NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

September 4, 2019

Ms. Janice H. Fulmore, Deputy Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 158 - In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018

Dear Ms. Fulmore:

Enclosed for filing in the above-referenced docket is the Proposed Additional Findings, Evidence, and Conclusions of the Public Staff, to be considered in conjunction with the Partial Joint Proposed Order of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and the Public Staff that was filed separately in this docket. The numbering used in the Additional Findings, Evidence, and Conclusions is intended to provide guidance to the Commission in its review, but does not reflect placement of the provisions in the Partial Joint Proposed Order.

By copy of this letter, we are forwarding copies to all parties of record.

Sincerely,

/s/ Tim R. Dodge
Staff Attorney
tim.dodge@psncuc.nc.gov

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	))))	**PROPOSED ADDITIONAL FINDINGS, EVIDENCE, AND CONCLUSIONS OF THE PUBLIC STAFF**

Public Staff's Additional Findings of Fact

1. The inputs and assumptions used by DENC for the purpose of determining its proposed avoided energy rates, including its fuel forecasts, are appropriate for use in this proceeding.

2. DEC and DEP should recalculate their avoided energy rates using forward natural gas prices for no more than five years before transitioning to fundamental forecast data for the remainder of the planning period.

3. DENC's inclusion of the avoided costs related to fuel hedging activities in its proposed avoided energy rates is appropriate for use in this proceeding.

4. DEC and DEP should recalculate their avoided energy rates to include the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement (PPA).

5. It is inappropriate to use the avoided transmission and distribution (T&D) capacity rates from the demand-side management/energy efficiency (DSM/EE) proceedings in calculating avoided T&D capacity costs for this proceeding.

6. Utilities must consider site and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and include an avoided transmission adder if a project can provide real and measurable avoided transmission capacity benefits.

7. Prior to the next biennial proceeding, the Utilities should evaluate the avoided transmission benefits associated with QFs interconnected to the distribution system that are eligible for the standard offer contract and determine an appropriate avoided transmission cost adder to the avoided energy rate to reflect these benefits, which would be available unless the QF would cause or increase reverse power flow, or the projected load growth over the next ten years on the interconnected feeder is negative or negligible. The avoided transmission adder should be included in the Utilities' tariffs, and rate schedules in the next biennial avoided cost proceeding.

8. To the extent a QF that is not eligible for standard offer rates can demonstrate that it is providing ancillary services benefits that the utility would otherwise be required to purchase, it is appropriate for the utilities to compensate the QF for those additional benefits.

9. DENC's proposed re-dispatch charge complies with the Commission's previous orders and is consistent with PURPA.

10. As modified, DENC's proposed re-dispatch charge of $0.78/MWh is a reasonable and appropriate mechanism to recover the costs imposed on DENC to redispatch intermittent, non-dispatchable QFs in its service territory, and should be accepted for purposes of this proceeding.

11. The proposed changes to DENC's energy and capacity rate design should send appropriate price signals to incentivize QFs to better match the generation needs of utilities, and thus should be used in calculating DENC's avoided energy and capacity rates in this proceeding.

12. DENC's proposed seasonal allocation weightings of capacity value of 50% for summer, 40% for winter, and 10% for shoulder seasons are appropriate and should be used in calculating DENC's avoided capacity rates in this proceeding. In the next biennial proceeding, DENC should evaluate alternative seasonal allocation and capacity payment hours that align more directly to its system, as opposed to the PJM Interconnection, LLC (PJM) system as a whole.

13. DENC's proposed limit on capacity payments for intermittent resources is not appropriate and necessary if DENC's seasonal allocation and capacity payment hours more appropriately align to its system, and therefore should be rejected.

14. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Method, based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's last biennial proceeding.

15. The proposed modifications to the Standard Terms and Conditions proposed by Duke, including the definition of Material Alteration, are reasonable and appropriate. In determining whether updates to a facility are a Material Alteration that would lead to the termination of the existing PPA, Duke should evaluate those changes in a commercially reasonable manner and with a "degree of reasonableness" regarding any increase in capacity that results from equipment replacement and repairs.

16. Prior to increasing their output consistent with the Terms and Conditions of their existing PPAs, "Committed" solar QFs (i.e., facilities that have (i) established a legally enforceable obligation (LEO); (ii) executed a PPA; or (iii) commenced operation and sale of the electric output of the facility) that seek to add storage or otherwise materially increase their output by re-paneling or over-paneling should obtain the utility's consent, contingent on an evaluation of the potential impacts to the utility's system or other customers.

17. Material alterations to committed facilities that increase a utility's obligations to purchase energy at prior avoided cost rates are inappropriate and would unfairly burden ratepayers with increased payments to QFs that exceed current avoided cost rates. However, it is premature at this time to determine whether the Public Staff's compromise position that existing solar facilities that add storage by co-locating a battery behind the meter should be compensated at the current avoided cost rates, is appropriate.

18. It is appropriate for the parties to continue to discuss the technical, regulatory, and contractual complexities of separately metering the energy output from energy storage equipment that is co-located at existing solar facilities for further consideration by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings of fact is found in the Joint Initial Statement of DEC and DEP; the Initial Statement of DENC; the Initial Comments of NCSEA, the Public Staff, and SACE; the Joint Reply Comments of DEC and DEP; and the Reply Comments of DENC, the NC Small Hydro Group, the Public Staff, NCSEA, and SACE.

Summary of the Evidence

In its Joint Initial Statement, Duke stated that for determining forecasted avoided energy costs, the utilities are relying upon forward market price data out ten years (2019-2028), indicating its belief that these numbers provide a more precise indicator of the near-term future commodity costs of natural gas for both integrated resource plan (IRP) purposes—to plan for the Companies' next capacity resource option to meet customers' future energy needs—as well as for purposes of calculating avoided energy costs to be paid to QFs to avoid such future energy needs. Duke indicated that after relying on ten years of forward market data, it assumes that commodity prices begin to transition to fundamental forecast data starting in year 11. Duke indicated that since the Sub 148 Proceeding, it has purchased ten-year forward gas contracts on five separate occasions (one in 2016, two in 2017, and two in 2018) for use in its IRP and avoided cost filings and to demonstrate that forward market liquidity exists ten years into the future. Duke indicated that based on historical experience and recently-transacted forward gas purchases, natural gas commodity prices are liquid ten years into the future and have continued to steadily decline, and support its position that the continued use of ten years of forward market commodity prices for both IRP purposes and in the calculation of avoided costs is prudent and reasonable. (Joint Initial Statement at 17-21)

DENC in its Initial Statement indicated that, consistent with its past practice, it developed its avoided energy rates for the first 18 months using forward market prices, for months 19 through 36 using of a blend of forward market prices and a commodity forecast provided by ICF International, Inc. ("ICF"), and for month 37 and thereafter on ICF prices exclusively. (DENC Initial Statement at 8)

The Public Staff stated that it analyzed the methodologies used by other utilities around the country by reviewing other utility IRPs, and did not identify any utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years. The Public Staff also noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana in their IRPs each rely wholly on market prices for the first five years, blend market and fundamental prices for the next five years, and switch to the fundamental forecast for the remainder of the planning period. The Public Staff noted that Duke did not purchase ten-year forwards as a standard part of its fuel procurement practices, and its ability to purchase ten-year forwards on five occasions in the past three years should not be determinative as to whether the use of ten-year forwards is appropriate. Therefore, the Public Staff recommended that the Commission require DEC and DEP to use no more than five years of forward market data before transitioning to the Companies' fundamental forecast. (Public Staff Initial Comments at 21-28).

SACE noted that the Commission in the *2016 Sub 148 Order* directed DEC and DEP to "recalculate their avoided energy rates using forward natural gas prices for no more than eight years and fundamental forecasts for the remainder of the planning period" and that contrary to this directive, Duke relied on ten years of forward natural gas market price data. (SACE Initial Comments at 6, citing Ordering Paragraph No. 5 in *2016 Sub 148 Order*). SACE further stated that reliance on long-term forward pricing is inappropriate because future markets, which are highly responsive to short term and temporary trends, are not good indicators of long-term market trends. SACE also noted that the lack of trading volume for NYMEX gas futures more than two to three years ahead prohibits prices from being robust forecasters of gas prices, and stated that long-term forecasts should not be based on short-term trends, but instead on more stable factors such as resource base and expected production costs. SACE therefore recommended that the Commission 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. SACE also indicated its general support for the approach utilized by DENC. (SACE Initial Comments at 6-7).

NCSEA proposed that the Utilities use forward market prices for two years, before transitioning over the next three years to an average of a set of recent fundamentals forecasts, including the ICF forecast and the 2019 Energy Information Administration ("EIA") Annual Energy Outlook forecast. NCSEA further noted that Duke's current hedging policies do not allow the companies to buy quantities of natural gas at 10-year fixed prices to displace solar generation. NCSEA did state, however, that it would not object in the alternative to use of the forecast methodology used by DENC. (NCSEA Initial Comments at 17-19). NCSEA affiant R. Thomas Beach also noted that, "[t]he DEC/DEP transactions are with financial institutions that may have a limited pool of counterparties for these transactions, but the utilities have not provided evidence of a deep and transparent market for 10-year gas transactions at fixed prices" and further noted that Henry Hub Forward Market Open Interest on January 10, 2019, showed that only "99.0% of the open interest is in the first two years" and that there are "small and sporadic volumes traded in the out years." (NCSEA Initial Comments, Attachment 2, at 11).

DENC in its Reply Comments stated that its reliance on the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136), and continues to be appropriate. DENC notes that the ICF forecasts are reputable and respected in the industry and that the nationwide EIA forecast does not provide the same level of regional pricing information on which to base forecasted fuel prices in this proceeding. (DENC Reply Comments at 3-5).

SACE in its Reply Comments indicated that it considers the proposals of both the Public Staff and NCSEA be more appropriate than the natural gas forecast methodology proposed by Duke (SACE Reply Comments at 3), while NCSEA indicated its continued position that the use of a two-year forwards forecast, then transitioning for three-years into a fundamentals forecast would be more appropriate and accurately reflect pertinent price signals. (NCSEA Reply Comments at 3-4). The Small Hydro Group indicated that it agrees with the Public Staff that the Commission should require Duke to use no more than five years of forward market data before transitioning to its fundamental forecast. (Small Hydro Group Reply Comments at 3).

In its Reply Comments, Duke recognized that the Commission declined to approve the Companies' forecasts in the Sub 148 proceeding, and emphasized the importance of internal consistency between the Utilities' IRPs and the biennial avoided cost proceeding. Duke also acknowledged that the Commission was not fully persuaded that the market was sufficiently liquid to support 10-year futures, but indicated its intention to continue to monitor liquidity in the natural gas market in future avoided cost proceedings. (Duke Reply Comments at 11-12, discussing *2016 Sub 148 Order* at 77-78).

Responding to the Public Staff's analysis of other utilities' IRPs to support its argument, Duke indicated that the fundamental purpose of integrated resource planning differs from fixing forecasted avoided cost rates under PURPA, and that the Public Staff's reliance on the fuel procurement practices used by other utilities in the development of their IRPs is misplaced. Duke also noted that since the time of filing of Initial Comments, it had identified another North Carolina market participant that has also purchased significant quantities of 10-year forward natural gas, providing additional evidence of liquidity in the 10-year forward natural gas market. (Id. at 13-16).

In response to NCSEA's comments regarding the limited number of NYMEX futures contracts with terms longer than two years, Duke reiterated its position from the 2016 Sub 148 proceeding, that the terms of exchange transactions should not be viewed as evidence for market liquidity for longer-term transactions; rather, market liquidity is demonstrated by readily available long-term natural gas forward contracts in bilateral markets as demonstrated by the transactions and price quotes entered into by Duke and other entities in North Carolina. (Id. at 16)

In response to SACE's comments that natural gas markets are too subjective to short-term influences to rely on ten-year forward prices for avoided cost purposes, Duke indicated its disagreement and noted that for the past few years, fundamental gas forecasts have lagged the market and have actually been more inconsistent year-over-year than the actual transactable market place over the past five years. Duke therefore recommended that the Commission approve Duke's proposed use of ten-year forward market prices. (Id. at 18)

Discussion and Conclusions

The Commission recognizes the continued declines in the price of natural gas and the fact that these lower prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates. In addition, the Commission notes that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and changes in the liquidity and trading prices in the natural gas markets over the long-term are being incorporated into long-term forecasts. In the context of both the avoided cost and IRP proceedings, recognition of these changing markets is appropriate.

In the 2016 Sub 148 Proceeding, the parties advocated for many of the same positions made in the current proceeding, and in its *2016 Sub 148 Order*, the Commission found merit in some of the arguments raised by each party, and in its expert judgment, adopted a method for the purposes of that proceeding that authorized Duke to rely on market data for eight years and fundamental forecasts thereafter. The Commission also indicated it would continue to monitor the liquidity of the market in future avoided cost proceedings.

In this proceeding, the Commission again recognizes the important relationship that exists between the biennial avoided cost proceeding and the IRP, as well as the importance of maintaining internal consistency between these proceedings. Given the growing use of natural gas-fired generation, the importance of having a sound and reasonable natural gas price forecast has also grown. In this proceeding and in the IRP proceeding, the Public Staff argued that Duke's reliance on ten years of forward market price data tends to lead to gas price forecasts lower than is appropriate, which may lead to an excessive reliance on natural gas-fired generation relative to other forms of generation; such as solar and battery storage. The Public Staff instead proposed the use of forward prices for no more than five years, combined with a fundamental forecast, arguing that after year five the current market is not sufficiently robust to supplant the predictions of market analysts. The Commission notes that, as shown by the Public Staff, Duke's other operating utilities do not use ten years of forward prices and the practice proposed by Duke is highly uncommon in the electric utility industry. The Commission further finds that this extended reliance on thinly traded future prices, which places greater emphasis on short-term market expectations, brings additional risks that should not be borne by ratepayers.

The Commission not only recognizes that the fuel forecasts used in IRPs and avoided cost should be consistent, but also that the fuel forecasts should not deviate significantly from a utility's actual fuel procurement practices. To the extent a utility limits its exposure to risk in its hedging and fuel procurement practices, forward prices that exceed the established risk limits and do not necessarily reflect the same level of information and analysis of a fundamental market forecast should not form the basis for establishing inputs for avoided costs and integrated resource planning. The Commission acknowledges that a fundamental forecast may inherently be slower to respond to short-term changes in the market, but if a utility calls into question the validity of its own fundamental forecast, then it is incumbent on the utility to consider updating this information or revising its calculation to ensure that the integrity of the fundamental forecast remains valid.

The Commission therefore finds that DEC's and DEP's use of ten-year forwards is inappropriate for use in the avoided cost proceeding and that their avoided energy rates should therefore be recalculated using natural gas price forecasts that more appropriately reflect the exclusive use of forward market prices for no more than five years, followed by a period of blending forward market prices with their fundamental forecasts, before transitioning to their fundamental forecasts for the remainder of the planning period.

The Commission recognizes that DENC's fuel forecasting methodology is generally in alignment with the fuel forecasting practices by other utilities identified by the Public Staff and reflects a reasonable balance between the weight given to both forward market purchases and longer-term fuel price forecasts. Therefore, the Commission accepts that the fuel forecasting methodology utilized by DENC is appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence supporting these findings of fact is found in the Joint Initial Statement of DEC and DEP; the Initial Statement of DENC; the Initial Comments of Cube Hydro, NCSEA, the Public Staff, and SACE; the Joint Reply Comments of DEC and DEP; and the Reply Comments of DENC, the Public Staff, NCSEA, and SACE.

Summary of the Evidence

DENC in its Initial Statement indicated that, similar to the approach taken in the 2016 Proceeding, it calculated a hedge value of renewable energy applying the Black-Scholes option pricing model using an estimate for gas price volatility, risk-free interest rate, and the strike price, which yielded a net option price of $0.0434/MMBtu. DENC stated that multiplying this value by a natural gas-fired combined-cycle plant heat rate of 7,000 btu/kWh results in a fuel price hedging value of $0.30/MWh, which is assumed to be constant for all years of its Schedule 19-FP contract. (DENC Initial Statement at 11)

In its Joint Initial Statement, Duke argued that PURPA provides for a "Put Option" to QFs, providing the QF with an option to sell at its sole discretion. Furthermore, Duke maintains that a QF would normally compensate Duke for taking on the role of obligating the utilities to purchase from the QF, regardless of the prevailing market value at the time of the exercise. Duke states that the value of this "Put Option" offsets the hedging value from the reduced fuel price volatility inherent with renewable generation, and therefore Duke did not include a hedging value calculated in a similar manner to the rates included in prior proceedings. (Joint Initial Statement at 22-23)

The Public Staff in its Initial Comments agreed with DENC's calculated hedge value, but disagreed with Duke's argument, stating that Duke's position "would essentially require QFs to compensate utilities for the right to sell their generation." (Public Staff Initial Comments at 28). The Public Staff stated that renewable generation provides additional fuel price stability that has value, as evidenced by the Utilities' ongoing hedging programs, and that it is reasonable to expect that the utility will be able to reduce its volume of hedged natural gas and coal fuels as a result of renewable generation. The Public Staff reiterated its support for inclusion of a hedging value for renewables, consistent with the findings of the Commission in the *Phase One Order*, and recommended 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. (Id. at 29).

NCSEA stated its continued support for the inclusion of a hedging value, finding that QFs not only displace natural gas-fired generation and reduce the Utilities' use of natural gas but also decrease the exposure to natural gas price volatility by providing a long-term physical hedge for the term of the PPA. NCSEA found, however, that the use of the Black-Scholes approach that reprices gas at the prevailing market price repeatedly over a 10-year period undervalues the hedge provided by a 10-year PPA with prices fixed from the start of the contract's term. NCSEA indicated that it reviewed several alternative methods used by other utilities that are superior to the current method and would result in higher avoided fuel hedging values. (NCSEA Initial Statement at 20-27).

SACE stated that it disagreed with Duke's proposal to eliminate the existing hedging value from its avoided energy rates, noting its disagreement with Duke's argument that PURPA creates a "Put Option" for QFs to sell to the utilities at avoided cost rates as inconsistent with the general principles in PURPA to grant QFs the right to sell energy and capacity to a utility at its avoided costs, as determined at the time the LEO is created. (SACE Initial Comments at 7-10).

Cube Yadkin stated that Duke's proposal to eliminate the hedging value from its avoided energy cost calculations misunderstands, if not misrepresents, the purpose of fuel hedging, stating that the purpose of fuel hedging is to insulate ratepayers from fuel volatility. Cube Yadkin stated that "the fact that natural gas prices did not rise but instead declined does not mean that the hedge had no value – any more than an insurance policy that never has to pay out a claim has no value." (Cube Yadkin Initial Comments at 4). Cube Yadkin noted that the main objective of a utility's fuel hedging program is to reduce customer exposure to fuel price volatility, not to reduce fuel costs. Citing recent proceedings in Florida and Ohio where other Duke Energy entities noted that downward trend in natural gas market prices experienced over the last several years would not continue indefinitely, Cube Yadkin stated that the hedge against fuel price volatility continues to have economic value and should be compensated. (Id. at 4-5).

Duke in its Reply Comments stated that the arguments raised by NCSEA and the Public Staff were internally inconsistent in that they challenged the discrepancies between DEC's and DEP's fuel procurement policies and the forward natural gas positions relied on in the avoided cost and IRP proceedings, but then supported the utilities being obligated to purchase QF power at prices based on 10-year duration gas without making equivalent changes to their fuel procurement practices. Duke stated that "to hold gas procurement to one standard and power procurement to another simply represents an artificial arbitrage opportunity to the detriment of consumers." (Duke Reply Comments at 20). Duke stated that in order to highlight the value of this cost being borne by customers, it sought a price quote for a put option on a fixed ten-year natural gas transaction that does not expire for two years. Duke indicated that that the put option premium quote was equivalent to the right provided by a QF to sell to the utilities without obligation. Duke further indicated that including the premium results in an overpayment by customers to QFs, contrary to PURPA, since avoided cost prices paid to QFs already reflect the Companies' fixed and avoidable cost of natural gas over a 10-year term. Duke noted in closing that it had identified only one other jurisdiction that has accepted hedging value as an avoidable cost, and that the alternative methods for determining the hedging value of renewable resources identified by NCSEA have not been applied in other jurisdictions. Therefore, a requirement that the Utilities include an avoided hedging cost adder would make North Carolina an outlier compared to methodologies employed by other states to determine avoided cost under PURPA. (<u>Id.</u> at 23-30).

<u>Discussion and Conclusions</u>

Consistent with the Commission's findings in the *Sub 140 Phase One Order*, the Commission recognizes that there are fuel price hedging benefits associated with renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased, and subsequently the amount of hedging and expected costs that the utilities would incur as part of its fuel procurement. It is, therefore, appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation, consistent with the hedging terms actually used by the utilities. The Commission also agrees with Cube Yadkin that the value of the hedge is to insulate ratepayers from fuel volatility and that the hedge value is appropriate for inclusion in avoided cost rates.

Duke's arguments that QFs are inappropriately being granted a "put option" without any obligation to sell does not comport with the Commission's traditional view of a QF's rights under Section 292.304(d)(2) of the FERC's regulations, which provides that a QF may choose to sell energy or capacity pursuant to a LEO for delivery "over a specified term," with rates determined at the time the obligation is incurred. Further, the Commission notes that N.C. Gen. Stat. § 62-156(b)(2) specifically provides that:

> A determination of the avoided energy costs to the utility shall include a consideration of the following factors over the term of the power contracts: the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources.

The Commission is not persuaded by Duke's position that paying QFs for the value of reduced volatility with fuel prices subjects its customers to additional overpayment risk. Nor is the Commission persuaded that QFs seeking to assert their PURPA rights to sell power to the utility should compensate Duke for having a "Put Option." As such, the Commission directs DEC and DEP to recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA.

The Commission finds that DENC's calculation of the fuel price hedging value associated with renewable energy of $0.30 per MWh, is appropriate for inclusion in its avoided energy rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 - 7

The evidence supporting these findings of fact is found in the Initial Comments of NCSEA, the Reply Comments of Duke, the Public Staff, SACE, and DENC.

<u>Summary of the Evidence</u>

In its Initial Comments, NCSEA pointed out that solar integration provides avoided transmission and distribution (T&D) system capacity costs, but the Astrapé Study failed to capture these benefits. NCSEA explained that QFs displace traditional central station generation with distributed generation that makes T&D capacity available to serve load growth and future transmission capacity. NCSEA in Attachment 2 to its Initial Comments, the Affidavit of R. Thomas Beach, presented a calculation of the avoided T&D capacity costs for the North Carolina utilities at the system level, building off the avoided T&D capacity costs used for in DSM/EE calculations. Mr. Beach allocated the avoided T&D costs to the hours of the year, using peak capacity allocation factors based on the hours when loads on the T&D system are highest. He used a sample of loads at DEC's and DEP's distribution substations, which Mr. Beach contends is a step toward more locational granularity in avoided cost rates. The avoided T&D capacity rates Mr. Beach derived also use the seasonal and time-of-day periods recommended by NCSEA affiant Dr. Ben Johnson, as discussed in Attachment 1 to NCSEA's Initial Comments. Based on its calculations using this more granular methodology, NCSEA contended that the avoided T&D capacity resulting from the integration of solar is a net benefit to Duke and ratepayers and so QFs should receive payment. NCSEA also noted that if distributed energy resources (DERs) can be targeted where avoided distribution costs are the highest, they can produce significantly higher benefits than estimated on a system-wide basis. (NCSEA Initial Comments at 39-43)

In its Reply Comments, Duke indicated that both NCSEA's recommendation and Mr. Beach's analysis of avoided T&D capacity costs were flawed legally, methodologically, and technically. Duke explained that generic future T&D investments across DEC's and DEP's systems are not known and measurable so that they are not avoidable. Duke contended that Mr. Beach's analysis using a generalized quantification of estimated locational values of load reductions across DEC's and DEP's entire distribution is in no way correlated or representative of the expected cost of upgrades that could be avoided by purchasing from QFs. Duke noted that no utility in the country had developed generic avoided cost rates that included the potential benefits of avoided T&D capacity costs from standard offer QFs in developing its avoided cost calculation. (Duke Reply Comments at 126-131)

Duke also argued that including future avoided T&D costs in calculating generic T&D costs was inconsistent with the Peaker Methodology. As has been its longstanding practice, Duke included generator interconnection costs to determine the avoided cost associated with a CT unit in quantifying the avoided capacity but excluded future T&D upgrade costs from the avoided capacity cost calculations as is appropriate under the Peaker methodology. (Id. at 128)

Duke also rejected Mr. Beach's PCAF analysis, wherein it assumed that integrating QF resources on the distribution system creates a known and measurable avoided capacity or energy benefit. Duke pointed to the broad assumptions used by Mr. Beach regarding transmission system upgrades, distribution system planning, and QF resources in calculating his avoided T&D capacity rates. Duke also found it inappropriate to use the DSM/EE avoided T&D capacity rates as a comparison because DSM/EE measures result in permanent changes in load as opposed to intermittent resources. Duke also noted that the failure of a DSM/EE measure usually results in the entire load-reducing impact of the measure being removed from the system, while a QF's failure or unavailability would result in increased circuit load. Duke also noted that T&D systems were designed to meet peak load on the circuit and at the substation, and it would violate planning norms to assume load reductions from intermittent resources. Further, individual T&D equipment must be designed for the highest loading scenarios, and Mr. Beach's reliance on generalized assumptions of average generation or state-wide geographical diversity of many QFs would be inappropriate. Thus, the Companies contended that adding incremental QF solar would potentially increase future T&D costs. (Id. at 129-131)

Duke pointed out that while QFs are responsible for the costs of delivering energy to the point of interconnection to the utility's system, the utility must acquire transmission capacity to deliver the QF's power to the utility's network and, instead, generally relies upon the utility's available transmission system, and thus have benefitted by consuming available transmission capacity. Duke concluded that any avoided T&D capacity costs would be speculative as they are not known and measurable and that instead there well may be more avoided T&D capacity costs than benefits from solar integration. (Duke Reply Comments at 123).

The Public Staff noted the testimony of Public Staff witness Dr. Richard E. Brown in the 2014 Avoided Cost proceeding in Docket No. E-100, Sub 140 (Sub 140 Proceeding) in which he indicated that a QF could be sited on an existing transmission system where it could reduce power flows on heavily loaded transmission lines,[1] but any benefits would be based on the individual site. He also stated that distribution-connected renewable energy facilities could help reduce future transmission capacity expenditures if their power does not flow onto the transmission system.[2] Dr. Brown noted that utility-scale photovoltaic (PV) facilities connected to the transmission system would provide no distribution capacity benefits; however, distribution-connected PV could provide avoided transmission benefits to the extent it reduced power flows at the feeder and distribution substation, and depending on the planning criteria used by the utility.[3] (Public Staff Reply Comments at 9)

While the Public Staff indicated that it generally agreed with Dr. Brown's statements regarding of avoided T&D capacity benefits in the Sub 140 proceeding, it noted that the significant increase in distributed generation facilities interconnecting in North Carolina since the Sub 140 proceeding raises questions regarding the proper allocation and assignment of costs associated with the use of the T&D system. The Public Staff noted that it had addressed this concern in the testimony of Public Staff witness Jay Lucas in his November 19, 2018, testimony in Docket No. E-100, Sub 101.[4]

---

[1] *See* April 25, 2014, Initial Testimony of Richard Brown (Brown Initial Testimony), in Docket No. E-100, Sub 140, at 35.

[2] *Id.* at 36-37.

[3] *Id.*

[4] *See* Initial Testimony of Jay Lucas at 44-48, filed November 19, 2018, Docket No. E-100, Sub 101.

The Public Staff stated that offering an avoided T&D cost adder to QFs eligible for the standard offer contract (Standard Offer QFs) was unlikely to result in QFs siting in locations more likely to result in avoided future T&D investments. Any avoided T&D benefit offered under the Standard Offer would not be site- and project-specific, thereby resulting in an inaccurate assessment of the avoided T&D benefit. The Public Staff indicated that there was insufficient evidence at this time on which to base avoided distribution capacity cost adders for either distribution or transmission connected QFs. The Public Staff noted that it may be appropriate, however, to provide an avoided transmission cost adder to the avoided energy rate applicable to the Standard Offer contract, unless the QF would cause or increase reverse power flow, or the projected load growth over the next ten years on the interconnected feeder is negative or negligible. The Public Staff, did not, however, recommend a specific method for calculating the adder. (Id. at 10)

The Public Staff also expressed its concerns regarding the applicability of the avoided T&D rates from the DSM/EE proceedings, as these rates were calculated based upon the availability of DSM during system peak and EE during all hours. However, the Public Staff indicated that NCSEA's use of a proposed Peak Capacity Allocation Factor (PCAF) with the DSM/EE avoided T&D capacity rates could mitigate its concern that QFs would be overpaid for avoided T&D benefits when QF generation was not deferring T&D investments. (Id. at 11)

The Public Staff supported the negotiation of avoided T&D benefits for QFs not eligible for the standard offer contract based on site- and project-specific characteristics. The Public Staff recommended that the Commission direct the Utilities to calculate an avoided transmission capacity cost adder for standard offer contracts, which would be conditioned on meeting certain requirements regarding backfeeding and load growth. It further recommended that the Utilities consider site and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and include an avoided transmission adder if a project can provide real and measurable avoided transmission capacity benefits. (Id. at 12).

SACE agreed with NCSEA that QFs should be compensated avoided T&D benefits. It noted a Federal Energy Regulatory Commission (FERC) decision upholding the inclusion of a 10% avoided cost "adder" for QFs located where transmission was constrained to account for the avoidance of deferred transmission and distribution costs.[5] SACE found NCSEA's proposed avoided T&D system cost analysis to be consistent with FERC precedent on this issue. (SACE Reply Comments at 13-14)

DENC noted that in its experience, intermittent, non-dispatchable QFs had not allowed it to avoid any T&D costs. DENC contended that due to backfeeding, these QFs had increased T&D costs. DENC pointed out that while its Initial Statement indicated that there are 70 solar QFs with approximately 491 MW of solar capacity operating in DENC's North Carolina service area, when the QFs with whom it has executed PPAs come online, it will have QF capacity of 621 MW, over 100 MW in excess of the Company's 2017 average on-peak load of approximately 520 MW in its North Carolina service area. Thus, DENC concluded that there would be little avoided T&D capacity benefit regardless of where a QF located in DENC's North Carolina territory. (DENC Reply Comments at 30-31, in the discussion of Re-dispatch Charge proposal).

[5] California Pub. Utilities Comm'n, 133 FERC ¶ 61,059 (2010)

Discussion and Conclusions

The Commission agrees that theoretically, a QF can be located on a transmission or distribution line and provide avoided capacity benefits, but this benefit is dependent on the particular location, and the utility's planning criteria. Indeed, a QF could be located so that it increases rather than avoids T&D capacity costs. The Commission agrees with the Public Staff that there is insufficient evidence at this time on which to base avoided distribution capacity cost adders applicable to all distribution or transmission connected QFs. However, the Commission finds it appropriate for the Utilities to evaluate prior to the next biennial avoided cost proceeding whether QFs interconnected to the distribution system that are eligible for the Standard Offer contract should receive an avoided transmission cost adder to the avoided energy rate, which would be available unless the QF would cause or increase reverse power flow, or the projected load growth over the next ten years on the interconnected feeder is negative or negligible. If found to be appropriate, the Utilities should include the avoided transmission adder and information supporting its calculation in the next biennial avoided cost proceeding.

The Commission finds that it is inappropriate to use the avoided T&D rates from the DSM/EE proceedings, as these rates were calculated based upon the availability of DSM during system peak and EE during all hours. Finally, the Commission will require the Utilities to consider site and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and include an avoided transmission adder if a project can provide real and measurable avoided transmission capacity benefits.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the Initial and Reply Comments of NCSEA; the Reply Comments of Duke and the Public Staff; and the testimony of Duke witnesses Snider and Wheeler, DENC witness Petrie, and Public Staff witness Thomas.

Summary of the Evidence

In its Initial Comments, NCSEA stated that to the extent the Commission finds that Duke's proposed Solar Integration Services Charge (SISC) is appropriate, the Commission should also enable a market to allow QFs a meaningful opportunity to avoid charges for such ancillary services as well as the opportunity to compete to provide such ancillary services. NCSEA stated that QFs may be able to provide these ancillary services at a lower cost than the Utilities, and noted that both small hydroelectric generation and solar QFs that are equipped with smart inverters and energy storage may be able to provide ancillary services more quickly and at less cost than the utility conventional generation. NCSEA noted that in the Sub 140 Phase II Order, the Commission directed the Utilities to compensate QFs that are required to provide or absorb reactive power at the utilities' request, "to the same extent they would pair their own or affiliated generator." NCSEA Initial Comments at 28-30, citing *Phase II Sub 140 Order* at 48.) NCSEA also recommended that the Commission consider utilizing the differential revenue requirement methodology for calculating avoided cost rates since this methodology would incorporate integration expenses. (Id. at 30)

SACE in its Initial Comments similarly noted that QFs' projects incorporating energy storage may be able to provide benefits beyond energy and capacity, such as frequency regulation and load following services, and that these benefits are not currently compensated under the Companies' proposed QF rates. SACE, therefore, recommended that QFs should not be required to provide these beneficial services without avoided cost rates being adjusted to reflect the system benefits. (SACE Initial Comments at 15-16).

In its Reply Comments, the Public Staff indicated that certain QFs have the technical ability to provide ancillary services, potentially at a lower cost than the costs estimated for DEC and DEP in the Astrapé Solar Ancillary Service Study (Astrapé Study), and that a market or competitive solicitation for ancillary services generators into which third parties could bid has the potential to reduce costs to ratepayers and facilitate the cost-effective integration of intermittent resources. Noting the regulatory complexity of implementing a market in North Carolina, as well as the fact that PURPA's mandatory purchase obligation does not extend to ancillary services, the Public Staff noted that other alternatives for identifying the ancillary service value provided by third parties such as QFs should be considered. The Public Staff noted that the Astrapé Study could potentially be used to help demonstrate the benefits derived from QFs that design their facilities to provide ancillary services. The Public Staff noted, however, that the limited quantity of load following reserves required in DEC and DEP, as well as the lack of a mandatory purchase obligation for ancillary services under PURPA, may present challenges to this approach. Nonetheless, the Public Staff recommended that Duke in its next avoided cost proceeding address how intermittent QFs could be compensated for providing ancillary services required to integrate its own facility, as well as other intermittent QFs, if the services were offered at a cost equal to or lower than the utility's own ancillary services. The Public Staff also noted that a QF that is not eligible for a standard offer contract should be able to avoid the application of Duke's proposed SISC if it can demonstrate that it can sufficiently mitigate volatility. (Public Staff Reply Comments at 23-26).

Duke witness Snider testified that in further conversations with the Public Staff, Duke evaluated whether innovative QFs could potentially provide ancillary services or reduce the additional ancillary services it would otherwise be required to provide to integrate solar QFs, and agreed in the Stipulation that solar QFs that are not eligible for standard offer contracts and "who contractually agree to operate their facilities through use of energy storage devices, dispatchable contracts, or other mechanisms that reduce or eliminate the intermittency of the facilities' generation output" can help to eliminate ancillary services costs that Duke would otherwise incur, and therefore these facilities should not be subject to the SISC. (Tr. Vol. 2 at 85-86)

In his testimony, Public Staff witness Thomas acknowledged that there were significant challenges to implementing a market for ancillary services in North Carolina, noting that PURPA does not require utilities to purchase ancillary services from QFs, and that since Duke is not a member of an RTO, there is no organized competitive market for third-party services like those that exist in PJM and other RTOs. Mr. Thomas noted, however, that Duke is still responsible for maintaining reliable grid operations, and that requiring Duke to purchase ancillary services from QFs for reliability purposes may raise complex regulatory and legal questions over ownership and control of the facility. Lastly, Mr. Thomas noted that to the extent the utilities conducted a competitive solicitation to procure the small amount of ancillary services identified in the Astrapé Study, the costs of conducting the procurement could exceed any savings that might be realized. Mr. Thomas recognized that the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the SISC by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements. (Tr. Vol. 6 at 379-381)

Discussion and Conclusions

As discussed in the portion of this order addressing the SISC Charge, the Commission finds it appropriate that QFs not eligible for standard offer contracts and who contractually agree to operate their facilities through use of energy storage devices, dispatchable contracts, or other mechanisms that reduce or eliminate the intermittency of the facilities' generation output should not be subject to the SISC. The Commission finds merit, however, in continuing to evaluate the potential benefits provided by QF resources, particularly as new technologies such as energy storage and smart inverters are incorporated into QF projects in North Carolina, as well as for those existing technologies such as small hydroelectric QFs that may have dispatch capability. Therefore, the Commission directs Duke in its next biennial proceeding to evaluate whether QF resources that can sufficiently demonstrate and contractually obligate itself to operate in a manner that not only eliminates the need for additional ancillary service requirements, but also has the capability to provide those benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9 AND 10

The evidence supporting this finding is contained in the Initial Statement of DENC; the Initial and Reply Comments of DENC, the Public Staff, NCSEA, and SACE; in the testimony of DENC witness Petrie, Public Staff witness Thomas, NCSEA witnesses Beach and Johnson, and SACE witness Kirby; and the entire record in this proceeding.

Summary of the Evidence

In the *2016 Sub 148 Order*, the Commission concluded 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." (*2016 Sub 148 Order* at 98) The Commission directed that with their initial filings in this proceeding the Utilities address, among other issues, "consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable." (*2016 Sub 148 Order* at 110-111) The 2018 Procedural Order in this proceeding reiterated that directive.

In its Initial Statement, DENC recognized these directives and noted that the addition of new QF generation could have an impact in two distinct areas: ancillary services and integration costs. DENC proposed to adjust the avoided energy cost payments to new QFs to reflect the increase in system supply costs—specifically called "re-dispatch" costs—caused by these generators. DENC clarified that it was not proposing to adjust avoided cost rates to specifically account for the potential costs or benefits related to changes in ancillary services requirements that occur due to increased levels of new QF generation on the system. DENC defined re-dispatch costs as the additional fuel and purchased energy costs incurred due to the unpredictability of events that occur during a typical power system operational day. It explained that as more and more intermittent generation such as solar or wind is added to the grid, the level of uncertainty regarding re-dispatch costs increases due to unpredictable cloud cover or changes in wind speed. (DENC Initial Statement at 12-13)

To calculate the re-dispatch cost, DENC explained that in conjunction with the development of its 2018 IRP, it performed a simulation analysis to determine the cost impact on generation operations. It used hourly generation data from 26 solar sites located within its service area and currently interconnected to its system to develop generation profiles for these facilities. DENC performed the study at three levels of solar photovoltaic (PV) penetration to provide a range of results. It compared the total system costs from these study runs to a base case without high levels of solar generation to determine an overall cost impact, which it calculated to be approximately $1.78/MWh. DENC proposed to adjust avoided energy payments made to QFs under Schedule 19-FP by that amount. (Id. at 13)

The Public Staff in its Initial Comments did not oppose the concept of a re-dispatch charge, but made some recommendations and raised some areas of concern. First, the Public Staff argued that the avoided energy rate should not be reduced by separately calculated charges, and stated that a consolidated charge would present difficulties for tracking costs of compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The Public Staff recommended that DENC collect and administer the re-dispatch costs separately from the avoided energy rate, similar to Duke's approach for the SISC. Second, while the Public Staff agreed that it was reasonable to calculate the re-dispatch charge using solar resource data, as solar is the dominant type of intermittent, non-dispatchable QF, it asked that in the future DENC separately calculate the charge specific to each type of intermittent, non-dispatchable QF seeking to interconnect to its system. (Public Staff Initial Comments at 30-31, 41-46)

Finally, the Public Staff noted that it had identified certain concerns with the re-dispatch proposal. Among those concerns, the Public Staff stated that DENC's calculation of the charge, which reflected equal weighting of multiple cost and solar penetration scenarios, may not be reasonable. More generally, the Public Staff noted the Commission's conclusions in the *2014 Parameters Order* that inclusion of costs and benefits related to solar integration in the Utilities' avoided cost calculations would be "appropriate only when both costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained." (Id. at 32 quoting Para. Order at 60-61) The Public Staff acknowledged that some costs of QF energy and capacity are less discernible than others, and stated that it may be appropriate for the Commission to consider evidence from other parties regarding what additional costs or benefits can be sufficiently known and verifiable such that they should be included in avoided cost rates. (Id. at 44-46).

In its Initial Comments, NCSEA asserted as it did with respect to Duke's SISC that the re-dispatch charge is inconsistent with previous Commission decisions and does not comply with PURPA. NCSEA pointed to the Commission's recognition in the *2014 Parameters Order* that it may be appropriate to reflect costs and benefits of integrated solar resources into the Utilities' avoided cost calculations. NCSEA contended that DENC's proposed re-dispatch charge failed to comply with the *2016 Sub 148 Order*, since the charge did not take the form of a separate rate schedule, and based on NCSEA's assertion that the proposal is inappropriately based on generation technology rather than QF characteristics. NCSEA asserted that DENC admitted such noncompliance in its initial statement. NCSEA also argued that the re-dispatch charge (and Duke's SISC) represents single-issue ratemaking because it is a "rate" under N.C. Gen. Stat. § 62-3(24) and should be set during a general rate case. NCSEA argued further that the charge is not a "rate" under 18 C.F.R. § 292.101(b)(5) because it does not involve the sale or purchase of electric energy or capacity, and that even if it is a rate under FERC rules it is not appropriate under 18 C.F.R. § 292.304(e). NCSEA also claimed that the Utilities failed to accurately capture the effect that wind and solar resources have on market prices by reducing demand on regional markets for electricity and natural gas and thereby reducing the prices of these goods. (NCSEA Initial Comments at 34-35)

In his affidavit attached to NCSEA's Initial Comments, witness Johnson stated that refining avoided cost rates to consider the costs and benefits associated with integrating solar resources is "not objectionable, per se," but took issue with how the Utilities conducted their respective analyses. He claimed, among other things, that the Utilities failed to take an unbiased approach, only considered negative impacts imposed by solar QFs, and ignored the geographic diversity of solar QFs that avoids transmission and distribution (T&D) costs. With regard to DENC's re-dispatch charge, in contrast to NCSEA's own position he did not oppose the concept of a re-dispatch charge itself, acknowledging that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy." Mr. Johnson asserted however that the proposed $1.78/MWh is too high because DENC (1) only partly considered the benefits of geographic diversity by only relying on 26 individual sites for its analysis and (2) improperly weighted the average of multiple costs and solar penetration scenarios. He presented his own calculation of a re-dispatch charge of $0.69/MWh, which appeared to be based on removal of the PJM and generation-only cost categories and the 80-MW solar penetration scenario.

In another affidavit attached to NCSEA's Initial Comments, witness Beach similarly claimed that the re-dispatch charge did not consider the benefits of integrating QF resources into the system. Witness Beach asserted that appropriately-located QFs would allow T&D costs to be avoided. In support of this assertion he provided an example using Duke's distribution substations to show how avoided T&D costs can be allocated to hours of the year using peak capacity allocation factors. Witness Beach also asserted a potential market suppression benefit of integrating QF power and recommended that the Commission direct the Utilities to study the ability of their T&D system to host distributed generation and storage resources.

In its Initial Comments, SACE disagreed with DENC's methodology for determining the re-dispatch charge for several reasons, including using the 80 MW solar penetration level and averaging the results of the analysis. Based on these alleged methodological flaws, SACE concluded that DENC failed to adequately support its re-dispatch charge and that the Commission should, therefore, reject it. (SACE Initial Comments at 17-18)

In its Reply Comments, DENC reiterated the basis for its re-dispatch proposal and explained in addition that applying the re-dispatch charge will help ensure that its customers pay for accurate avoided costs since without the charge customers would overpay for QF output. DENC explained that in the analysis providing the basis for the proposed charge, and it gave equal weight to each of the cost categories considered, which included all costs, PJM purchases/sales, pumping costs/reserves, and generator costs only.

DENC stated that it chose solar penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the analysis, and described the process it used to use those levels to calculate the charge. (DENC Reply Comments at 12-14)

In response to the Public Staff, DENC stated that while it proposed to apply the re-dispatch charge as a reduction to the avoided energy rate for purposes of administrative efficiency, if the Commission agrees with the Public Staff that it should be separated from the avoided energy rate, DENC could modify the administration of the charge to occur as a separate line item on a QF invoice. DENC also stated that it is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases.

DENC explained that it had discussed its proposal with the Public Staff and had addressed a number of the Public Staff's questions and concerns. DENC also stated that in those discussions, the Public Staff recommended re-calculating the re-dispatch charge without considering an 80 MW solar penetration level and allocating 70% to the 2,000 MW scenario and 30% to the 4,000 MW scenario. DENC described these points as representing Public Staff's remaining concerns with the re-dispatch proposal. DENC explained that it continued to believe that the approach it took in the simulation analysis with respect to cost category and solar penetration level selection and weighting to be reasonable and provided arguments in support of those aspects of its original approach to calculating the charge. DENC explained that it believed it was appropriate to weight each category equally since each plays a major role in the total re-dispatch cost related to distributed solar generation. DENC also explained the rationale for including each of the solar penetration levels and for weighting each level equally in the charge calculation. DENC concluded, however, that in the interest of reaching compromise on the issue and narrowing down the areas of dispute, it was willing to recalculate the re-dispatch charge for purposes of this proceeding with modified cost category and solar penetration scenario weightings, resulting in a re-dispatch charge of $0.78/MWh. (DENC Reply Comments at 9-11)

In response to NCSEA, DENC first clarified that its presentation of the re-dispatch proposal did not constitute an admission of noncompliance with the *2016 Sub 148 Order*, but rather made clear that the proposal was intended to quantify the added costs due to re-dispatching of units caused by the intermittency of solar QF output, and not to specifically account for potential costs or benefits related to changes in ancillary service requirements. DENC also stated that in preparing the Initial Filing and developing the re-dispatch charge proposal, it carefully evaluated the Commission's directives in the *2016 Sub 148 Order*. DENC acknowledged the Commission's directive for 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 DENC explained that in developing its proposal, DENC determined that it would be more efficient, and therefore benefit both the QF and DENC, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. DENC stated its belief that QF developers are generally sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. DENC also noted, however, that it will comply with any Commission determination that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule. (Id. at 17-18)

DENC next explained that the charge was derived based on data associated with the intermittent, non-dispatchable QFs in its service area, all of which at this point in time are in fact solar QFs. DENC noted that, while the proposed charge is actually "based upon a consideration of the characteristics of the power supplied by" these QFs (those characteristics being intermittency and unreliability), for purposes of North Carolina, where almost all intermittent nondispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." DENC concluded that, practically, these terms present a distinction without a difference. DENC noted its willingness to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, nondispatchable QFs in a future proceeding.

DENC also addressed NCSEA's contention that the re-dispatch charge is a "rate" under N.C. Gen. Stat. § 62-3(24) that should be set during general rate cases pursuant to N.C. Gen. Stat. § 62-133, and that it is not a "rate" under FERC rules implementing PURPA because it does not involve the sale or purchase of electric energy or capacity. As to the former, DENC showed that the re-dispatch charge is not a "rate" as that term is contemplated by Section 62-3(24), which contemplates charges for services or commodities offered by the utility to the public, as the charge is not so related, but instead reflects the impact to DENC's system of intermittent, non-dispatchable QFs from which DENC is required by law to purchase energy. DENC also explained that taken to its logical end, NCSEA's argument would nullify N.C. Gen. Stat. § 62-156. As to the latter, DENC noted that the charge is valid regardless of whether it qualifies as a "rate" under 18 C.F.R. § 202.101(b)(5), and explained that it is also consistent with the Section 202.304(e) because it properly considered the enumerated factors listed in the FERC regulations. (DENC Reply Comments at 19).

DENC also addressed NCSEA's and witness Johnson's contentions regarding costs and benefits. In particular, due to their intermittent nature and concentration in its small North Carolina service territory, DENC stated that non-dispatchable QFs do not allow DENC to avoid T&D costs and that due to the potential for additional line losses resulting from backfeeding, the opposite is more likely true. DENC further addressed costs and benefits in witness Petrie's testimony as discussed below.

In response to SACE, DENC stated that its willingness to recalculate the re-dispatch charge consistent with the Public Staff's recommendations should address SACE's concerns with the proposal.

In its Reply Comments, the Public Staff presented a summary of DENC's proposed charge and stated that it was not convinced that DENC considered the appropriate cost and solar scenarios in its re-dispatch charge calculation. The Public Staff disagreed with the "no PJM," "no pumped storage," and "generator cost only" scenarios based on its belief that those categories do not represent DENC's current operations. The Public Staff stated that DENC is a part of PJM, and also has access to energy and capacity from the Bath County pumped storage facility in Virginia. It stated that while these scenarios may be illustrative of the impact solar "might" have on system costs were DENC to leave PJM or decommission its pumped storage facility, they are not appropriate for use in specifying a charge to apply to non-dispatchable QFs today. The Public Staff noted that the higher re-dispatch charge associated with a "No PJM" scenario indicates the value of being able to sell excess energy into the PJM market. The Public Staff also found the 80 MW solar penetration scenario to be inappropriate because DENC already has several hundred MW of solar capacity installed. It stated that the 2,000 MW is more likely in the future due to the higher probability that DENC's total system will realize this level of intermittent capacity, and that the 4,000 MW scenario might be achieved in the more distant future due to Virginia's mandate of increased deployment of solar resources through the Grid Transformation and Security Act of 2018. To address these concerns, the Public Staff proposed that DENC give 100% weight to the all costs category and no weigh to the other cost categories, and give 70% weight to the 2,000 MW solar penetration scenario, 30% weight to the 4,000 MW scenario, and none to the 80 MW scenario. The Public Staff also noted that the re-dispatch charge and Duke's proposed SISC may result in recovery of overlapping costs and stated that to the extent the Commission approves the broader application of these calculations in future proceedings, it is appropriate for the costs to be fully delineated to reduce any overlap. (Public Staff Reply Comments at 23)

In its Reply Comments, NCSEA agreed with SACE's position that DENC inappropriately averaged costs associated with multiple solar penetration levels and combinations of assumptions, which resulted in an inflated charge. NCSEA also echoed some of the questions raised by the Public Staff in its Initial Comments. NCSEA stated its opposition to any fixed charge that "allegedly" offsets costs to the grid due to intermittent QFs, reiterating its position that distributed generation, including solar, causes a net benefit to the grid and rate payers.

In its Reply Comments, SACE contended that the Utilities failed to analyze the potential benefits of solar integration and therefore did not comply with the Commission's previous orders. SACE also agreed with NCSEA that QFs should be compensated for the full range of costs they allow the purchasing utility to avoid, including applicable T&D costs. SACE also recognized the Public Staff's concerns regarding an integration charge's potential impact on REPS and other programs' administration if the charge is embedded in the avoided cost rate, but ultimately supported DENC's approach of applying the re-dispatch charge, if approved, as a decrement rather than as a stand-alone charge. SACE suggested that the Commission could establish a procedure to remove any integration charge in the administration of the applicable REPS or other program, to address this concern. (SACE Reply Comments at 15-16)

In his direct testimony, DENC witness Petrie stated that in the *2016 Sub 148 Order* and the *2018 Procedural Order,* the Commission found merit in the concept that evaluation of the Utilities' avoided costs should consider factors such as a QF's capacity, dispatchability and reliability, and the value of QF energy and capacity in establishing avoided cost rates. Witness Petrie reiterated DENC's explanation of the meaning of re-dispatch costs and description of its calculation of the re-dispatch charge. He clarified that DENC's proposal to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP by $1.78/MWh applied to both standard offer QFs and larger QFs with negotiated PPAs. He also clarified that while the re-dispatch charge is complementary to Duke's proposed SISC, the charges are not the same, as DENC and Duke each analyzed a different aspect of the impact of resource intermittency on their respective systems. (Tr. Vol. 5 at 15-16)

Witness Petrie noted that the Public Staff did not disagree with the re-dispatch charge in theory and responded to several of the Public Staff's concerns and recommendations consistent with DENC's Reply Comments. First, witness Petrie stated that if the Commission agreed that the re-dispatch charge should be separated from the avoided cost payment, DENC can modify the administration of the re-dispatch charge to appear as a separate line item on a QF's invoice. He also testified that DENC is willing to evaluate the potential for separately calculating re-dispatch charges for other types of QF generation in future cases. Finally, he explained that since the filing of initial comments, DENC and the Public Staff discussed the re-dispatch proposal, including how the generation portfolios were constructed, how the 85 PLEXOS model runs were used, and other issues raised by the Public Staff and resolved most of the Public Staff's concerns. With respect to Public Staff's remaining concerns regarding the weighting of cost categories and selection of solar penetration weights, witness Petrie stated that while it believes its initial analysis was appropriate, in the interest of compromise, DENC was willing to re-calculate the re-dispatch charge with modified cost categories and solar penetration scenarios as recommended by Public Staff. Specifically, he clarified that DENC is willing to re-calculate its re-dispatch charge giving 100% weight to the "all cost" cost category, and 70% and 30% weight to the 2,000 and 4,000 MW solar penetration levels, respectively. Witness Petrie testified that these modifications resulted in a $0.78/MWh re-dispatch charge. (Id. at 19-20)

Witness Petrie responded to NCSEA's contention that the re-dispatch charge failed to comply with the *2016 Sub 148 Order*. He stated that the re-dispatch charge is compliant with the *2016 Sub 148 Order's* statement to "consider and propose additional rate schedules" because DENC did consider proposing new rate schedules but determined that, in the interest of efficiency, the re-dispatch charge should be included in the existing rate schedule. He testified that if the Commission determines that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, DENC will comply with that determination. With respect to NCSEA's assertions regarding the focus on generation technology, he stated that the re-dispatch charge is based on data associated with the intermittent, non-dispatchable QFs in DENC's service area, all of which are solar QFs. Therefore, he explained, there is an inherent overlap between the concepts of "generation technology" and "QF characteristics," and for DENC's purposes, those terms present a distinction without a difference. (Id. at 24)

Witness Petrie stated that NCSEA and SACE's concerns regarding the actual derivation of the re-dispatch charge should be addressed by DENC's willingness to recalculate the charge as recommended by the Public Staff. He also responded that DENC did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis as well as in the basic avoided energy rate. He testified that the macro benefits to new solar generation, including zero fuel cost for solar generation, displacement of DENC owned generation, and PJM purchases during daytime hours, and the related fuel price hedge benefit were reflected in the production cost modeling and in the separate hedge value adder to the energy rates. He noted that DENC has not observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid from the addition of intermittent resources, such as solar QFs, to its system that are not already accounted for in the avoided energy costs. (Id.)

Witness Petrie also responded to witness Johnson's contentions regarding geographic diversity, explaining that the QFs evaluated for the re-dispatch analysis are in fact geographically dispersed throughout DENC's service area, including North Carolina.

He explained further, however, that the North Carolina portion of that service area is relatively small, with very limited geographic diversity as compared to the rest of DENC's footprint. He noted that as a result, the intermittency of solar QFs located in North Carolina is not mitigated by their geographic diversity throughout that DENC's service area. Witness Petrie also clarified that PJM market purchases and sales are accounted for in the re-dispatch study, as the PLEXOS model assumed DENC would sell excess power into PJM during the peak hours with higher LMP costs and make market purchased at low prices. In calculating the re-dispatch cost, he explained, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost. (Id. at 26)

Witness Petrie concluded by noting that there are 72 solar QFs operating in DENC's North Carolina service area, representing approximately 501 MW of solar capacity, and that once all of the QFs with which DENC has executed PPAs come online, that total will rise to 691 MW, which significantly exceeds DENC's 2018 average on-peak load of approximately 525 MW. He stated that DENC's proposed re-dispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar PV generation onto its system, which was first addressed in the 2012 avoided cost case, Docket No. E-100, Sub 136. He stated that DENC will continue to work on this issue, but for purposes of this biennial period believes that the re-dispatch charge is fair to both QFs and DENC's retail electric customers, because it will provide energy payments to QFs that better reflect DENC's actual avoided energy costs. (Id. at 28)

In his testimony, Public Staff witness Thomas described the re-dispatch charge as reflecting the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. He explained that similar to the changes in dispatch order caused by load certainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of the least cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs, which are passed on to ratepayers. He also noted that unlike the Duke method of calculating the SISC, DENC's method of calculation is not probabilistic and does not measure system reliability. (Tr. Vol. 6 at 373-374)

Witness Thomas testified that the re-dispatch charge is a reasonable attempt to quantify the costs incurred by intermittent generators, but noted that the Public Staff had identified potential concerns with the charge as proposed. He noted the Public Staff's suggestion of an alternate set of weightings resulting in a re-dispatch charge of $0.78/MWh, which the Public Staff believes better reflects the DENC system and actual costs incurred. He argued that including cost scenarios such as the "no PJM" scenario would inappropriately exclude benefits provided by solar QFs due to DENC's membership in PJM. He acknowledged DENC's willingness to recalculate the charge with the Public Staff's recommended weightings. He recognized that the re-dispatch charge and Duke's SISC attempt to quantify different aspects of integrating intermittent generation and use different approaches, but based on the Public Staff's review of these proposals stated that there is likely some overlap between them. Finally, he testified to the Public Staff's belief that certain technologies, such as energy storage, could if operated appropriately reduce or eliminate the intermittency of solar generator output, and recommended that to the extent a QF can materially demonstrate that it does not impose additional ancillary costs on the system, it should not be subject to the SISC or, to a lesser extent, the re-dispatch charge. (Id. at 380-381)

NCSEA witness Johnson did not offer testimony on the re-dispatch charge. NCSEA witness Beach testified generally on the re-dispatch charge together with the Duke SISC. Witness Beach recommended that the Commission not adopt either of these proposed charges and asserted that any cost to integrate solar resources will be offset by benefits of these resources that he contended the Utilities have not recognized. (Tr. Vol. 5 at 112-113) In his testimony, SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations and contended that DENC did not include an analysis of the benefits of solar projects. He also, however, testified that DENC's agreement to remove the 80 MW solar penetration scenario from its analysis and to solely use the "all costs" category for its re-dispatch charge analysis instead of averaging all four of its originally proposed cost categories helped alleviate his concerns on these fronts. (Tr. Vol. 5 at 209-210)

In his rebuttal testimony, DENC witness Petrie testified that DENC remained willing to accept the Public Staff's recommended modifications to the re-dispatch charge calculation and resulting charge of $0.78/MWh for purposes of this proceeding. He noted that while NCSEA witness Beach generally recommended rejection of the re-dispatch charge, he did not offer any specific critiques of the charge itself. To the extent witness Beach's claims that the "utilities" did not properly consider and quantify the benefits of solar in presenting their proposed charges were made with respect to DENC, witness Petrie referenced his direct testimony and DENC's Reply Comments and testified that DENC has properly considered both costs and benefits in both the avoided cost rates and the re-dispatch charge. (Tr. Vol 5 at 40)

Witness Petrie also disagreed with any characterization of the charge as a "penalty." He explained that DENC's avoided energy costs are based on the difference in system production costs between a PROMOD model case without incremental QF energy deliveries and a case with a 100 MW flat block of zero-cost QF energy added to the system. He stated that because QFs do not deliver the same amount of energy every hour (i.e., they are intermittent and fuel limited), the rates derived from those model results should be adjusted to reflect the cost impact of the QF generation profile. He stated that the re-dispatch charge represents that adjustment, which improves the accuracy of the avoided energy rates and accounts for the way that the rates are calculated from the modeling results. With regard to SACE, witness Petrie reiterated that DENC did consider the benefits of solar facilities interconnected to its system, but noted that DENC's willingness to recalculate the re-dispatch appeared to mitigate witness Kirby's concerns. (Tr. Vol. 5 at 37-39)

Finally, witness Petrie responded that to the extent a QF can materially demonstrate that it does not impose additionally ancillary services costs on the system, it should not be subject to re-dispatch charge. He explained that although the addition of battery storage may potentially smooth the QF's output during certain hours, the shape of the MW output during the middle of the day, in between charging in the morning and discharging in the evening, will still exhibit a considerable amount of volatility, which the re-dispatch charge would account for. He noted that DENC had yet to study the actual effect of a battery on output, which would need to be calculated to determine any appropriate discount to the re-dispatch charge. Therefore, he testified that the recalculated $0.78/MWh charge should apply to all solar QFs in this biennial period and updated as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities. (Tr. Vol. 5 at 40-42)

At the hearing, NCSEA witnesses Johnson and Beach did not address the re-dispatch charge. In his summary of testimony, SACE witness Kirby recommended rejection of the re-dispatch charge until it is recalculated based on both the cost and benefits of integrating solar. (Tr. Vol. 5 at 215) DENC witness Petrie clarified in response to questions from counsel for SACE that in developing the re-dispatch charge, DENC focused only on re-dispatch costs and not ancillary services, and that he could not speak to whether Duke's SISC reflected some element of re-dispatch costs. He also clarified that DENC has no intention of double-counting re-dispatch costs and that he expects DENC in the future to conduct a more comprehensive study that accounts for ancillary service costs. (Tr. Vol. 5 at 80-82) He also testified, and reiterated upon questioning by Commissioner Brown-Bland, that there are conceivable circumstances where it would be appropriate to not apply the re-dispatch charge to a QF that has installed battery storage. (Tr. Vol. 5 at 92-93, 100-103) Witness Petrie also agreed in response to questions by counsel for the Public Staff that the re-dispatch charge could decline in the future. (Tr. Vol. 5 at 94) DENC witness Billingsley clarified in response to questions from SACE counsel that if approved the re-dispatch charge would apply prospectively only, including to QFs that renew their PPAs after the initial term has concluded. (Tr. Vol. 5 at 92)

Discussion and Conclusions

Based on the evidence presented, the Commission accepts DENC's proposed re-dispatch charge, as modified to be $0.78/MWh, as reasonable and appropriate for purposes of this proceeding.

N.C. Gen. Stat. § 62-156(b)(2) provides in relevant part that

> The rates paid by an electric public utility to a small power producer for energy shall not exceed, over the term of the purchase power contract, the incremental cost to the electric public utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source.

Section 292.304(e) of FERC's regulations implementing PURPA provides that

> in determining avoided costs, the following factors shall, to the extent practicable, be taken into account: … (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[.]

In the *2016 Sub 148 Order*, the Commission found merit in the concept reflected in testimony presented in that case that an evaluation of the Utilities' avoided costs should consider the characteristics of the power supplied by a QF. The Commission stated that considering the factors in N.C. Gen. Stat. § 62-156 and the FERC regulations in the determination of avoided cost rates ensure that the Commission's avoided cost methodology remains true to PURPA's directive that avoided cost rates be based on the costs that the utility avoids. We concluded that it would be appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power if the Utilities' cost data demonstrates marked differences in the value of the energy and capacity provided by these QFs. We also concluded:

> that it is appropriate to require the Utilities to calculate avoided energy and capacity costs for purposes of establishing rates available to QFs eligible for the standard offer without regard to the technology the QF uses to generate electricity. 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.

2016 Sub 148 Order at 98. In Ordering Paragraph (16) of the *2016 Sub 148 Order,* we required that:

> in addition to their cost data and any other usual and appropriate matters, DEC, DEP, and Dominion shall, in their initial filings in the Commission's next biennial proceeding established to determine avoided cost rates for electric utility purchases from QFs, address the following issues consistent with the discussion and conclusions in this order: … consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable.

With this background in mind, the Commission has carefully considered all of the evidence presented on this issue. Notably, no party presented evidence to contradict that DENC is experiencing re-dispatch costs associated with the integration of intermittent, non-dispatchable QFs on its system. NCSEA witness Johnson specifically acknowledged that it is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, due to the variability of solar generation caused by cloud cover. With the exception of witness Johnson, NCSEA and SACE oppose the re-dispatch charge proposal, but do not present evidence to contradict it, particularly given DENC's agreement to recalculate the charge consistent with the Public Staff's recommendation. Given the evidence presented, the Commission concludes that the charge, modified as agreed to by DENC, should be accepted for purposes of this proceeding.

First, the Commission concludes that the re-dispatch charge complies with our previous orders and with PURPA and FERC's regulations. As directed in the *2016 Sub 148 Order*, DENC has proposed an adjustment to its rates to account for the characteristics of intermittent, non-dispatchable QFs. The Commission recognizes DENC's interest in administrative efficiency in incorporating the cost as a decrement to the avoided cost rates, but concludes that it is appropriate for this rate to be set out as a separate charge similar to the approach taken by Duke in order to account for the characteristics of intermittent, non-dispatchable QFs in avoided cost rates while not affecting the overall avoided cost rates that the utilities apply more broadly in the context of other proceedings, including in the context of Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cost recovery, fuel clause adjustment proceedings, and demand-side management/energy efficiency programs pursuant to N.C. Gen. Stat. § 62-133.9.

The Commission also concludes that the re-dispatch charge does not constitute single-issue ratemaking or otherwise violate N.C. Gen. Stat. § 62-156 or FERC's regulations. As DENC showed in its Reply Comments, NCSEA's arguments on this score are not consistent with the plain meaning of these statutory and regulatory provisions and taken to their logical end would result in a practical nullification of the North Carolina PURPA implementation statute, N.C. Gen. Stat. § 62-156. That statute expressly requires the Commission to, every two years, determine the standard contract avoided cost rates to be included within the tariffs of each electric public utility and paid by electric public utilities for power purchased from small power producers. The Commission concludes it is appropriate to include the re-dispatch charge as a separate charge applicable to the avoided cost rates DENC must pay for purchases made under Schedule 19-FP to intermittent generating resources. With regard to FERC's regulations, whether or not the re-dispatch charge is a "rate" under 18 C.F.R. § 292.101(b)(5) is not relevant; the charge is applied as a decrement to the avoided cost rate – it is not presented as the "rate" itself.

On a more substantive note, the Commission also recognizes that the *2016 Sub 148 Order's* directives specified that the proposed schedules be developed to reflect characteristics of intermittent generation and not be technology-specific. We are persuaded, however, that currently and for purposes of this proceeding, there is an inherent overlap and no real distinction between the concepts of "generation technology" and "QF characteristics," due to the fact that all of the intermittent non-dispatchable QFs in DENC's service area are in fact solar QFs. DENC has stated that it is willing to evaluate the potential for developing re-dispatch charges for other generation technologies in the future, and the Commission finds that this would be appropriate for DENC to do in the next avoided cost proceeding to the extent relevant data is available. As that data becomes available, it is possible that a real distinction will emerge. For purposes of this case, however, the Commission concludes that the re-dispatch charge appropriately accounts for the characteristics referenced by N.C. Gen. Stat. § 62-156 and FERC's regulations and should be accepted. Specifically, with regard to Section 292.304(e) of FERC's regulations, those rules provide that avoided cost rates should account for the availability of capacity or energy from a QF during the system daily and seasonal peak periods, "including" (but not limited to) several factors. NCSEA is reading too much into this regulation to argue that because re-dispatch costs (or ancillary services costs) are not expressly listed, they may not be considered as affecting the availability of a QF.

The Commission is also not persuaded by the comments and testimony offered by NCSEA and SACE that DENC did not consider benefits as well as costs in developing the re-dispatch charge. We find DENC's filings and particularly witness Petrie's testimony convincing on this point. DENC has already reflected some benefits of solar, including hedging value, in the underlying avoided energy cost rate. For purposes of the re-dispatch charge, DENC's calculation accounts for benefits associated with its membership in PJM, and it has shown that its system does not lend itself to T&D benefits from distributed solar. Therefore, the Commission concludes that DENC's proposal is consistent with the Commission's discussion in the *2014 Parameters Order* that the integration of solar resources into a utility's generation mix results in both costs and benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculation. In addition and as noted by the Public Staff and NCSEA, in the 2014 avoided cost proceeding, the Commission found that

> while ultimately it may be appropriate for DEC, DEP and DNCP to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained.

(*2014 Parameters Order* at 60-61) The re-dispatch charge does, as shown by DENC's testimony and other evidence presented, reflect benefits as well as costs. In contrast to intervenors who advocate for rejection of the re-dispatch charge without relevant evidence, DENC provided actual data supporting the charge. Evidence presented relating to the New England ISO, for example, is not relevant to this proceeding.

In addition, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations because, without the charge, DENC's customers will overpay for QF power, as those payments will not reflect the costs to DENC to re-dispatch its system with large quantities of distributed solar generation interconnected to it. PURPA and FERC's rules provide that avoided cost rates be fair to utilities and QFs and that utilities should not pay more than avoided cost. The re-dispatch charge helps meet those requirements.

With regard to DENC's approach to calculating the re-dispatch charge, the Commission concludes that the approach of using the re-dispatch analysis from the 2018 IRP was reasonable and appropriate. The analysis was based on actual historical data from solar facilities existing on DENC's system, which was analyzed over 85 model runs in various scenarios to develop the charge. In sum, the Commission finds that DENC has made a substantial and well-supported effort to comply with the Commission's directive, which is augmented by DENC's willingness to re-calculate the charge consistent with the Public Staff's recommendations. The Commission is persuaded by the Public Staff's recommendations regarding cost and penetration level scenario weighting and agrees that the calculation of the charge should reflect actual system operations and expected future market conditions. The Commission notes that the resulting $0.78/MWh charge is also in line with the $0.69/MWh charge that witness Johnson calculated as an alternative. DENC has indicated that the charge represents its first step in quantifying the costs of integration large volumes of solar PV generation onto its system and that it will continue to evaluate these costs and benefits going forward. The calculation was made using the best information available at the time, but with further evaluation and refinements, as well as further changes in the development of QF projects, DENC acknowledged that it may be reduced by the Commission in future proceedings. We, therefore, agree with witness Petrie that for purposes of this biennial period the re-dispatch charge is fair to both QFs and DENC's retail electric customers because it will provide payments to QFs that better reflect DENC's actual avoided costs.

The Commission recognizes the discussions regarding a potential overlap between the costs being born by each utility that DENC's re-dispatch charge and Duke's SISC are intended to recover. In this proceeding, each utility has taken its own approach to evaluating and quantifying the costs to its system from intermittent non-dispatchable QFs. Should DENC propose a revised charge or charges in the next biennial proceeding to address other costs to its system resulting from such QFs, however, the Commission will evaluate the reasonableness of such a charge at that time, including any potential overlaps in the proposed charges.

Finally, DENC acknowledged that there could be circumstances where a QF, due for example to the addition of a battery, could justify an exception from the re-dispatch charge. Given DENC's limited experience with this issue to date, the Commission concludes that DENC should continue to evaluate this issue and update the charge as appropriate in future proceedings based on further modeling to analyze the impact of new solar QFs co-locating battery storage at their facilities.

In conclusion, DENC's proposed re-dispatch charge of $0.78/MWh is reasonable and appropriate for purposes of this proceeding and is accepted. In the filing of rate schedules that it makes in compliance with this order, DENC should reflect the modified re-dispatch charge of $0.78/MWh in its Schedule 19-FP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 THROUGH 14

The evidence supporting these findings of fact is found in the Initial Statement of DENC; the Initial Comments of the Public Staff, NCSEA, and SACE; the Reply Comments of DENC, the Public Staff, and NCSEA; and the testimony of DENC witness Petrie, NCSEA witness Johnson, and Public Staff witness Thomas.

Summary of the Evidence

In the *2016 Sub 148 Order*, the Commission held that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities," and, therefore, required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in the Sub 158 proceeding. (*2016 Sub 148 Order* at 56). The Commission specifically ordered that the Companies should consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." (Id.) The *2018 Scheduling Order* similarly directed the Companies to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." (*2018 Scheduling Order* at 1-2).

In response to the Commission's directives, DENC proposed changes to the rate schedules for both energy and capacity that offer additional granularity and improved price signals to QFs to better match the generation needs of the utilities. DENC proposed six pricing periods, with distinct on- and off-peak hours for each of three seasons based on Average day-ahead LMPs at the DOM Zone for each season, although the on- and off-peak rates do not vary between seasons. (DENC Initial Statement at 29). DENC also proposes a shoulder season that removes the influence of an average shoulder season's relatively flat LMPs from the winter season, resulting in the winter season's energy rates being more pronounced and reflective of actual winter costs.

With regard to capacity rates, DENC similarly based its proposed capacity peak loads on the hours when system peak loads historically have occurred, and when system emergencies are most likely to occur. DENC proposed to allocate capacity costs 50% to the summer season, 40% to the winter season, and 10% to the shoulder season, maintaining a slightly higher cost allocation to the summer months due to the Company's participation in PJM, which is a summer peaking system. (DENC Initial Statement at 30-31)

DENC further discussed the capacity value of intermittent, non-dispatchable resources like solar relative to a CT and stated that since intermittent resources cannot be dispatched on demand like a CT, they provide a lower capacity benefit. Therefore, DENC proposed an annual payment limit (or cap) that reflect the capacity value of intermittent QFs relative to a fully dispatchable CT facility. DENC stated that all QFs would continue to receive the same capacity rates, but the capacity payments would be capped on an annual basis for intermittent non-dispatchable QF at levels that reflect the operating characteristics and capacity value of these resources. DENC proposed to limit the capacity value of a solar tracking facility at 23% of the capacity value of a CT, a solar fixed tilt facility at 16% of a CT, and a wind facility at 13% of a CT. DENC highlighted the parallels between its proposed cap and the PJM Capacity Performance Market, citing the "risk adjusted capacity offer" that a rational bidder of an intermittent generation facility would offer into the market. (Id. at 18-26) Consistent with its comments regarding Duke's proposed rate design changes, the Public Staff in its Initial Comments stated that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believed that energy rate mismatches were still likely that could result in QFs potentially being over- or under-paid for the energy generated. (Public Staff Initial Comments at 47-48). As a result, the Public Staff proposed its own seasonal energy rates and hours.

Regarding DENC's proposed seasonal allocation of capacity payments and its selection of Capacity Peak Hours, the Public Staff found them to be reasonable, but notes that the reliance on the broader characteristics of the PJM region results in a misalignment of DENC's system with the seasonal allocation and Capacity Peak Hour, and recommended that DENC evaluate alternative seasonal allocation and Capacity Payment Hours that align more directly to its system (as opposed to the PJM system as a whole, which has different capacity needs from a utility operating in North Carolina). (Id. at 60, 64)

Similarly, with regard to DENC's proposed limit on capacity payments, the Public Staff noted that capacity payments to an intermittent QF will inherently be lower than the capacity payments to a dispatchable QF if the seasonal allocation and Capacity Payment

Hours are accurately chosen to reflect the utility's seasons and hours of greatest capacity need. The Public Staff noted that a solar QF cannot provide its nameplate capacity early in the winter morning, and as such, will only be paid a fraction of the available early winter morning capacity payment, relative to a dispatchable QF. The Public Staff recommended that rather than implementing the cap based on the projected capacity value of an intermittent QF relative to a fully dispatchable CT resource, DENC should instead adjust its seasonal allocation and capacity payment hours as described above to help ensure that the rates protect ratepayers from overpayment in hours where the capacity provided by intermittent QF resources has little or no value to the utility, while also providing a better price signal for market participants. (Public Staff Initial Comments at 60-64)

NCSEA also stated that the utilities did not adequately recognize how costs vary across different times of day, despite having access to detailed avoided cost data for all 8,760 hours for the next ten years. NCSEA proposed that instead of the utilities' proposals, the Commission should adopt the time-of-day periods it proposed, as well as an optional, real-time pricing tariff for QFs. (NCSEA Initial Comments at 28)

In its Reply Comments, DENC responded to NCSEA's proposal to incorporate geographic price signals that provide an economic incentive for QFs to locate in areas that are most advantageous to the grid, by noting that QFs may choose to sell its power under the Schedule 19-LMP tariff, which is locational in nature and has hourly granularity in its market-based prices. (DENC Reply Comments at 25).

DENC further stated that it continues to believe that its original proposed energy seasons and peak hours designations are reasonable and appropriate, particularly for the purposes of the standard rates and terms. It also stated that in subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in the Company's summer peak season. In addition, the Public Staff has proposed expanding the "premium peak" summer and winter hours such that there are four premium peak summer hours in the afternoon and four premium peak winter hours, two in the morning and two in the evening. As a result of these discussions, DENC indicated that it would be willing to accept the Public Staff's proposal, as modified, in the interest of achieving consensus on this issue. DENC noted that its initial proposal included the afternoon hours on weekdays and weekends in the Energy Peak Hours, but under the modified proposal, it will pay on-peak and premium peak avoided energy rates on weekdays only. (Id. at 22-24)

DENC further stated that due to its participation in summer-planning PJM and to recently observed strong winter peak loads, the Company continues to believe that its original 50%, 40%, 10% seasonal allocations were reasonable, but indicated that the Company would be willing to use a 45%/40%/15% seasonal allocation of CT costs as an alternative, indicating that weightings would continue to reflect the Company's participation in PJM and the recent strong winter peak loads, but also reflect shifting the month of May from being a summer month for capacity to being a shoulder month. DENC stated that given the uncertainty of future QF capacity factor performance, it still believes that the inclusion of a capacity payment was appropriate. (Id. at 38-39)

NCSEA witness Johnson testified that NCSEA witness Johnson testified in favor of real-time pricing during "extreme conditions." He acknowledged the Utilities' reply comments on this topic and agreed that the utilities raised practical considerations that needed to be considered, but asserted that those considerations do not justify rejection of his proposal. He further stated that DENC's LMP tariff is not as good a solution as NCSEA's proposal because of its linkages to volatile natural gas and other energy markets, and instead recommended that the utilities submit proposed RTP rates consistent with NCSEA's proposal at least six months before the next biennial proceeding. Mr. Johnson also testified that capacity cap is not needed if NCSEA's alternative pricing proposal is adopted (Tr. Vol. 6 at 233-236)

Public Staff witness Thomas testified that the Public Staff agrees with DENC's proposed rate design modifications, which include; (i) the inclusion of September as a summer month; and (ii) the expansion of the premium peak hours to encompass four hours in the summer and four hours in the winter (two in the morning and two in the evening). He further notes that while the rate design proposals for DENC and Duke agreed to by the Public Staff were nearly identical, they supported continued consideration of the unique characteristics for each utility in rate design. (Tr. Vol. 6 at 394)

DENC witness Petrie testified that NCSEA witness Johnson's proposal to implement real-time pricing "essentially asks for both long term fixed prices and short term variable prices." He noted that QFs cannot, however, have it both ways. His proposal would effectively result in "higher-of" pricing, that is, the higher of the known FP rates and the potentially volatile LMP rates for a certain number of hours during the year. Witness Petrie testified that DENC believes this type of hybrid pricing is not reasonable because it is unfair to customers both for the optionality benefits provided to QFS at the expense of customers, as well as for administrative complexity. (Tr. Vol. 5 at 47-48)

Discussion and Conclusions

Based on the evidence in this proceeding, the Commission finds that the revised rate design changes proposed by DENC and agreed to by the Public Staff, are responsive to the Commission's directives in the *2016 Sub 148 Order* and the *2018 Scheduling Order*, and provide QFs with more granular price signals to incentivize QFs to better match the DENC's generation needs. DENC should, therefore, file updated rate schedules consistent with the energy and capacity rate design described in DENC witness Petrie's rebuttal testimony.

With regard to NCSEA witness Johnson's recommendation that DENC provide a hybrid rate that includes some real-time pricing components, the Commission agrees with that real-time pricing rates for QFs could better align the utilities' avoided cost rates to QF payments, but recognizes that such an option must be balanced with the utilities obligations under PURPA to provide a QF with the option to commit to deliver its power at the utility's avoided cost either calculated at the time of delivery or calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity. The Commission notes that DENC continues to make available its Schedule 19-LMP Rates for QFs, as well as offer standard, fixed rate contracts under Schedule 19-FP. The Commission finds that it is appropriate for DENC to continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Methodology, based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's last biennial proceeding.

The Commission also finds DENC's proposed seasonal allocation weightings of 50% for summer, 40% for winter, and 10% for shoulder seasons are appropriate for use in weighting capacity value between seasons, and should be used in calculating DENC's avoided capacity rates in this proceeding, but agrees with the Public Staff that DENC should continue to evaluate the appropriate seasonal allocation based on its system, as opposed to the PJM system as a whole. Therefore, the Commission directs DENC in the next biennial proceeding to evaluate alternative seasonal allocation and Capacity Payment Hours that align more directly to its system, as opposed to the PJM system as a whole.

With regard to DENC's proposed annual capacity payment limit based on the projected capacity value of an intermittent QF relative to a fully dispatchable CT resource, the Commission agrees with the Public Staff that such a limit on payments is unnecessary if DENC appropriately evaluates and adjust its seasonal allocation and capacity payment hours based on the specific characteristics of its system. This allocation will help to ensure that ratepayers are protected from overpayment in hours where the capacity provided by intermittent QF resources has little or no value to the utility, while also providing a better price signal for market participants. Therefore, the Commission directs DENC proposed capacity limits and directs DENC to appropriately revise its Schedule 19-FP rates to remove the capacity payment limits.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 - 18

The evidence supporting these findings of fact is contained in: the Joint Initial Statement of DDEC and DEP; the Initial Comments of NC WARN, NCSEA, SACE, and the Public Staff; Duke's Reply Comments; the supplemental testimony of Duke witness Snider and DENC witness Billingsley; the supplemental responsive testimony of Public Staff witness Metz, Ecoplexus witness Wallace, NCSEA witness Norris, and SACE witness Glick; and the Supplemental Rebuttal testimony of witness Snider, Wheeler, and Johnson, and DENC witness Billingsley.

Summary of the Evidence

Through its Initial Statement and the attached exhibits, Duke has amended its Schedule PP PPA and Terms and Conditions to address modifications to a QF Facility that seeks to increase its energy output. Duke amends the Terms and Conditions for new PPAs to state that the Company may terminate or suspend purchases of electricity from the seller for "any material modification to the Facility without the Company's consent or otherwise delivering energy in excess of the estimated annual energy production of the Facility." (Duke Initial Statement, DEP Exhibit 4, Page 12 of 20, DEC Exhibit 4, Page 2 of 24). The Terms and Conditions do not specifically define the term "material modification." A material modification is, however, a term defined in the NCIP.

In its comments, Duke stated that the right to sell power under the pre-existing PPA and standard offer rates should be limited to the Facility that established a LEO and originally entered into the PPA. Duke commented that adding batteries or other technologies for the storage and later injection of energy to an existing Facility that has committed to sell power under then-effective PPA rates is an example of a material modification that could constitute an event of default resulting in termination of the PPA, at the Companies' election. (Duke Initial Statement, at 35).

Duke further stated that any such increase to the "Contract Capacity" will not be allowed if the QF seeks to retain its pre-existing standard offer PPA at the Companies "stale and significantly higher avoided cost rates." (Id.) The Company believed it would be inappropriate to compensate capital investment made today based "on stale avoided cost rates that were established many years in the past and which far exceed the currently-effective avoided cost rates." (Id. at 35-36). Duke stated that acceptance of such modifications would materially increase the financial obligations of the Companies' customers at rates significantly above the current avoided cost.

Duke included amendments to Section 1.4 of the Schedule PP PPA and Section 4 of the Terms and Conditions to clarify that changes that increase the AC energy output or the delivered DC capacity of the QF facility would be an event of default if the QF proceeds to make the modification. (Id. at 38) Duke specifically amended the terms and conditions to clarify the term "Contract Capacity" to include the estimated annual energy production of the Facility.

In its Initial Comments, the Public Staff agreed with Duke that the increased energy output of a Facility that adds storage should be subject to the rates determined in the most recently effective avoided cost docket. (Public Staff Initial Comments, at 73). The Public Staff stated that allowing a QF facility to increase their energy output by adding storage could significantly change the total cost of the QF's energy and capacity to the detriment ratepayers if, for example, the Facility adds energy during on-peak periods as reflected in prior tariffs that do not reflect the utility's highest production cost hours today. (Id. at footnote 111)

However, the Public Staff was concerned that Duke's approach to requiring a new PPA at current avoided cost rates for the entire Facility would disincentivize the adoption of new energy storage technologies at existing facilities, which also have the potential to benefit ratepayers by allowing the Facility to operate it in such a way to provide energy and capacity during periods when the utility faces high production costs or critical demand.

Further benefits could include operational controls that may also help to reduce the impacts associated with the intermittent, uncontrolled output from solar-only facilities. (Id. at footnote 112)

The Public Staff agreed with Duke that if a QF seeking to add any new capability for energy output after execution of a System Impact Study (SIS) Agreement or execution of an Interconnection Agreement following the Fast Track Process or Supplemental Review pursuant to the North Carolina Interconnection Procedures (NCIP), should be required to receive authorization from the Utility in order to ensure that the addition does not negatively impact the safe and reliable operation of the grid. (Id. at 75)

The Public Staff proposed an alternative approach to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its pre-existing PPA. (Id. at 76)

The Public Staff stated, "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." (Id.) The Public Staff was also concerned that having multiple PPAs at the same site may result in timeframes that do not align, potentially causing confusion regarding QF eligibility (Id. at 76-77)

The Public Staff noted that Duke does not specifically define the term "material modification" in its amendments to the Terms and Conditions. As that term is also used in the interconnection proceeding, the Public Staff recommends that Duke define the term explicitly. (Id. 77-78)

In its Initial Comments, NCSEA stated that Duke provides "no limitation or quantification" on its proposed "unilateral authority to void a PPA if a QF increases its annual energy production above an estimated production number stated in the PPA" and that that "occurs on a regular basis for QFs." (NCSEA Initial Comments, at 55). NCSEA further stated that the annual production number is an estimate that will vary up and down due to a variety of circumstances. (Id.)

NCSEA asserted that it is commercially unreasonable to require that a QF never exceed its estimated annual energy production without risking termination of the PPA. NCSEA argued that Duke's proposal violates PURPA requirements that of purchasing all of a QF's output provided that the QF does not exceed its nameplate capacity. (Id.) NCSEA disagreed with Duke's assertion that the right to sell under PURPA should be limited to the Facility that established a LEO and originally entered the PPA. NCSEA stated that the CPCN requirement was not intended to lock QFs into construction of a facility exactly as described in the CPCN application. (Id.)

In its Initial Comments, SACE stated that Duke's changes to the Terms and Conditions are troubling because coupling battery storage technologies with intermittent generation will allow the QF to sell energy and capacity at times of greatest value to the utility, grid operators, and ratepayers. (SACE Initial Comments, at 14). SACE further stated that Duke's barriers to storage deployment discriminates against QFs, creates economic inefficiencies, and misses opportunities to add value to the grid. (Id.)

In its Initial Comments, NC WARN disagreed with Duke's changes to the Terms and Conditions for early contract termination for changes in Contract Capacity or energy output and stated that the proposed amendments would give the Companies the ability to deny a QF's request to add battery storage to an existing solar project for any reason and without limitations. (NC WARN's Initial Comments, at 4)

In its Reply Comments, Duke maintained the position that allowing QFs to add storage would disadvantage customers and result in potentially significant additional future payments to QFs in excess of current and projected avoided costs. Duke clarified that the changes to the Schedule PP PPA and the Terms and Conditions are due to recent inquiries from developers of operating QFs desiring to make new investments in their Facilities, such as installing additional solar panels, replacing existing panels with panels with greater MW_{DC} capacity, known as "over-paneling", or proposing to co-locate battery storage at a QF Facility, and represent what Duke believes is already the case under the existing language – that they will not agree to modifications that will increase the Companies' and customers' obligations to purchase energy at prior avoided cost rates. (Duke Reply Comments, at 134). Duke developed a chart to show the scenarios and the overpayment risk to installing storage at existing QF Facilities. (Id. at 135, Figure 11)

Duke added a defined term for "Material Alteration" to their amended Terms and Conditions to more clearly define what constitutes a material change to a Facility. The proposed definition will allow the repair or replacement of equipment at the Facility with "like-kind equipment" to clarify that developers and owners may undertake routine operations maintenance and replace equipment if the facility is impacted by storm damage. (Id. at 139-140).

Duke's amended Terms and Conditions define Material Alterations to the QF Seller's Facility as follows:

> (f) "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the "Existing Capacity"), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the ***repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration.*** (Emphasis added).

(Id. at 139).

With regard to the Public's Staff recommendation in its Initial Comments to explore separately metering battery storage and compensating additional output at the current avoided cost rate, Duke stated that it does not support the Public Staff's recommendation to allow amendments to prior standard offer PPAs to accommodate the addition of storage for contractual, technological, and regulatory policy reasons. First, contractually, Duke believes that a material alteration of the Facility would require the consent of utility and failure to obtain consent would be a material breach of the contract.

Second, from a technological perspective, Duke states that the Companies' current metering system does not have the capability to segregate or estimate the production of a solar QF Facility separate from a co-located battery storage Facility. Furthermore, if the battery is shifting the time of energy delivered it could result in inequities; under the levelized rate concept, there would be overcompensation being paid to the Seller because there would be higher deliveries and payments in the early years prior to the installation of battery storage when levelized rates artificially high.

Third, Duke objected from a regulatory policy perspective. QFs and their investors have often selected the longest possible term of 15-year contracts in order to benefit from locking in higher avoided cost rates that are now projected to significantly exceed future avoided costs. Duke believes it would be inequitable to allow those Facilities to leverage the current contractual relationship to sell more MWhs or shift energy output in ways that were not contemplated when the contract was entered. (Id. at 145-146)

Finally, Duke stated that it agrees with the Public Staff that there would be challenges in determining the eligibility for QF status as a small power production facility under PURPA; the potential co-location of battery storage with a solar facility raises federal and regulatory policy questions that have not fully been answered including eligibility for 5 MW projects that will add generation that will increase nameplate capacity of the Facility as a whole and the potential violation of the half-mile rule. (Id. at 147-148)

In its Reply Comments, NCSEA stated that energy storage is now cost-competitive and there is likely to be substantial deployment before the next avoided cost biennial proceeding. NCSEA agrees with the Public Staff and SACE that the proposed additions to the PPA and Terms and Conditions regarding energy storage and increases to energy output are overly and unduly restrictive. (NCSEA Reply Comments, at 21-22). NCSEA agreed with SACE that the replacement of older solar panels with newer solar panels should not be considered a material modification that would require the QF to enter a new PPA. (Id. at 22)

NCSEA disagreed with the Public Staff's suggestion that increased energy output be separately metered and compensated at the most recently effective avoided cost rate. NCSEA asserted that the fact that a QF could increase its total revenue generated through the addition of energy storage is an insufficient reason "to violate the PURPA rights of QFs." (Id.) A QF that is already providing electricity to the grid has already met the requirements to establish a LEO and adding energy does not void the LEO. (Id. at 22-23)

SACE stated that it agrees with the positions of the Public Staff, NCSEA, and NC WARN that a number of Duke proposed amendments to the Schedule PP terms and conditions will likely discourage QF development, including the addition of energy storage. SACE states that it agrees with the Public Staff that it is not appropriate for a QF that adds storage to forfeit its existing PPA or to characterize the addition of energy storage as a new and separate facility. (SACE Reply Comments, at 17-18). SACE stated that it does consider it "appropriate at this time to require existing QFs that add storage or replace existing solar panels, but which do not exceed their AC to capacity, to enter into new contracts with new avoided cost rates." (Id. at 18). SACE believes requiring QFs to enter into bifurcated avoided cost rates "when the QF is not exceeding its original AC capacity is inconsistent with PURPA's requirements." (Id.)

Furthermore, SACE agreed with the Public Staff that "material modification " is undefined and that term should be defined further for the purposes of avoided cost contracts, with stakeholder input. SACE pointed out that NCSEA argued that material modification is more appropriately addressed in the interconnection proceeding. SACE agrees and believes that to the extent material modification is used in avoided cost contracts that Duke's definition is overly broad. (Id.)

Duke witness Snider testified that the proposed changes to the PPA and Terms and Conditions are meant to clarify that operational QFs should not be allowed to modify their generating facility in order to increase generation and that to allow that would be "unjust and unreasonable and would result in significant customer overpayment relative to the incremental generation value being put to the grid." (Tr. Vol. 2 at 87). Witness Snider stated that the modifications are necessary to protect customers from overpayment at rates that exceed the utility's current avoided cost and that power being delivered today from QFs date as far back as the 2010 E-100, Sub 127 docket. (Id.)

In quantifying the potential impacts to customers, witness Snider stated that Duke is "committed to purchase the full contracted-for output from over 3,600 MW of currently- or to-be installed QF generating facilities, all of which are subject to rate schedules approved in Docket No. E-100, Sub 140 or earlier vintages." (Id. at 88).

Duke witness Johnson stated in his direct testimony that Duke is not making any further changes to the proposed PPA and Terms and Conditions than those modifications proposed in the Duke's Reply Comments. (Id. at 261). Witness Johnson reiterated that Duke added a defined term for "Material Alteration" in response to comments of the intervenors to more clearly describe what changes or alterations an operating QF can make in the normal course of operations and to signify when the QF must obtain prior authorization from Duke. (Id.) The addition of a Storage Resource, as that term is now also defined in the Terms and Conditions, would be a Material Alteration. (Id. at 263). Witness Johnson also stated that Duke has clarified in the definition of Material Alteration that any changes, including routine maintenance, to existing Facilities will be evaluated in a commercially reasonable manner. (Id.)

Witness Hinton testified that the Public Staff reviewed the addition of the term "Material Alteration" and other changes made to the Terms and Conditions in Duke's Reply Comments and found that it addressed earlier concerns raised by the Public Staff and NCSEA. The Public Staff stated that it was generally supportive of Duke's modifications but emphasized that a "degree of reasonableness" is appropriate regarding equipment replacement and repairs made by QFs. The Public Staff testified that it is important that the modifications to the Terms and Conditions do not have the effect of discouraging efficient investments made by QFs, but also "recognize that material alterations made without reconsideration of the facility's interconnection study, and the avoided cost rates that are applicable to the QF, would be inappropriate." (Tr. Vol. 6 at 321).

In rebuttal testimony, Duke witness Johnson noted the Public Staff's general support for the modifications to the Terms and Conditions and testified that the defined term "Material Alteration" provides that "Duke will assess any proposed modifications to a QF generating facility in a commercially reasonable manner and expressly provides QF owners with contractual assurance that equipment at the facility (including solar panels) can be repaired or replaced with like-kind equipment during the term of the contract." (Tr. Vol. 2 at 274)

Supplemental Testimony

On June 14, 2019, the Commission directed the parties to address the avoided cost rate schedule and contract terms and conditions that would apply when a QF proposes to add battery storage. Three specific scenarios were identified for consideration: (i) where a QF has established a LEO to sell power to Duke, (ii) where a QF has executed a PPA with Duke to sell its power over a specified term, and (iii) where a QF has commenced operations and is now selling the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

In supplemental testimony, Witness Snider stated Duke's position that a "committed" QF may not integrate battery storage without first obtaining Duke's consent, and, in all three scenarios, should enter into a new or modified PPA at the most recent avoided cost rates. (Tr. Vol. 2 at 162-163) Witness Snider testified that "[a]llowing QF investors to integrate battery storage systems or any other technology that materially alters a QF's energy output or shifts power production under stale, legacy avoided cost rates would result in increased payments to QFs that exceed current avoided costs, in direct contravention of PURPA and HB 589's standard offer rate requirements." (Id. at 166)

Witness Snider stated that once the LEO is established, both the QF and the utility are bound for the duration of the LEO or the contract. Duke believes it is inconsistent with PURPA and state law for a QF to rely upon an existing LEO to make new investments. Witness Snider cited FERC Order 69 in its implementation of PURPA, which states that while a LEO provides certainty to the QF and ensures it is not "deprived of benefits of its commitment as a result of changed circumstances," that it "can also work to preserve the bargain entered into by the electric utility." (Id. at 167, citing FERC Order No. 69, implementing 18 C.F.R. § 292.304(b)(5)).

DENC witness Billingsley testified that DENC has not made any changes to the Schedule 19 tariffs or PPAs to specifically address the addition of battery storage. (Tr. Vol. 5 at 58) Witness Billingsley states DENC's position in all three scenarios is that if a QF that seeks to add storage to a proposed or existing facility that has established a LEO or entered into a PPA, it would be required to establish a new LEO or execute a new PPA at current avoided cost rates. (Id.) DENC testified that a QF that seeks to expand its maximum capacity, energy production, or shift its hours of production under those rates and terms would burden the Company and its customers with newly-obligated overpayments at stale avoided cost rates, in contravention of PURPA's requirement that utilities not pay more than their avoided cost for QF output. (Id. at 59) The addition of batteries would exacerbate the overpayment burden that the utility already faces and "contradicts the requirement of PURPA that purchases at avoided cost rates be fair to both QFs and the utility (and its customers)." (Id.)

Witness Billingsley stated that nearly all solar QFs that executed PPAs during the Sub 136 and Sub 140 vintage biennial periods elected Option B peak hours definition pricing and those hours no longer represent the utility's highest capacity value hours. Witness Billingsley believes that allowing them to deliver energy from storage during those periods with higher capacity payments would be contrary to the recent movement towards more granular rate design that would incent QFs to deliver energy during a higher value set of hours. (Id. at 62-63). At the hearing, witness Billingsley was asked whether some of DENC's concerns would be alleviated if existing QFs were incentivized to produce energy during the newly proposed peak periods. Witness Billingsley agreed that DENC would like to send price signals during peak hours. (Id. at 89)

In responsive testimony, Public Staff witness Metz testified that the complementary function of energy storage, when paired with intermittent generation, can reduce needed system reserves by improving predictability of energy output, alleviate other challenges to the electrical grid, and increase the overall dependable capacity. Therefore, witness Metz stated that it is the Public Staff's position that energy storage coupled with solar generation has the potential to provide benefits to ratepayers and should be appropriately encouraged and fairly treated. (Tr. Vol. 6 at 349)

Public Staff witness Metz testified that the challenge to the Commission is how to allow battery storage development with both future and existing solar QF generation and provide its benefits in a way that is fair to ratepayers. (Id. at 331) Witness Metz testified that he agrees with the utilities that a "QF proposing to integrate battery storage should: (a) not be allowed to do so without the utility's consent; and (b) be required to enter into a new or modified power purchase agreement (PPA) at the Companies' then-current avoided cost rates." (Id. at 332) Witness Metz stated that paying for additional energy and capacity at old, higher avoided cost rates that no longer reflect the actual avoided costs of the utility would be unfair to ratepayers, as they would "no longer be indifferent between energy supplied by a QF and energy generated by the utility." (Id. at 332)

The Public Staff, however, did not agree with the utilities that a QF that adds storage or increases output should lose its eligibility for the rates it established for its original Facility output (contract capacity and energy). (Id. at 332) Rather, any "additional energy" put to the electrical grid from an already existing QF, whether commercially operational or studied as part of the facility's original interconnection request, should be compensated at the most current avoided cost rates and schedules. (Id. at 349)

Witness Metz testified that it is possible for a QF to produce "additional energy" without adding battery storage by deciding to "re-panel" or "over-panel" to increase its DC capacity, which does not necessarily increase nameplate capacity due to inverter settings and other utility equipment limitations. These modifications, however, can result in faster ramp rates and increased "clipped" energy. (Id. at 334-5). Witness Metz stated that, under the proposed definition of Material Alteration, over-paneling and re-paneling would likely not be considered a Material Alteration so long as Existing Capacity is not increased.

Witness Metz noted the Public Staff's continued position that "a degree of reasonableness should be applied to these thresholds, and the Companies should review these revisions in a commercially reasonable manner." (Id. at 335)

At the hearing, in response to the Chair Mitchell's question regarding whether it was possible to add energy storage without increasing the overall output of the facility, witness Metz replied that it was possible, but there would have to be validation of certain equipment and contractual terms and conditions developed to ensure the Facility's output is not increased. (Id. at 433)

With regard to adding storage and separately compensating the additional energy output of the Facility, witness Metz testified that there are multiple possibilities to measure the output co-located batteries but would likely require further restrictions of commercial terms and conditions and may prove uneconomical. Witness Metz testified that in addition to engineering and technical challenges, impacts on the interconnection queue, as well as the applicable contract terms and conditions would have to be further considered. (Id. at 344). For example, witness Metz testifies that if an existing facility sought to add battery storage and took the position that the storage could be separately measured, a methodology would have to be created to develop a baseline of current output for comparison purposes and incorporated into the commercial terms and conditions. (Id. at 345)

Witness Metz proposed a focused stakeholder discussion with an accelerated timeline to explore and develop a deployable energy storage solution for existing QFs and to identify specific challenges that prevent the commercial viability of adding energy storage to existing facilities. (Id. at 351)

In responsive testimony, Ecoplexus witness Wallace stated the purpose of his responsive supplemental testimony is to (1) respond to the utilities and the Public Staff's testimony that the addition of battery storage should be at current avoided cost rates; and (2) to provide technical information regarding how a DC coupled battery solution can be metered once added to an existing QF. (Tr. Vol. 5 at 345)

Witness Wallace testified that Ecoplexus agrees with the approach recommended by the Public Staff in its Initial Comments to separately meter any additional output at the then current commission approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its current PPA. (Id. at 346). Witness Wallace stated there are multiple methods to measure the energy output of a battery system; including: (1) "transferring that data directly from the Energy Management System provided by the battery storage provider through network communications onsite;" and (2) "add a DC meter to the storage output so that energy output could be compensated at the current avoided cost rates and separated from the pre-existing PPA." (Id.)

In the first option, the battery management system (BMS) collects information in real time and delivers it to the Energy Storage System (ESS), which processes and analyzes the data. BMS and ESS integrators provide a cloud-based system for monitoring, sharing, and displaying data. (Id. at 347-8). In the second option, Witness Wallace states that a DC meter could be added for each storage block in addition to the AC revenue meter installed at the point of interconnection, which will remain in place. (Id. at 349). While witness Wallace states there "are no ANSI or IEEE standards in place for DC-meters" there are companies that can meet certain the ANSI C12.1 accuracy specification. (Id.) Witness Wallace takes the position that if DC energy can be measured with revenue grade accuracy, a "simple ratio can be calculated and used at the utilities AC meter to decipher energy from the array as opposed to energy from the storage system to ensure the proper rate is assigned." (Id. at 350)

Witness Wallace states further that there are two outstanding issues that would need to be discussed and considered collaboratively, including (1) a metering and communications standard; and (2) commercial PPA terms. Witness Wallace proposes a schedule for such discussions with a formal proposal submitted to the Commission within 150 days. (Id. at 351)

In responsive testimony, NCSEA witness Norris testified that energy storage will play an increasingly significant role in enabling "a more affordable, reliable, and sustainable electricity system." (Tr. Vol. 6 at 124) Witness Norris states that NCSEA and Cypress Creek believe that "it is incumbent upon the Commission to make decisive regulatory interventions to remove barriers to market entry for energy storage" and that is of substantial importance in this State for committed QFs because more utility-scale solar is installed in North Carolina than any other state except California. (Id. at 125)

At the hearing, witness Norris testified "there is nothing in the standard offer terms and conditions that prohibits a QF from making equipment changes that change the schedule of the output" and "there is nothing in the standard offer QF PPA that prohibits or requires the Utility's consent for equipment changes." (Id. at 150) Witness Norris states that "it is the view of NCSEA that committed generators are fully entitled to add storage under the terms and conditions of the standard offer PPA." (Id.) However, NCSEA offered to accept the alternative arrangement proposed by the Public Staff that output from the storage equipment would be compensated at the most recently determined avoided cost rate. (Id. at 151). Witness Norris stated that both NCSEA and NCCEBA are "willing to make this significant concession in the interest of achieving an amicable resolution of the issue." (Id.)

Witness Norris testified that utilities' position that any committed generator that adds storage must terminate its existing PPA, or LEO, and seek an entirely new PPA would "wholly obstruct the addition of storage resources." (Id.) Witness Norris stated that ratepayers could benefit from the addition of storage by "including bulk energy time shifting, peak capacity deferral, interconnection efficiency, [and] reduced solar curtailment" among other benefits. (Id. at 152) Witness Norris also testified during the hearing that the addition of battery storage could also smooth the production curve in a way that could obviate the need for the solar integration charge. (Id. at 177)

Witness Norris disagreed with DENC Witness Billingsley's assertion that a QF with LEO under the Sub 136 or Sub 140 tariff should not be able to deviate from the configuration specified in its CPCN or FERC Form 556 without losing its LEO. Witness Norris stated that if a QF that changes its facility, it must file an updated form and inform the Commission, but that hundreds of such amendments have been made and approved by the Commission or a recertified by FERC without voiding the established LEO.

Witness Norris also testified that the essential element of their compromise is that the avoided cost rate available to its output is set at the 10-year avoided cost rate. Under NCSEA's approach, the modified PPA would also maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor. This would properly value the capacity and will allow the QF to attract financing. A 5-year avoided cost rate would "undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable." (Id. at 147)

SACE witness Glick recommended that the Commission reject Duke's proposed changes to the Terms and Conditions, require Duke to honor existing contracts with QFs that integrates battery storage, and develop a modified rate design proposal for existing QFs that seek to integrate battery storage. (Id. at 287-288). Witness Glick stated that as long as the QF does not increase its AC capacity, then "the utility has no reasonable basis to regulate the operation of individual components on the operator side of the meter." (Id. at 274)

In joint supplemental rebuttal testimony, Duke witnesses Snider, Johnson, and Wheeler reiterated Duke's position that a committed QF proposing to integrated energy storage should not be able to do without the utility's consent and should enter into a new PPA at current avoided cost rates. (Tr. Vol. 2 at 176) Duke witness Snider testified that Duke is not opposed to entering a new PPA or negotiating a modified PPA if an existing QF proposes adding storage. (Id.) Witness Snider disagreed with NCSEA that the addition of storage to operating QFs will inherently create benefits for consumers. (Id. at 181-182) Witness Snider states under the compromise position, even if "all the complex federal and state regulatory issues, contract law issues, and technical interconnection and metering issues" are resolved that customers will, at best, only be indifferent to adding storage because "it would be procured from an uncontrolled must-take QF generator being dispatched to maximize revenue and being paid at the utility's full avoided cost value rather than at competitively bid prices." (Id. at 183)

Witness Snider testified that if the Commission accepts the compromise, that the QF owner seeking to add storage should be required to offer additional consideration that benefits customers in exchange for Duke agreeing to modify the existing commitment to purchase. (Id. at 184-185) Also with regard to NCSEA's position that the Utilities should offer a standard offer avoided cost rate for additional output from a storage facility of 10 years, Witness Snider stated that this is a deviation from the express requirements of HHB 589. (Id.)

Duke witness Wheeler stated that he has several concerns with Ecoplexus' proposal to measure energy storage output on the DC side of the power inverter and point of interconnection with the Duke system. (Id. at 147-148) First, it is Duke's business practice to install metering exclusively on the utilities' side of the point of interconnection, and if it is installed on the QF side, the QF would have the opportunity to change the operation of the equipment without the utilities' knowledge or control. Second, as witness Wallace admits, no ANSI standards currently exist to judge the accuracy of the Accuenergy data logger of DC meter proposed in witness Wallace's testimony. (Tr. Vol. 2 at 147-149)

Duke witness Johnson testified that he disagreed with NCSEA's assertion that energy shifting is currently allowed under Duke's avoided cost tariffs. (Id. at 202-204). Mr. Johnson stated that a unilateral change such as adding storage to a committed facility without obtaining the Companies' consent would be an event of default. (Id. at 204)

In responsive testimony, Public Staff witness Metz noted that Duke should clarify the definition of "Material Alteration" by adding a set of commas to make it unambiguous that only a decrease of 5% would not be considered a material alteration whereas any increase would be a material alteration. (Tr. Vol. 5 at 338, fn. 22) Witness Johnson testified that Duke has no objection to witness Metz's recommendation for the grammatical clarification. (Tr. Vol. 2 at 204)

In supplemental rebuttal testimony, DENC witness Billingsley states that "the Company believes that allowing the existing solar generation facility to continue to receive the original rates for which it was eligible while applying current rates to the output from the battery addition, appears a reasonable approach." (Tr. Vol. 5 at 69) Witness Billingsley also stated DENC would be willing to participate in a working group to address various technological and commercial challenges and these issues would need to be studied and addressed before the "compromise approach could be fully implemented." (Id. at 69-70)

Discussion and Conclusions

With regard to Duke's proposed changes to its Terms and Conditions, the Commission distinguishes between two issues in contention between the parties: (1) whether regular maintenance of a facility or repair after a storm is a material change that can lead to default of the existing PPA; and (2) whether upgrading the facility to increase its energy output by re-paneling, over-paneling, or co-locating storage devices such as a batteries is a material change that can trigger default of the existing PPA, at the utility's option. Duke, through its Reply Comments, adds the defined term "Material Alteration" to the Schedule PP PPA and Terms and Conditions to more clearly define the instances of what is a material change that requires the utility's consent, and without consent, may lead to default of an existing PPA.

With regard to the first issue, the Commission shares the concerns raised by the intervenors and by Public Staff regarding the term "Material Alteration." As testified to by several witnesses, QF Facility owners and operators often complete maintenance on their

Facilities that could increase the energy or capacity such as replacing existing solar panels with newer panels, or re-paneling, without first obtaining the consent of the utility. The Commission generally agrees that this type of maintenance should not trigger a default of the existing PPA. The Commission believes that Duke has adequately addressed these concerns with the defined term "Material Alteration" which expressly allows replacement of "like-kind" equipment and states that material alterations will be evaluated by the Company in a "commercially reasonable manner."

The Commission agrees in general with Duke that the right to sell power under the pre-existing PPA and standard offer rates should be limited to the Facility that originally entered into the PPA. However, the Commission also agrees with NCSEA that the CPCN requirement was not intended to lock QFs into the construction of a Facility exactly as described in the CPCN application and that the Commission does, in regular instances, approve amendments to CPCNs without voiding the Facility's LEO. Those amendments, however, are usually limited in scope and do not involve changes to the Facility that would require reconsideration of the Facility's interconnection study and substantially increase the lifetime energy output or revenue potential of the Facility.

Under the terms and conditions of the existing PPAs, material changes to the capacity of the QF facility should be authorized by the utility. However, as stated above, the evaluation of any material alteration should be treated in a commercially reasonable manner." The Commission believes that regular maintenance and repair of the Facility after a storm, or similar instances that occur on a normal basis, should be treated within the normal course of operations and should not consider a change that would allow the utility to void the existing PPA.

Turning to the second issue, the Commission agrees with the utilities and the Public Staff that it is inappropriate to compensate QFs for new capacity and energy at prior avoided cost rates that do not reflect current avoided cost rates and do not align price signals for energy with the highest needed capacity windows. However, the Commission also recognizes the intervenor's concerns, including the Public Staff, that requiring existing or "committed" facilities to enter a new PPA and forfeit prior, higher avoided cost rates will disincentive QFs from adding storage, which if allowed under new rate design hours, could allow intermittent generation to sell energy and capacity at times of greatest value to the utility and ratepayers.

The Commission finds persuasive NCSEA's argument that removing barriers to energy storage is particularly important in this State because of the amount of utility-scale solar that is already installed surpasses that of any other state except California. The Commission also notes NCSEA's testimony that energy storage is now a cost-competitive option and there is likely to be a substantial deployment of storage before the next avoided cost biennial proceeding and that energy storage will play a significant role in enabling a more affordable, reliable, and sustainable electricity system. The Commission notes that in its June 14, 2019, *Order Approving Revised interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100, Sub 101, the Commission has already directed Duke to host stakeholder meetings to develop an expedited study process for energy storage that is proposed to be added to an existing generation site.

In supplemental responsive testimony, NCSEA stated that it is willing to accept the "compromise" suggested by the Public Staff to explore separately metering battery storage and compensating additional output at the then current avoided cost rate. NCSEA states though, that this may not be an economically viable alternative at this point in time and that the Commission would need to ensure that those QFs received the 10-year avoided cost rate for the tenor of the PPA.

The Commission disagrees with NCSEA's position regarding the rate and tenor for new capacity added to the QF PPA or entered into under a new PPA. HB 589 requires that the rates to be paid by electric public utilities to small power producers not eligible for the standard contract shall be for a fixed five-year term. See N.C. Gen. Stat. § 62-156(c). If the compromise position is implemented and a new PPA is entered into, or the existing PPA is amended to add the output of an energy storage device, at the then current avoided cost rate, the Commission finds that the rate shall be established through good-faith negotiations between the utility and the power producer, but the term of the new contract shall not exceed five years.

The Commission also disagrees with SACE that the QF Facility should be allowed to add energy storage and be compensated for the additional energy added to the system and not contemplated in the original PPA at prior avoided cost rates. The Commission believes that the addition of energy storage to an existing QF is a material change to the terms of the prior contract and requires the utility's consent. In addition to being a material change that could, at the utility's option, void the existing PPA, the Commission also finds that allowing QFs to modify their Facility to substantially increase energy output and be compensated at prior avoided cost rates would result in significant overpayment beyond the current avoided cost based on Sub 140 and earlier rates that would be unfair to ratepayers.

The Commission agrees with all the parties that allowing QFs to add storage at bifurcated avoided cost rates raises a multitude of challenging administrative and regulatory issues. Those issues include, but are not limited to, the development of metering and communication standards and new commercial PPA terms that have not been fully considered in this proceeding. For that reason, the Commission finds that it is premature at this time to decide whether the compromise position is appropriate. Rather, the Commission finds it appropriate to continue to investigate the proposed compromise as a potential solution finding a balance between properly encouraging the implementation of battery storage in a manner that is fair to ratepayers.

In conclusion, based on the evidence in this proceedings, the Commission finds that Duke's proposed modifications to the Schedule PP PPA and the Terms and Conditions, as revised in its Joint Reply Comments, and with the grammatical change proposed by Public Staff witness Metz in responsive testimony, are appropriate. Specifically, Duke's clarification and addition of the defined term "Material Alteration" is appropriate because it excludes the repair or replacement of equipment at the Facility with like-kind equipment, which does not increase Existing Capacity, or decrease the Existing Capacity by more than five percent. The Commission also agrees that the addition of a "Storage Resource," as that term is now defined, is a Material Alteration of the contract that will require the prior authorization of the utility.

As has been previously discussed at length in this proceeding with regard to the proposed Solar Integration Charge proposed by Duke and the re-dispatch cost proposed by DENC, intermittent generation has a cost to the system, and that cost can potentially be offset by the addition of energy storage technology like co-located batteries. For that reason and because energy storage paired with intermittent generation can increase the overall dependable capacity on the system, the Commission believes it is appropriate from a policy perspective to encourage QF development, consistent with PURPA, and to encourage the improvement of existing QF Facilities through the addition of battery storage where that technology has the potential to provide benefits to ratepayers and grid operators alike.

The Commission is encouraged by Duke's statement that it is willing to enter a new PPA or negotiate a modified PPA if an existing QF proposes adding storage. Similarly, the Commission appreciates DENC's statement that the compromise appears to be a reasonable approach and their willingness to participate in a working group to address various technological and commercial challenges.

The utilities and the intervenors appear to agree, that in the case that the Commission adopts the Public Staff's compromise approach, that it is appropriate for the parties to further discuss how to integrate storage with solar through a stakeholder group process that would specifically address the complexities of modifying existing facilities that request to add capacity through the co-location of batteries. The Commission agrees this an appropriate and critical step towards determining whether adding storage to existing facilities is feasible and economically viable if compensated at current avoided cost rates.

Therefore, the Commission finds that Duke should organize the stakeholder group and report to the Commission no later than March 1, 2020. The goal of the stakeholder process is to create a working forum to:a) identify critical issues that are barriers to the addition of energy storage to existing facilities, b) develop solutions that will encourage deployment of energy storage, and c) further identify specific challenges that prevent the commercial viability. The intent of the working forum would be to work toward a common goal, through collaboration, of determining the viability, identifying challenges and efforts required to add energy storage to existing facilities. The report shall include, at a minimum, the following categories:

I. Technology

a) Identify the metering challenges for AC and DC measured systems.
b) Proposed solutions for AC and DC measured systems.
c) Cost analysis of design and implementation from both the Facility and Utility.

II. Commercial

a) Report on what existing commercial terms and conditions are preventive barriers for implementation.
b) Propose solutions to remove or mitigate preventive barriers.
c) Billing and Payment for separately metered systems.

III. Regulatory

a) Regulatory barriers that are dampening or preventing implementation.
b) The appropriate avoided cost rates and terms of the PPA.
c) Cost recovery for additional services

IT IS, THEREFORE, ORDERED as follows:

1. DEC and DEP shall recalculate their avoided energy rates using forward natural gas prices for no more than five years before transitioning to their fundamental forecasts for the remainder of the planning period;

2. DEC and DEP shall recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA;

3. Prior to the next biennial proceeding, the Utilities should evaluate the avoided transmission benefits associated with QFs interconnected to the distribution system that are eligible for the Standard Offer contract and determine an appropriate avoided transmission cost adder to the avoided energy rate to reflect these benefits, which would be available unless the QF would cause or increase reverse power flow, or the projected load growth over the next ten years on the interconnected feeder is negative or negligible. The avoided transmission adder should be included in the Utilities' tariffs and rate schedules in next biennial avoided cost proceeding;

4. The Utilities must consider site and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and include an avoided transmission adder if a project can provide real and measurable avoided transmission capacity benefits;

5. Prior to its next biennial proceeding, Duke shall evaluate whether a QF resource that can sufficiently demonstrate and contractually obligate itself to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits. Duke shall include this evaluation in its next biennial proceeding, and identify mechanisms to quantify the ancillary service benefits that such innovative QFs can provide;

6. DEC and DEP shall update their Standard Terms and Conditions, including the definition of Material Alteration, in compliance with this Order. DEC and DEP shall evaluate in a commercially reasonable manner whether any updates to a facility as a result of equipment replacement and repairs are a Material Alteration that would lead to the termination of the existing PPA; and

7. DEC and DEP shall convene a working group of the interested parties in this proceeding and submit a report to the Commission addressing the technical, regulatory, and contractual complexities of separately metering the energy output from energy storage equipment that is co-located at existing solar facilities, as identified further in this Order, no later than March 1, 2020.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of September, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Kimberly A. Campbell, Chief Clerk