate, require Duke to correct its underlying modeling so as to incorporate more historical data. Further, the Astrapé Study only models a single ancillary service and completely ignores other methods of addressing intermittency of generation. "The Public Staff has concerns that this modeling assumption is not valid, and that there may be other ancillary service products, or even alternative methods entirely, of handling the volatility of solar generation."[43] NCSEA believes this is integral to any discussion regarding a fixed charge for QFs to interconnect to the grid. Duke has failed to list any benefits for the interconnection of QFs to the grid and, unsurprisingly, ignored a litany of established and emerging technologies that have been or could be incorporated by QFs which could offset the alleged "costs" of solar integration due to intermittency. For these reasons, NCSEA believes that any solar integration cost analysis model should include a forward-facing model that incorporates any and all benefits currently incorporated by QFs and also those that may be incorporated in the near-future based upon analysis of the solar sector and

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[42] *Id.* at 37.
[43] *Id.* at 42.

emerging technologies which have become able to be incorporated to scale of North Carolina QFs.

5. Dominion Re-Dispatch Charge

NCSEA agrees with SACE that the Dominion re-dispatch charge is based on analysis of inappropriate solar penetration levels as Dominion simply averaged re-dispatch costs of multiple solar penetration levels resulting in an inflated charge.[44] NCSEA also agrees with SACE that Dominion simply averaged multiple combinations of assumptions which conflated inputs and ultimately resulted in inaccurate and unsupported conclusions.[45]

NCSEA agrees with the Public Staff on some of the issues related to the proposed re-dispatch charge contained in Dominion's avoided cost proposal. NCSEA agrees that it's unclear whether Dominion's re-dispatch costs are an incremental or an average charge and that this calculation could impact the magnitude of the charge.[46] NCSEA shares Dominion's concern about the utilization of historic data versus average generation portfolios.[47] Finally, NCSEA agrees with the Public Staff's concern regarding modeling a charge based upon smaller systems being scaled up in profile to match a larger solar facility profile. This "scaling" may create high volatility and negatively affect the model.[48]

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[44] SACE Initial Comments, p. 18.
[45] *Id*.
[46] Public Staff Initial Statement, p. 45.
[47] *Id*.
[48] *Id*.

B. NCSEA SPECIFICALLY OPPOSES THESE INTERVENOR POSITIONS ON THE SOLAR INTEGRATION CHARGE AND THE RE-DISPATCH CHARGE

As a matter of initial concern, NCSEA opposes the concept of any fixed charge which allegedly offsets costs that accrue on the grid due to QF intermittent generation. NCSEA has long taken the position – and does so in depth in its Initial Comments – that distributed generation, including solar, causes a net benefit to the grid and to rate payers. NCSEA disagrees with the Public Staff's position to the extent that it allows for fixed charges related to solar intermittency. Furthermore, NCSEA believes that while the Public Staff acknowledges the benefits of distributed generation, including solar, to the grid, the Public Staff fails to capture the totality of such benefits given that they do not oppose the underlying structure of the Solar Integration Charge. Any review of the effect of solar on the grid must include a cost/benefit analysis of solar, including ancillary benefits, and also allow for forward-looking analysis to future benefits. NCSEA would encourage the Commission, as well as the Public Staff, to acknowledge and heavily account for the benefits of solar and the current and emerging ancillary benefits of QFs which provide net benefits to the grid. Ultimately, as ancillary benefits become more prevalent, utilities will no longer be charged with replacing energy from intermittent sources as that problem will be solve by the QFs themselves.

NCSEA also disagrees with the Public Staff's conclusions regarding the Astrapé Study and "operational challenges". "The Public Staff reviewed the Astrapé Study and generally agrees that DEC and DEP face operational challenges resulting from the current and pending amount of a single specific aggregate resource connected to its electrical grid."[49] While NCSEA will acknowledge the difficulty inherent in interconnecting QFs to the grid in a vacuum, this position is undercut by the fact that Astrapé gave no credence to the benefits of solar and did not sufficiently measure current and future ancillary services which will offset many of the alleged "operational challenges" referred to here.

Finally, the Public Staff states that the "general concept of the Astrapé Study has merit from a both a system operations perspective and a modeling methodology" and requests that "Duke, in conjunction with Astrapé, also provide analysis of other types of QFs and other distributed energy resources (DERs) in addition to solar facilities and develop similar average and incremental service cost estimates." The Public Staff further requests that a new model provided by Astrapé need to address the numerous concerns laid out in the Public Staff Initial Statement. These requests, while reasonable, are counter to the underlying point and also ignore other intervenors' positions. As stated repeatedly, the solar integration charge, and the Astrapé Study which allegedly justifies it, completely ignores the benefits of distributed generation on the grid, particularly including solar, and is inherently flawed in its approach. Further, even if a compelling argument is made to introduce a new fixed charge for QFs, the Astrapé Study is so fundamentally flawed and one-sided that it cannot plausibly be relied upon. The Astrapé Study, in fact, has a poor modeling methodology as set forth in NCSEA's comments and exhibits and also SACE's Initial Comments and attached exhibits. Should the Commission determine that an integration charge is necessary, to which NCSEA holds a continuing objection, then NCSEA believes that a completely new model, incorporating inputs and methodologies from a diverse group engineers and/or economists must be included, and this diverse group

[49] *Id.* at 34.

must represent the not only utility interest but, also, the interests of solar developers, clean energy advocates, and other groups directly impacted by the proposed charge.

VI. RATE STRUCTURES

A. THE RATE STRUCTURES NEED TO BE REFINED

NCSEA and the Public Staff agree that the rate structures implemented by the Utilities currently do provide sufficient granularity to determine accurate price signals. "In light of current and future potential uses of avoided cost hours and rates, the Public Staff believes that additional granularity, beyond that proposed by Duke and DENC in this proceeding, is appropriate and beneficial to North Carolina ratepayers."[50] NCSEA agrees that

> [M]ore granular pricing would signal a dispatchable QF to provide energy during times when the Utilities are most likely to operate their highest marginal cost generation units, thus avoiding the need to run those units, and would also provide clear price signals to developers interested in adding new technologies, such as energy storage, to their intermittent facilities. Avoided energy rates that accurately reflect the Utilities' highest production cost hours (lambdas) increase the likelihood that the interests of ratepayers and developers align."[51]

The Public Staff, like NCSEA, has concerns about Duke's resource adequacy studies:

> As stated previously, the Public Staff raised concerns with the assumptions made in the Resource Adequacy Studies, documenting them extensively in its April 2, 2018 Joint Report filed in Docket No. E-100, Sub 147. These concerns center around assumptions made regarding the relationship between cold weather and load, estimates of load forecast error distributions, and a lack of recognition of winter hardening efforts undertaken by the utilities, among others. Many of these concerns were addressed in the Public Staff's proposed Public Staff Scenario #2 (PS-S2) that was analyzed by Duke in the 2018 IRP proceeding. […] Because of these concerns, the Public Staff recommends that the Commission order

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[50] Public Staff Initial Statement, p. 54.
[51] *Id*.

> Duke to rerun its Resource Adequacy Studies using PS-S2 to determine the effect of the Public Staff's proposed modifications on the Capacity Payment Hours and seasonal allocation.[52]

NCSEA agrees with the concerns of the Public Staff regarding the Resource Adequacy Studies and generally agrees with the Public Staff's recommended solution to modify and rerun the studies based upon the proposed modifications of both the Public Staff. NCSEA would add, for comparison's sake, any other intervenors' proposals to the new studies who have proposed modifications to rate structure of this nature. It should be noted that NCSEA specifically seeks a new model which displays the proposed, increased granularity discussed in the Public Staff Initial Statement and NCSEA's Initial Comments.

NCSEA also supports the Public Staff's position that the LOLE method to establish eligibility for capacity payments is inappropriate and generally prefers the Dominion method.[53] However, like the Public Staff, NCSEA is concerned about the future impact of Dominion's proposed capacity payments and supports the Public Staff's position that DENC should evaluate alternative seasonal allocation and Capacity Payment Hours that align to DENC's system.[54]

VI. <u>INCREASES TO ENERGY OUTPUT</u>

As has been discussed extensively in other proceedings,[55] energy storage is now cost-competitive with other resources and is likely to see substantial deployment before the next biennial avoided cost proceeding. Therefore, the decisions made by the Commission in this proceeding will set the stage for energy storage deployment in North Carolina. Given

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52 *Id.* at 58-59.
53 *Id*. at 57-60.
54 Public Staff Initial Statement, p. 64.
55 *See generally*, Docket No. E-100, Sub 101; Docket No. E-100, Sub 157.

this reality, NCSEA shares the concerns expressed by the Public Staff and SACE that Duke's proposed additions to the PPA Terms and Conditions regarding energy storage and increases to a QF's energy output are overly and unduly restrictive.[56]

NCSEA agrees with the Public Staff "that requiring a new PPA for existing facilities using the most recently approved avoided cost rates may disincentivize the adoption of new energy storage technologies at existing facilities, which have the potential to benefit ratepayers."[57] Even more importantly, NCSEA agrees with SACE that "the replacement of older solar panels with newer solar panels that does not increase the AC output capacity of the facility should not be considered a material modification to the QF, and it should not require the QF to forfeit is existing standard offer contract and enter into a new PPA."[58] Both the Public Staff and SACE note that requiring a new PPA for any such changes could mean that a QF that was previously subject to a standard contract PPA is now subject to a negotiated PPA.[59]

Despite these areas of agreement, NCSEA disagrees with the Public Staff's assertion that "the increased energy output should be subject to the rates determined in the most recently effective avoided cost docket."[60] The fact that a QF "could increase its total revenue generated through the addition of energy storage or other technologies"[61] is insufficient reason to violate the PURPA rights of QFs. A QF that is already providing

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[56] *See,* Public Staff Initial Statement, pp. 74-76; SACE Initial Comments, pp. 16-17.
[57] Public Staff Initial Statement, p. 74 (internal citations omitted).
[58] SACE Initial Comments, p. 17.
[59] Public Staff Initial Statement, p. 76 ("The Public Staff also believes that designating the addition of energy storage at an existing facility as a new and separate facility may result in unintended consequences, including loss of eligibility as a standard offer QF or a FERC-certified QF."); SACE Initial Comments, p. 17 ("Because such changes would not increase the QF's nameplate capacity beyond the threshold under which the standard offer contract was available, the QF should be permitted to make such changes under its existing PPA.").
[60] Public Staff Initial Statement, p. 74 (internal citations omitted).
[61] Public Staff Initial Statement, pp. 74-75.

electricity to the grid has already met the Commission's requirements to establish a LEO,[62] and an increase in energy output does not void that LEO. No new CPCN is necessary to increase energy output; instead, a QF is required to seek a modification to the CPCN. Therefore, NCSEA respectfully disagrees with the Public Staff's suggestion that any increase in energy output should be separately metered and paid at a different avoided cost rate.[63] However, should the Commission agree with either Duke or the Public Staff's proposals, NCSEA agrees with the Public Staff that authorization to increase energy output "should not be unduly withheld."[64]

VII. CONCLUSION

As set forth herein, NCSEA supports many of the positions taken by intervenors in this docket and also opposes some positions. Accordingly, NCSEA restates its request for the Commission to reject the Utilities' avoided cost plans and require the Utilities to file new avoided cost plans, consistent with the positions taken herein and also in NCSEA's Initial Comments, and which include accurate representations of the avoided cost of both energy and capacity, including highlighting the benefits of distributed generation and solar.

Respectfully submitted, this the 27th day of March, 2019.

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[62] E-100 Sub 148 Order, p. 8.
[63] Public Staff Initial Statement, p. 75.
[64] *Id*.

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.

Respectfully submitted, this the 27th day of March, 2019.

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