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	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, February 19, 2019, at 9:30 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Monday, July 15, 2019, at 1:30 p.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC:

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For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27604

For Carolina Utility Customers Association, Inc.:

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For Cube Yadkin Generation LLC:

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For North Carolina Clean Energy Business Alliance and Ecoplexus, Inc.:

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For North Carolina Small Hydro Group:

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For NC WARN, Inc.:

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For Southern Alliance for Clean Energy:

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For the Using and Consuming Public:

Jennifer T. Harrod, Special Deputy Attorney General, and Teresa Townsend, Special Deputy Attorney General, North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Tim R. Dodge, Lucy E. Edmondson, Layla Cummings, and Heather D. Fennell, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the 2018 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegates responsibilities in that regard to this Commission. This proceeding is also held pursuant to N.C. Gen. Stat. § 62-156, which requires this Commission to determine the rates to be paid by electric public utilities for power purchased from small power producers, as defined in N.C.G.S. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to adopt such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. In adopting such rules, the FERC stated:

> Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities [QFs], and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state regulation, the FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings as required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

As noted above, this proceeding also results from the mandate of N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that, "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric public utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The General Assembly recently amended N.C.G.S. § 62-156 in 2017 through enactment of Session Law 2017-192 (House Bill 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On June 26, 2018, the Commission issued in this docket an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (2018 Scheduling Order). Pursuant to the 2018 Scheduling Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP, and together with DEC, Duke); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities); Western Carolina University (WCU); and New River Light and Power Company (New River) were made parties to the proceeding. The 2018 Scheduling Order specifically directed the Utilities to address issues as required by Ordering Paragraph No. 16 of the Commission's October 11, 2017 Order in the last avoided cost proceeding, Docket No. E-100, Sub 148 (2016 Sub 148 Order), in presenting their avoided cost rates and terms in this proceeding, and further stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules rather than a full evidentiary hearing. The 2018 Scheduling Order also established deadlines for the filing of petitions to intervene, initial comments and exhibits in response to the Utilities' filings, reply comments, and proposed orders. The 2018 Scheduling Order also scheduled a public hearing for February 19, 2019, solely for the purpose of taking non-expert public witness testimony. Finally, the 2018 Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication no later than the date of the hearing.

The following parties filed timely petitions to intervene that were granted by the Commission: Carolina Utility Customers Association, Inc. (CUCA); Cube Yadkin Generation LLC (Cube Yadkin); Ecoplexus, Inc. (Ecoplexus); North Carolina Clean Energy Business Alliance (NCCEBA); North Carolina Small Hydro Group (NC Small Hydro Group); North Carolina Sustainable Energy Association (NCSEA); NC WARN, Inc. (NC WARN); and Southern Alliance for Clean Energy (SACE). Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e). The North Carolina Attorney General's Office gave notice of its intervention pursuant to N.C.G.S. § 62-20.

On November 1, 2018, Duke filed the Joint Initial Statement and Exhibits of DEC and DEP, which were verified by Glen A. Snider; DENC filed its Initial Statement and Exhibits, which were verified by Bruce Petrie; and WCU and New River jointly filed their comments and proposed avoided cost rates, which was verified by Kevin W. O'Donnell. DENC subsequently revised its proposed standard offer rate schedules by filings on March 7, 2019, and March 14, 2019.

On November 13, 2018, Duke filed a motion for approval to implement temporary variable rate credits, which was allowed pursuant to the Commission's order issued on December 3, 2018.

On or before February 13, 2019, the following parties filed initial comments: NC WARN, NC Small Hydro Group, Cube Yadkin, NCSEA, SACE, and the Public Staff.

On February 19, 2019, the public hearing was held as scheduled. Three public witnesses testified.

On March 27, 2019, the following parties filed reply comments: Duke, DENC, NC Small Hydro Group, NCSEA, SACE, and the Public Staff.

On April 18, 2019, Duke filed an Agreement and Stipulation of Partial Settlement with the Public Staff pertaining to rate design methodology (Rate Design Stipulation).

On April 24, 2019, the Commission issued an order scheduling an evidentiary hearing in this proceeding, identifying the issues in dispute that would be considered at the hearing, and establishing deadlines for the filing of testimony prior to the hearing.

On May 21, 2019, DENC filed the direct testimony of Bruce E. Petrie, and Duke filed the testimony and exhibits of Glen A. Snider, Steven Wheeler, David B. Johnson, and Nick Wintermantel. On the same day, Duke also filed the Stipulation of Partial Settlement with the Public Staff Regarding Solar Integration Services Charge (SISC Stipulation).

On June 14, 2019, the Commission issued an order requiring the Utilities to file supplemental testimony and allowing the other parties to file responsive testimony specifically addressing the following question:

> what avoided cost rate schedule and contract terms and conditions apply when a [QF] adds battery storage to an electric generating facility that has (i) established a legally enforceable obligation (LEO), (ii) executed a power purchase agreement (PPA) with the relevant utility, and/or (iii) commenced operation and sale of the electric output of the facility to the relevant utility pursuant to an established LEO and executed PPA.

On June 21, 2019, NCSEA filed the testimony of Ben Johnson, R. Thomas Beach, and Carson Harkrader; SACE filed the testimony of James F. Wilson and Brendan Kirby; and the Public Staff filed the testimony of Jeff Thomas and John R. Hinton.

On June 25, 2019, Duke filed the supplemental testimony of witness Snider on the addition of storage to existing QFs, and DENC filed the supplemental testimony of James M. Billingsley.

On July 3, 2019, Duke filed the rebuttal testimony of witnesses Snider, Wheeler, Johnson, and Wintermantel; DENC filed the rebuttal testimony of witness Petrie; NCSEA filed the supplemental responsive testimony of Tyler Norris; SACE filed the supplemental responsive testimony of Devi Glick; Ecoplexus filed the supplemental responsive testimony of Michael R. Wallace; and the Public Staff filed the supplemental responsive testimony of Dustin Metz.

On July 11, 2019, Duke filed the supplemental joint rebuttal testimony of witnesses Snider, Wheeler, and Johnson; DENC filed the supplemental rebuttal testimony of witness Billingsley.

On July 12, 2019, Duke filed a letter to the NC Small Hydro Group in response to their request to extend the current performance adjustment factor (PAF) beyond the term of the Stipulation of Settlement Among Duke Energy Carolina, LLC, Duke Energy Progress, LLC, and North Carolina Hydro Group (Hydro Stipulation), which was filed in the 2014 biennial avoided cost proceeding, Docket No. E-100, Sub 140, on June 24, 2014, and expires at the end of 2020.

On July 15, 2019, the Commission resumed the hearing, as scheduled, for the purpose of receiving expert witness testimony. Duke presented the testimony of witnesses Snider, Wheeler, Johnson, and Wintermantel. DENC presented the testimony of witnesses Petrie and Billingsley. NCSEA presented the testimony of witnesses Beach, Johnson, and Norris. SACE presented the testimony of witnesses Kirby, Wilson, and Glick. Ecoplexus presented the testimony of witness Wallace. The Public Staff presented the testimony of witnesses Thomas, Hinton, and Metz. The prefiled testimony of those witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket (with the exception of NCSEA witness Harkrader), were copied into the record as if given orally from the stand. Ms. Harkrader's prefiled testimony was allowed to be considered as a consumer statement of position.

On August 2, 2019, and August 14, 2019, Duke filed late-filed exhibits in response to questions from the Commission during the expert witness hearing.

On October 7, 2019, the Commission issued a Notice of Decision in this docket addressing issues relevant to the calculation of avoided capacity rates and avoided energy rates so that Duke and the Independent Administrator of the CPRE Program can calculate such rates; adjust implementation of the CPRE Program, as necessary; and proceed with the evaluation of proposals submitted in the Tranche 2 CPRE RFP Solicitation. The decisions announced therein are incorporated into this Order, including a discussion of the evidence supporting the findings and conclusions included in the Notice of Decision.

In its Notice of Decision, the Commission noted that issues related to the proposed integration services charge remained under consideration, and on October 17, 2019, the Commission issued a Supplemental Notice of Decision in this docket addressing such issues. The decisions announced therein are incorporated into this Order, including a discussion of the evidence supporting the findings and conclusions included in the Supplemental Notice of Decision.

On and after November 1, 2019, parties made various compliance filings associated with the Notice of Decision and Supplemental Notice of Decision, which will be decided by separate order.

In addition, on March 16, 2020, NCCEBA and NCSEA jointly filed Notice of Additional Authority providing a copy of the South Carolina Public Service Commission's avoided cost order, and on March 27, 2020, Duke filed a Response requesting the Commission to strike NCCEBA and NCSEA's filing. The Commission notes that it had reached its decisions in this docket but not yet finally reduced them to writing prior to NCCEBA and NCSEA's late filing, and that such filing played no part in the Commission's decisions announced in the Notice of Decision, Supplemental Notice of Decision, or in this Order.

Based on the foregoing and the entire record herein, the Commission now makes the following

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DENC to offer long-term levelized capacity payments and energy payments for ten-year periods as a standard option to all QFs contracting to sell one megawatt (MW) or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option subject to renewal for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties

negotiating in good faith and taking into consideration the utility's then-avoided cost rates and other relevant factors, or (2) set by arbitration.

2. It is appropriate for DEC, DEP, and DENC to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding.

3. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (2006 Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (2016 Sub 148 Order).

4. The proposed changes to DEC's and DEP's energy and capacity rate design, as indicated in the Rate Design Stipulation between Duke and the Public Staff, are appropriate for use in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding.

5. The Rate Design Stipulation is the product of the give-and-take in settlement negotiations between Duke and the Public Staff, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, along with the other record evidence.

6. DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

7. Duke's assumptions regarding the availability of demand-side management (DSM) programs for reducing winter peak demand are appropriate for use in calculating avoided capacity costs in this proceeding, and it is appropriate to require Duke to place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands.

8. It is appropriate to require DEC and DEP to continue to evaluate methods to better align their avoided cost rates with actual real-time system conditions to enable QFs to maximize their facilities' value to ratepayers through real-time pricing or other tariffs that provide more granular rate structures and price signals.

9. As a result of changes to the on- and off-peak hours being implemented in this Order, it is appropriate to waive the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) and to require an applicant for a certificate of public convenience and necessity (CPCN) to submit information regarding the projected annual production profile of the proposed generating facility, until such time as the Commission adopts revisions to the these Rules.

10. It is appropriate to consider amendments to the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) to include information regarding the annual energy production profile and other factors influencing the shape of the production profile in a generic proceeding.

11. The installed cost of a combustion turbine (CT) used by the Utilities, including the exclusion of hypothetical firm natural gas pipeline transportation capacity costs, is appropriate for use in calculating avoided capacity costs in this proceeding.

12. It is appropriate to require DEC, DEP, and DENC to include in their initial statements to be filed in the 2020 biennial avoided cost proceeding an evaluation and application of cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure will be used to meet future capacity additions by the utility.

13. Power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continues to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated.

14. It is appropriate for DENC not to include a line loss adder in its standard offer avoided cost payments to solar QFs on its distribution network.

15. It is appropriate to require DEC and DEP to continue to include the line loss adjustments in their standard offer avoided energy calculations, to study the effects of distributed generation on power flows on their electric systems to determine if there is sufficient power backflow at their substations to justify eliminating the line loss adjustment from their standard offer avoided cost calculations filed in the next avoided cost

proceeding, and to evaluate whether power committed to be sold and delivered by distribution-connected QFs not eligible for the standard offer is causing power backflow on the substation and whether the line loss adjustment is appropriate based upon the characteristics of the individual QF's power.

16. It is appropriate to require DEC and DEP to utilize a performance adjustment factor (PAF) of 1.05 in their respective avoided cost calculations for all QFs, other than hydroelectric QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued in accordance with the Hydro Stipulation.

17. It is appropriate to transition hydroelectric QFs currently selling the output of their facilities pursuant to the Hydro Stipulation to an applicable sales arrangement that is generally available to QFs, either the utility's standard offer contract or a negotiated contract, beginning December 31, 2020, and to require DEC and DEP to address issues related to this transition in their initial filings in the 2020 biennial avoided cost proceeding.

18. It is appropriate to require DEC and DEP to consider the use of other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support development of the PAF and to address this issue in its initial statement in the 2020 biennial avoided cost proceeding.

19. DEC, DEP, and DENC have complied with amended N.C.G.S. § 62-156(b)(3) and appropriately identified their first avoidable capacity need, as presented in their 2018 Integrated Resource Plans (IRPs).

20. For purposes of determining the first year of capacity need for negotiated contracts and for Competitive Procurement of Renewable Energy (CPRE) Tranche 2, it is appropriate for a utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need.

21. There is insufficient evidence in this record for the Commission to find that any utility uprates shown in DEC's or DEP's most recent IRPs are deferrable or avoidable for purposes of establishing a capacity rate; therefore, these uprates shall not be included in the determination of avoided capacity costs for purposes of this proceeding.

22. Beginning with the 2020 IRPs, the Utilities shall include a specific statement addressing the utility's future capacity needs to be used to determine the first year of avoidable capacity need in the next biennial avoided cost proceeding.

23. It is appropriate for the Utilities to recognize that a swine or poultry waste generator, or a hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed-term contract prior to the termination of the QF's existing contract term is avoiding the Utilities' future capacity need for these designated resource types

beginning in the first year following expiration of the QF's existing PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended in House Bill 329.

24. For other types of QF generation, it is appropriate under PURPA and consistent with N.C.G.S. § 62-156(b)(3) for the Utilities to recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRPs.

25. It is appropriate for DEC, DEP, and DENC to continue their current approach to the assumed January 2019 in-service date for the purposes of this proceeding.

26. It is appropriate for the utility and a QF not eligible for the standard offer contract to negotiate a presumed in-service date for rate calculation purposes accounting for any anticipated date of the QF project coming online.

27. It is appropriate to require DEC and DEP to continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period, and to authorize DENC to use its proposed fuel forecasting methodology in calculating its avoided energy costs for the purposes of this proceeding.

28. It is appropriate to require DEC and DEP to recalculate their avoided energy costs 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.

29. There is insufficient evidence in this record for the Commission to find that the rates established for DEC or DEP should include an avoided distribution capacity cost adder applicable to all distribution- or transmission-connected QFs for the purposes of this proceeding.

30. It is inappropriate to require DEC or DEP to use avoided transmission and distribution (T&D) capacity rates from the demand-side management/energy efficiency proceedings in calculating avoided T&D capacity costs for the purposes of this proceeding.

31. It is appropriate to require DEC and DEP to consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and to include an avoided T&D capacity adder if a project can provide real and measurable avoided transmission capacity benefits.

32. It is inappropriate to require DEC or DEP to include an "adder" for avoided energy costs based upon a generalized assumption that the integration of uncontrolled

solar QF generating capacity, in the aggregate, suppresses or reduces prices in the wholesale power market.

33. DEC and DEP are incurring increased intra-hour ancillary services costs to integrate the “Existing plus Transition” level of solar QFs into the DEC and DEP systems, and it is appropriate to require DEC and DEP to account for these costs when calculating the costs and benefits resulting from the purchase of energy and capacity from solar QFs.

34. The determinations based upon the results of the Astrapé Study demonstrate that an additional 26 MW of load following reserves are required to integrate 840 MW of solar-QF capacity in DEC at an average cost of $1.10/MWh and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar-QF capacity in DEP at an average cost of $2.39/MWh, and are reasonable for use in this proceeding.

35. It is appropriate for Duke to apply prospectively the integration services charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018.

36. It is appropriate to apply the integration services charge as a fixed amount of $1.10/MWh for DEC and $2.39/MWh for DEP during the term of the contracts for those QFs that establish a LEO during the availability of the rates established in this proceeding as a decrement to and included in DEC’s and DEP’s respective avoided energy rates.

37. It is inappropriate for DEC or DEP to impose the integration services charge on QFs that qualify as “controlled solar generators” by demonstrating that their facility is capable of operating, and by contractually agreeing to operate, in a manner that materially reduces or eliminates the need for additional load following reserves required to integrate solar-QF capacity.

38. It is appropriate to require DEC and DEP to file with the Commission proposed guidelines for QFs to become “controlled solar generators” and thereby avoid the integration services charge.

39. The SISC Stipulation between Duke and the Public Staff is the product of the give-and-take in settlement negotiations between the Duke and the Public Staff, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, to the extent that those agreements are consistent with state and federal law.

40. The Astrapé Study methodology used to quantify DEC’s and DEP’s increased ancillary services costs and to calculate each utility’s integration services charge presents novel and complex issues that warrant further consideration.

41. It is appropriate to require DEC and DEP to calculate avoided energy rates that do not include an integration services charge and to include these rates that would

be available to “controlled solar generators” as a part of the tariffs and standard contracts in this proceeding.

42. It is appropriate to require DEC and DEP to submit the Astrapé Study methodology to an independent technical review and to include the results of that review and any revisions to the methodology that is supported by the results of that review in its initial filing in the 2020 biennial avoided cost proceeding.

43. The proposed changes to DENC’s energy and capacity rate design are appropriate to send better price signals to incent QFs to better match DENC’s system generation needs, and it is appropriate to require the use of this rate design in calculating DENC’s avoided energy and capacity rates in this proceeding.

44. DENC’s revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in this proceeding.

45. DENC’s proposed input assumptions to be used in determining its proposed avoided energy costs, including those related to fuel hedging activities and the LMP adjustment, are appropriate for use in this proceeding.

46. DENC’s proposed re-dispatch charge of $0.78/MWh is reasonable for use in this proceeding as an appropriate mechanism to recover costs incurred by DENC to integrate intermittent, non-dispatchable QFs in its service territory.

47. It is inappropriate to authorize the use of DENC’s proposed annual capacity payment cap for the purpose of calculating rates in this proceeding.

48. It is appropriate to require DENC to utilize a PAF of 1.07 in its avoided cost calculations for all QFs.

49. 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.

50. 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.

51. 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.

52. 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.

53. It is appropriate to require WCU and New River to offer to all QFs contracting to sell 1 MW or less variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year term standard offer.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 3

The evidence supporting these findings of fact is found in Duke's verified Joint Initial Statement filed on behalf of DEC and DEP and the exhibits attached thereto (Duke's verified JIS) and DENC's verified Initial Statement and the exhibits attached thereto (DENC's verified Initial Statement). These findings are essentially jurisdictional and administrative and are not contested.

Summary of the Evidence

In its JIS Duke filed updated standard offer avoided cost rates available to all QFs that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PPs and that establish a LEO committing to sell the output of their QF generating facility to DEC or DEP on or after November 1, 2018, but prior to the initial filing in the next biennial avoided cost proceeding. As provided in these schedules:

> In order to be an Eligible Qualifying Facility and receive Energy Credits under this Schedule, the Qualifying Facility must be a hydroelectric or a generator fueled by trash or methane derived from landfills, solar, wind, hog or poultry waste-fueled or non-animal biomass-fueled Qualifying Facility with a Contract Capacity of one (1) megawatt or less, based on the nameplate rating of the generator(s), which are interconnected directly with the Company's system and which are Qualifying Facilities as defined by the Federal Energy Regulatory Commission pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978.

Duke further states that pursuant to N.C.G.S. § 62-156(b)(3), electric generation fueled by swine waste and poultry waste may be eligible for a different avoided capacity rate "if Seller sells the output of its facility, including renewable energy credits," to Duke for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements set forth in N.C.G.S. § 62-133.8(e) and (f). JIS at 1; JIS DEC Exhibit 1 and DEP Exhibit 1.

Along with its Initial Statement DENC filed Schedule 19-FP and Schedule 19-LMP, to be available to any QF eligible for these tariffs that has (a) submitted to the Commission a report of proposed construction pursuant to N.C.G.S. § 62-110.1(g) and Rule R8-65, (b) submitted to the Company an Interconnection Request pursuant to Section 2 or Section 3 of the North Carolina Interconnection Procedures (NCIP), and (c) submitted to the Company a duly executed "Notice of Commitment to Sell the Output of a Qualifying Facility of No Greater Than 1 Megawatt Maximum Capacity to Dominion Energy North Carolina" by no later than the date on which proposed rates are filed in the next biennial avoided cost proceeding.

In its Initial Statement DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19-LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone Day-Ahead hourly locational marginal prices (LMPs) divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs that elect to supply energy only would be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DENC used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the Dom Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations. DENC's verified Initial Statement at 13, Exhibit DENC-3 at 5.

In its Initial Comments the Public Staff reviews and summarizes the rate schedules proposed by the Utilities but does not recommend any changes to the standard offer term and eligibility thresholds proposed by the Utilities.

No party proposes changes to the standard offer term and eligibility thresholds or otherwise raised objections to the approval of the Utilities' proposed schedules with respect to these issues.

Discussion and Conclusions

In the 2016 Sub 148 Order, the Commission approved changes to the standard offer term and eligibility thresholds as a result of changes in the marketplace for QF-supplied power in North Carolina and as a result of the amendments to N.C.G.S. § 62-156 enacted through S.L. 2017-192. The Commission noted that these changes were appropriate to

> reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs.

2016 Sub 148 Order at 38. The Commission further indicated that it would "continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms." *Id.* at 23.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

In past biennial avoided cost proceedings the Commission ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding. The Commission again recognizes the enactment of N.C.G.S. § 62-110.8, providing for a competitive procurement option for renewable energy facilities. *See* 2016 Sub 148 Order at 38-39. To date, the Commission has not received a motion, nor issued an order, addressing the exact points when an active solicitation shall be regarded as beginning or ending nor addressed whether the CPRE program may be considered an active solicitation for PURPA compliance purposes. Accordingly, it is appropriate for the arbitration option to remain available for issues arising during negotiations between a utility and QF.

The Commission further finds, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, that as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM RPM, are appropriate subject to the same conditions as approved in the 2006 Sub 106 Order and most recently restated in the 2016 Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 – 8

The evidence supporting these findings of fact is found in Duke's verified JIS and in the testimony of Duke witnesses Snider and Wheeler, NCSEA witness Johnson, SACE witness Wilson, and Public Staff witness Thomas.

Summary of the Evidence

In its JIS Duke states its Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity are paid on a $/MWh basis versus a separate fixed payment for capacity), and the rates are designed to credit QFs for avoided energy supplied during predesignated on-peak and off-peak hours. Payments for avoided energy are applicable to all QF energy supplied during the year and vary for the designated on-peak and off-peak hours in a day. Payments for avoided capacity are applicable to all QF energy supplied during the designated capacity payment hours.

In the 2016 Sub 148 Order the Commission observed that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities." The Commission 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 directed the Utilities to 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.* In this proceeding, the Commission similarly directed the Utilities 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 Duke proposes changes to its Schedule PP to eliminate the pre-existing Option A and Option B hours and to develop updated, more granular rate designs that better recognized the value of QF energy and capacity. JIS at 27. Duke's initially proposed Schedule PP rate structure for energy payments defines the summer period as May through September and the non-summer period as October through April. The energy pricing includes five distinct pricing periods, each of which has an independent price block to better reflect the value of QF energy during the different periods. Each utility defines its energy pricing hours separately to account for the differences in each utility's load profile net of solar generation.

For capacity, Duke's initially proposed updated Schedule PP capacity pricing period consists of six months with summer defined as July and August and winter defined as December through March. *Id.* at 28. The capacity pricing is comprised of three pricing periods which include defined evening hours in the summer, and morning and evening hours in the winter.

Duke's initial proposal to update the Schedule PP rate design for energy and capacity reflects more narrowly defined seasons and hours compared to the former Option A and B definitions, and higher energy payments during Duke's highest production cost hours and capacity payments only in hours with high loss of load risk. The new rate design also reflects changes to the seasonal allocation weighting for capacity payments. The new seasonal allocation is more heavily weighted to winter than the prior allocation based on the impact of summer versus winter loss of load risk. As presented in Duke's 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter, and approximately 90% of DEC's loss of load risk occurs in the winter. Thus, DEP's new rates pay all of its annual capacity value in the winter, and DEC's new rates pay 90% of its annual capacity value in the winter and 10% in the summer period. *Id.* at 29.

In its Initial Comments NCSEA states that Duke's proposed allocations are inappropriate due to flaws in the loss of load analysis that underlies the proposed allocations, underestimates of winter DSM assumptions, a failure to consider imports, and flawed solar modeling. NCSEA recommends that the Commission instead require Duke to utilize the allocation ratios previously approved by the Commission in the 2016 Sub 148 Order. NCSEA Initial Comments at 13-14. NCSEA further recommends that Duke provide granular rate schedules that incorporate geographic granularity. NCSEA notes that without such geographic granularity, there is no incentive for QFs to locate in areas where transmission and distribution costs can be avoided. *Id.* at 26-27. NCSEA further states that the Utilities failed to adequately recognize how costs vary by seasons and that Duke's proposal not to differentiate a winter season did not appropriately consider the different patterns of electrical usage, net system load, marginal production costs, and avoided costs that occur during winter as opposed to spring and summer. NCSEA also states 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 proposes that instead of the Utilities' proposals, the Commission should adopt the time-of-day periods it proposes, as well as an optional real-time pricing tariff for QFs. *Id.* at 28. NCSEA witness Johnson supports this proposal by detailing the following specific energy rate design schedules: (i) a 12 month by 24 hour rate design (12x24 Design), and (ii) a fixed tariff with a set number of real time pricing (RTP) high and low cost hours (Hybrid Tariff), both of which would provide additional granularity to avoided energy rates. Johnson Affidavit at 64-76.

In its Initial Comments SACE also argues that Duke's proposal to allocate all or nearly all loss of load risk in the winter devalues the capacity contributions of solar QFs and almost completely eliminates consideration of the capacity benefits solar QFs provide during summer demand peaks. SACE provided the Report on the Resource Adequacy Studies and Capacity Value Study prepared by James F. Wilson (Wilson Report), which raised the following four concerns: (1) the representation of winter loads under extreme cold conditions, based on an extrapolation of the relationship between very cold temperatures and winter loads; (2) the "economic load forecast uncertainty" layered on top of the weather-related load distributions; (3) the assumptions regarding future winter demand response capacity; and (4) the assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings. SACE Initial Comments at 11-12.

SACE further argues that Duke's rate design contained several methodological flaws, which combined with the above-listed concerns result in Duke greatly overstating DEC's and DEP's winter resource adequacy risk compared to summer, and inappropriately allocating 100% and 90% of winter loss of load risk in DEP and DEC, respectively. Witness Wilson testified that these shortcomings also directly impact Duke's proposed avoided capacity rate designs for Schedule PP, which are derived from the same flawed analysis, and that the Commission should require Duke to re-calculate and file revised avoided capacity rates and rate designs. *Id.* at 13.

In its Initial Comments the Public Staff states 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 believes that energy rate mismatches were still likely and could result in QFs potentially being over- or under-paid for the energy generated. As a result, the Public Staff proposes its own seasonal energy rates and hours:

> The Public Staff's proposed seasonal energy rates and hours were developed with a basic core premise: that, to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost. Using this guiding principle, the avoided cost hours and rates then provide price signals to QF developers that will increase each QF's relative value to the grid and, ultimately, to ratepayers. For example, more granular pricing would signal a dispatchable QF to provide energy during times when the Utilities are most likely to operate their highest marginal cost generation units, thus avoiding the need to run those units, and would also provide clear price signals to developers interested in adding new technologies, such as energy storage, to their intermittent facilities. Avoided energy rates

that accurately reflect the Utilities' highest production cost hours (lambdas) increase the likelihood that the interests of ratepayers and developers align.

Public Staff Initial Comments at 54.

With regard to capacity, the Public Staff also raises concerns regarding the Resource Adequacy Studies that Duke used, including the assumptions made regarding the relationship between cold weather and load, estimates of load forecast error distributions, and a lack of recognition of winter hardening efforts undertaken by the utilities, among others. Because of these concerns, the Public Staff recommends that the Commission direct Duke to rerun the Resource Adequacy Studies using the Public Staff Scenario #2 (PS-S2) that was analyzed by Duke in the 2018 IRP proceeding to determine the effect of the Public Staff's proposed modifications on the capacity payment hours and seasonal allocation. *Id.* at 58-59.

In its Reply Comments Duke states that as a result of further discussions between Duke, Astrapé, and the Public Staff, the Public Staff now concurs with Duke's proposal and accepts that the alternative PS-S2 scenario would not have a material impact on the seasonal allocation weightings or capacity payment hour designations. Duke Reply Comments at 61. Regarding the concerns raised by SACE over the methodology Duke used to capture the relationship between winter load and cold temperatures, Duke states that it performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years, and it resulted in a small decrease (0.33%) in the reserve margin. Duke recommends that the Commission reject the concerns raised by witness Wilson on this topic. *Id.* at 62.

Similarly, with regard to the claims raised by witness Wilson that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions, Duke indicates that witness Wilson's statements regarding the operating reserves that are held back in the Strategic Energy Risk Valuation Model (SERVM) model are inaccurate, and therefore should be rejected. *Id.* at 62-63.

Regarding the claims raised by NCSEA and SACE that winter DSM programs are a reasonable tool for reducing winter peak demand, when available, Duke agrees with these assessments. Duke states, however, that the levels of reduction proposed by NCSEA and characterized by NCSEA witness Johnson as "conservative," are actually extremely optimistic and not reasonably achievable in the timeframe proposed, if at all. *Id.* at 33. Duke states that NCSEA fails to accurately support its proposal, and notes that some of the comparisons drawn by NCSEA are flawed and fail to recognize differences between utilities including climate, residential and commercial water and space heating sources, industrial demand, and avoided costs. In addition, Duke notes that winter DSM programs raise different challenges than summer programs. Duke notes that it plans to continue to implement new winter DSM programs as proposed in DEC's and DEP's 2018 IRPs, but the amount proposed by NCSEA is not supported and cannot be prudently included in the IRP forecast. Therefore, Duke recommends that the Commission reject NCSEA's claim and accept Duke's seasonal allocation as reasonable and appropriate for purposes of inclusion in the avoided capacity rate. *Id.* at 66. Duke further notes that as a result of on-going discussions with the Public Staff and other parties, and to better align the winter capacity season with energy payment hours, Duke proposes to redefine the winter capacity season as December through February. *Id.* at 66.

Regarding its energy rate design Duke states that it generally does not oppose the Public Staff's objective of providing more granular rates with greater rate differentiations and concurs with the Public Staff's proposal to use an objective rate design methodology to establish rate periods that better reflect cost causation principles. As a result, Duke proposed a modified Schedule PP energy rate design following a three-step process similar to that originally proposed by the Public Staff, but with the concept of a more flexible design that considers the practicality of the design which enhances customer acceptance and compliance with the intended price signals. *Id.* at 69. In the updated energy rate design, the season definitions would be expanded to include Summer, Winter, and Shoulder seasons as compared to Duke's initial proposal which included Summer and Non-Summer only. Second, the newly proposed Winter season would be defined to include December, January, and February. Third, the concept of higher-priced rating periods, called Premium Peak hours, would be included during the Winter and Summer seasons, similar to the Public Staff's original proposal, but with slightly expanded premium peak windows during each peak day. *Id.* at 70-71.

In response to NCSEA's recommendation that Duke introduce geographic price signals and develop hosting capacity maps, Duke states that: (1) requiring the Utilities to incur increased costs to develop hosting capacity maps is neither appropriate under PURPA nor cost beneficial, particularly in the context of the standard offer framework; (2) hosting maps have already been considered by the parties in the context of the interconnection proceeding in Docket No. E-100, Sub 101, in which the Public Staff indicates that the benefits associated with developing distribution level hosting capacity maps was outweighed by their costs; and (3) the information provided in the hosting capacity maps would be static and not adequately recognize the Utilities' capability to reconfigure the distribution grid to shift load and generation across distribution circuits to achieve a better balance, resulting in changes in the cost/benefit of having generation on a specific circuit. As a result, Duke argues that non-geographic specific pricing offers a fair rate to all generators committing to sell under the standard offer tariff and allows Duke to adjust system line loadings to maximize benefits for all customers, and that NCSEA's recommendation therefore should be rejected. *Id.* at 73-74.

With regard to NCSEA's time-of-day pricing periods and optional real-time pricing tariffs, Duke agrees that this information could help align actual avoided costs to QF payments, but that the granular pricing periods proposed in this proceeding are sufficient at this time. Duke further agrees to continue to investigate development of time-of-day and real-time pricing periods for standard offer QFs but recommends that the Commission accept the updated avoided cost rate design as reasonable and appropriate. *Id.* at 74-75.

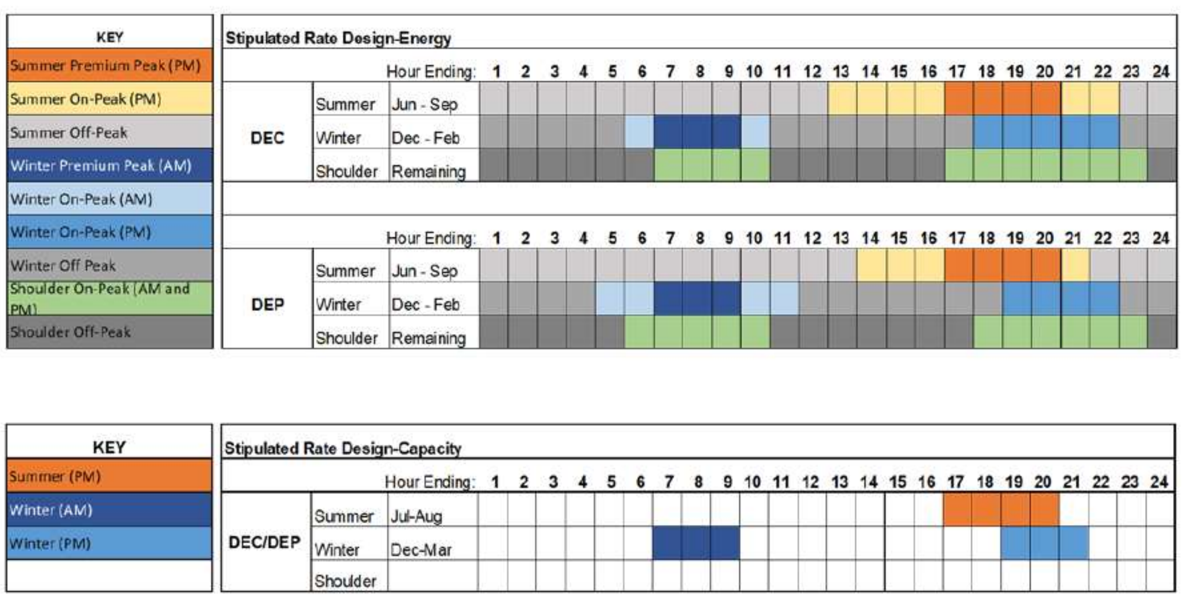
In response to NCSEA's proposed rate design changes, the Public Staff in its Reply Comments states that hourly pricing for each month, as proposed in the

12x24 Design, could provide benefits to ratepayers and send appropriate price signals to QFs. However, the Public Staff notes that because some months have similar energy price characteristics, this approach may increase complexity without providing significant additional benefits. Instead, focusing on three seasons, each with multiple pricing tiers, would provide more granular pricing information to QFs without imposing significant new administrative burdens. Public Staff Reply Comments at 3.

The Public Staff also indicates that it supports the availability of an RTP tariff for avoided energy, which could enable QFs to maximize their facilities' value to customers, particularly in light of innovative technologies such as energy storage, while minimizing the risk of over- and under-payments for energy. The Public Staff recommends that DEC and DEP offer an RTP avoided cost tariff as an optional alternative to their proposed Schedule PP in the next avoided cost filing. *Id.* at 7.

Duke witness Snider testified that the Rate Design Stipulation was the result of the parties attempting to resolve their differences regarding different rate design alternatives. The stipulated rate design, as indicated in Snider Figure No. 2 reproduced below, is similar to the Public Staff's original three-step rate design approach and identifies the energy and capacity periods that best reflect each utility's avoided cost based upon seasonal and time-of-day characteristics. Tr. vol. 2, 65.

Snider Figure 2: Stipulated Energy and Capacity Rate Periods (By Hour)



In support of the Rate Design Stipulation, Duke witness Snider testified that the updated rate designs reasonably and accurately reflect the avoided cost value of QF energy and capacity being delivered to Duke and paid for by customers, explaining that the proposed rate design contained in the Rate Design Stipulation will also provide strong price signals to QFs by identifying the times that generation is of the most value to customers and providing a financial incentive to maximize their generation during these higher production cost hours. Thus, he testified that the rate design encourages QFs to configure their operating scheme to take advantage of these higher rate periods when energy and capacity are of the highest value to customers. Tr. vol. 2, 29.

Witness Snider also testified in response to SACE witness Wilson's argument that the stipulated avoided capacity rate design focuses on too narrow periods of time, stating that the stipulated rate design is consistent with the Commission's direction in the 2016 Sub 148 Order in that it provides for higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during critical peak demand periods. In addition, he argues that the stipulated rate design is consistent with the Commission's 2018 Scheduling Order in that it also reflects Duke's highest production cost hours with more granularity than under prior rate schedules. Tr. vol. 2, 76, 115.

Witness Snider also responded to NCSEA witness Johnson's recommendation that the Utilities calculate different rates for each hour of the month, explaining that this proposal would tend to lock in price differences and price relationships between the hours in a manner that would likely not coincide with actual real-time system conditions, particularly over time, and also unnecessarily increase billing complication, thereby increasing the risk of billing errors. In addition, regarding witness Johnson's RTP pricing proposal, witness Snider testified that the proposal does not appear to support a true RTP rate similar to DENC's LMP tariff during all hours, but instead appears to call for RTP rates during times when costs to serve are high, and a guaranteed forecasted average cost rate during all other hours, including hours when the cost to serve is lower than the average avoided cost rate. Witness Snider stated that such an approach would be inconsistent with the FERC's general implementation of PURPA, which provides that a QF may elect 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. Witness Snider noted that Duke would be agreeable to investigating development of RTP periods for standard offer QFs that do not require the financial assurance of a fixed rate and instead are willing to accept rates calculated at the time of delivery, based upon Duke's actual hourly marginal cost of energy. Tr. vol. 2, 116-18. Witness Snider also testified that for the same reasons stated in Duke's Reply Comments, the Commission should reject NCSEA's recommendation that Duke offer geographically differentiated avoided cost rates. Tr. vol. 2, 119-20.

In response to NCSEA witness Johnson's argument that an assessment of historical loads does not support a seasonal allocation heavily weighted to winter, witness Snider testified that NCSEA's criticisms are essentially the same arguments that were made in the 2016 Sub 148 Proceeding and ignore the impact of continued increases in the amount of must-take solar generation on the utilities' loss of load risk. Witness Snider noted that the Commission in its 2016 Sub 148 Order rejected the arguments raised by NCSEA and instead recognized the significant impact that high penetrations of solar were having on summer versus winter loads net of solar contribution. Witness Snider also noted that Duke has seen significant cold weather load responses in recent years in excess of summer conditions that were not fully considered in NCSEA witness Johnson's review period. Witness Snider concluded that an assessment of historic loads without consideration of the impact of current and projected levels of must-take solar output does not provide meaningful insights into the appropriate seasonal allocation weightings. Tr. vol. 2, 122-26.

In response to SACE witness Wilson's criticisms of Duke's reliance on its 2016 Resource Adequacy Study for purposes of determining seasonal allocation capacity payments, witness Snider stated that the Commission found in its 2016 Sub 148 Order that it was appropriate to rely on the Resource Adequacy Study for purposes of establishing seasonal allocation of capacity payments. Witness Snider further noted that the use of the loss of load risk values as allocation factors appropriately represents the seasonal capacity benefit provided by a QF, and properly aligns with cost causation principles. Witness Snider also noted that Duke and the Public Staff agree that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in the 2020 biennial IRP filings. Tr. vol. 2, 127-30.

In response to NCSEA witness Johnson's suggestion that Duke's seasonal allocation is inconsistent with PURPA, in that QFs are not being fully compensated for the capacity costs they enable the utilities to avoid, Duke witness Snider testified that Duke's IRP planning methodology and approach to recognizing future capacity needs based upon future loss of load expectation (LOLE) is consistent with the general principles of PURPA and is technologically agnostic. He stated that non-dispatchable QFs therefore are being fully compensated for the capacity value they provide. In addition, witness Snider argued that Dukes' methodology is fully consistent with N.C.G.S. § 62-156(b)(3), which provides that:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to [N.C.G.S. §] 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power . . . .

Witness Snider testified that Duke's seasonal allocation may continue to change over time as customer mix, customer energy usage, and changes to the summer and winter resource mix, including the continued addition of solar resources, the addition of battery storage capability, longer-term potential wind resources, additional DSM programs or other changes impacting the balance of summer versus winter resources, and other factors change. As these changes occur, Duke will update these seasonal allocations as appropriate in future biennial proceedings. Tr. vol. 2, 133-35.

Public Staff witness Thomas testified that the Public Staff largely agrees with Duke's proposed capacity payment hours and seasonal allocation and did not propose any significant changes to the capacity rate design. He testified that to prevent overpayment to QFs for capacity that is not needed, it is most appropriate to pay capacity payments only during hours where there is a loss of load risk. Finally, witness Thomas testified that Duke's use of the LOLE metric is reasonable and protects ratepayers from overpaying for QF capacity, and that the proposed rate design sends the appropriate price signals to QFs. Tr. vol. 6, 389-91.

Discussion and Conclusions

Avoided Energy Rates

In the 2018 Scheduling Order the Commission directed Duke to address in its initial filings in this proceeding, 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. 2018 Scheduling Order at 1. More specifically, and consistent with the discussion and conclusions reached in the Commission’s 2016 Sub 148 Order, the Commission expressed its expectation that Duke would file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more granularity than the current Option A and Option B rate schedules historically used in the implementation of PURPA and N.C.G.S. § 62-156.

As summarized above Duke responded to this direction through its initial filing, and the Public Staff conducted an extensive investigation as to the reasonableness of Duke’s proposed rate design. The product of that investigation was filed with the Commission in this docket as the Rate Design Stipulation. Based upon the foregoing and the entire record herein, the Commission finds that the Rate Design Stipulation is the product of give-and-take in negotiations between Duke and the Public Staff and that along with the testimony in support of the Rate Design Stipulation, is entitled to appropriate weight in this proceeding.

For the following reasons the Commission gives substantial weight to the Rate Design Stipulation and the testimony in support thereof and finds that the proposed changes to DEC and DEP’s energy rate design as indicated in the Rate Design Stipulation are appropriate for use in calculating energy rates in this proceeding. First, the Commission finds merit in the general approach utilized by the Public Staff to develop granular pricing methods for avoided energy that more accurately reflect Duke’s highest production cost hours and loads to increase the likelihood that the interests of ratepayers and developers of QF generators align. The Rate Design Stipulation reflects an agreement between the Public Staff and Duke on more granular pricing methods consistent with the Public Staff’s approach. Second, the Commission determines that the modifications made through discussions between the Public Staff and Duke to further refine this rate design approach, as memorialized in the Rate Design Stipulation, strike an appropriate balance between accurate avoided cost pricing, administrative efficiency, and the general acknowledgment that these factors will continue to change over time. Third, the stipulated rate design was the result of a methodological approach to evaluate system costs and impacts as described in the Rate Design Stipulation, and properly aligns price signals provided in the rate design with Duke’s avoided energy costs.

With regard to NCSEA's proposal to develop more geographically granular rates, the Commission finds that there is insufficient evidence demonstrating that such an effort is appropriate for the standard offer tariff or would be cost beneficial at this time. After carefully considering NCSEA's evidence and arguments on this issue, the Commission is not persuaded that the benefits associated with developing detailed geographic guidance for smaller generating facilities seeking to select suitable interconnection locations will outweigh the costs when similar information is already made available through other interconnection processes such as the Section 1.3 Pre-Application Reports.[1] Further, as Duke witness Snider testified, utilities are constantly reconfiguring their distribution grid to better balance load and generation, and as a result, the information for a specific circuit may be dynamic in nature. Lastly, the administrative efficiency of providing non-geographically differentiated standard offer pricing must also be considered in light of the fact that the standard offer tariff is an optional tariff intended to be generically available to small QFs pursuant to 18 C.F.R. § 292.304(c) and N.C.G.S. § 62-156(b), and is limited to small power producer QFs with a design capacity up to 1 MW pursuant to N.C.G.S. § 62-156(b).[2] Any QF that seeks to introduce "individual characteristics of the small power producer," such as geographic location, that the QF believes may impact the "individual . . . value of energy and capacity from [the QF] on the electric utility's system" may do so in negotiating avoided cost rates based upon the specific costs that it allows the utility to avoid under N.C.G.S. § 62-156(c) and 18 C.F.R. § 292.304(e)(2)(vi). As such, the Commission determines that geographically granular rates should not be required for standard offer facilities in this proceeding.

Regarding the proposal by NCSEA to require the Utilities to provide 24 different hourly rates each day, the Commission agrees with Duke that offering such specific hourly rates would lock in price differences and price relationships between the hours in a manner that would likely not coincide with actual real-time system conditions over time. Instead, the Commission determines that the approach recommended by the Public Staff and Duke in the Rate Design Stipulation to provide a defined range of hours in distinct price groups based on periods where higher costs are generally expected will provide a reasonable and consistent price signal to QFs, encouraging them to align their generation with the time periods that have most value to customers in a forward-looking fashion.

Finally, the Commission agrees with Duke, NCSEA, and the Public Staff 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

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[1] *See* Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, *Petition for Approval of Revisions to Generator Interconnection Standards*, No. E-100 Sub 101, at 58 (N.C.U.C. June 4, 2019).

[2] Amendments enacted pursuant to S.L. 2017-192 broadened the definition of "small power producer" to include QFs that use renewable resources as a fuel source, but not cogeneration facilities. 2016 Sub 148 Order at 18. While the Commission previously took care to acknowledge the distinction, *id.* at 37-38, the parties here have focused their arguments and testimony on solar QFs. Because issues specific to cogeneration facilities are not in dispute in this proceeding, the Commission will likewise dispense with the technicality of this amended definition and use the more general term QFs in this Order.

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. 18 C.F.R. § 292.304(d)(2). Therefore, consistent with the recommendation of the Public Staff, the Commission directs Duke to evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding.

Avoided Capacity Rates

In the 2018 Scheduling Order the Commission also directed Duke to address in its initial filings in this proceeding consideration of issues that impact DEC's and DEP's avoided capacity rates, such as the weighting of capacity value between the summer and non-summer seasons. States must consider a number of factors in determining avoided costs, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs. 18 C.F.R. § 292.304(e). Pursuant to N.C.G.S. § 62-156, the Commission must consider the availability and reliability of QF power in establishing rates to be paid for capacity purchased from a small power producer.

The Rate Design Stipulation reflects that after Duke made its initial filings and engaged in discussions with the Public Staff, these two parties reached agreement on the appropriate seasonal and hourly allocations of capacity payments based on the Astrapé Capacity Value of Solar study that was filed with Duke's IRPs in Docket No. E-100, Sub 157. As with issues related to energy rate design, the Commission also finds that the Rate Design Stipulation is the product of give-and-take negotiations with respect to capacity rate issues, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding along with the other record evidence. The Commission gives substantial weight to the agreements articulated in the Rate Design Stipulation and the testimony in support thereof. For the following reasons the Commission concludes that these agreements should be approved as part of the acceptance of the Rate Design Stipulation.

First, the Commission finds that Duke's reliance on LOLE is appropriate in the context of determining when a QF can help a utility avoid or defer a planned capacity addition. Duke's evaluation of the PS-S2 scenario proposed by the Public Staff, as well as the sensitivity analysis performed by Duke in response to SACE's concerns over the relationship between winter load and cold temperatures, is adequately responsive to the concerns SACE raised. Second, the Commission finds Duke's description of the consideration of operating reserves that are held back in the SERVM model persuasive, as it demonstrates the reasonableness of Duke's modeling with respect to this issue. Third, the Commission agrees with Duke and the Public Staff that the use of the loss of load risk values to establish seasonal allocation factors is appropriate, as it aligns with cost causation principles. The Commission also agrees that these factors change over time, and that it is appropriate that the resource adequacy studies, along with all inputs and modeling assumptions, should be updated for use in the 2020 biennial IRP filings and taken into account in the 2020 avoided cost proceedings. Thus, as in the 2016 Sub 148 Order, the Commission will continue to review these issues in future avoided cost proceedings.

The Commission acknowledges that witness Johnson's assessment of historical loads for the years 2006 to 2017 has relevance to Duke's proposed seasonal allocation of future capacity need; however, the evidence in this proceeding confirms the Commission's determination in the 2016 Sub 148 Order that the high solar penetrations in Duke's service territory that it is experiencing today and expects to continue in the future will have different impacts on summer versus winter loads net of solar contribution than in the past. Therefore, the Commission agrees with Duke witness Snider that an assessment of historic loads without consideration of the impact of current and projected levels of solar output does not provide a complete or reasonably accurate picture of the appropriate seasonal allocation weightings to assign to forward-looking avoided cost rates.

The Commission disagrees with NCSEA witness Johnson that Duke's seasonal allocation is inconsistent with PURPA. Instead, the Commission finds that the seasonal allocation proposed by Duke and supported by the Public Staff provides a more reasonable quantification of the capacity costs that QFs enable the utilities to avoid. Consistent with N.C.G.S. § 62-156(b)(3), it is not only appropriate but required that the utility evaluate whether "the identified need can be met by the type of small power producer resource based upon its availability and reliability of power." Under the seasonal allocations proposed in the Rate Design Stipulation, a QF that can provide capacity during the identified need, as expressed by the LOLE hours, is fully compensated under seasonal capacity allocations that more accurately reflect the utility's avoided cost than seasonal allocations used in previous avoided cost proceedings. As indicated by Public Staff witness Thomas, to prevent overpayment to QFs for capacity that is not needed it is most appropriate to pay capacity payments only during hours where there is a loss of load risk, and therefore future capacity need, that can be avoided. The Commission agrees. Therefore, based upon the foregoing and the entire record herein, the Commission finds that DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

On the related issue of the availability of winter DSM programs, the Commission agrees with Duke witness Snider that significant differences can exist between utilities, including climate, heating sources, industrial demand, and avoided costs, among others, as well as between portfolios of DSM programs targeting providing summer and winter capacity. Thus, the Commission finds Duke's assumptions regarding the availability of DSM programs for reducing winter peak demand are reasonable and appropriate for use in calculating avoided capacity rates in this proceeding. However, as discussed in the 2018 IRP proceeding, the Commission determines that Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands. Therefore, the Commission will require Duke to address this issue in its initial statements filed in the 2020 biennial avoided cost proceeding.

Conclusion

In conclusion the Commission finds that the proposed avoided energy and avoided capacity rates presented in the Rate Design Stipulation are reasonable and appropriate. These stipulated rates are responsive to the Commission's direction to develop a rate design that sends stronger price signals to incent QFs to better match the generation needs of utilities. Therefore, the Commission concludes that the energy and capacity rates presented in the Rate Design Stipulation should be approved for use in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding. As with other determinations in this case, these assumptions can be dynamic and can change in the future. The Commission will be receptive to revisiting these issues in future proceedings, as appropriate, to continue to evolve the State's implementation of PURPA, consistent with federal and state law, and to more accurately reflect utilities' avoided costs resulting from the purchase of QF power.

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

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Thomas and Duke witness Johnson. These findings are not contested.

Summary of the Evidence

Public Staff witness Thomas recommended that as a result of the changes to the rate design proposed in this proceeding, it would be appropriate for the Commission to make two minor changes to Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6), which require applicants to submit a "detailed explanation of the anticipated kilowatt-hour outputs, on-peak and off-peak, for each month of the year." Witness Thomas suggested that the Rules be amended to instead request an hourly production profile from the applicant for one year. Witness Thomas indicated that this step would eliminate the additional processing required by the applicant to fit the output into the on- and off-peak periods and would also provide additional information regarding the facility's production profile for the Public Staff's review of the CPCN application. Tr. vol. 6, 395-97.

Duke witness Johnson testified that Duke agrees with the Public Staff that the stipulated rate design is inconsistent with the Rules' requirements and therefore appropriate for revision. He stated that Duke believes that other parties not currently participating in this proceeding may have an interest in the proposed rule revisions, and therefore the Commission should address the proposed revisions in a separate rulemaking proceeding. Witness Johnson further testified, however, that Duke requests that the Commission authorize a limited waiver of application of Rules R8-64 and R8-71 as they are currently written and approve the revisions proposed by witness Thomas on an interim basis until such time as a separate rulemaking proceeding can be initiated to review the proposed revisions. He stated that Duke discussed this proposal with the Public Staff and that the Public Staff did not have any objection to Duke's proposal. Tr. vol. 2, 282-85.

Discussion and Conclusions

In light of the changes to the energy and capacity rate designs being implemented in this proceeding, the Commission agrees with the Public Staff and Duke that the information currently required to be submitted in a CPCN application under Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) requires an additional step to be taken by CPCN applicants beyond the presentation of an annual energy production profile, resulting in some additional administrative efforts that may only provide limited additional benefit, and that changes to the rule may be appropriate. The Commission also agrees that requiring a CPCN applicant to submit information regarding the additional factors influencing the shape of the production profile may be relevant in the Public Staff's and the Commission's consideration of the application. The Commission also agrees with Duke, however, that other parties not currently participating in this proceeding may have an interest in the proposed rule revisions and finds that establishing a separate rulemaking proceeding to evaluate the proposed rule revisions is appropriate. Therefore, the Commission will grant the limited waiver, as recommended by Duke and agreed to by the Public Staff, to allow CPCN applicants to substitute the following for the information currently required in Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6):

> The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits.

In the near future the Commission will issue an order establishing a rulemaking proceeding for the purpose of considering amendments to these Rules. The limited waiver allowed pursuant to this Order shall be in effect from the date of this Order until the Commission adopts revisions to Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 AND 12

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Evidence

In its JIS Duke states that DEC and DEP each calculated their respective avoided capacity cost based upon the overnight cost of a CT unit, using publicly available industry data from the Energy Information Administration (EIA), tailored to the extent needed to adapt such information to North Carolina and to conform to the Commission's previous avoided cost orders. Duke notes that the EIA CT capital cost is based on construction of a single CT unit at a greenfield site, and that consistent with prior Commission orders, the CT capital cost calculation does not assume any economies of scope. JIS at 15.

In its Initial Statement DENC indicates that it used the applicable costs of the Greensville combined cycle power plant as the basis for the CT equipment costs, which was consistent with the approach it took in the 2016 biennial avoided cost proceeding. DENC states that these costs are current and verifiable and represent the Company's actual procurement costs of CT equipment related to a power plant that is currently under construction and was expected to become operational in December 2018. DENC states further that for the remaining costs, including construction and owner costs, it utilized the PJM cost of new entry estimates, based primarily on the "PJM Cost of New Entry for Combustion Turbine and Combined Cycle Plants With June 1, 2022 Online Date" report prepared by The Brattle Group and Sargent & Lundy, dated April 19, 2018. DENC indicates that it also made several adjustments to the Brattle Study results, consistent with prior guidance from the Commission. DENC Initial Statement at 14-15.

In its Initial Comments the Public Staff indicates that it reviewed the capital cost inputs, line losses, and assumptions incorporated in the Utilities' avoided capacity calculations and finds them reasonable for purposes of this proceeding. Public Staff Initial Comments at 12, 17. The Public Staff recommends, however, that in future avoided cost proceedings the Utilities should evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility. The Public Staff notes that the Utilities have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several brownfield sites for potential future use for both baseload and peaking needs that may "represent potential value to customers that is not reflected in the costs of a greenfield site." *Id.* at 17-18, 66-70.

NCSEA's Initial Comments and the supporting affidavit of witness Thomas Beach advocate for an adjustment to the Utilities' respective CT costs to include an adder for firm natural gas pipeline transportation capacity cost or backup fuel (oil) arguing that CTs require either firm pipeline transportation capacity or backup fuel to ensure availability during winter peak hours when gas demand peaks and pipeline capacity is constrained. NCSEA Initial Comments at 23-24.

NCSEA further states in its Reply Comments that it opposes the Public Staff's suggestion that Duke incorporate brownfield site data in its CT cost calculations. NCSEA states that Duke predicts only two capacity additions which may be brownfield sites — neither of which is incorporated into its avoided cost peaker plant calculations — so Duke does not appear to intend to utilize numerous brownfield sites; therefore, the use of a greenfield site for good cost calculations is appropriate. NCSEA states, however, that it does not oppose Duke's utilization of brownfield sites in its next avoided cost filing, but only if Duke plans to utilize brownfield sites and it will be reflective of true cost data. NCSEA Reply Comments at 6-8.

In its Reply Comments DENC indicates that it has long advocated for the use of a brownfield CT to determine avoided capacity cost rates, and it agrees with the Public Staff's recommendation that brownfield sites may be efficient locations for construction of new CT facilities because of their land availability and existing gas and electrical infrastructure. DENC Reply Comments at 29-30.

Duke similarly indicates in its Reply Comments that it is not opposed to the Public Staff's recommendations to consider appropriate increments or decrements of publicly available CT cost data, such as consideration of a brownfield site. Duke states that the Public Staff's proposal reflects an incremental improvement over the current methodology that will more accurately reflect Duke's true avoided cost of capacity under the Peaker Methodology, as Duke's best estimate of a future avoidable CT is based upon the type and operating characteristics of the CT that DEC or DEP would actually build in the Carolinas. Duke emphasized that this may necessarily include confidential internal data and consultant's estimates that consider economies of scale adjustments as well as economies associated with brownfield sites in deriving future CT costs in the Carolinas. Duke Reply Comments at 32-34.

Duke also opposes NCSEA's recommendation that a hypothetical adder for firm natural gas pipeline transportation capacity cost be included in the Utilities' CT costs, noting that DEC and DEP do not reserve firm pipeline capacity for CTs. Duke Reply Comments at 35. Duke points to the Public Staff's Initial Comments that recognized DEC and DEP included the cost of fuel oil as backup, which allows Duke to exclude the cost of securing firm pipeline capacity for CTs. Public Staff Initial Comments at 7. Duke also highlights that this proposal would deviate from Duke's consistent application of the Peaker Methodology in North Carolina by assigning a cost premium solely to the winter capacity price period versus allocating DEC's and DEP's avoided capacity costs between the winter and summer periods based upon loss of load risk. Finally, Duke disputes NCSEA witness Beach's quantification of the additional pipeline capacity cost proposed to be added to the avoided winter capacity rate, finding that it was either miscalculated or excessive. Duke Reply Comments at 35 (citing Beach Affidavit at 18).

Discussion and Conclusions

In the Commission's Order Setting Avoided Cost Input Parameters, issued on December 31, 2014, in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available

> industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Sub 140 Phase One Order at 48.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that the Utilities appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that their respective source information was tailored in a manner consistent with the guidance previously provided by the Commission. The Commission therefore finds that the CT cost information used by DEC, DEP, and DENC, respectively, is reasonable and appropriate for purposes of calculating avoided capacity costs in this proceeding.

The Commission further finds that the Public Staff's recommendation that in future proceedings the Utilities should evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates based on brownfield sites and existing infrastructure is appropriate in light of the number of current facilities that have been built on brownfield sites, as well as the number of plant retirements projected in the Utilities' IRPs. The Commission agrees that these existing facilities may represent potential value to customers, and that, to the extent the Utilities plan to utilize those existing facilities for new capacity additions, it is appropriate for the potential cost savings to be considered in avoided cost calculations. Therefore, the Commission will require the Utilities to evaluate these potential adjustments and address through their initial statements filed in the next avoided cost proceeding the extent to which each utility expects to use this existing infrastructure to meet future capacity additions by each utility and whether adjustments to their avoided capacity calculations are needed to account for this expectation.

In addition, the Commission agrees that there may be some circumstances where it is appropriate for the CT costs derived from generic publicly available estimates to be tailored based on internal data and actual construction experience. However, the Commission stresses that these adjustments must be clearly delineated and justified to ensure the Commission's effort in recent proceedings to increase the transparency in these CT cost inputs to the avoided capacity rate calculations is not lost. Further, when the Utilities use generic publicly available estimates, whether adjusted or not, the burden is on the utility to demonstrate that the estimates approximate the utility's actual costs, and procedures should be made available that allow not only parties but other interested persons to obtain access to the estimates and any adjustments made to the estimates, if applicable.

The Commission has carefully considered NCSEA's proposed upward adjustment to the Utilities' winter avoided capacity costs to account for hypothetical firm natural gas pipeline transportation capacity costs but is not persuaded that this proposal should be adopted. Comments filed by Duke and the Public Staff demonstrate that Duke does not purchase firm pipeline transportation capacity for CTs. The Commission agrees with these parties that it would be inappropriate to adjust the avoided capacity cost calculated under the Peaker Methodology by imposing an adder or decrement that does not reflect the utility's actual planned cost of building a CT in the Carolinas. Moreover, the Commission concludes that hypothetical firm natural gas transportation costs, as presented in this proceeding, are not sufficiently known and quantifiable to be included in avoided cost calculations approved herein. Based upon the foregoing and the entire record herein, the Commission finds that the exclusion of hypothetical firm pipeline transportation costs from the rates in this proceeding is appropriate. Accordingly, the Commission concludes that the Utilities' data on the installed cost of a CT used by the Utilities to calculate avoided capacity rates is appropriate for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 – 15

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Testimony

In its Initial Statement DENC notes that in the 2016 Sub 148 Order the Commission directed the Utilities to address in the next avoided cost proceeding "the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations." 2016 Sub 148 Order at 110. DENC indicates that consistent with the Commission's directive it updated the data related to power flows at its substations for the period September 2016 to August 2018 and found that transformers with high levels of connected distributed solar generation continue to experience backflow conditions where generation exceeds the load requirements of the circuit. DENC states that the number of transformers experiencing backflow has increased, indicating the continued appropriateness of not requiring DENC to include an adder for line losses in the calculation of avoided energy payments to QFs. DENC Initial Statement at 34-35.

In its JIS Duke states that it analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of substations that currently are experiencing or are expected to experience backfeed in the near future because of the recent growth in utility-scale solar QFs. As a result, DEP indicates that 50 out of 367 substations (14%) are currently backfeeding into the transmission system due to distribution-connected generation, and that based on the number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 96 out of 367 substations (26%) are estimated to experience backfeed. Duke indicates that this lower percentage as compared to DENC is in part due to the concentrated nature of QF solar development in more rural areas of the DEP eastern North Carolina service territory. Duke indicates that the percentages of DEC substations currently experiencing backfeed due to distribution-connected projects is significantly less — only 5%. As a result of its analysis, Duke indicates that it is appropriate for both DEC and DEP to retain a line loss adder for distribution-connected QFs eligible for Schedule PP at this time. Duke indicates, however, that for proposed distribution-connected QFs that are not eligible for the standard offer Schedule PP, Duke plans to consider on a case-by-case basis whether the QF's energy output would backfeed the substation and inject energy onto the transmission system, and whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate. JIS at 23-25.

In its Initial Comments the Public Staff indicates that it agrees with the information filed by the Utilities related to line loss adders and backfeeding of substations, as well as their proposals, and that the appropriateness of line loss adders should continue to be evaluated in future avoided cost proceedings. The Public Staff further recommends that in the next avoided cost proceeding the Commission require DEC and DEP to take into account the aggregate amount of renewable generation that will be, or is expected to be, interconnected by the end of the CPRE Program in their consideration of line loss impacts. Public Staff Initial Comments at 72-73.

SACE in its Initial Comments indicates that it retained Synapse to analyze DENC's most recent power flow data and came to the same conclusion that it reached in the 2016 Sub 148 Proceeding: solar QFs continue to provide line loss avoidance benefits, and it is inappropriate to entirely eliminate the line loss adder. SACE indicates that Synapse evaluated DENC's half-hour data associated with the 38 substations connected to QFs from August 16, 2017, to August 15, 2019, and found that the majority of substations are still experiencing positive flows during the majority of half-hour blocks. Synapse also evaluated the 38 substations during solar-producing hours and determined that line losses are still avoided during the majority of hours when QFs are generating power; therefore, DENC continues to benefit from solar QF line loss avoidance. SACE states that complete elimination of the 3% line loss adder may not accurately reflect line loss avoidance benefits, and it requests that the Commission require DENC to re-calculate and include a line loss adder in its avoided energy rates available to QFs. SACE Initial Comments at 18-20.

In its Reply Comments DENC disagrees with SACE's analysis for three reasons. First, SACE's analysis did not take into account irradiance levels to determine whether a solar QF could generate energy, and the period of time evaluated included the wettest year on record for much of DENC's territory. Second, SACE failed to acknowledge the general observable trend at several DENC substations that backflows are occurring with more frequency as more distributed solar generation is connected to the system. Third, even when DENC substations are experiencing positive flows, outside of a few outlier data points, the "room" remaining on the transformer before it starts experiencing backflows is reduced, and with the significant number of projects still seeking to interconnect, the prevalence of backflow conditions will continue to increase. DENC therefore recommends that the Commission reject SACE's analysis and find that it is appropriate for DENC to continue not to include the line loss adder in its avoided energy rates. DENC Reply Comments at 42-45.

Discussion and Conclusions

Pursuant to 18 C.F.R. § 292.304(e)(4), in determining avoided costs "the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity," shall, to the extent practicable, be taken into account. In the 2016 Sub 148 Order the Commission concluded that line losses may not exist if power purchased from a distribution-connected QF is backfeeding to the substation, and the Commission directed the Utilities to further evaluate this issue in this proceeding.

Based on the foregoing and the entire record herein, the Commission finds that backflows are continuing to occur with regularity on a number of DENC's distribution system circuits and that backflows will continue to increase over time. The Commission further determines that this development greatly reduces or eliminates the benefits of the solar QFs' line loss avoidances, and that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer.

The Commission also finds that it is appropriate for DEC and DEP to continue to incorporate the line loss factor in their standard offer avoided energy calculations at this time. With regard to Duke's proposal to assess the individual characteristics of the QF that is not eligible for Schedule PP standard offer rates and to address the line loss adder as part of the PPA negotiation process, the Commission agrees with Duke that such an analysis is consistent with N.C.G.S. § 62-156(c) by taking into consideration the individual characteristics of the QF. Lastly, the Commission finds it appropriate to require the Utilities to continue to study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16 – 18

The evidence supporting these findings of fact is found in Duke's verified JIS, DENC's verified Initial Statement, NCSEA witness Johnson's Affidavit, and the entire record herein.

Summary of the Evidence

In its JIS Duke proposes to continue to recognize a 1.05 PAF in its calculation of avoided capacity cost rates to be paid to QFs (other than certain hydroelectric QFs) eligible for the standard offer. In the 2016 Sub 148 Order, the Commission agreed with Duke that the equivalent forced outage rate (EFOR) metric represents an appropriate peak season reliability indicator, but to keep avoided cost aligned with other routine filings, the Commission directed the Utilities to support their recommendations for PAF calculations based on peak season equivalent availabilities for utility fleets in total in this proceeding. In response to this direction Duke compiled five years of historic equivalent availability (EA) data for the entire fleet during Duke's critical peak season months of January, February, July, and August — the critical peak season that reflects the high load periods in which Duke typically does not schedule planned maintenance outages for generating facilities. Duke further states that DEC's and DEP's respective EA during this timeframe averages 95%, which it argues continues to support a PAF of 1.05. JIS at 15-16.

In the 2016 Sub 148 Order the Commission also directed Duke to address whether the 2.0 PAF for hydroelectric QFs without storage should continue for the standard offer in this biennial proceeding. 2016 Sub 148 Order at 57. In its JIS Duke proposes in light of the Hydro Stipulation to retain the 2.0 PAF that the Commission had approved in previous avoided cost dockets. Under the terms of the Hydro Stipulation Duke agreed that it would continue to use a 2.0 PAF to calculate the avoided cost rates for hydroelectric QFs without storage and that have a capacity of 5 MW or less. Duke details that DEC and DEP negotiated the Hydro Stipulation in good faith, and its terms and conditions were based on both North Carolina's policy of supporting small hydroelectric QFs and the relatively small and finite amount of small hydroelectric capacity in the State. Thus, Duke supports continuation of the 2.0 PAF for hydroelectric facilities without storage in its standard offer Schedule PP (DEC) and Schedule PP-3 (DEP). JIS at 15-17.

In its Initial Comments the Public Staff generally agrees with the Utilities' base methodology for calculating the PAF, but notes that (i) as avoided cost proceedings continue to evolve, it may be appropriate for the Utilities to apply prospective, forward-looking EFOR components in the PAF calculation, and (ii) the Utilities' EFOR data should include a greater consideration of critical peak periods. The Public Staff states that because avoided costs are inherently forward-looking, it is also appropriate to take a forward-looking approach when determining each utility's EFOR for use in avoided cost calculations. The Public Staff argues that investments leading to improvements in the overall reliability (i.e., a decrease in forced outages) of the generation fleet should be given consideration. Therefore, although the Public Staff agrees that the Utilities met the intent of the 2016 Sub 148 Order with their filing of EFOR data, the Public Staff recommends that the Commission direct the Utilities to refile their fleet weighted average peak month EFOR using five years of historical data and a minimum of five years of prospective data (but in no event greater than ten years). The Public Staff further states that use of the EFOR data that includes greater consideration of critical peak demand periods on each utility's system is appropriate. Therefore, the Public Staff requests that the Commission direct the Utilities to perform a revised PAF calculation that includes June and December EFOR data.

In their Initial Comments the Public Staff and the NC Small Hydro Group support Duke's inclusion of the 2.0 PAF for hydroelectric QFs without storage that were eligible for the standard offer. Public Staff Comments at 72; NC Small Hydro Group Comments at 10. Emphasizing that there were only ten hydroelectric QFs between 1 MW and 5 MW in size, the NC Small Hydro Group in its Reply Comments also supports Duke's using a 2.0 PAF for hydroelectric QFs without storage up to 5 MW. The NC Small Hydro Group notes that a reduction of almost 50% in the PAF (from 2.0 to 1.05), coupled with the lower avoided cost rates in general proposed in this proceeding, would be financially devastating to those QFs. The NC Small Hydro Group also argues that the General Assembly recognized the need for hydroelectric QFs with a total capacity of 5 MW or less to have greater certainty in their future revenues by allowing those facilities between 1 MW and 5 MW to negotiate for contracts longer than five years. N.C.G.S. § 62-156(c)(ii). Thus, the NC Small Hydro Group claims that there is no reason to treat these facilities differently with respect to the 2.0 PAF. NC Small Hydro Group Reply Comments at 2-3.

In its Initial Comments NCSEA challenges Duke's proposed 1.05 PAF included in DEC's and DEP's avoided capacity rates, arguing that the historical EA data used to quantify the PAF narrowly defined January, February, July, and August as "peak season." NCSEA indicates that DEC and DEP have historically had summer peaks during the months between June and September, and, less frequently, winter peaks between December and March. Therefore, argues NCSEA, the historical data for both DEC and DEP do not support considering only January and February as winter peak months, while excluding December and March. Similarly, NCSEA argues that the historical data for DEC does not support considering only July and August as summer peak months, while excluding June and September. In his affidavit, NCSEA witness Johnson states that regardless of how carefully DEC and DEP schedule their maintenance activities away from summer and winter, extreme peaks can occur in response to extreme weather, overlapping the time periods when maintenance occurs. Therefore, NCSEA recommends that the Commission direct Duke to revise its avoided capacity rates to reflect a PAF between 1.08 and 1.10. NCSEA Initial Comments at 31-32; Johnson Affidavit at 36-37.

In its Reply Comments Duke acknowledges that it engaged in several discussions with the Public Staff concerning Duke's use of EA data, EFOR, and the appropriateness of the Public Staff's proposed adjustments to the PAF calculation. As a result of these discussions, Duke notes that it also supports the Public Staff's proposal to include the months of June and December if the EFOR metric is used to calculate the PAF. However, Duke does not think June and December represent appropriate months to use in determining the PAF and points to the fact that LOLE results used in the avoided cost rate design show that LOLE is zero in June and very small in December. Duke Reply Comments at 52.

Duke notes that the Commission directed Duke to use the EA as the metric to support the PAF. Further, Duke states that the Commission recognized that unit reliability should be evaluated during peak demand periods outside of planned maintenance intervals, and Duke believes that calculating the EA for the critical peak season months of January, February, July, and August is appropriate and complies with the 2016 Sub 148 Order. Duke Reply Comments at 51.

Duke also reports that it calculated the PAF based on the Public Staff's recommendation to use EFOR and to include the additional months of June and December and that the data would support a slightly lower PAF than the EA data using the months proposed by Duke. Accordingly, Duke supports either approach, as both approaches generally arrive at consistent results supporting a PAF of 1.05 or lower. Duke Reply Comments at 53-54. Duke also notes in its Reply Comments that it appreciates the Public Staff's recommendation to take a forward-looking approach and consider utility investments to improve reliability in quantifying the PAF. The data and process suggested by the Public Staff, however, is not conducted by Duke, and it would require Duke to make several assumptions that may not be readily accepted by the other parties. Duke believes that using five years of historic data captures periods when reliability issues may have surfaced for a unit and subsequent periods of improved reliability following investments and resolution. Thus, Duke maintains that the use of historic data largely provides the forward-looking process suggested by the Public Staff. Duke Reply Comments at 54-55. Finally, Duke agrees that the Public Staff's recommended EUOR metric may have merit because it accounts for unplanned outages classified as "maintenance" outages, which are outages that may be deferred beyond the end of the next weekend but must occur prior to the next planned outage. Thus, Duke recommends that the Commission approve a PAF of 1.05 for QFs except for hydro QFs without storage and agrees to continue discussions with the Public Staff to determine whether EUOR is a more appropriate reliability metric to use for the PAF in future avoided cost dockets. Duke Reply Comments at 56.

In its Reply Comments the Public Staff indicates that its Initial Comments did not recognize the complexity of comparing two separate metrics — EA and EFOR — and the challenges of applying a prospective element. Therefore, the Public Staff proposes that if a rate-based metric is applied, the use of three (as used by DENC) to five (as used by Duke) years of historic data is appropriate. Furthermore, an EFOR metric does not properly address other types of outages that can occur during the peak season. Thus, the Public Staff suggests that other reliability metrics used by the North American Electric Reliability Corporation (NERC), such as EUOR or weighted EUOR, may be an appropriate metric because it accounts for the types of outages that can occur during peak periods: forced outages, maintenance outages, and derates. The EUOR removes planned outages from the base calculation; therefore, planned outages, like a nuclear refueling outage (or equivalent) that could occur occasionally in the late fall or early spring, would not be included in the calculation and give a negative indication of utility performance during the critical peak seasons. As a result of this further analysis and discussion with the Utilities, the Public Staff recommends that the Commission approve the initial PAF calculations proposed by the Utilities in their November 1 filings for the purposes of this proceeding, but direct the Public Staff, Utilities, and other parties to discuss whether another metric may be a more appropriate reliability metric to support quantification of the PAF in future avoided cost proceedings. Public Staff Reply Comments at 15-17.

In its Reply Comments NCSEA states that Duke biased its current PAF calculations and that the calculations understate a QF's contribution to capacity during peak months. NCSEA renewed its recommendation that the Commission reject Duke's PAF proposal and adopt its proposal from its Initial Comments of a PAF between 1.08 and 1.10. NCSEA Reply Comments at 11-12.

In its Reply Comments SACE agrees with NCSEA and the Public Staff's recommendation that the Commission require the Utilities to perform a revised PAF calculation including the shoulder month data. SACE Reply Comments at 7-8.

On July 12, 2019, Duke filed a letter to counsel for the NC Small Hydro Group that outlines Duke's commitment to honor the Hydro Stipulation's provision for using 2.0 PAF for hydroelectric QFs without storage contracting to sell 5 MW and less until the expiration of the Hydro Stipulation on December 31, 2020. Duke details, however, that their commitment was subject to any adverse regulatory decisions by the Commission finding that Duke should not offer the 2.0 PAF to these small hydroelectric QFs. No party opposed Duke's proposal to retain the 2.0 PAF for hydroelectric QFs without storage eligible for Duke's standard offer tariffs in fulfillment of the Hydro Stipulation.

Discussion and Conclusions

In the 2016 Sub 148 Order the Commission recounted the historical approach to including a PAF in the Utilities avoided cost rates. 2016 Sub 148 Order at 55. The Commission has consistently recognized that because standard avoided capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours, without any reasonable opportunity to experience outages during each peak period, to receive the total available avoided capacity payment. Recognizing that the Utilities' generating units experience outages and do not operate 100% of the time, the Commission therefore has ordered the Utilities to apply a PAF, or a simple capacity multiplier, in calculating avoided capacity rates paid to QFs in previous avoided cost proceedings.

In the 2016 Sub 148 Order the Commission found that the methodology used to calculate the PAF should include greater precision than in past proceedings and required the Utilities to calculate the PAF using a system availability metric representing the reliability of the Utilities' respective systems during peak periods. In particular, the Commission agreed with Duke witness Snider that use of the EFOR metric represents the reliability of a unit or generating fleet during periods between planned maintenance intervals, making it an appropriate indicator of utility generating fleet performance during the utility's on-peak periods. The Commission additionally concluded that the similarly focused EA metric is also an appropriate peak season reliability indicator and ordered the Utilities to support development of the PAF using the EA metric in this proceeding to harmonize the development of the PAF with other routine filings (such as the power plant performance reports) made by the Utilities. 2016 Sub 148 Order at 57.

As in the 2016 Sub 148 Proceeding, the Commission determines that the evidence in this proceeding supports calculating the PAF based upon a metric or metrics that assess generating unit "availability" and that the methodology used to calculate generating unit availability should be based upon an informed discussion of utility system planning and load forecasting. The evidence in this proceeding also confirms that the purpose of the PAF, to allow QFs reasonable periods for unplanned outages similar to the utilities' fleet during the year, remains valid.

The parties do not dispute that DEC and DEP have generally complied with the 2016 Sub 148 Order to support development of the PAF using the EA metric. However, disagreement remains among the parties regarding the appropriate peak months to use to calculate the PAF when using either the EA or EFOR metric. Specific to Duke's initial reliance upon the EA of the generation fleet in total, as directed in the 2016 Sub 148

Order, the Commission finds that the LOLE results provide the correct signal for defining peak months when planned maintenance would not be scheduled for purposes of supporting the EA calculation. The Commission therefore determines that Duke appropriately included the months of January, February, July, and August in quantifying the PAF based upon EA, while the inclusion of additional months as recommends by NCSEA and initially by the Public Staff would introduce periods with planned outages that would have the effect of artificially increasing the EA and thereby overstating the PAF.

The Commission gives significant weight to the arguments of Duke and the Public Staff and the evidence in support thereof, which demonstrates that the PAF calculations proposed by the Utilities in their initial filings are consistent with the intent of the 2016 Sub 148 Order and appropriate for purposes of this proceeding. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require DEC and DEP to use a PAF of 1.05 in their avoided cost calculations for all QFs except hydroelectric facilities without storage capability. The Commission also accepts the Public Staff's recommendation to consider other reliability metrics, specifically the EUOR, which may have merit given that EUOR includes an additional type of outage classified as "maintenance" outages which can also occur during peak demand periods. As detailed by the Public Staff and supported by Duke, the EUOR metric appropriately excludes planned outages from calculation of the PAF. The Commission therefore will direct Duke and the Public Staff to address the appropriateness of using EUOR as an alternative to EA through their initial filings in the next avoided cost proceeding.

Finally, although the Public Staff initially advocated that the Utilities should begin to incorporate prospective data in applying the PAF metric, the Public Staff's reply comments suggest that further discussions with Duke supports a conclusion that use of prospective data would be challenging and should not be approved at this time. It is uncontroverted that use of prospective data would be inconsistent with Duke's current process, and the Commission agrees that it may present additional complexities as it would require the Utilities to make assumptions that may not be readily accepted by other parties. The Commission therefore adopts the Public Staff's recommendation to require the Utilities to continue to use three (as used by DENC) to five (as used by Duke) years of historic outage rate data to support the PAF. In support of this finding, the Commission finds persuasive Duke's position that use of historic data largely provides a forward-looking process because it captures periods when reliability issues may have emerged for a particular unit and subsequent periods of improved reliability following investments and resolution of reliability issues. The Public Staff's own examples of historic capital investments that enhanced reliability stemming from prior Polar Vortex events also support the conclusion that investments in reliability are being recognized through the use of historic data.

In the 2016 Sub 148 Order, in addition to the 1.05 PAF included in avoided cost rate calculations that are generally available to QFs (through Duke's Schedule PPs), the Commission considered the 2.0 PAF included in the separate standard offer contract available to run-of-the-river hydroelectric QFs without storage capability (DEC Schedule PP-H; DEP Schedule PPH-1). While the Commission concluded that changes to the calculation of the PAF were appropriate for the Schedule PPs, the Commission further concluded that the continued use of a 2.0 PAF in the calculation of rates for Schedules PP-H and PPH-1 should be approved. In reaching that conclusion, the Commission noted that historically the PAF was supported by state policy supporting the development and economic feasibility of small hydroelectric generating facilities, as provided in N.C.G.S. §§ 62-2(27a) and 62-156. The Commission also noted that no alternative PAF for run-of-the-river hydro QFs was proposed in that proceeding and concluded that considerations of regulatory certainty further supported allowing the Hydro Stipulation to continue through the two-year period that was covered by that biennial proceeding. Finally, the Commission directed the Utilities to address whether the utilization of a 2.0 PAF as provided in the Hydro Stipulation should continue as provided in that agreement.

The NC Small Hydro Group's uncontested evidence demonstrates that only a limited and finite amount of hydroelectric capacity exists in North Carolina. In addition, like in the previous avoided cost proceeding, there is no evidence here of an alternative PAF for run-of-the-river hydro QFs. Further, the Commission determines that prudential considerations and those of regulatory certainty apply with equal force here as was noted in the 2016 Sub 148 Order. Therefore, the Commission concludes that the Hydro Stipulation, including the 2.0 PAF, should be allowed to continue through its natural expiration on December 31, 2020.

The Commission has carefully considered the NC Small Hydro Group's arguments regarding state policy continuing to provide for favorable treatment of small hydro facilities. *See* N.C.G.S. § 62-156; House Bill 329, § 3 (establishing a designated avoidable capacity need to be met by purchases from certain legacy small hydroelectric QFs that had executed PPAs in effect as of July 27, 2017). As noted in the 2016 Sub 148 Order, the articulation of these policy goals, and the direction provided to achieve these goals, is not specific to the calculation of the appropriate PAF. Moreover, these provisions of the Public Utilities Act are specific to discrete questions that are a part of calculating avoided cost rates (the establishment of a designated avoidable capacity) and the maximum length of a negotiated contract. Now absent from the Public Utilities Act is the specific focus on the use of hydroelectric power previously included in the definition of "small power producers." N.C.G.S. § 62-3(27a). In light of these legislative changes, the Commission finds it appropriate to consider again the question of the appropriate PAF to apply in calculating capacity rates available to run-of-the-river hydro QFs after the natural expiration of the Hydro Stipulation. Therefore, the Commission will require Duke to address these issues through its initial statements filed in the next biennial avoided cost proceeding.[3]

[3] DENC notes that it was not a party to the Hydro Stipulation and states that it does not appear to have any hydroelectric QFs in its service area. DENC Proposed Order at 93. The 2016 Sub 148 Order was less than clear on this point, and the Commission appreciates DENC's clarification of this issue in this proceeding. *See* 2016 Sub 148 Order at 7. There appears to be no possibility that a run-of-river hydroelectric QF will seek to avail itself of the opportunity to sell electric power from its facility to DENC; thus, the Commission does not require DENC to offer avoided cost rates that reflect a PAF of 2.0 for these QFs, nor does the Commission require DENC to address these issues in the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 – 22

The evidence supporting these findings of fact is found in Duke's verified JIS and the entire record herein. The Commission takes judicial notice of all filings made in the 2018 IRP Proceeding, Docket No. E-100, Sub 157, as they relate to the Utilities' respective determination of projected capacity needed to serve system load.

Summary of the Evidence

In its JIS Duke notes that in the 2016 Sub 148 Order the Commission accepted the reasonableness of the overall Peaker Method and found that avoided capacity value should be recognized beginning with the year that the utility's IRP forecast shows a capacity need. Duke states that this determination was consistent with N.C.G.S. § 62-156(b)(3), as amended by House Bill 589, which provides that a "future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan . . . has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power . . . ." JIS at 12-13.

Duke indicates that its avoided capacity rates are consistent with the 2016 Sub 148 Order and N.C.G.S. § 62-156(b)(3) in that they recognize each utility's next avoidable future capacity need based upon DEC's and DEP's most recent biennial IRPs filed on September 5, 2018, in Docket No. E-100, Sub 157 (2018 IRPs). These 2018 IRPs show that DEC's next avoidable capacity need is a planned 460 MW (winter rating) CT in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020. *Id.*

In its Initial Comments the Public Staff does not take issue with DEC's and DEP's identified first avoidable capacity needs, as presented in their 2018 IRPs. The Public Staff notes that pursuant to the 2018 IRPs, QFs located in DEC's service area that select a ten-year contract would receive avoided capacity rates that reflect the present value of one year of avoided capacity costs in 2028; whereas, QFs located in DEP's service area will receive avoided capacity rates that reflect the present value of avoided capacity costs for nine of the next ten years. The Public Staff also does not take issue with DENC's identification of its deferrable capacity need in 2022, as shown in its 2018 IRP filed May 1, 2018, in Docket No. E-100, Sub 157. The Public Staff also indicates that if utility inputs change, such as the anticipated date of the first avoidable capacity need, the utility should update its avoided capacity calculations for negotiated contracts, as well as for use in CPRE Tranche 2. Public Staff Initial Comments at 9-10, 17.

In its Initial Comments SACE notes that DEP's IRP showed a series of nuclear uprates between 2019 and 2028, but DEP did not indicate whether the uprates would involve capital investments or only a change in the enrichment of the fuel source. SACE states that if capital investments are required in the near term, there could be an avoidable capacity need as early as 2019, and that such capacity should be reflected in DEP's avoided capacity rates. SACE Initial Comments at 14.

In regard to DEC's capacity need, NCSEA notes in its Initial Comments that while DEC contends that it has no capacity need until 2028, its IRP shows a 30-MW short-term market capacity purchase in 2020 and uprates at existing units in 2021 through 2025. NCSEA contends that these market purchases and uprates are relevant in determining an avoidable capacity need and that Duke has not addressed whether the capacity expansions can be met by small power producers. NCSEA Initial Comments at 11.

In response to NCSEA's and SACE's comments on DEC's and DEP's first avoidable capacity needs, Duke explains in its Reply Comments that DEC and DEP determine their future (avoidable) generation needs based on the difference between customer demand, net of energy efficiency, and the sum of the utility's existing resources and projected resources, to meet a required annual planning reserve margin (currently 17%). When the annual planning reserve margin falls below 17%, new capacity is required. As indicated by DEC's and DEP's 2018 IRPs, DEC's and DEP's first avoidable capacity needs are in 2028 and 2020, respectively. Duke comments that while future planned market power purchases are undesignated resources and thus avoidable, near-term designated capacity additions, including nuclear uprates, do not constitute avoidable capacity. Duke indicates that the near-term planned nuclear uprates during 2019-2022 are O&M-related investments rather than new, undesignated capacity additions. According to Duke, DEC and DEP uprate their nuclear plants as part of the normal course of business during maintenance cycles. These planned uprates include normal maintenance of system equipment, such as feedwater heaters and moisture separator reheater tubes. Duke concludes that as these activities will occur regardless of whether QF capacity or energy is available, the capacity gained through uprates cannot be avoided. Duke also indicates that the uprates are relatively small and would have very little impact on the timing of the next undesignated capacity resource need. Duke Reply Comments at 37-40.

Duke agrees with the Public Staff's recommendation that DEC and DEP should update their first year of avoidable capacity need in calculating avoided cost rates for future negotiated contracts as well as for CPRE Tranche 2. Thus, if DEC's or DEP's first avoidable capacity needs change due to new contracts for purchased capacity, they would update their avoided capacity cost calculations for negotiated contracts with larger QFs. Duke Reply Comments at 41-42.

In its Reply Comments the Public Staff restates that the year of capacity need should be determined by the IRP. It agrees with Duke that plant uprates should not constitute a deferrable capacity need as they are essentially "sunk costs." The Public Staff points out that a utility should make plant uprates when it is reasonable and prudent to do so, such as to meet revised regulatory requirements, address aging and obsolete parts, increase operational flexibility to meet changing grid constraints, install new equipment that is more efficient or reduces parasitic loads, and better utilize the existing equipment and total stored energy of a nuclear fuel assembly.

The Public Staff finds valid intervenors concerns related to the lack of a specific statement of capacity need in each utility's 2018 IRP. The Public Staff notes that its initial comments in Docket No. E-100, Sub 157 recommended that a Utility Statement of Need be filed in the IRP docket in order to remove uncertainty surrounding the exact year of avoidable capacity need and to provide a clearer standard for all parties in various regulatory proceedings.

In its Reply Comments SACE indicates that it does not object to the Public Staff's recommendation that avoided capacity costs should be updated for negotiated contracts between biennial avoided cost proceedings to accurately reflect utility capacity needs, but SACE recommends that any such adjustments resulting from capacity additions of utility-acquired resources must have been included in the utility's most recently approved IRP. SACE agrees with NCSEA that DEC's projected 30-MW short-term market capacity purchase in 2020 should be considered an avoidable capacity need. SACE makes reference to its comments in Docket No. E-100, Sub 157 in which SACE contended that Duke failed to evaluate the potential retirement of aging fossil plants in its modeling and recommended that the Commission direct Duke to revise its IRPs by allowing its modeling to evaluate the cost-effectiveness of retiring fossil plants in the near term. In its Reply Comments in this proceeding, SACE recommends that if the Commission adopts this IRP recommendation, Duke should revise its avoidable capacity needs to include any capacity needs identified as a result of this modeling. SACE Reply Comments at 7.

Regarding DENC, SACE contends that DENC has not complied with the 2016 Sub 148 Order directive to provide avoided capacity payments in years that the utility's IRP forecast period demonstrates a capacity need. SACE argues that because the VSCC rejected the Company's IRP as originally filed in 2018, the 2018 IRP does not accurately represent the Company's future capacity plans and cannot be relied upon in this proceeding. SACE also contends that DENC has not identified a "preferred plan" in its 2018 IRP, and that without a preferred plan the capacity need should be demonstrated based on the Alternative Plan that anticipates the most immediate capacity need. Finally, SACE contends that certain capacity additions in 2019, 2020, and 2021 that are reflected in the 2018 IRP could be deferred, delayed, or reduced "as a result of QF capacity contributions," and therefore that DENC's calculation of avoided capacity costs without such costs through 2021 does not comply with the FERC's conclusion in Order No. 69 that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, to build a smaller unit, or to purchase less firm power.

In its Reply Comments the NC Small Hydro Group agrees with the Public Staff that the Commission should require a Utility Statement of Need in the IRP process. However, the NC Small Hydro Group recommends that this Statement of Need process be completed before the 2019 IRP update in order to benefit the current biennial avoided cost docket. NC Small Hydro Group Reply Comments at 5.

In response to SACE, DENC notes that it refiled its 2018 IRP on March 7, 2019, as required by the VSCC. DENC points out that the Company's need for capacity did not change in the refiled 2018 IRP using the input assumptions required by the VSCC, including the solar build-out per the Virginia GTSA in Plan F (No CO_2 Tax with GT Plan).

Thus, the revised capacity expansion plan continues to show the first capacity need in the "No CO_2" case to occur in 2022. DENC Reply Comments at 32-33.

DENC also argues that it based its determination of capacity need used in calculating avoided capacity rates on the "No CO_2 case resource expansion plan" in its originally filed 2018 IRP. Using the projection of the next capacity need in Plan F in the refiled 2018 IRP, the basis for the Company's determination of capacity need for purposes of calculating avoided capacity rates did not change. DENC states that its reliance on a "No CO_2" plan is appropriate because it is consistent with the Commission's conclusions in its Sub 140 Phase One Order that only known and quantifiable costs should be reflected in avoided cost calculations. DENC states that as CO_2 costs are not yet known or quantifiable, a preferred plan is not relevant to the determination of avoided cost, and the Company's reliance on a "No CO_2" plan is appropriate. *Id.* at 33-34.

Finally, DENC responds to SACE's contention that certain capacity additions in 2019, 2020, and 2021 reflected in the 2018 IRP could be deferred, delayed, or reduced by QF capacity, and thus DENC's calculation of avoided capacity costs without such costs through 2021 was inconsistent with the FERC's directive that QFs should be compensated for avoided capacity if purchasing from that QF allows the utility to avoid construction, build a smaller unit, or purchase less firm power. DENC states that new QFs signing PPAs during the biennial period will not avoid any capital costs related to these near-term generation projects; indeed, some of the projects projected for 2019 to 2021 in the IRP are already under construction. *Id.* at 34.

Discussion and Conclusions

The Commission concludes that DEC, DEP, and DENC have complied with N.C.G.S. § 62-156(b)(3). In its August 27, 2019 Order on the 2018 IRPs in Docket No. E-100, Sub 157, the Commission found the IRPs of DEC, DEP, and DENC to be reasonable for planning purposes. In this proceeding, the Commission finds that the Utilities have also appropriately identified their first avoidable capacity needs, as presented in their 2018 IRPs. The Commission agrees with the Public Staff that if utility inputs change, the utility should update its avoided capacity cost calculations for negotiated contracts, as well as for use in CPRE Tranche 2. As pointed out by NCSEA, planned wholesale power purchases are undesignated resources and thus avoidable. However, with respect to the uprates at issue in this proceeding, the Commission determines that there is insufficient evidence in this record for the Commission to find that these plant uprates shown in DEC's or DEP's most recent IRPs are deferrable or avoidable for purposes of establishing a capacity rate; therefore, these uprates shall not be included in the determination of avoided capacity costs for purposes of this proceeding. Beginning with the 2020 IRP, the Commission finds that it is appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23 AND 24

The evidence supporting these findings of fact is found in testimony of Duke witness Snider, DENC witness Petrie, Public Staff witness Hinton, and NCSEA witness Johnson. The Commission takes judicial notice of all filings made in the 2018 IRP Proceeding, Docket No. E-100, Sub 157, as they relate to the Utilities' assumptions regarding expiring wholesale purchases from QFs, and also takes judicial notice of House Bill 329, as recently enacted into law on July 19, 2019.

Summary of the Evidence

In its Initial Comments NCSEA states that it understands DEC's and DEP's IRPs to assume that a QF will continue providing capacity in DEC's and DEP's respective generation stacks even after the expiration of the QF's PPA. NCSEA argues that renewals of current PPAs that include payment for capacity should continue to include capacity payments, as otherwise Duke would be forced to obtain capacity from another source. NCSEA's witness Johnson also addressed this issue and recommends that avoided costs be analyzed in this proceeding using the assumption that existing QF contracts could be displaced by new QF PPAs. Witness Johnson believes that it is not reasonable to assume either that none of smaller, existing QFs are providing Duke with capacity or that all of these existing QFs will renew their contracts and provide capacity without compensation. NCSEA therefore recommends that the Commission consider the rights of QFs with expiring PPAs and that seek to renew and provide these QFs with some certainty in this proceeding. NCSEA Initial Comments at 10-11.

The NC Small Hydro Group notes that existing biomass and hydroelectric capacity resources subject to contract renewals decrease over time in DEC's IRP from 119 MW in 2019 to 52 MW in 2033, and in DEP's IRP from 266 MW in 2019 to 0 MW in 2033. The NC Small Hydro Group contends that Duke's approach leads to reductions in capacity payments for QFs and rates lower than actual avoided capacity costs. It argues that Duke's approach penalizes these QFs that have provided energy and capacity for years and suggests that it is inconsistent with PURPA. It distinguishes its situation where existing QF capacity would be displaced from that in the case of *City of Ketchikan, Alaska*, 94 FERC ¶ 61,293 (2001), where the utility was not required to pay for capacity that would displace the utility's existing capacity. The NC Small Hydro Group contends that House Bill 589 only addressed future capacity and did not require the Utilities to disregard existing QF capacity or stop capacity payments to this existing capacity after the existing contract expires based upon an assumption that the QF will renew its contract to deliver power for a future term. NC Small Hydro Group Initial Comments at 5-10.

In its Reply Comments Duke states that DEC's and DEP's 2018 IRPs do not assume that QFs will continue providing capacity after the QF's PPA term ends, but rather reduce the exiting capacity by the amount of capacity provided by the expiring wholesale purchase contract in the year following the contract expiration. Duke notes that it has been consistently using this approach for DEC and DEP in all IRPs since 2012. Duke explains that using this approach, the expiration of a wholesale contract can affect the timing of its first capacity need. Duke contends that it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. Duke recognizes parties' interest in the timing of capacity additions and deficits and agrees to address this issue in future IRPs through a new Statement of Need section, as recommended by the Public Staff. Duke Reply Comments at 42-47.

In its Reply Comments NCSEA states that it finds compelling the NC Small Hydro Group's legal argument that existing QF capacity should have an expectation of a renewal of the capacity in the QF's new PPA. NCSEA supports recognizing the capacity need as relating back to the date of the original contract for a QF as proposed by the NC Small Hydro Group. NCSEA Reply Comments at 10-11. SACE in its Reply Comments also agreed with the NC Small Hydro Group's position. SACE Reply Comments at 6.

The NC Small Hydro Group in its Reply Comments agrees with NCSEA's position that existing QFs already in the utility's generation stack should continue to be paid for capacity after PPA renewal. The NC Small Hydro Group points out that if QF capacity is undervalued, existing QFs may not be able to renew their PPAs due to economic reasons, resulting in less QF generation and the need for more capacity from natural gas or other non-renewable resources. The NC Small Hydro Group also reiterates its position supporting the Statement of Need proposed by the Public Staff. NC Small Hydro Group Reply Comments at 4.

In its Reply Comments the Public Staff agrees with the NC Small Hydro Group's assertion that DEC's and DEP's 2018 IRPs show the existing capacity of biomass and hydroelectric Non-Utility Generators (NUGs) declining over time, indicating that DEC and DEP do not assume these contracts will be renewed or replaced in kind. However, the Public Staff does not agree with the NC Small Hydro Group's conclusion that this approach will "reduce capacity payments to QFs." The Public Staff points out that by assuming that small hydro and biomass capacity will expire at the end of the current PPA term, each utility's available capacity is effectively decreased, increasing the need for undesignated future resources. Public Staff Reply Comments at 26-28; *see also* NC Small Hydro Group Initial Comments at 7.

The Public Staff also notes that DEC's and DEP's IRPs appear to assume that solar QF contracts will be renewed or replaced in kind, unlike the treatment applied to hydro and biomass PPAs. The Public Staff points out that this disparity in the treatment of solar and other QF resources could impact avoided capacity rates in future proceedings, though not in the current proceeding. As this issue will become more and more important in future years, the Public Staff notes the importance of having the utilities file a formal Statement of Need as recommended by the Public Staff in the Sub 157 proceeding. Public Staff Reply Comments at 26-28.

In his direct testimony Duke witness Snider stated that Duke has appropriately assumed in its IRPs that upon expiration of any third-party wholesale purchase contract, capacity is reduced by the amount of the capacity provided by the expiring wholesale purchase contract in the year following contract expiration. Witness Snider reiterated that this is Duke's long-standing approach used in its IRPs. He maintained that it is prudent for the Companies not to rely on future third-party owned capacity in years unless there is a contract or other legally enforceable commitment. Witness Snider also pointed out that QF owners have the right at the end of a contract to make their unrestricted decision as whether to renew their PPAs, cease business, or sell their energy and capacity to another buyer. Further, there is no guarantee for Duke and its customers that the QF will be able to provide energy and capacity after expiration of the PPA. Tr. vol. 2, 52-55.

Public Staff witness Hinton reviewed Duke's assumptions regarding expiring PPAs. He testified that Duke's IRPs indicate a reduction in capacity from expiring biomass and hydro PPAs in the planning period, but an increase in capacity from solar facilities. Witness Hinton stated that while this assumption regarding solar PPAs may be appropriate for planning purposes, it is inappropriate for determining the first year of capacity need as it could elongate the time before there is a capacity need. Witness Hinton noted that the Statement of Need addition to the Utilities' future IRPs, as proposed by the Public Staff in its IRP comments, would help clarify the assumptions used by the Utilities. Witness Hinton also indicated that after further discussions with Duke, it was his understanding that Duke used the same assumptions for all wholesale contracts — i.e., that the contracts would expire and the capacity would no longer be available — in establishing its first year of capacity need for avoided cost purposes. Further, regardless of the assumption made regarding expiring QF solar contracts being replaced in kind in the future, the first year of capacity need would be the same for DEC and DEP in their 2018 IRPs and this proceeding. Finally, witness Hinton indicated that he disagreed with the position of the NC Small Hydro Group and NCSEA that the Utilities should assume that all QF contracts renew and that existing QFs should be entitled to a capacity payment beginning in the first years of their new contract term. Tr. vol. 6, 311-14.

NCSEA witness Johnson argued that existing capacity is used in the IRP process to determine whether there is a need for additional capacity, and this existing capacity included wholesale contracts. He contended that contract renewals do not add new capacity but maintain existing capacity. Witness Johnson stated that because of long lead times for new generating units, the first year of a capacity need is likely always to be at least a few years away. He found Duke's approach to be discriminatory as QFs may never receive capacity payments and Duke would continue to receive full capacity cost recovery for its units. He warned the Commission against interpreting House Bill 589 to require taking the capacity of QFs without compensating them fairly as unfair and discouraging investment in North Carolina. Witness Johnson recommended that QFs be given the option to sign contracts several years before the existing contract ends so that there is a legally binding commitment that could be included in the existing generation in a utility's IRP. Tr. vol. 6, 206-15.

In his rebuttal testimony, witness Snider indicated that the Commission's decision on this issue must be considered in accordance with House Bill 589's amendment of N.C.G.S. § 62-156(b)(3), which provides that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission has identified a projected capacity need to serve system load and the identified need can be met by the type of QF resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f)." He also pointed to the Commission's holding in the 2016 Sub 148 Order that the purpose of PURPA was not to force utilities and their customers to pay for unneeded capacity. Witness Snider noted that purchases of generation from swine and poultry waste were exempted as the General Assembly in House Bill 589 designated an immediate need for this generation to meet the requirements of the REPS Program. Tr. vol. 2, 97-102.

Witness Snider also pointed out that Public Staff witness Hinton had indicated in his testimony that the Public Staff supported Duke's assumptions as to expiring contracts. In response to NCSEA witness Johnson's claim that Duke's approach to contract renewals is discriminatory, witness Snider contended that, actually, witness Johnson's approach was discriminatory in that it would favor existing QFs over new capacity resources, including new QFs. Witness Snider explained that House Bill 589 directs the Commission to treat all small power producer QFs in a like manner, whether existing or new. In response to witness Johnson's contention that Duke's approach would result in a QF never being paid for capacity, witness Snider pointed to the DEP 2018 IRP's avoidable need in year 2 and the utilities' requests for proposals for new resources. Witness Snider also rebutted witness Johnson's contentions that it would be discriminatory not to continue paying for QF capacity, whether needed or not, after contract expiration, as utilities receive full capacity cost recovery in rate base. He pointed to the Commission's conclusions in 2016 Sub 148 Order where the Commission differentiated QFs from utilities, especially as utilities have an obligation to serve customers. Tr. vol. 2, 102-09.

Discussion and Conclusions

The Commission finds House Bill 589's and House Bill 329's recent amendments to N.C.G.S. § 62-156(b)(3) to be controlling on this issue. House Bill 589 provides that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission has identified a projected capacity need to serve system load and the identified need can be met by the type of QF resource based upon its availability and reliability of power . . .," but expressly carves swine and poultry waste generation out from this requirement based upon their designated need to meet REPS compliance. Section 3(a) of House Bill 589 adds to N.C.G.S. § 62-156(b)(3) an additional carve out for "legacy" hydroelectric QFs of 5 MW or less selling and delivering power under QF PPAs in effect as of July 27, 2017. Notably, Section 3(b) of House Bill 329 provides further direction to the Commission:

> The *exception for hydropower* small power producers *from limitations on capacity payments established in G.S. 62-156(b)(3),* as amended by Section 3(a) of this act, shall not be construed in any manner to affect the

> applicability of G.S. 62-156(b)(3) as it relates to any other small power producer. [Emphasis added.]

The Commission finds that the clear intent of the General Assembly as shown through House Bill 589 and House Bill 329 is to treat swine and poultry waste QF resources and legacy small hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period. Subsection (b)(3) of N.C.G.S. 62-156, as amended by House Bill 589, specifically identifies the Utilities' statutorily designated need to procure swine and poultry waste resources to meet REPS, while House Bill 329's specification that the small hydroelectric QF's PPA be in effect as of July 27, 2017 (the date that House Bill 589 was enacted into law), establishes that these legacy small hydroelectric QFs are similarly now meeting a statutorily designated, resource-specific capacity need that cannot be met by other types of QF resources. Establishing avoided cost rates based upon the ability of specific QF resources to meet statutorily designated requirements to procure capacity from specific QF resource types has been recognized to be consistent with PURPA. *Cal. Pub. Utility Comm'n*., 133 FERC ¶ 61,059 at 20, 26-30 (2010) (providing that in setting avoided cost rates, a state "may take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration"), *reh'g denied*, 134 FERC ¶ 61,044 (2011). For other types of QF generation, which do not meet a designated capacity need specified by the General Assembly, it is appropriate for QFs electing to obligate themselves to deliver power for a new contract term to be considered as avoiding undesignated new generation projected to be needed in the future to serve the utility's system load; therefore, N.C.G.S. § 62-156(b)(3) prescribes that a QF avoiding an undesignated future capacity need shall not be entitled to a capacity payment unless the utility's IRP identifies an undesignated capacity need to meet the utility's system load that the QF may avoid within the contract period. The Commission also agrees with Duke and the Public Staff that QFs commit to deliver their power for a specified term and that it would be imprudent resource planning to assume that QFs are obligating themselves to deliver capacity and energy past the end of their contract term. Moreover, it would be discriminatory between QFs to assume that a pre-existing QF has a priority right to enter into a new contract to sell and deliver capacity over a new term versus the rights of any other QF to commit itself to avoid the utility's capacity need.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for the Utilities to recognize any new commitment by a swine or poultry waste QF generator or a legacy small hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, obligating itself to sell and deliver its full energy and capacity output over a future contract term as helping the Utilities avoid a designated future capacity need beginning in the first year of the new QF PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended by House Bill 329. For other types of QF generation, it is appropriate under PURPA and consistent with N.C.G.S. § 62-156(b)(3), for the Utilities to recognize a QF's commitment to sell and deliver energy and capacity over a specified future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an undesignated (i.e., avoidable) capacity need identified in DEC's, DEP's, or DENC's most recent IRPs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 – 26

The evidence supporting these findings of fact is contained in the testimony of Duke witnesses Snider and Johnson, DENC witness Petrie, NCSEA witness Johnson, and Public Staff witness Hinton.

Summary of the Evidence

In its Initial Comments NCSEA states that because of "well documented delays" in the interconnection queue, a Sub 158 PPA will likely not begin providing capacity until December 2021 or later. When considering when there is a capacity need, consistent with the utilities' 2018 IRPs, NCSEA argues it would be more appropriate to use December 31, 2021 as the presumptive in-service date for the purpose of calculating avoided capacity costs. NCSEA Initial Comments at 12. In his affidavit, NCSEA witness Johnson states that the utilities treat 2019 as the starting point for calculating the biennial standard offer avoided cost rate calculations. Johnson Affidavit at 58-59. Witness Johnson further states the current in-service date is an "arbitrary, and obviously unrealistic, assumption" and December 31, 2021, or three years later, is a more reasonable assumption. *Id.*

NCSEA Witness Johnson further asserts in his affidavit that an unrealistic timeline distorts all of the avoided cost calculations but has the most impact on the avoided capacity rates. He states, for example, "DENC assumes the QF will start delivering power in January 2019, and it does not pay for capacity during the years 2019, 2020 and 2021. This effectively reduces its capacity rate by about 30% for a 10-year fixed rate contract." *Id.* at 59-60. Witness Johnson states that DEP and DEC would have similar under-payments for capacity depending on their capacity need in certain years over the span of a ten-year contract. In its Reply Comments SACE agrees with NCSEA's recommendation and states that it considers using a December 31, 2021, as the date on which Sub 158 contracts are considered to begin providing capacity to be a reasonable approach. SACE Reply Comments at 6.

In its Reply Comments Duke states that its proposed avoided capacity rate calculations are based on DEC's first avoidable capacity need in 2028 and DEP's first avoidable capacity need in 2020, as addressed in their respective 2018 IRPs. Duke Reply Comments at 41. Dukes' Schedule PP rates are based upon an assumed 2019 in-service date and are available for an approximate two-year period. Duke states that NCSEA's premise that smaller QFs eligible for the standard offer will not enter into service for years is factually incorrect because small QFs 1 MW or less proceeding under Section 3 Fast Track and Supplemental Review interconnection processes routinely complete construction and are placed in service in less than a year. *Id.* at 49. In addition, Duke asserts that the statutory process for fixing standard offer avoided cost rates does not precisely align with the utility's avoided cost as being incurred the moment a generator comes online, and argues that the QF has the ability to delay the point at which it establishes its LEO or it can elect to pursue a negotiated PPA. Duke therefore states that the Commission should reject NCSEA's proposed delayed hypothetical in-service date. *Id.* at 49-50.

In its Reply Comments DENC argues that setting the January 2019 start date for entering into a standard PPA is an administratively efficient way to develop standard rates and terms for small QFs, rather than adjusting assumed start dates based on uncertainty regarding QFs' commercial operation dates. DENC Reply Comments at 31.

In its Reply Comments the Public Staff states that the Utilities' current approach for establishing the presumed in-service date for standard offer QFs is reasonable and is an equitable way of treating existing and new facilities. The Public Staff, however, recommends that the Commission direct the Utilities to clarify the point when an existing QF seeking to renew its PPA can establish a new LEO for both calculating rates and determining when the facility will be eligible to receive a capacity payment. The Public Staff states that "[t]his period of time should be long enough to allow the QF to have sufficient information regarding its proposed rates to determine whether it would seek to renew, as well as provide the utility with assurance as to whether it may rely on the QF in its planning for future capacity needs." Public Staff Reply Comments at 29.

In response to witness Hinton's recommendation regarding existing QFs that seek to establish a new commitment, Duke witness Johnson states that Duke does not accept requests to enter into a new PPA earlier than 12 months prior to the end of the QF's existing PPA term. For negotiated contracts, consistent with the standard prescribed by the Commission in the Notice of Commitment form, the QF must execute the newly tendered PPA within six months. Tr. vol. 2, 281. An existing QF eligible for the standard offer would automatically have the right to enter into a new ten-year term PPA at Duke's standard offer avoided cost rates applicable to new QFs as of the date the QF's current PPA is set to expire.

Regarding negotiated contracts, NCSEA and witness Johnson also state that the Utilities should be directed to calculate rates for negotiated PPAs based on the presumed in-service date of the QF subject to the negotiated PPA. NCSEA Initial Comments at 12; Johnson Affidavit at 59. The Public Staff agrees that it is appropriate for the utility and QF negotiating a PPA to agree to a presumed in-service date for rate calculation purposes that takes into account any anticipated delays in the project coming online, such as delays in the interconnection queue. Public Staff Reply Comments at 29-30.

In direct testimony Duke witness Snider stated that small QFs can proceed under Section 3 Fast Track and Supplemental Review interconnection under the NCIP, and they are routinely placed in service in less than a year. Tr. vol. 2, 60. Moreover, witness Snider argues that NCSEA does not account for operating QFs seeking to enter into a new PPA under Schedule PP at the time their existing PPA expires that will begin immediately delivering energy at the conclusion of the prior contract term. *Id.* at 61.

In direct testimony DENC witness Petrie testified that NCSEA's assertions regarding the timeline QFs will likely come online are not supported and that many QFs eligible for Sub 158 rates have planned ahead, started the interconnection process, and will come online this year. He also testified that NCSEA's proposal was impractical and inefficient to administer, particularly for standard contracts. Moreover, witness Petrie argued that the proposal itself is arbitrary because the assumed in-service date would change in each avoided cost proceeding and is not based on any standard. Tr. vol. 5, 30.

Regarding negotiated contracts, witness Petrie further stated that the proposal by NCSEA witness Johnson that the Utilities calculate capacity costs for negotiated projects individually based on projected in service date and present a range of rates based on different in-service dates should be rejected because the process would also be inefficient and would likely lead to disagreements about in-service dates. *Id.*

In his direct testimony Public Staff witness Hinton stated that the Public Staff does not support NCSEA's recommendation for the December 31, 2021 presumed in-service date because the utilities filing of their avoided cost rates is designed to provide a predictable and certain point in time from which the avoided cost rates can be calculated and should be reflective of the utilities' current estimate of the inputs in the calculations at that time. He stated that the Public Staff agrees with Duke that smaller facilities may be able to take advantage of the Section 3 Fast Track and Supplemental Review processes under the NCIP and may not be subject to long delays in the interconnection queue. He further stated that the Public Staff recommends that the Utilities clarify when an existing QF seeking to renew its PPA can establish a new LEO for both calculating its rates and determining when the facility will be eligible to receive a capacity payment. Tr. vol. 6, 314-16.

In his direct testimony NCSEA witness Johnson stated that NCSEA is raising this issue for the first time in this proceeding because the impact of an inaccurate in-service date has become "more evident and more serious." Witness Johnson agreed that QFs proceeding under the fast track and supplemental review process can proceed more expeditiously and may warrant an earlier in-service assumption for smaller projects. Another solution would be for the Commission to publish a schedule of rates that specifies the applicable rate for all projects signing a contract during the biennial period where each QF would receive a rate based on it actual in-service date. Tr. vol. 6, 216, 222.

Witness Johnson testified that unrealistically early in-service dates results in QFs being compensated for avoided energy costs based on lower gas prices associated with earlier years than when the QF will be producing power. The problem is particularly severe when it comes to capacity costs because the Commission is now including zeros in the capacity cost calculation, and capacity may be excluded during certain years of the contract. Tr. vol. 6, 217.

Witness Johnson responded to witness Petrie's testimony that he offered no support for his assertion that few QFs will seek to establish LEOs under new rates, stating that QFs are reluctant to commit to a LEO unless and until they have a reasonable degree of certainty that their project will be economically viable. Witness Johnson stated that he was not proposing that December 2021 would align with every QF's actual in-service date, but rather his goal was to propose a more realistic date than January 2019. A more realistic date would be one where roughly half the QFs have an actual in-service date before the date and roughly half have an actual in-service date after the date. *Id.*

Regarding negotiated contracts, witness Johnson rebutted DENC's concerns that there would be difficulties in negotiations because his recommendation was that rates be tied to the actual in-service date and not a projected in-service date. Witness Johnson stated that this reduces or eliminates any risk of under-payment or over-payment and, if rates are tied to an actual in-service date, there would no reason to anticipate difficulties in negotiations. Tr. vol. 6, 224.

Witness Hinton agreed with NCSEA that it is appropriate for a utility and QF negotiating a PPA to agree to a presumed in-service date for rate calculation purposes that takes into account any extended timelines that may affect the project coming online. He also testified that it is consistent with N.C.G.S. § 62-156(c) and the Commission's March 6, 2015 Order on Clarification issued in Docket No. E-100, Sub 140 for either party to bilateral negotiations of a PPA to identify specific characteristics that merit consideration the calculation of avoided cost rates. *Id.* at 317.

In rebuttal testimony, witness Snider agreed with witnesses Petrie and Hinton that using a later in-service date or requiring the Utilities to publish and update multiple pricing schedules as recommends by NCSEA would inject uncertainty into the process. Tr. vol. 2, 110.

DENC witness Petrie on rebuttal also stated that DENC agrees with the Public Staff that a later in-service date should not be assumed for standard offer QFs. Furthermore, witness Petrie testified that using the January 2019 in-service date is the most administratively efficient method to develop standard rates and terms for all QFs. Alternatives to this accepted approach would add unnecessary complications and give rise to more disputes. Tr. vol. 5, 45, 53.

At the hearing, in response to questions from NCSEA, Duke witness Snider testified that with respect to negotiated contracts it is currently Duke's practice that the avoided rates included in those contracts be based on the actual projected in-service dates. Tr. vol. 3, 10.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, and for the reasons detailed by Duke and the Public Staff, the Commission finds that it is appropriate for DEC, DEP, and DENC to continue their current approach to the assumed January 2019 in-service date for the purposes of this proceeding, and that it is appropriate for the utility and a QF to negotiate a presumed in service date for rate calculation purposes taking into account any anticipated date of the QF project coming online. In making this finding of fact, the Commission gives substantial weight to the evidence and arguments of Duke and the Public Staff, which the Commission views as highly persuasive. The Commission further finds that the Utilities' historical practice is appropriate for use in this proceeding. The Commission also agrees with the Public Staff that this issue may become more important as more QF contracts approach their expirations. Therefore, the Commission will require the Utilities to provide further justification for the timeline of the delivery of the Notice of Commitment to existing QFs in their initial filing in the next biennial avoided cost proceeding, and the Commission may further consider the issue in that proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 27

The evidence supporting this finding of fact is found Duke's verified JIS, DENC's verified Initial Statement, and the entire record herein.

Summary of the Evidence

In its JIS Duke states 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 IRP purposes — to plan for Duke's 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 indicates 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 indicates that since the 2016 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 indicates 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. JIS at 17-21.

In its Initial Statement DENC indicates 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 a blend of forward market prices and a commodity forecast provided by ICF International, Inc. (ICF), and for month 37 and thereafter based on ICF prices exclusively. DENC Initial Statement at 8.

In its Initial Comments the Public Staff states 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 notes 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 notes 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 recommends that the Commission require DEC and DEP to use no more than five years of forward market data before transitioning to Duke's fundamental forecast. Public Staff Initial Comments at 21-28.

SACE notes in its Initial Comments 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 2016 Sub 148 Order, Ordering Paragraph No. 5). SACE further states 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 notes 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 states 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 recommends 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 indicates its general support for the approach utilized by DENC. SACE Initial Comments at 6-7.

In its Initial Comments NCSEA proposes 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 EIA Annual Energy Outlook forecast. NCSEA further notes 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 does 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 witness Beach also notes in his affidavit 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 notes 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." Beach Affidavit at 11.

In its Reply Comments DENC states 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 (2012 Sub 136 Proceeding), 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.

In its Reply Comments SACE indicates 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. The Small Hydro Group indicates 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 recognizes that the Commission declined to approve Duke's forecasts in the 2016 Sub 148 Proceeding and emphasized the importance of internal consistency between the Utilities' IRPs and the biennial avoided cost proceeding. Duke also acknowledges that the Commission was not fully persuaded that the market was sufficiently liquid to support ten-year futures but indicates its intention to continue to monitor liquidity in the natural gas market in future avoided cost proceedings. Duke Reply Comments at 11-12.

Responding to the Public Staff's analysis of other utilities' IRPs to support its argument, Duke indicates 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 notes that since the time of filing of Initial Comments, it has identified another North Carolina market participant that has also purchased significant quantities of ten-year forward natural gas, providing additional evidence of liquidity in the ten-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 reiterates 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 indicates its disagreement and notes 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 recommends that the Commission approve Duke's proposed use of ten-year forward market prices. *Id.* at 18.

Discussion and Conclusions

The evidence in this proceeding demonstrates continued declines in the price of natural gas. In addition, the evidence demonstrates that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and that 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 2016 Sub 148 Proceeding the parties advocated for many of the same positions as in this proceeding. In the 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 that 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 Commission's biennial avoided cost proceeding and the Commission's review of IRPs, as well as the importance of maintaining internal consistency between these proceedings. In this proceeding and in the IRP proceeding, the Public Staff argues 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 proposes 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 finds somewhat persuasive the Public Staff's evidence demonstrating that Duke's other operating utilities do not use ten years of forward prices and that the practice proposed by Duke is highly uncommon in the electric utility industry. NCSEA and SACE argue in favor of less reliance on forward market price data, or in support of the Public Staff's position.

After careful consideration, the Commission is not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, at this time. While the parties who have addressed this issue produced substantial, competent, and material evidence and well-articulated arguments in support of their positions, this evidence does not definitively support movement in either direction between fundamental forecasting and forward-market purchases. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require DEC and DEP to continue to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period. The Commission also 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 finds that the fuel forecasting methodology utilized by DENC is also appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 28

The evidence supporting this finding of fact is found in Duke's verified JIS, Public Staff's Initial Comments, NCSEA's Initial Comments, SACE's Initial Comments, Cube Yadkin's Initial Comments, Duke's Reply Comments, and the entire record herein.

Summary of the Evidence

In its JIS Duke argues that PURPA provides a QF a “Put 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. JIS at 22-23.

In its Initial Comments the Public Staff disagrees 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 states 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 reiterates its support for inclusion of a hedging value for renewables, consistent with the Commission’s findings in the Sub 140 Phase One Order, and recommends that the Commission require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing Model or similar method. *Id.* at 29.

NCSEA states 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 finds, however, that the use of the Black-Scholes approach that reprices gas at the prevailing market price repeatedly over a ten-year period undervalues the hedge provided by a ten-year PPA with prices fixed from the start of the contract’s term. NCSEA indicates 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 Comments at 20-27.

SACE states that it disagrees 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 states 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 states 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 notes 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 states that the hedge against fuel price volatility continues to have economic value and should be compensated. *Id.* at 4-5.

In its Reply Comments Duke states that the arguments raised by NCSEA and the Public Staff are 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 ten-year duration gas without making equivalent changes to their fuel procurement practices. Duke states 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 states that 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 indicates 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 indicates that including the premium results in an overpayment by customers to QFs, contrary to PURPA, since avoided cost prices paid to QFs already reflect Duke's fixed and avoidable cost of natural gas over a ten-year term. Duke notes in closing that it has 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. *Id.* at 23-30.

Discussion and Conclusions

In the Sub 140 Phase One Order the Commission found that renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase. In doing so, the Commission acknowledged that purchasing solar power can be seen as the equivalent of buying natural gas forwards. Based upon the foregoing and the entire record herein, the Commission finds that the evidence in this proceeding demonstrates again that there are fuel price hedging benefits associated with renewable generation. Purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that must be purchased and, therefore, the costs that the utilities would incur toward fuel procurement. In making this finding, the Commission gives substantial weight to the comments and arguments of the Public Staff, SACE, Cube Yadkin, and NCSEA on this issue. The Commission 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.

The Commission is not persuaded that Duke's argument that QFs are inappropriately being granted a "put option" without any obligation to sell is consistent with the requirements of 18 C.F.R. § 292.304(d)(2), 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, pursuant to N.C.G.S. § 62-156(b)(2):

> 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 likewise not persuaded that Duke's view is consistent with this direction, nor is the Commission persuaded by Duke's position that paying QFs for the value of reduced volatility with fuel prices subjects its customers to additional overpayment risk. Instead, based upon the foregoing and the entire record herein, the Commission finds, consistent with the Public Staff's arguments, that DEC and DEP should be required 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.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29 – 31

The evidence supporting these findings of fact is found in Duke's verified JIS, NCSEA witness Beach's Affidavit, and the entire record herein.

Summary of the Evidence

Duke's JIS notes the Commission's direction in the Sub 140 Phase One Order to continue to study the potential impacts of integrating increasing levels of solar resources into Duke's generation mix and contends that the increased levels of uncontrolled solar QF generation are resulting in increased operating costs relative to dispatchable generation resources. While Duke continues to recognize an avoided energy line loss adjustment for distribution-interconnected QFs and supports identified integration costs associated with increasing penetrations of variable and non-dispatchable solar capacity, it does not identify any avoidable transmission or distribution capacity benefits associated with QF generation in quantifying avoided cost. JIS at 31-32.

In its Initial Comments NCSEA contends that solar integration allows utilities to avoid future transmission and distribution capacity costs and asserts that these "benefits" should be considered when developing Duke's avoided cost rates. NCSEA relies on the affidavit of Thomas Beach filed in support of its Initial Comments to argue that small QF generation can reduce peak loads on the Utilities' upstream distribution and transmission systems, thereby allowing the Utilities to avoid the need to expand the entire transmission and distribution system and to avoid future load related transmission and distribution capacity costs. NCSEA Initial Comments at 39-43.

NCSEA witness Beach proposes quantifying avoided transmission and distribution costs by allocating avoided transmission and distribution costs "to the hours of the year, using peak capacity allocation factors (PCAFs) based on the hours when loads on the transmission and distribution system are highest." He explains that the PCAF-based allocation of avoided distribution costs uses a sample of loads at DEC's and DEP's distribution substations and that analyzing this data is a first step toward including more locational granularity in avoided cost rates to quantify transmission and distribution costs that could be avoided by purchases from distribution-connected QFs. NCSEA witness Beach's PCAF analysis was developed based on the avoided transmission and distribution capacity costs that Duke has relied upon for purpose of quantifying the avoided transmission and distribution capacity value attributed to Duke's DSM programs and energy efficiency (EE) programs. Beach Affidavit at 7, 21-26.

The Public Staff's Initial Comments highlight the Commission's discussion in the Sub 140 Phase One Order that integration of solar resources into a utility's generation mix can result in both costs and benefits, but that it is "inappropriate for ratepayers to shoulder such costs [as includable in avoided costs] until they become known and verifiable." The Public Staff comments that it may be appropriate for the Commission to consider evidence from other parties as to what additional costs or benefits can be sufficiently known and verifiable at this time such that they should be included in avoided cost rates. Public Staff Initial Comments at 32-33.

In its Reply Comments the Public Staff reintroduces Dr. Richard Brown's testimony on behalf of the Public Staff from the 2014 Sub 140 Proceeding addressing the theoretical potential for QFs to avoid future transmission and distribution capacity investments. The Public Staff details that, theoretically, a renewable energy facility can be located on an existing transmission system at a place that can reduce power flows on heavily loaded transmission lines. However, the Public Staff also notes that the ability of a facility to provide this benefit will be very site-specific. Similarly, distribution-connected renewable energy facilities could potentially help reduce future transmission capacity expenditures, if their power does not flow onto the transmission system. Public Staff Reply Comments at 9.

The Public Staff also recognizes, however, that the significant increases in distributed generation facilities interconnecting to the distribution and transmission system in North Carolina in recent years raises additional questions regarding the proper allocation and assignment of costs associated with use of the grid. The Public Staff specifically cites to Public Staff witness Jay Lucas' recent testimony in Docket No. E-100, Sub 101 regarding the additional system costs being imposed on retail customers to integrate QF solar generators to support their argument. Public Staff Reply Comments at 9-10.

The Public Staff also comments that offering an avoided transmission and distribution cost adder to all QFs eligible for the standard offer would likely not incentivize such QFs to locate in places that are more likely to result in future avoided transmission and distribution investments. In support of this contention the Public Staff states that an avoided transmission and distribution benefit offered to all Standard Offer QFs would ignore the site- and project-specific considerations that are critical to an accurate assessment of potential avoided transmission and distribution system benefit. Public Staff Reply Comments at 10.

The Public Staff finds that evidence was lacking to warrant an avoided distribution capacity cost adder for either distribution or transmission connected QFs. However, the Public Staff argues that it may be appropriate for the Utilities to calculate an avoided transmission cost adder to the avoided energy rate applicable to a standard offer contract, with a provision within the contract allowing the utility to remove the availability of the avoided transmission adder if (i) the QF would cause or exacerbate reverse power flow, or (ii) the projected load growth on the interconnected feeder over a ten-year time horizon was negative or negligible. The Public Staff states that the goal of provision (i) is to ensure that a QF interconnecting to a distribution feeder that is experiencing backfeeding will not receive avoided transmission benefits, and that provision (ii) would ensure that a QF interconnecting to a feeder that is experiencing little to no load growth, and thus is not expected to make load growth-related transmission upgrades in the foreseeable future, does not receive avoided transmission benefits. Public Staff Reply Comments at 10. Specific to the standard offer contract, the Public Staff recommends that the Commission direct the Utilities to calculate a conditional avoided transmission capacity cost adder for standard offer contracts, which can be removed if certain conditions are met regarding backfeeding and load growth. Public Staff Reply Comments at 9-11.

The Public Staff also supports QFs not eligible for the standard offer contract being able to quantify site- and project-specific characteristics to show that the QF's operations create future avoided transmission capacity benefits and to include those avoided system costs in their negotiated contracts. Specific to negotiated QF avoided costs, the Public Staff recommends that the Utilities consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract, and that an avoided transmission adder be included if such a project can provide real and measurable avoided transmission capacity benefits. Public Staff Reply Comments at 11.

In response to NCSEA's proposal the Public Staff states that it has concerns with the use of the avoided transmission and distribution rates from the DSM/EE proceedings as it is not clear that those rates, which were calculated based upon the availability of DSM during system peak and EE during all hours, are applicable to QFs. Public Staff Reply Comments at 11-12.

In its reply comments SACE agrees with NCSEA that QFs should be compensated for the full range of costs that they allow the purchasing utility to avoid, including applicable transmission and distribution costs. SACE notes that the FERC previously upheld a state utility commission's authority to include an avoided cost "adder" for transmission-connected QFs located in transmission-constrained areas to reflect the savings from the deferred transmission- and distribution-related costs. Therefore, SACE argues that NCSEA's proposed avoided transmission and distribution system cost analysis is consistent with the FERC's precedent on the issue under PURPA. SACE Reply Comments at 13-14.

Duke's Reply Comments provide that PURPA's foundational "but for" premise prescribes that a utility should pay QFs its full avoided costs but cannot be required to pay a QF more than the cost the utility would incur if the utility generated the power or purchased it from another source. Citing prior guidance from the FERC evaluating what constitutes a utility's avoided costs under PURPA, Duke comments that costs which are speculative or otherwise not measurable or quantifiable are inappropriate in arriving at the utility's avoided costs, whereas costs actually incurred by the utility that are quantifiable and "real" are appropriately considered in arriving at a utility's avoided costs. Duke Reply Comments at 126-27.

In response to NCSEA, Duke argues that including an adder for future avoided transmission and distribution costs in the standard offer would be unprecedented under PURPA due to the generalized and speculative nature of "potential" future transmission and distribution system costs advocated by NCSEA as avoidable. Duke asserts that the FERC has accepted only "an actual determination of the expected costs of upgrades to the distribution or transmission system that [purchasing from QFs] will permit the purchasing utility to avoid," where the adder reflected the utility's avoided future cost of constrained transmission and distribution infrastructure that would be required to deliver power to a transmission-constrained area. Therefore, Duke rejects NCSEA's PCAF analysis as a generalized quantification of estimated "time varying locational values" of load reductions across DEC's and DEP's entire distribution systems, which in no way correlates to or represents the expected cost of upgrades to the utility's system that theoretically could be avoided by purchasing from QFs. Accordingly, Duke argues that it has properly excluded the potential that purchasing energy from standard offer QFs might avoid some level of future system transmission and distribution costs in developing the avoided cost rate calculations. Duke Reply Comments at 126-27.

Duke also asserts that the system impact of distribution-connected QFs and DSM/EE program are not comparable. Unlike solar generation, DSM/EE measures are permanent changes in load that do not diminish with cloud cover or other conditions that impact the availability of intermittent generation. If the DSM/EE measure fails, this typically results in the entire load-reducing benefit from the measure being removed from the system as opposed to the increased circuit load that would be experienced when generation fails (or is not available due to intermittency of generation output). Accordingly, Duke argues that while avoided transmission and distribution benefits can potentially be realized from customer-sited EE measures, intermittent generation does not provide the same benefit. Duke Reply Comments at 128-30.

Next, Duke asserts that the Companies design their transmission and distribution systems to meet peak load on the circuit and at the substation. Due to the intermittent and daytime nature of solar generation, Duke cannot rely upon QF solar being available to meet peak load, and therefore cannot reasonably assume any load reduction due to QF solar that could support the downsizing of Duke's transmission and distribution assets. Moreover, Duke asserts that distribution and transmission planners do not reduce the capacity of installed facilities due to concerns that circuits will be overloaded if generation is unavailable or intermittent during peak conditions. Duke Reply Comments at 129-30.

Duke then argues that if anything, QFs have benefitted by consuming available distribution and transmission capacity up to the limits of the existing system, as exemplified by the fact that in some areas, QF generation exceeds load and exporting from the region is constrained in some hours. In conclusion, Duke reiterates that it has properly concluded that there presently are no real or quantifiable costs of future avoided transmission and distribution or benefits resulting from solar installations and contends that it would be more reasonable for the Commission to recognize that incremental QF energy on the distribution system could actually increase future transmission and distribution costs, noting statements by the Public Staff expressing concern as to whether solar QFs were properly bearing the representative responsibility of increased grid O&M costs. Thus, Duke recommends the Commission reject NCSEA's proposal. Duke Reply Comments at 130-31.

Discussion and Conclusions

The Commission has carefully considered NCSEA's proposed avoided transmission and distribution adder, as well as the evidence in rebuttal to NCSEA's proposal, and finds persuasive Duke and the Public Staff's arguments that NCSEA's proposal should not be adopted in this proceeding. The Commission agrees with the Public Staff that the significant increase in QFs interconnecting in North Carolina in recent years has raised questions regarding the proper allocation and assignment of costs associated with the use of the grid. On this issue, the Commission gives weight to the comments of Duke and the Public Staff addressing this issue.

Specific to NCSEA's proposal, the Commission finds persuasive Duke's arguments that relying upon generic assumptions about future avoidable transmission and distribution system investments based upon witness Beach's PCAF analysis is inappropriate and fails to accurately quantify specific costs that would be avoided as a result of purchasing energy and capacity from QFs. PURPA requires that costs must be quantifiable and "real" to be included in avoided costs. *Cal. Pub. Utility Comm'n.*, 132 FERC ¶ 61,047, 61,267-68, *clarification granted & reh'g denied*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011). Similarly, the Utilities' avoided costs must be "known and measurable," and the Commission "should not rely on conclusions derived from limited observations or speculation to definitively establish the parameters of what should be included in avoided cost rates." Sub 140 Phase One Order at 61. The Commission agrees with Duke that witness Beach's analysis presents a generalized quantification of estimated "time-varying location values" of load reductions across DEC's and DEP's entire distribution systems and not a quantifiable or known and measurable quantification of Duke's expected cost of system upgrades that could be avoided from purchasing power from specific QFs.

The Commission also finds persuasive Duke's arguments that excluding the potential that purchasing energy from standard offer QFs might avoid some level of future transmission or distribution costs in developing the avoided cost calculation is similar to avoided cost calculations in other jurisdictions. NCSEA has not identified other jurisdictions as including such an adder to generic avoided cost rates for avoided transmission or distribution costs, even though utility systems with lower penetrations of distribution-connected generation would theoretically achieve greater benefits from these distributed energy resources in terms of avoiding the need for potential future transmission or distribution system investments. In addition, the Commission agrees with the Public Staff and Duke's conclusion that the use of avoided transmission and distribution assumptions for DSM/EE resources and measures, as proposed by NCSEA, is not reasonably representative of the system impacts and capacity contribution of distribution-connected QFs. The Commission also agrees with Duke that due to the intermittent and daytime nature of solar generation, Duke cannot rely upon QF solar being available to meet peak load and, therefore, cannot reasonably assume any load reduction due to QF solar that could support the downsizing of transmission and distribution assets. The Commission also finds persuasive Duke's explanation that DSM/EE measures are permanent changes in load that do not diminish with cloud cover or other conditions that impact the availability of intermittent generation. In short, intermittent QF generation does not provide the same quantifiable benefit of reducing load on the distribution system during the utility's peak periods as DSM/EE measures.

Finally, the Commission finds persuasive Duke's arguments that the growth of QF solar in North Carolina could potentially increase transmission and distribution costs for retail customers. In addition, the Public Staff cites to its testimony in Docket No. E-100, Sub 101 addressing this issue. As asserted by Duke, QFs are responsible for funding distribution system or transmission network upgrades to support their own interconnection; QFs are not obligated to acquire transmission capacity to deliver QF power to the utility's network, and instead rely upon the utility's transmission system. These arguments are consistent with and provide support for the Public Staff's contention that there is insufficient evidence to warrant avoided distribution capacity cost adders for either distribution- or transmission-connected QFs at this time. The Commission agrees, and therefore declines to adopt NCSEA's proposal.

Similarly, for purposes of this proceeding the Commission declines to adopt the Public Staff's recommendation for the Utilities to calculate a conditional avoided transmission capacity cost adder for standard offer contracts, which could be removed if certain conditions are met regarding backfeeding and load growth. As stated by the Public Staff:

> [O]ffering an avoided T&D cost adder to all QFs eligible for the standard offer contract (Standard Offer QFs) would not likely incentivize direct Standard Offer QFs to locations that are more likely to result in avoided

> future T&D investments. An avoided T&D benefit offered to all Standard Offer QFs would ignore the site- and project-specific considerations that are critical to an accurate assessment of the avoided T&D [system] benefit.

Public Staff Reply Comments at 10.

The Public Staff's comments and Duke's evidence summarized above tends to demonstrate that intermittent QFs do not generically provide firm load reductions across the system, and therefore the presence of QF-supplied power cannot support the downsizing of Duke's transmission and distribution assets. This evidence lends further support to the Commission's decision not to adopt the Public Staff's proposal. Nonetheless, the Commission appreciates the Public Staff's nuanced attention to this issue and will maintain an openness to revisit this issue in a future proceeding where the evidence can be more fully developed. The Commission anticipates greater clarity on this subject as Duke advances its Integrated Systems and Operations Planning effort currently underway that leverages the functionalities afforded by foundational grid improvement plan investments. The Commission expects that this work should inform the evaluation of avoided transmission and distribution capacity costs and benefits in future avoided cost dockets. The Commission will direct the Utilities to provide additional discussion, insights, and plans in the next avoided cost proceeding. Finally, in the negotiated contract setting, where project-specific characteristics during contract negotiations with a QF must be considered, the Commission expects the Utilities to include an avoided T&D capacity adder if a project can provide real and measurable avoided transmission or distribution capacity benefits.

Based upon the foregoing and the entire record in the proceeding, the Commission finds that it is inappropriate for the Utilities to include a transmission and distribution capacity adder within their avoided cost calculations available to standard offer QFs, and that the use of transmission and distribution capacity rates from DSM proceedings is inappropriate for use in calculating avoided transmission and capacity costs in this proceeding. The Commission further finds that the Public Staff's proposed conditional avoided transmission cost adder is not sufficiently supported nor fully developed at this time, and therefore the Commission determines to not approve this recommendation. However, the Commission will direct the Utilities and the Public Staff to work together to more precisely define these issues for the Commission's consideration in the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact is found in Duke's verified JIS and the entire record herein.

Summary of the Evidence

NCSEA advocates for the Utilities to include a market price suppression adder to their avoided energy cost calculations. NCSEA argues that integrating renewables in regional power markets causes a "reduction in demand [that] will cause a corresponding reduction in the price in these markets, which benefits the Utilities when each must buy power or natural gas in these markets." NCSEA suggests that increasing penetrations of renewables "causes the prices of energy to reduce across the country, on a whole," and therefore concludes that the Commission should "require the Utilities to account for such market changes caused by distributed energy resources." NCSEA Reply Comments at 34.

In its Reply Comments Duke argues that NCSEA's proposal to include a "market price suppression" adder in avoided costs was in no way based upon known and measurable costs actually avoided by Duke's procurement of alternative energy. Duke contends that even assuming NCSEA's point — that increasing renewables in regional power markets impacts electricity and natural gas prices in those markets — has some validity, NCSEA ignores numerous other factors that have significantly greater impacts on the market price of energy, including, but not limited to natural gas production costs, weather, and environmental regulations. Moreover, Duke responds further that the market price of energy that is avoidable by Duke is precisely that — a market price — and reflects both higher and lower cost resources (such as DEC and DEP's combined 9,100 MW (winter) of baseload, low variable cost nuclear generation). Duke states NCSEA's recommendation for Duke and DENC to account for inclusion of above-market "price benefits" of integrating renewables in their avoided costs is speculative, unquantified, and not reflective of costs actually avoidable by the utility. Duke concludes that accepting above-market adders in calculating Duke's cost of energy essentially forces Duke to pay avoided energy rates that are above the Utilities' forecasted incremental cost of procuring alternative energy, which is inappropriate under PURPA. Duke Reply Comments at 29-30.

Discussion and Conclusions

The Commission agrees with Duke that NCSEA's proposed "market price suppression adder," designed to capture a decrease in wholesale power prices due to the increasing integration of renewable QFs, is not based upon known and measurable costs that can accurately be calculated to include in the Utilities' avoided energy costs. Therefore, based upon the foregoing and the entire record in the proceeding, the Commission finds that it is not appropriate for the Utilities to incorporate a market price suppression adder in their avoided cost calculations for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33 – 42

The evidence supporting these findings of fact is found in Duke's verified JIS; the testimony of Duke witnesses Snider, Wheeler, and Wintermantel, SACE witness Kirby, NCSEA witness Beach, Public Staff witness Thomas; and the entire record herein.

Summary of the Evidence

Duke's JIS provides that the 2018 Scheduling Order directed the Utilities to consider factors relevant to the characteristics of QF-supplied power — specifically intermittent and non-dispatchable power — in designing rates to meet PURPA's objectives of appropriately valuing Duke's incremental costs of alternative energy to be avoided from purchasing power from a QF. Further, the 2016 Sub 148 Order similarly emphasized 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. JIS at 30-31 (quoting 2016 Sub 148 Order).

In response to these Commission directives, Duke argues that the costs avoided by growing levels of solar QFs that provide intermittent, non-dispatchable power is markedly different from integrating firm power and that it is appropriate to recognize integration costs that Duke is now incurring in valuing the energy and capacity provided by QFs eligible for Schedule PP. Based on Duke's recent experience integrating surging levels of variable and intermittent solar QF power, Duke has included an integration services charge in its rate design to reflect the impact on operating reserves, or generation ancillary requirements, for new variable and non-dispatchable solar capacity. JIS at 30-31; tr. vol. 2, 38.

The JIS and the testimony of witness Snider explain that that meeting its obligation to provide reliable electric service to its customers requires Duke to dispatch DEC's and DEP's generation fleet resources to meet real-time load on a moment-to-moment basis. Witness Snider testified that the energy output from solar resources is variable, and that it can unexpectedly and rapidly drop-off or ramp-up in real-time, thereby increasing uncertainty in day-ahead, hourly, and sub-hourly projections for fleet operations. The addition of solar volatility to the system increases the real-time volatility the system experiences as compared to just servicing load without solar on the system. Witness Snider stated that this additional uncertainty and volatility requires Duke to carry additional operating reserves, which are the real-time system resources required to balance and regulate the system on an hourly and sub-hourly basis. These operating reserves are provided by reserving additional dispatchable conventional fleet resources to ensure that sufficient operational flexibility is available to respond in real-time to rapid changes in solar output. Additionally, ensuring that sufficient operating reserves are available is also required to maintain compliance with NERC bulk electric system balancing and reliability standards. The need for increased real-time system operating reserves to reliably integrate increased levels of uncontrolled must-take solar generation results in additional operating costs relative to integrating a dispatchable or baseload generation source. As solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases. JIS at 32-33; tr. vol. 2, 78-81.

To quantify the increasing costs of integrating solar generation into the DEC and DEP systems, witness Snider testified that Duke commissioned Astrapé Consulting (Astrapé) in late 2017 to analyze the impacts of integrating solar into Duke's systems at varying solar penetration levels and to quantify the cost of utilizing the DEC and DEP conventional fleets to provide the additional operating reserves or generation "ancillary services" needed to reliably integrate the various levels of intermittent solar generation. Tr. vol. 2, 80-81.

Duke witness Wintermantel testified in support of the Astrapé Solar Ancillary Services Study (Astrapé Study). He began by describing the integration challenges utilities experience as solar penetration increases on the utilities' systems. As solar penetration increases, the uncertainty and intra-hour volatility in net load increases, meaning five-minute deviations in net load can be much more significant in systems with high penetrations of variable and intermittent solar as compared to systems with no solar. To manage the increase in intra-hour volatility, additional load following reserves are required to allow generators additional flexibility to meet these unexpected movements in net load, which thereby increase ancillary services cost. In addition, witness Wintermantel stated that generators are forced to start more frequently, causing additional startup and maintenance costs. Tr. vol. 4, 51-56.

Witness Wintermantel then provided an overview of the SERVM model, which commits DEC's and DEP's resources on week-ahead, day-ahead, and hour-ahead bases and dispatches resources to load on a five-minute time step. For each year simulated, total production costs are then calculated and reported, as well as the reliability metrics of the system. To analyze the economic impact of integrating solar, witness Wintermantel testified that the SERVM model, which was similarly used in Duke's Commission-approved 2012 and 2016 Resource Adequacy studies, modeled Duke's system reliability with and without solar generation at various penetration levels. As detailed in the JIS, witness Wintermantel testified that this modeling analysis was performed for the 2020 study year across several solar penetrations including a No Solar scenario, the Existing plus Transition scenario (840 MW in DEC and 2,950 MW in DEP), Tranche 1 solar scenario (1,520 MW in DEC and 3,110 MW in DEP), and the Plus 1,500 MW of solar generation scenario (3,020 MW in DEC and 4,610 in DEP). Once the required ancillary services were determined, the costs of the ancillary service were also computed through the SERVM model. JIS at 32-33; tr. vol. 4, 56-59, 65-66.

Witness Wintermantel stated that an important aspect of the Astrapé Study is that the SERVM model is designed to recognize that utility system operators will have imperfect knowledge of day-ahead net load, net load a few hours ahead, and intra-hour net load to make generation commitment decisions. This imperfect knowledge is accounted for by incorporating load and solar forecast error, meaning the model commits its conventional generation fleet to a net load that has some level of error and then must adjust accordingly in real time, similar to the way system operators must adjust in real time. To mimic the movement of load and solar on a five-minute basis, the SERVM model requires one year of five-minute load and solar data as an input. For both DEC and DEP, the Astrapé Study used historical five-minute load and solar data from the 12-month period between October 2016 and September 2017. Witness Wintermantel stated that the five-minute data was scrubbed for reporting anomalies or errors and the volatility embedded in these five-minute profiles was applied to the load and solar generation for each penetration analyzed. Tr. vol. 4, 58-61.

After providing background on the Astrapé Study's inputs and modeling framework, witness Wintermantel stated that the underlying premise of the Astrapé Study is to ensure that the operating reliability of the DEC and DEP systems is the same before and after additional solar is added to Duke's systems. To study the impact on system reliability with and without solar, Astrapé utilized the $LOLE_{FLEX}$ metric of 0.1 within the model to measure the number of loss of load events due to system flexibility constraints, calculated in events per year. Witness Wintermantel testified that $LOLE_{FLEX}$ as used in the SERVM model is a measure of the system's ability to satisfy net load obligations assuming that net load is known five minutes before it materializes and provides a means of measuring if the system has enough load following reserves. As additional solar is added to the system, load uncertainty and intra-hour volatility increase, causing $LOLE_{FLEX}$ to increase. To maintain the same reliability on the system as before the solar was added, load following reserves needed to be increased. Witness Wintermantel further testified that the Astrapé Study determines the appropriate amount of load following reserves to add by forcing the system back to the original $LOLE_{FLEX}$ metric of 0.1 events per year. He clarified, however, that $LOLE_{FLEX}$ events cannot be mitigated by allowing area control error (ACE) to deviate for short periods, as $LOLE_{FLEX}$ events and ACE deviations are not synonymous. Tr. vol. 4, 62-66.

As also detailed in the JIS witness Wintermantel testified that at the Existing plus Transition solar penetration level for DEC, the Astrapé Study determined that an additional 26 MW of load following reserves were required to integrate 840 MW of solar. For DEP, the Astrapé Study identified that 166 MW of additional load following reserves were required to integrate 2,950 MW of solar. He then described Duke's use of these study results, which utilize the average costs of the Existing plus Transition solar penetrations for each utility to establish the integration services charge. Specifically, based upon the results of the Astrapé Study, Duke included a $1.10/MWh integration services charge for DEC and a $2.39/MWh integration services charge for DEP. Witness Wintermantel presented the Astrapé Study's modeling results for DEC and DEP in Figures 4 and 5 of his testimony, respectively. Witness Wintermantel also noted that Duke's proposed integration services charges for DEP and DEC were based on the lower "average" cost to integrate the Existing plus Transition solar capacity in DEP (2,950 MW) and DEC (840 MW), instead of the significantly higher "incremental" integration cost. Witness Wintermantel concluded that in his expert opinion, Duke had appropriately used the results of the Astrapé Study to establish a reasonable integration services charge. JIS at 33; tr. vol. 4, 66-74.

Duke and the Public Staff entered into the SISC Stipulation, which addresses the quantification of DEC's and DEP's ancillary services costs as well as the integration services charge rate design. Duke and the Public Staff agree in the SISC Stipulation that the Astrapé Study's data, methodology, results, and conclusions are reasonable for purposes of quantifying Duke's "average" and "incremental" ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating Duke's respective integration services charges. SISC Stipulation, § III.A. The SISC Stipulation also provides that solar integration services charges collected from solar generators will be credited to ratepayers in future fuel proceedings to offset the increased fuel and fuel-related costs associated with integrating solar resources. SISC Stipulation, § IV.D.

Duke witness Wheeler testified that Duke calculated the integration services charge based upon the average integration costs for the Existing plus Transition solar capacity, as quantified by the Astrapé Study. He further stated that while Duke was proposing to use the lower average integration cost, the integration charge would be applied only to new solar generators coming onto the system, which would include QFs that establish a LEO under the biennial standard offer avoided costs rates filed in this proceeding. As existing contracts expire and new contracts are executed, this average integration services charge will apply to solar providers uniformly. Duke proposes to update the integration services charge every two years as part of the biennial avoided cost proceeding. Duke plans to continue to study the cost to integrate operating and incremental solar generation and to update the Commission on changes to the cost to integrate additional solar capacity, considering factors such as solar penetration levels, prevailing fuel prices, and the makeup of Duke's future portfolios. Witness Wheeler noted that these proposals were agreed to by the Public Staff and memorialized in Section IV of the SISC Stipulation. Tr. vol. 2, 227.

Witness Wheeler also testified in support of the integration services charge average cost rate design, explaining that all intermittent generation resources create this higher cost of service, not just new generation resources. In contrast, designing the charge to collect the incremental cost would result in preferential pricing for the first entrants while shifting cost recovery to new sellers. Witness Wheeler opposed this approach, explaining that it would be equivalent to only charging generation cost to new retail customers that cause the need for a new generator while allowing all existing customers to benefit from greater resources, which is potentially discriminatory and inconsistent with average-cost ratemaking principles. Witness Wheeler testified that he views applying the charge only to solar QFs that either establish a LEO or renew, or otherwise extend, a PPA on or after November 1, 2018, as appropriate. By delaying implementation until their current PPA expires and is subsequently renewed, witness Wheeler stated that QFs with existing contracts are protected from immediately being subject to the new charge while also ensuring that they will eventually be responsible for these increased costs if they continue to sell their generation output to the utilities. He also highlighted, however, that until their current term expires, any increased ancillary services cost that Duke incurs would be borne by retail customers. Tr. vol. 2, 230-33.

Witness Wheeler testified in support of biennially updating the integration services charge while establishing a cap on future adjustments to the charge, as recommended by the Public Staff and agreed to in Section V of the SISC Stipulation. Witness Wheeler stated that the integration services charge rate design recognizes that Duke's integration costs are expected to change with increased deployment of intermittent resources but will also vary in the future based upon actual load growth, the mix of Duke's generation resources, and potential impacts of electricity storage capability. This potential for significant changes in the future makes developing an accurate long-term estimate that would be necessary to establish a longer-term fixed rate challenging, and Duke supports biennially updating DEC's and DEP's quantification of ancillary services costs over time, subject to a cap to be approved by the Commission and included in the Schedule PP tariffs. Tr. vol. 2, 230-33.

Witness Wheeler also testified that the proposed cap on future increases to the integration services charge mitigates the risk for Sub 158 Vintage solar generators of currently unquantifiable potential future increases in DEC's and DEP's average ancillary services costs attributable to the installation of incremental solar on Duke's systems during the term of Sub 158 Vintage PPAs. Witness Wheeler testified that while the cap is not consistent with how other costs incurred to serve distributed generation are treated, Duke agreed to the cap as a reasonable approach to address the Public Staff's concerns and to offer QFs limited price certainty during their contract term. Witness Wheeler also testified that inclusion of the cap might result in some level of subsidization of QFs by the general body of customers if the average cost of these ancillary services continues to grow. Tr. vol. 2, 228.

Duke witness Wintermantel testified that he quantified the cap consistent with the methodology used in the Astrapé Study. Witness Wintermantel stated that at the direction of Duke and in support of the SISC Stipulation, Astrapé performed additional modeling simulations to calculate the incremental ancillary service cost impact of the last 100 MW of solar generation expected to be installed by the end of 2020, based upon DEC's and DEP's 2018 IRPs, to determine a potential cap for the charge, which was determined to be $3.22/MWh for DEC and $6.70/MWh for DEP. Tr. vol. 4, 78-80.

Witness Wheeler stated that the cap amount would be incorporated into Schedule PP to prescribe that "[i]n no event shall the integration services charge exceed [$0.00322 for DEC; $0.00670 for DEP] per kWh for Purchased Power Agreements executed under rates approved in Docket No. E-100, Sub 158." Tr. vol. 2, 229-30.

Section II of the SISC Stipulation provides that a solar generator that can demonstrate its capability of operating in a controlled manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by Duke) may reduce or eliminate the applicability of the integration services charge (Controlled Solar Generator). This capability could be demonstrated through inclusion of energy storage devices, agreeing to a dispatchable purchase contract, or other mechanisms that materially reduce or eliminate the intermittency of the output from the operating solar generator. Witness Wheeler clarified, however, that a solar QF seeking to eliminate the integration services charge must also contractually agree to operate its solar generating facility to meet operating requirements, as reasonably determined by Duke, that will actually reduce or eliminate the need for additional ancillary services. Witness Wheeler further testified that a QF committing to operate as a Controlled Solar Generator must enter into a negotiated PPA as QFs contracting to sell under Schedule PP are "must take" and may only be curtailed during system emergencies. Therefore, Schedule PP does not include the terms and conditions necessary for Duke and a solar generator to agree to operate as a Controlled Solar Generator. Tr. vol. 2, 229.

Witness Snider also testified that the SISC Stipulation's Controlled Solar Generator proposal reflects reasonable cost causation principles and allows an innovative solar QF not imposing incremental ancillary service requirements due to its operations to avoid paying the integration services charge. Witness Snider acknowledged NCSEA witness Beach's assertion that a solar generating facility that adds "significant storage" should be allowed to avoid the integration services charge and pointed out that the Controlled Solar Generator proposal provides an avenue to do that. Witness Snider, however, testified that even if a solar generating facility adds storage, it is critically important that the solar plus storage facility operate in a way that avoids incremental ancillary service requirements to avoid the integration services charge. Finally, witness Snider stated that without the operational control addressing how and when the solar generating facility is discharging output from its storage device, these facilities would likely just "shift" the time they discharge their batteries to premium pricing windows, which would not reduce the facilities' volatility nor avoid Duke's cost of providing additional ancillary services to address the solar generator's volatility. Tr. vol. 2, 147-58.

In its Initial Comments the Public Staff agrees that DEC and DEP face operational challenges due to the intermittent nature of solar resources and that intermittent and non-dispatchable resources have a direct impact on system operations, including cost. Public Staff Initial Comments at 34. The Public Staff also initially identifies certain concerns with the Astrapé Study's modeling approach, which were ultimately resolved as further described by Public Staff witness Thomas.

As Public Staff witness Thomas noted, in the 2016 Sub 148 Proceeding Public Staff witness Dustin Metz testified on the issue of integrating significant solar QF capacity, explaining that as installed solar QF capacity increases, Duke faces "increasing operational challenges as they seek to maintain the proper amount of contingency reserves that can be 'ramped up' and 'ramped down' in real time to meet resulting demand/supply imbalances." Tr. vol. 6, 357 (quoting 2016 Sub 148 Proceeding, tr. vol. 8, 117). Witness Thomas stated that integrating intermittent, non-dispatchable energy sources causes system operators to make decisions and deploy the fleet of utility-owned generation assets in ways that can increase costs to customers due to (1) thermal units operating outside their optimal output range, and (2) additional dispatchable units operating in standby mode, ready to respond within minutes to meet applicable NERC balancing requirements. Tr. vol. 6, 358.

Witness Thomas noted that the Public Staff identified technical concerns with the Astrapé Study in its Initial Comments, but that it later withdrew some of these concerns based upon additional discovery and ongoing technical discussions with Duke and Astrapé, and that it now supports Duke's integration services charge. Tr. vol. 6, 358-61. Further, witness Thomas stated that the Public Staff performed a review of seven integration studies from other utilities to compare methodologies and assess how the studies were conducted, including whether the utilities were modeled as load islands and what metrics were used to evaluate the system impact of intermittent resources. While every approach taken in the integration studies were different, the Public Staff's review indicates that Duke's proposed integration services charge is generally reasonable and within the other range of studies. In sum, witness Thomas testified that he believes that the methodology used to quantify the integration services charge is reasonable and that assessing this charge on solar QFs is appropriate. Tr. vol. 6, 361-67.

Witness Thomas testified that to address the Public Staff's concerns with Duke's proposal to update the charge biennially, Duke agreed to apply a cap on potential future increases of the integration services charge, as detailed in Section VI of the SISC Stipulation. Although as stated by Duke witness Wheeler, the inclusion of a cap might result in some level of subsidization of QFs, the Public Staff believes that it is important to ensure that the majority of costs imposed by intermittent solar QFs is recovered from intermittent solar QFs, and the cap provides a reasonable balance between reducing uncertainty for QFs and refunding ratepayers for the cost of integrating intermittent QFs. Tr. vol. 6, 368-72.

Regarding differing ancillary services costs for innovative QFs, witness Thomas testified that PURPA does not obligate the utility to purchase ancillary services from QFs. However, he agrees with NCSEA witness Johnson that QFs have the technical ability to provide ancillary services, and identified the Public Staff's interest in a potential future competitive solicitation for a limited quantity of ancillary services into which third-party generators could bid that has the potential to reduce costs to ratepayers and facilitate solar integration through cost-effective decisions. Witness Thomas also noted that there are several challenges to implementing a market for ancillary services in North Carolina, specifically that: (1) Duke is not a member of an RTO, and as such no organized competitive market for third-party services exists, (2) PURPA does not require utilities to purchase ancillary services from QFs, and because the responsibility for reliable grid operation falls on the utility, a market for such services would face significant regulatory challenges, and (3) the additional ancillary services needed, as identified by the Astrapé Study, is limited (192 MW); therefore, the costs to implement an ancillary services market might exceed the benefits. Witness Thomas stated that the Public Staff believes that innovative QFs installing technologies such as energy storage could reduce the need for ancillary services in a way that make imposition of the integration services charge on their facilities unnecessary. He stated that to the extent a QF can materially demonstrate that it does not impose additional ancillary service costs on the system, it should not be subject to the integration services charge. He concluded by explaining that Section II.A of the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the integration services charge by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary services requirements. Tr. vol. 6, 376-81.

SACE's Initial Comments include a report by witness Kirby critiquing the Astrapé Study relied upon by Duke to quantify the integration services charge. Witness Kirby generally asserted that the Astrapé Study relied upon an inappropriate study methodology and contained errors in assumptions that resulted in the Astrapé Study overestimating Duke's operating reserve requirements and inflating solar integration cost projections. His primary critiques were that (1) the $LOLE_{FLEX}$ reliability metric is not related to mandatory NERC reliability requirements and is inappropriate for an integration cost analysis, (2) the production cost modeling assumption that DEC and DEP are “islanded” systems disconnected from the Eastern Interconnection is wrong, and (3) the linear scaling of expected short-term variability from new solar generators as solar penetration rises is physically incorrect.

Witness Kirby criticized the Astrapé Study’s use of the $LOLE_{CAP}$ and $LOLE_{FLEX}$ metrics to identify instances of insufficient generation capacity or flexibility. He argued that the metrics were “misnamed” and “inappropriate” because there would be no loss of load expected during the identified imbalances for DEC or DEP Balancing Authorities (BA), which operate in the larger Eastern Interconnection. Interconnection, he stated, increases reliability while dramatically reducing individual BAs’ balancing requirements. Consequently, Witness Kirby concluded that NERC reliability standards do not require the level of reserves or balancing operations necessary to meet the 0.1 $LOLE_{FLEX}$ for five-minute balancing that is the basis of the Astrapé Study. Tr. vol. 5, 178.

The Astrapé Study was modeled to require the DEC and DEP systems to meet a 0.1 $LOLE_{FLEX}$ requirement that allowed for a single five-minute imbalance every ten years. Although witness Kirby acknowledged that an LOLE of 0.1 is an appropriate and accepted standard for long-term planning of reserve capacity, he believes it was not required by NERC, “excessively expensive” when applied to actual operations, and inappropriate because a five-minute imbalance will not result in the need to shed firm load or a blackout. Witness Kirby argued that Astrapé subjectively used the $LOLE_{FLEX}$ standard and that it is not a generally used industry metric. Instead, according to witness Kirby, NERC determines operational reliability standards, and it does not require continuous perfect balancing from each BA. Witness Kirby elaborated that the applicable NERC reliability standard, BAL-001-2, Real Power Balancing Control Performance, establishes two reliability metrics that apply during normal operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). Tr. vol. 5, 178-82.

With respect to those metrics, witness Kirby noted in his testimony and in his Report that of the NERC requirements to which the Astrapé Study referred, CPS1 and CPS2, the CPS2 standard had been replaced in July 2016 with the BAAL requirement BAL-001-02. He characterized CPS2 as having a much more relaxed balancing requirement than the 0.1 $LOLE_{FLEX}$ requirement because CPS2 measured balancing over ten-minute intervals and required compliance only 90% of the time. According to witness Kirby, short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the Eastern Interconnection. Therefore, CPS1 does not require correction of imbalances about half of the time, which significantly reduces the times Duke must exercise those reserves. In response to Duke’s Reply Comments that described the $LOLE_{FLEX,}$ he noted that NERC’s CPS1 does not require perfect balancing for all but one five-minute interval in ten years; it instead limits annual average imbalances. Witness Kirby further contended that all imbalances are not bad. When interconnection frequency is below 60 Hz, over-generation helps to raise frequency and aids reliability; conversely, when interconnection frequency is above 60 Hz, under-generation helps lower frequency and aids reliability. Witness Kirby also offered that the NERC BAAL standard does not require perfect compliance. BAAL only limits ACE deviations that exceed 30 consecutive minutes and hurt interconnection frequency. He stated that ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as the frequency deviates from 60 Hz. Therefore, witness Kirby concluded that the Astrapé Study used an unnecessarily stringent standard that resulted in an inflated integration services charge. Tr. vol. 5, 181-85.

Witness Kirby also disagreed with the Astrapé Study treating DEC and DEP as "islanded" power systems instead of modeling the interconnected BAs as part of the Eastern Interconnection. He argued that utilities interconnect because it gives all participants reliability and economic benefits. He doubted whether DEC or DEP would ever withdraw from the Eastern Interconnection because doing so would increase costs for ratepayers and reduce reliability. Therefore, he indicated that Astrapé should not have modeled DEC and DEP as islanded power systems. Witness Kirby instead argued that determining reserve requirements for islanded versions of DEC and DEP is not relevant to the way power systems are built and operated. In his opinion, the Astrapé Study failed to account for these reduced requirements and thus overstates the regulation requirements under which Duke operate. Tr. vol. 5, 185-89.

Witness Kirby also cited DEC's and DEP's participation in the VACAR Reserve Sharing Group, which he asserted enables them to significantly reduce the amount of contingency reserves they carry while still maintaining reliability. As members of a reserve sharing group, they can meet NERC standards and operate reliably with only a fraction of the contingency services required for islanded operations. Tr. vol. 5, 190-91.

Although witness Kirby acknowledged that the Astrapé Study had to model solar sites that do not yet exist and for which there is no data, he faulted the Astrapé Study's linear scaling of existing solar plant output data to represent new solar plants at higher penetrations. Witness Kirby testified that his review of the historic solar output of DEC and DEP showed an expected trend of short-term variability increasing more slowly than solar capacity as solar penetration increases. Thus, witness Kirby stated that the assumption of linear scaling is unjustified. He also faulted the Astrapé Study as using unrealistic geographic locations, leading to an increased short-term variability. Tr. vol. 5, 192-94.

Witness Kirby promoted the 2016 Idaho Power Integration Cost Study (Idaho Study) as a better model and methodological approach than the Astrapé Study because it employs production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels and targeted reserves sufficient to compensate for 99% of the differences between the hour ahead average and actual five-minute deviations of solar output. He emphasized that the Idaho Study allows a cumulative 90 hours per year of deviations rather than one-event-in-ten-years, like the Astrapé Study relied upon by Duke. Witness Kirby further testified that the $LOLE_{FLEX}$ metric used in the Astrapé Study requires balancing that is over 10,000 times stricter than the 99% confidence level used in the Idaho Study. Witness Kirby disagreed with Duke witness Wintermantel that the Idaho Study's incremental load following reserves are comparable to the load following reserves required by the Astrapé Study. Instead, stated witness Kirby, while

Idaho Power had higher rates of renewable penetration, DEC's and DEP's additional operating reserves far exceeded Idaho Power's as a function of renewable generation penetration. Tr. vol. 5, 200-05.

In its Initial Comments NCSEA states that the imposition of an integration services charge as proposed by Duke is inconsistent with previous Commission decisions in Sub 140 and Sub 148 because: (i) Duke did not include the benefits provided by QF generation in calculating the charge, and (ii) Duke developed a single standard offer rate schedule and separate "penalties" for intermittent QFs. NCSEA argues that the Commission had instead intended for the Utilities to propose multiple rate schedules based on the characteristics of the QF and not on the generation technology used by the QF. NCSEA Initial Comments at 32-35.

NCSEA also argues that Duke's request and DENC's similar request to implement a re-dispatch charge in this proceeding is improper as single-issue ratemaking. As such, NCSEA indicates that any integration services charge should be set during general rate cases. NCSEA agrees with Duke that 18 C.F.R. § 292.304(e) allows for the consideration of factors that may affect rates in determining avoided costs but notes that ancillary services are not listed among the factors and that charging intermittent QFs for ancillary services is not allowed. NCSEA Initial Comments at 47-49.

Moreover, NCSEA contends that the Astrapé Study is deficient in several ways. First, the Astrapé Study viewed DEC's and DEP's service territories as islands and not connected to neighboring grid systems. Citing to the Energy Imbalance Market (EIM) in the western United States, NCSEA argues that regional cooperation among utilities was a key factor in reducing integration costs and curtailment and had been successfully adopted in other parts of the United States. NCSEA Initial Comments at 36-42.

In his affidavit NCSEA witness Beach agrees with the concerns about the Astrapé Study expressed by SACE witness Kirby, and he also raises several other deficiencies. In addition to supporting the potential for increased solar penetration and integration cost savings through adoption of an EIM, witness Beach argued that the Astrapé Study appears to assume that future solar resources will be "must-take" with no flexibility in dispatching them and with no ability for the solar projects to provide ancillary services such as load following. Witness Beach indicates that utility-scale projects have demonstrated the capability to provide ancillary services, including upward regulation and load following. He also faults the Astrapé Study for not modeling the pairing of solar and storage projects. Witness Beach asserts that the use of storage will reduce substantially the variability of solar output and become a firm source capable of providing a variety of ancillary services. Beach Affidavit at 5.

Witness Beach additionally urges the Commission not to approve the integration services charge as proposed by Duke, arguing that the integration benefits of solar QFs outweigh the costs. He argues that Duke failed to analyze and quantify proposed avoided transmission and distribution capacity costs associated with integrating solar resources onto Duke's distribution systems. Witness Beach suggests that QF generation can reduce peak loads on the utilities' transmission and distribution systems, allowing the Companies to avoided capacity-related transmission and distribution costs. Witness Beach also asserts that an offsetting adder or increase in avoided costs is appropriate to recognize that the integration of zero-variable cost output of wind and solar resources into wholesale power markets can suppress market prices, thereby benefiting utilities and customers. He also argues that the integration services charge should not be applied in any case when a solar project includes significant storage. *Id.* at 6, 19-21.

In its Reply Comments Duke addresses NCSEA's arguments that an integration services charge, in general, is inconsistent with PURPA and prior Commission decisions. Duke explains that FERC's implementing regulations expressly acknowledge that standard avoided cost rates may differentiate among QFs using various technologies based on their supply characteristics. Additionally, prior Commission orders acknowledge growing operational challenges due to non-dispatchable and intermittent resources, and specifically directed the Utilities to consider dispatchability, reliability, and other factors in determining avoided costs. Therefore, Duke responds that the consideration of increased ancillary service costs due to increased penetration of solar QFs through establishment of an integration services charge applicable only to solar generators reasonably and appropriately adheres to FERC's regulations implementing PURPA and the Commission's prior avoided cost orders. Duke also points out that other state commissions have similarly established wind- and solar-only integration charges as separate charges from avoided energy rates. Duke also rebuts NCSEA's argument that establishing the integration services charge in this proceeding violates the prohibition on single-issue ratemaking, explaining that while Duke agrees that general rates charged by a utility should be set in a general rate case proceeding, this standard is irrelevant in this case where the rates to be established are rates paid by the utilities to QFs under PURPA. Duke argues that establishing the integration services charge is well within the Commission's authority under N.C.G.S. § 62-156(b)(2) as part of the State's implementation of PURPA. Duke Reply Comments at 80-86.

In response to parties' technical concerns regarding the Astrapé Study, Duke reiterates in its Reply Comments that the proposed integration services charge is a conservative first step in incorporating the appropriate integration price signal for intermittent solar resources on Duke's system. Specific to parties' concerns over the Astrapé Study modeling DEC and DEP as islands, Duke explains that the Public Staff's and witness Kirby's assumptions that Duke can rely upon external market assistance from other BAs, VACAR Reserve Sharing Group members, or transfers of non-firm energy under Duke's Joint Dispatch Agreement to meet regulation reserve requirements on a real-time, intra-hour basis is incorrect. In response to NCSEA's critique that the Astrapé Study is flawed because intra-hour interchange of power could potentially be achieved through "regional cooperation" in the form of an EIM, Duke states that DEC and DEP are not market participants in an EIM, and that no such market construct exists across the entire Eastern Interconnect. Duke also notes that the Idaho Study, identified by SACE as a reasonably acceptable integration study, similarly does not assume that regional cooperation exists to manage intra-hour volatility, despite Idaho Power participating in the Western EIM. Additionally, Duke ran a sensitivity analysis to assume an unrealistic best-case scenario of full intra-hour coordination and sharing of load following reserves between the DEC and DEP BAs, which resulted in only a modest 15% decrease in the ancillary service cost impacts due to the resource sharing benefit being included in both the base (No Solar) and change (with solar) cases with the Astrapé Study model. In explaining the Companies' actual system operations and presenting these additional sensitivity analyses, Duke supports analyzing DEC and DEP as islands for purposes of the model and illustrates that it would be unreasonable to assume that the Companies could rely upon one another or other BAs to provide the additional ancillary services required to respond to increased intermittent solar penetration in real-time. Duke Reply Comments at 86-94.

Regarding SACE's critique that the Astrapé Study used only one year of historic volatility data of the solar portfolio from October 2016 to September 2017 to quantify future volatility, Duke explains that the Astrapé Study attempted to address how to represent the aggregated volatility of the solar fleet as it increases in size on a forward-looking basis. Noting that SACE witness Kirby aptly characterized the Astrapé Study as "model[ing] solar sites that do not yet exist and for which there is no actual data," Duke states that the question for the modeler, then, is whether to assume available solar volatility data from operating solar facilities today is reasonably representative of the volatility that will occur at higher penetrations of solar projects to be installed in the future. Duke also highlights that the Public Staff's comments that "Astrapé self-identified the issues with solar volatility and fleet diversity within the report and made a fair conclusion," recognizes that future solar volatility is more uncertain at the significantly higher Plus 1,500 MW penetration level, and that it is difficult to project intra-hour solar volatility for these higher penetration levels without historical data. In other words, and as detailed in the Astrapé Study, it is a general principle of forward-looking modeling that the further out into the future that results are modeled, the more uncertain the results become; thus, Duke asserts that the Astrapé Study is not unreasonable in that its most forward-looking scenario analyzed is the most uncertain scenario produced in the Astrapé Study. Duke Reply Comments at 102-05.

In response to the Public Staff's concern regarding the Astrapé Study's use of historic vintage intra-hour volatility data for the period October 2016 to September 2017, Duke explains that the data used was the best and most current data available at the time. The Companies do not dispute, however, that use of more current solar volatility data can impact assumptions over time, especially as market conditions around the types of solar facilities being built in North Carolina evolve in the future. For this reason, Duke advocates updating the historic volatility data biennially in future avoided costs proceedings, just as it updates other aspects of its avoided costs to recognize changing resource mixes, load forecasts, and gas forecasts to ensure that the solar resource data is up to date and accurate. As discussed above, Duke and the Public Staff agreed in the SISC Stipulation to biennially review the integration services charge in future avoided costs proceedings and to cap increases in the integration services charge to mitigate this impact on QFs. Duke Reply Comments at 108-10.

As to the issue of applying the integration services charge on an incremental or average basis, Duke explains that applying the charge on an alternative "incremental" basis would unfairly burden new solar capacity with the full cost of ancillary services needed based on total solar capacity. Duke notes that no party challenged the average cost rate design or advocated that assigning the higher incremental ancillary services costs would be more appropriate. Concerning the Public Staff's comments on the integration service charge impacting market participants' costs in future CPRE RFPs, Duke contends that this is a risk faced by all business owners that can't control 100% of the factors impacting their business, and that it isn't unique to solar generators or CPRE participants. Solar generators do have an advantage over other business owners, however, as the rate cannot be adjusted without the full review and approval of the Commission. Duke's objective with introducing this rate is not to burden solar generation with new charges; instead, the integration services charge is intended to more accurately reflect the costs caused by the characteristics of solar generators on the system and to minimize potential future subsidization by ratepayers. Duke Reply Comments at 102-08.

As to SACE witness Kirby's comments stating that the Astrapé Study inappropriately models contingency reserve requirements, Duke states that his argument is flawed and that he incorrectly states that the SERVM model does not use contingency reserves where there is a loss of a generator or other reliability issues. Thus, Duke dismisses SACE's criticisms of the Astrapé Study, explaining that the criticisms were based upon an incorrect characterization of the $LOLE_{FLEX}$ metric used in the Astrapé Study. In support of the reasonableness of the Astrapé Study, Duke presents an analysis showing that the incremental operating reserves determined to be required by the Astrapé Study to integrate increasing penetrations of solar were reasonably comparable to the 2016 Idaho Study advocated for by SACE as a more appropriate and reasonable solar integration study to be utilized in North Carolina. Duke also notes that the Idaho Study suggests that the probability metric is "relatively immaterial" because the modeling objective of the Astrapé Study is to maintain the system at the same level of reliability both before and after solar is added to the system. In sum, Duke argues that the Public Staff's and other intervenors' technical concerns should be dismissed, and that the Astrapé Study reasonably and accurately calculated the solar integration costs applicable to QFs, resulting in a reasonable and appropriate solar integration charge of $1.10/MWh for DEC and $2.39/MWh for DEP. Duke Reply Comments at 93-110, 113-15.

In his rebuttal testimony Duke witness Snider emphasized that while SACE witness Kirby and NCSEA witness Beach continue to challenge certain technical aspects of the Astrapé Study, there is no dispute amongst the expert witnesses that the integration of uncontrolled, intermittent, and variable solar generators is causing Duke to incur increased ancillary services cost and that — absent an appropriate charge being established — such costs will continue to be recovered from customers. Tr. vol. 2, 136-37.

In response to NCSEA witness Beach's position that the Commission should recognize that future solar generators will be more controllable and that battery storage can reduce or eliminate integration costs, witness Snider testified that the Commission must not lose sight of the fact that any "benefit" to the grid is, in fact, limited to eliminating the intermittency and volatility caused by the solar QF generator's operations that are creating these incremental costs in the first place. To address the potential for solar generators to reduce or eliminate their increased ancillary services costs on the system, witness Snider stated that Duke and the Public Staff agreed in the SISC Stipulation to the Controlled Solar Generator option, which would allow innovative QFs to avoid these charges. Witness Snider also noted that future changes to the design and operational characteristics of the solar fleet actually installed in North Carolina can be addressed in future biennial reviews and updates to the integration services charge. Witness Snider also rejected Witness Beach's recommendation that the integration services charge should not be approved without recognizing purportedly offsetting "benefits" of integrating solar generation. Unlike the reduced line losses actually avoided by distribution-connected QFs, which Duke continues to recognize in quantifying avoided energy costs, the categories of costs identified by witness Beach are speculative and not real costs that will be avoided from QF purchases. Therefore, they do not offset the actually quantified increase in ancillary services costs caused by solar QF generators; accordingly, witness Beach's reasoning for opposing the integration services charge should be rejected. Tr. vol. 2, 139-41, 146-47.

Witness Snider further opposed NCSEA witness Beach's position that the Commission should consider an ancillary services market like the Western EIM to enable QFs to provide ancillary services. First, he stated that consideration of an EIM market is beyond the scope of this limited PURPA proceeding and is highly unlikely to occur before the next biennial avoided cost proceeding, when Duke propose to next review and update the integration services charge. In the interim, Duke will continue to incur increased ancillary services costs associated with integrating solar generators into the DEC and DEP systems; the integration services charge assures that the costs of these incremental ancillary services requirements are recovered from the solar generators who are the cost causers versus from retail customers. Witness Snider also questioned whether an ancillary services market enabling third party QF developers to make new investments to provide such ancillary services could provide the cost-savings benefit to customers advocated by NCSEA in light of the fact that the Duke-owned fleet has sufficient available capacity to meet the relatively limited additional ancillary services requirements (26 MW in DEC and 166 MW in DEP) identified as currently needed to manage the incremental volatility of QF solar resources. Establishing a new ancillary services market would not benefit customers as they would continue to pay for the Duke fleet as well as new resources procured through a market or competitive solicitation to provide the ancillary services. Witness Snider also highlighted that the Controlled Solar Generator provisions of the SISC Stipulation provides solar QFs pricing signals to evaluate the "market opportunity" to make incremental investments that could enable Duke to avoid incurring the increased ancillary services requirements caused by the uncontrolled volatility and intermittency of their operations. Tr. vol. 2, 142-45.

Witness Wintermantel highlighted in rebuttal testimony that collaboration between Duke, Astrapé, and the Public Staff had resolved each of the Public Staff's previous concerns, and that the Public Staff now supports the methodologies and assumptions underlying the Astrapé Study. He then responded to SACE witness Kirby's argument that the $\text{LOLE}_{\text{FLEX}}$ metric inappropriately requires the system to maintain enough ramping capability to match five-minute load ramps in all but one period every ten years, reiterating that SERVM models the DEC and DEP systems assuming perfect foresight for the next five-minute time step, meaning that net load is frozen and generators are allowed to catch up to load. Given this perfect foresight, the SERVM model should attempt to carry enough reserves to match the five-minute ramps in all but one period in ten years; however, in reality, operators never have perfect foresight, so many five-minute balancing deviations are expected to occur every year. If Astrapé had added reserves consistent with the largest five-minute unexpected solar deviation in ten years, more than 109 MW of load following reserves, and more than 354 MW of load following reserves, would have been required in the DEC and DEP Existing plus Transition cases, respectively, rather than the 26 MW and 166 MW identified by the SERVM model for DEC and DEP. Tr. vol. 4, 86-88.

Witness Wintermantel further stated that the SERVM model is not even capable of identifying the frequency of five-minute balancing deviations, and that the balancing requirements imposed by the NERC CPS1 and BAAL standards do not conflict with the 0.1 $LOLE_{FLEX}$ metric. Thus, the 0.1 $LOLE_{FLEX}$ metric is not designed as a measure of a system's compliance with NERC CPS1 and BAAL standards. However, the NERC balancing standards and $LOLE_{FLEX}$ metric should correlate, meaning that if $LOLE_{FLEX}$ is allowed to increase substantially, it is expected that the NERC CPS1 and BAAL standards would be violated more often. To further rebut witness Kirby's arguments, witness Wintermantel explained that Astrapé performed additional calculations at the request of the Public Staff that demonstrated that if the flexibility reliability were measured at 1.0 events per ten years — i.e. the metric was "relaxed" to be "less stringent" by being increased ten-fold — the average ancillary service costs would only decrease from \$1.10/MWh to \$1.03/MWh for DEC and \$2.39/MWh to \$2.35/MWh for DEP, illustrating the relative immateriality of the reliability level. Therefore, testified witness Wintermantel, witness Kirby's objection to the subjective nature of the $LOLE_{FLEX}$ metric was overstated, and even the Idaho Study supported by witness Kirby similarly recognized that the selected reliability level is "relatively immaterial" in terms of quantifying integration cost because both the base case and change case are subject to the same metric. Further, witness Wintermantel explained that Astrapé compared the results of the Idaho Study to the Astrapé Study, and that the results were reasonably similar. Lastly, concerning the Idaho Study, witness Wintermantel stated that witness Kirby's alternative comparison of operating reserves based on a function of solar penetration is an inappropriate comparison and therefore should be ignored because the studies employ two different modeling approaches. Tr. vol. 4, 88-97.

Witness Wintermantel further testified that witness Kirby also incorrectly compared the need for load following reserves to one-minute net volatility because load following reserves are intended to cover volatility over longer five-minute time steps. He stated that witness Kirby incorrectly concluded that modeling DEC and DEP as islands precludes the consideration of the benefits of interconnected systems, explaining that doing so would imply that neighboring BAs would bear the costs of Duke's integration of solar resources. He further stated that the SERVM model implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves. Moreover, solar integration studies in other jurisdictions also do not assume that more frequent and larger magnitude balancing deviations should be absorbed through interconnections. In response to witness Kirby's concerns that an automatic generation control (AGC) tuning effort undertaken by Duke's system operations staff conflicts with the assumptions made in the Astrapé Study, he explained that there is no conflict because the Astrapé Study does not penalize solar for one-minute movements because it is conducted on a five-minute basis with perfect foresight, citing witness Kirby's own statements explaining that it is infeasible to actually model NERC BAAL standards in real time. Lastly, witness Wintermantel testified that witness Kirby's formula related to intra-hour volatility lacks empirical evidence, and contended that given the uncertainty in an actual diversity benefit of solar resources, it is more appropriate to rely upon actual historical data to set ancillary services cost rates at the time of the study and to perform updates of the study every two years so that the data used is the most accurate. Tr. vol. 4, 97-103.

Witness Wintermantel further disagreed with NCSEA witness Beach's statements that "there is no evidence that the high penetration of wind and solar resources that the CAISO system has integrated in recent years has increased ancillary service cost," citing to CAISO's 2016 Annual Market Performance Report stating that ancillary service costs had nearly doubled from 2015. Witness Wintermantel additionally rebutted NCSEA witness Johnson's claims that Astrapé by modeling one site per grid zone potentially misses diversity across the fleet, explaining that the number of sites modeled would not have a significant impact because Astrapé was concerned with the intra-hour diversity that would not be captured in the hourly solar profiles developed with NREL data. In conclusion, witness Wintermantel disagreed with Witness Johnson's arguments that Astrapé inappropriately failed to consider possible configurations which might alleviate some volatility, explaining that solar developers were not massaging their configurations to favorably affect the integration costs of solar at this time. Tr. vol. 4, 103-07.

Duke witness Wheeler testified in opposition to arguments by SACE witness Kirby and NCSEA witness Beach that the cap on the integration services charge agreed to in the SISC Stipulation should be set at the average projected integration cost versus the higher incremental level of costs, as agreed to by the Duke and the Public Staff. Witness Wheeler explained that it is important to first recognize that Duke and the Public Staff are not recommending that the monthly integration services charge rate be set at the higher "incremental" or marginal cost level because the cost is caused by all uncontrolled intermittent generators and will eventually be paid by all intermittent generators as the rate is phased-in with newly executed PPAs. However, the potential cost risk to customers during the biennial period as new intermittent generation is added up to the point in time when Duke's ancillary services costs are again reviewed in the next biennial proceeding is equivalent to the marginal or "incremental" ancillary services cost associated with this added generation. He argued therefore that the integration services charge rate design fairly balances generator and ratepayer interests by collecting an average cost rate, while recognizing the actual cost impact of the new intermittent generator on system costs by using a marginal cost rate cap. Tr. vol. 2, 240-41.

Witnesses for the intervenors also challenged the Astrapé Study on the basis that the study was not peer reviewed by a third party. In response, Duke witness Snider asserted that the Astrapé study was made available to the Public Staff and intervenors in

November 2018, providing 8 months' opportunity to review, and that the Public Staff ultimately found the study results to be reasonable. Witness Snider also claimed that based on his ten years of testimonial experience, the Astrapé Study received "more attention than any other study" he could remember in recent history. Further, witness Snider noted that engaging third parties such as the intervenors in this proceeding in a peer review process would not be independent as these parties would have a specific objective to minimize or eliminate the integration services charge. Duke witness Wintermantel also testified that the technical studies that his consulting firm conducts for utilities and state public utility commissions typically are not circulated to additional academic firms for validation. Finally, Public Staff witness Thomas testified that to the extent the Commission is inclined to require a technical review group similar in structure to the one utilized in the Idaho Study, its emphasis should be on including technical experts and academics, and it would not be appropriate to include renewable energy developers or their advocates in the process. He concluded, however, that after a "thorough review of the Astrapé study and its results," the Public Staff found that the charge was reasonably calculated and that it was appropriate to assess that charge at this time. Tr. vol. 3, 11-14; tr. vol. 4, 204-05; tr. vol. 6, 433; tr. vol. 7, 105.

In response to questions from NCSEA, Duke witness Wheeler testified that Duke's intent was for the integration services charge to apply to Tranche 2 of the CPRE Program; however, the Duke witnesses were unaware of whether the integration services charge would be applied to solar generators contracting to deliver power under the Green Source Advantage Program. Public Staff witness Thomas stated that the charge would be considered for an uncontrolled solar generator participating in the CPRE and GSA programs, but noted that there were complexities in implementing the integration services charge under the CPRE program and that the charge had not been previously discussed in the GSA proceeding. Tr. vol. 2, 290-91; tr. vol. 7, 131-35; *see also* tr. vol. 2, 350-51.

Discussion and Conclusions

PURPA directs the FERC to adopt rules that require electric utilities to offer to purchase electric energy from QFs at rates that (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against QFs. Further, the statute provides that no such rule adopted by the FERC shall provide for a rate which exceeds the incremental cost to the electric utility of alternative energy. 16 U.S.C. § 824a-3(b). "Incremental cost of alternative energy" means the cost to the electric utility of the electric energy, which, but for the purchase from the QF, such utility would generate or purchase from another source. 16 U.S.C. § 824a-3(d).

The FERC adopted 18 C.F.R. § 292.101, *et. seq.*, to implement these directives, and nothing in these rules requires any electric utility to pay a QF more than the utility's avoided costs, or "the incremental costs to an electric utility of the electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(6).

Additionally, pursuant to N.C.G.S. § 62-156 the Commission is directed to determine standard avoided cost rates for each electric public utility according to standards set forth in N.C.G.S. § 62-156(b) with respect to rates paid for energy and for capacity purchased from small power producers. With respect to the rates that a utility pays for energy, N.C.G.S. § 62-156(b)(2) provides that such rates "shall not exceed . . . the incremental cost to the electric public utility which, but for the purchase from a small power producer, the utility would generate or purchase from another source." With respect to the rates that a utility pays for capacity, N.C.G.S. § 62-156(b)(3) provides that such rates "shall be established with consideration of the reliability and availability of the power."

In the Sub 140 Phase One Order the Commission stated:

> The Commission agrees that 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 calculations. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, may require the consideration of additional factors, such as the potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support. The Commission is aware that several studies regarding, and methods to calculate these costs and benefits, are currently under development. . . . In light of these developments and the potential for significant amounts of solar generation to be constructed in North Carolina in the next few years, the Commission determines that It is premature for DEC, DEP and DENC to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

Sub 140 Phase One Order at 60.

In that proceeding Duke presented a study conducted by Pacific Northwest National Laboratory (PNNL Study) that analyzed the operational impacts to the DEC and DEP systems as installed solar generation continued to increase. Duke proposed that "integration costs" associated with the increased reserve requirements identified in the PNNL Study that result from the increase in net load variability due to solar penetration should be taken into account in calculating Duke's avoided energy cost rates. Sub 140 Phase One Order at 57. The Commission determined that no comprehensive evaluation of solar integration costs in North Carolina had yet been undertaken and concluded that it was premature to apply any selected findings that could be derived from the PNNL Study:

> The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DENC 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. Accordingly, the Commission concludes that it is premature for DEC, DEP and DENC to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

Sub 140 Phase One Order at 61. The Commission found, however, that it would be "appropriate for the costs and benefits attributed to solar integration as such integration becomes more pervasive to be more fully evaluated in detailed integration studies." *Id.* at 8.

In the 2016 Sub 148 Proceeding the Commission determined that the pace and level of QF development continuing unabated posed serious risks of overpayment by utility ratepayers and raised concerns as to the operational soundness of the Utilities' electric systems. 2016 Sub 148 Order at 15. The Commission also recognized that North Carolina was at a "critical crossroads regarding the integration, development, and customer costs of renewable generation, and specifically with regard to QFs powered by solar energy," noting that installed solar QFs on the combined Duke systems had rapidly increased from 125 MW in 2012 to 1,600 MW in 2016. *Id.* at 15-16. Recognizing the economic and regulatory circumstances facing QFs, Utilities, and ratepayers in 2016, the Commission approved a number of modifications to North Carolina's avoided cost framework. The 2016 Sub 148 Order directed the Utilities in this 2018 proceeding 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. 2016 Sub 148 Order at 98. In the 2018 Scheduling Order, the Commission again directed the Utilities to consider factors relevant to the characteristics of QF-supplied power — specifically intermittent and non-dispatchable power — in designing rates to meet PURPA's objectives of appropriately valuing Duke's incremental costs of alternative energy to be avoided from purchasing QF power.

Duke proposes the integration services charge in response to these directives in an effort to recognize integration costs that Duke is incurring and to appropriately value the energy and capacity provided by QFs eligible for Schedule PP. The integration services charge reflects the impact on operating reserves, or generation ancillary requirements, as increasing levels of variable and non-dispatchable solar capacity continue to be installed on the DEC and DEP systems. Duke notes that installed utility-scale QF solar capacity in DEC and DEP has continued to increase from 1,600 MW in 2016 to over 2,300 MW as of September 30, 2018, including almost 1,800 MW of uncontrolled PURPA solar installed in DEP alone. JIS at 6.

As a threshold matter the Commission addresses NCCEBA and NCSEA's arguments that the proposed integration services charge is inconsistent with state and federal law. First, NCCEBA and NCSEA argue that the proposed charge is unlawful "single-issue ratemaking." In their view, avoided cost rates are within the term "rates" defined pursuant to N.C.G.S. § 62-3(24), and the Commission can only revise rates of a public utility in four contexts: (1) a general rate case held pursuant to N.C.G.S. § 62-133; (2) a proceeding pursuant to a specific, limited statute, such as N.C.G.S. § 62-133.2; (3) a complaint proceeding pursuant to N.C.G.S. § 62-136(a); or (4) a rulemaking proceeding.

Because this biennial avoided cost proceeding is none of those proceedings, NCCEBA and NCSEA conclude that the Commission lacks authority to approve the proposed integration services charge. Further, they argue that "nothing in the statutory avoided cost mechanism contemplates" the proposed integration services charge or a decrement to avoided cost rates. Specifically, NCCEBA and NCSEA argue that N.C.G.S. § 62-156(b)(2) does not authorize a charge that captures a utility's costs that are caused by, rather than avoided by, the purchase of electric power from QFs. Duke and the Public Staff urge the Commission to reject this view.

After careful review of the plain text of the relevant statutes the Commission concludes that the term "rates" as defined in N.C.G.S. § 62-3(24) does not include the avoided cost rates established in the Commission's biennial proceedings held pursuant to N.C.G.S. § 62-156. As Duke argues, "rates" as defined in Chapter 62 applies to "every compensation, charge, [etc.] . . . *demanded, observed, charged or collected by* any public utility" for public utility service, N.C.G.S. § 62-3(24) (emphasis added), not to the avoided cost rates paid by electric public utilities. The provisions of N.C.G.S. § 62-156 support this conclusion by its use of the word "rates" with modifiers such as "rates…established as provided in subsection (b) or (c)," "the standard contract avoided cost rates," "rates paid by an electric public utility," and "rates to be paid by electric public utilities." It is a well-established principle of statutory construction that a section of statute dealing with a specific situation controls with respect to that situation, as against other sections of statute which are general in their application. *LexisNexis Risk Data Mgmt. v. N.C. Admin. Office of the Courts*, 368 N.C. 180, 187, 775 S.E.2d 651, 656 (2015) (citing *In re Testamentary Tr. of Charnock*, 358 N.C. 523, 529, 597 S.E.2d 706, 710 (2004) and *State ex rel. Utils. Comm'n. v. Lumbee River Elec. Membership Corp.*, 275 N.C. 250, 260, 166 S.E.2d 663, 670 (1969)). Therefore, the Commission concludes that the more specific statute, N.C.G.S. § 62-156, applies to the establishment of the avoided cost rates paid by electric public utilities in this and similar biennial proceedings, and not the sections of the Public Utilities Act that apply generally to the establishment or adjustment of rates any public utility may charge for public utility service. Accordingly, the Commission further concludes that the doctrine of "single-issue rate making" does not apply in this or similar proceedings, and the Commission will continue to establish avoided cost rates consistent with the provisions of N.C.G.S. § 62-156 and the FERC regulations implementing PURPA.

NCCEBA and NCSEA also argue that the integration services charge cannot be approved as proposed because the charge would be updated for a QF every two years during its contract as a result of the Commission's determination of the appropriate calculation in a biennial avoided cost proceeding. In support of their argument NCCEBA and NCSEA cite the 2016 Sub 148 Order, where the Commission determined that Duke's proposed two-year reset in the avoided energy component of the standard offer rate should not be adopted. The Commission finds the following discussion from that Order to be illuminating on the issue here:

> The Commission notes that a QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's *J.D. Wind* Orders. FERC's intention in Order No. 69 was to enable a QF to establish a fixed

> contract price for its energy and capacity at the outset of its obligation. . . . Further, in *Windham*, FERC reiterated Order No. 69 requires certainty with regard to return on investment and, thus, a legally enforceable obligation must be long enough to allow QFs reasonable opportunities to attract capital from potential investors. Subsequent FERC actions or inactions in allowing states to approve short-term fixed rates in standard offer PURPA PPAs must also be acknowledged in resolving the issues in this case.

2016 Sub 148 Order at 68-69 (citations omitted).

The Commission agrees with NCCEBA and NCSEA and affirms its view of the FERC's *J.D. Wind* Orders, Order No. 69, and *Windham*, as articulated in the 2016 Sub 148 Order for the purposes of this proceeding. Like the biennial adjustment in avoided energy rates that was at issue in the 2016 Sub 148 Proceeding, the proposed integration services charge that adjusts every two years "adds an additional element of uncertainty" to QFs' "ability to reasonably forecast their anticipated revenue, which may make obtaining financing more difficult than a longer term, fixed-rate PPA." 2016 Sub 148 Order at 68-69. Duke and the Public Staff base their support for the adjustment in the integration services charge on the goal of most accurately reflecting the ancillary services costs that Duke is incurring and ensuring that its customers are not unfairly subsidizing QFs. While a laudable goal, the Commission concludes that this is a goal that must yield to the PURPA mandate to provide QFs a reasonable opportunity to obtain financing, as that requirement is understood and has been applied by the Commission. Therefore, the Commission declines to adopt the proposed adjustment in the integration services charge and will require Duke to implement a fixed integration charge for the duration of the QF's contract and to provide sufficient data for Commission review of a similar charge for evaluation in future biennial avoided cost proceedings.

NCCEBA and NCSEA next argue that the proposed integration services charge cannot be approved as a "stand-alone charge" because a "third component of avoided cost" is inconsistent with FERC's regulations that require only the purchase of energy and capacity. The implication, in NCCEBA and NCSEA's view, is that any integration services charge deducted from the avoided cost rate would have to be calculated as part of either the avoided energy or avoided capacity rate. The Commission agrees with NCCEBA and NCSEA that the integration services charge proposed as a separate line item charge calls into question compliance with FERC's regulations requiring utilities to purchase energy and capacity from QFs.[4] Therefore, the Commission concludes that the reasonably

[4] The Commission is not prepared to categorically agree that FERC's regulations prohibit the approval of any rate or charge other than those offered for energy and capacity. For example, the Commission has historically approved an "administrative charge" and a "monthly seller charge" in DEC's and DEP's respective standard offer schedule tariffs. No party has argued that this charge is unlawful as inconsistent with FERC's regulations, and the Commission does not so conclude here. In addition, if NCCEBA and NCSEA's prediction comes to pass that including the integration services charge as a decrement to the avoided energy rate is fraught with administrative and procedural hurdles, the Commission may consider revisiting this issue in the future.

known and quantifiable costs of integrating intermittent solar generation should not be approved as a separate line item charge for the purposes of this proceeding.

In their final legal objection NCCEBA and NCSEA argue that the integration services charge cannot be approved as a decrement to Duke's avoided energy rate because the charge is not a "rate" as defined in 18 C.F.R. § 292.101(b)(5), does not involve the sale or purchase of energy or capacity, and is not encompassed in the factors to be considered as affecting avoided cost rates pursuant to 18 C.F.R. § 292.304(e). Duke and the Public Staff argue that the Commission should take a broader view of these regulations. For the following reasons the Commission agrees with Duke and the Public Staff. First, the Commission agrees that the FERC's definition of "rate" applies to "*any* price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or *any* rule, regulation, or practice respecting any such rate, charge, or classification, and *any* contract pertaining to the sale or purchase of electric energy or capacity." 18 C.F.R. § 292.101(b)(5) (emphasis added). Significantly, this definition is not limited to prices, rates, or charges paid by an electric public utility nor is it limited to prices, rates, or charges received by an electric public utility. Conversely, "rate" is not limited to prices, rates, or charges received by a QF, nor to prices, rates, or charges paid by a QF. Instead, the Commission concludes that "rates" as defined in 18 C.F.R. § 292.101(b)(5) broadly encompasses all economic transactions between QFs and an electric public utility within the implementation of PURPA and the rules, regulations, practices, and contracts involved in such a transaction. Properly established, these rates must, as reasonably accurately as possible, approximate economic indifference between a utility's purchase of energy and capacity from a QF and supplying the equivalent energy and capacity from another source, including self-generation. 2016 Sub 148 Order at 17.

Similarly, the Commission concludes that NCCEBA and NCSEA's view of the factors affecting rates for purchase is too narrow. As provided in 18 C.F.R. § 292.304(e):

> In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:
>
> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
>
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

The provisions of this regulation not only allow but require the Commission to consider both the costs that the utility avoids by purchasing from a QF and the costs that the utility may incur, not otherwise accounted for, as a result of purchases from a QF. Consistent with 18 C.F.R. § 292.304(e), evidence of costs that a utility may incur because of purchases from a QF may be presented for review by the Commission (1) as part of the data provided pursuant to 18 C.F.R. § 292.302(b), (c), or (d); (2) in accounting for the factors listed in 18 C.F.R. § 292.304(e)(2); or (3) in taking into account the relationship of the availability of energy or capacity from QFs as derived in 18 C.F.R. § 292.304(e)(2) to the ability of the electric utility to avoid costs. This conclusion is consistent with the Commission's determination in the 2014 Sub 140 Order that it may be appropriate for the Utilities to include the costs and benefits related to solar integration in their avoided cost calculations 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. The Commission affirms that conclusion here. Therefore, the Commission proceeds to weigh the record evidence related to the reasonableness of the accuracy of the quantification of the integration services charge and its development as a component of Duke's avoided energy rates.

After careful consideration of such evidence and that no party otherwise contested or disputed such evidence, the Commission determines that DEC and DEP are incurring increased intra-hour ancillary services costs to integrate the "Existing plus Transition" level of solar QFs into the DEC and DEP systems. Therefore, for reasons discussed above it is appropriate to require DEC and DEP to account for these costs when calculating the costs and benefits resulting from the purchase of energy and capacity from solar QFs.

In determining whether the quantification of Duke's ancillary services costs is reasonable, the Commission finds the testimony of Duke witness Wintermantel, including the Astrapé Study he sponsored as an exhibit, to be quite persuasive. The independent review conducted by the Public Staff, as described by witness Thomas, lends further credibility to Duke's evidence. Further, the agreements reached in the SISC Stipulation reflect the give-and-take in negotiations, and the Commission finds the testimony in support thereof to be quite persuasive. Finally, while NCSEA witness Beach and SACE witness Kirby have advanced reasonable and well-articulated criticisms of this evidence, the Commission determines that Duke and the Public Staff have adequately addressed these criticisms sufficient to rebut these arguments. In summary, the Commission gives weight to the testimony of witnesses Wintermantel and Thomas, and based upon a review of the foregoing evidence and the entire record herein finds that the results of the Astrapé Study that an additional 26 MW of load following reserves are required to integrate 840 MW of solar in DEC at an average cost of $1.10/MWh, and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar in DEP at an average cost of $2.39/MWh are reasonable for use in this proceeding. The Commission further finds that it is appropriate for Duke to prospectively apply the integration services charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems on or after November 1, 2018, and to any pre-existing solar QF not subject to the integration services charge committing to sell to Duke under a new PPA in the future.

As stated above, however, the proposed adjustment in the integration services charge cannot be approved as it is inconsistent with FERC's regulations implementing PURPA. Although the Commission agrees with NCCEBA and NCSEA on the legal result, the Commission does not agree that the provisions of the SISC Stipulation, which the Commission otherwise has determined are lawful and supported by evidence of record, should be discarded. The evidence in this proceeding demonstrates that the increased ancillary services costs are sufficiently known and quantifiable to be impacting the value of QF-supplied energy and capacity, and the Commission has concluded here and in past avoided cost proceedings that such costs must be reflected in the avoided energy or avoided capacity rates established in this and similar proceedings. Therefore, based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to apply the integration services charge as a fixed amount of $1.10/MWh for DEC and $2.39/MWh for DEP during the term of the contracts for those QFs that establish a LEO during the availability of the rates established in this proceeding, and this cost or charge should be included in each utility's avoided energy costs.

The Commission next determines that the agreement reached in the SISC Stipulation allowing "controlled solar generators" the opportunity to avoid the integration services charge through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators should be approved. The Commission agrees with the Public Staff and NCSEA's in its Initial Comments that where certain QFs have the technical capability to reduce the additional ancillary services caused by the operation of uncontrolled solar QFs, such QFs should be able to avoid the integration services charge. Inclusion of this provision enables such innovative solar QFs to appropriately avoid the charge, reflects the give-and-take in negotiations between the Public Staff and Duke, and sufficiently responds to intervenors' recommendations.

Further, as Duke witness Snider testified, allowing such opportunity also reflects reasonable cost causation principles; to otherwise require a QF to pay for increased ancillary services that it is not causing would be unfair and create a disincentive for QFs to seek to avoid the charge. The Commission also agrees that having the ability to avoid the integration services charge may incentivize the deployment by QFs of battery storage and other technologies that can benefit Duke's system operators and customers through more coordinated dispatch and operational control of intermittent QFs, which, in turn, benefits customers by increasing system reliability and reducing costs. The Commission also finds persuasive that this may offer QFs the opportunity to adjust their production hours to maximize their financial benefit, which, in a time of declining natural gas prices, helps to further ensure the financial viability of North Carolina's renewable energy industry.

The record reflects that the Public Staff invested significant time in investigating the Astrapé Study through discovery, technical discussions with Duke and Astrapé personnel, and requests for further post-Study analyses and validation, as well as through a comparison of the Astrapé Study to other recent integration studies across the country. Tr. vol. 6, 409. The Commission appreciates the Public Staff's thorough investigation in this regard and finds highly persuasive Public Staff witness Thomas' testimony that the Public Staff's undertook review of seven integration studies from other utilities to compare methodologies and assess how the studies were conducted, including issues such as whether the utilities were modeled as load islands and what metrics were used to evaluate the system impact of intermittent resources. This testimony indicates that Duke's proposed integration services charge is generally reasonable and within the range of other studies.

Therefore, the Commission finds that it is not appropriate for DEC or DEP to impose the integration services charge on QFs that qualify as "controlled solar generators" by demonstrating that their facility is capable of operating, and by contractually agreeing to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility. In making this finding, the Commission has again placed weight on the evidence presented by Duke and the Public Staff. The Commission agrees with Duke and the Public Staff that it is appropriate to allow "controlled solar generators" the opportunity to avoid the integration services charge. The Commission also agrees with NCCEBA and NCSEA that such a provision should be submitted for Commission review and approval, and therefore finds that is appropriate to require DEC and DEP to file with the Commission proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the integration services charge.[5]

The Commission also finds merit in the Public Staff's recommendation that Duke should be required to continue 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 those existing technologies

[5] Subsequent to issuance of the Supplemental Notice of Decision, as required by Ordering Paragraph No. 4 of that order, on November 18, 2019, Duke filed for approval its Requirements for Avoidance of SISC. The Commission will issue an order shortly in this docket allowing parties to comment on Duke's proposal.

such as small hydroelectric QFs that may have dispatch capability. Therefore, the Commission will direct Duke to provide the Commission, in its initial filing made in the 2020 biennial avoided cost proceeding, with an evaluation of whether a QF that can sufficiently demonstrate and contractually obligates 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.

In conclusion, the Commission approves of certain provisions of the SISC Stipulation and Duke's integration services charge to be applicable to all non-controlled solar generators that either have committed to sell or prospectively commit to sell to Duke under Schedule PP or negotiated avoided cost rates on or after November 1, 2018, until the date that Duke next files avoided cost rates for Commission review in the next biennial avoided cost proceeding. Consistent with the agreement reached between Duke and the Public Staff in the SISC Stipulation, the Commission will review and update Duke's average and incremental ancillary services costs in the next biennial avoided cost proceeding to accurately reflect changes to DEC's and DEP's ancillary services costs as incremental solar is installed on the DEC and DEP systems; however, for reasons discussed herein, the charge will be fixed for the duration of the contract, as appropriate, for QFs establishing a LEO during the availability of the avoided cost rates established in each biennial proceeding. The Commission further finds that it is appropriate to require DEC and DEP to calculate avoided energy rates that do not include an integration services charge and to include these rates that would be available to "controlled solar generators" as a part of the tariffs and standard contracts in this proceeding.

Finally, the Astrapé Study methodology used to quantify DEC and DEP's increased ancillary services costs and to calculate each utility's integration services charge presents novel and complex issues that warrant further consideration. Therefore, the Commission agrees with NCCEBA, NCSEA, and SACE that the Commission would benefit from the results of an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings where similar issues will be reviewed. Therefore, the Commission directs Duke to assemble a technical review committee to provide a review of the Astrapé Study. The technical review committee shall be comprised of individuals, not otherwise affiliated with Duke or any of its affiliates or organizations in which Duke is a member, who have technical expertise, knowledge, and experience related to the integration of solar generation as well as the development of complex research, development, and modeling. The committee should include personnel employed by the National Laboratories with relevant experience and expertise. The purpose of the work with a technical review committee is to provide an in-depth review of the study methodology and the model used for system simulations. The technical review committee should provide specific comments or feedback to Duke in the form of a report, which report is to be included in the initial filing made in Duke's 2020 biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 43 AND 44

The evidence supporting these findings of fact is found in DENC's verified Initial Statement and in the testimony of DENC witness Petrie, Public Staff witness Thomas, and NCSEA witness Johnson.

Summary of the Evidence

In the 2016 Sub 148 Order the Commission determined that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities," and required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in this proceeding. 2016 Sub 148 Order at 56. The Commission directed the Utilities to 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 Utilities 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 in its Initial Statement proposes changes to the rate schedules for both energy and capacity that offer additional granularity and improved price signals to QFs to better match DENC's generation needs. DENC proposes a revised rate structure that includes seasonal capacity rates and non-seasonal on- and off-peak energy rates. DENC Initial Statement at 29.

With regard to capacity rates, DENC bases its proposed capacity peak hours on the hours when system peak loads historically have occurred, and when system emergencies are most likely to occur. DENC proposes 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. *Id*. at 30-31.

Consistent with its comments regarding Duke's proposed rate design changes, the Public Staff in its Initial Comments states 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 believes that energy rate mismatches are 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 proposes its own seasonal energy rates and hours.

Regarding DENC's proposed seasonal allocation of capacity payment costs and its selection of Capacity Peak Hours, the Public Staff finds them to be reasonable, but states 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 recommends 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.

NCSEA states that the Utilities do not adequately recognize how costs vary across different times of day. NCSEA proposes that instead of the Utilities' proposals, the Commission should adopt its proposed time-of-day periods, as well as an optional, real-time pricing tariff for QFs. NCSEA Initial Comments at 28.

In its Reply Comments, DENC responds 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 a QF may choose to sell its power under the Schedule 19-LMP tariff that is locational in nature and has hourly granularity in its market-based prices. DENC Reply Comments at 25.

DENC further states 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 offer. It also states that in subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in DENC's summer peak season. In addition, DENC notes that in those discussions 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 indicates that it is willing to accept the Public Staff's proposal, as modified, in the interest of achieving consensus on this issue. DENC notes 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. With regard to capacity, DENC states it is willing to use a 45/40/15 seasonal allocation of CT costs, which would continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder season for capacity. *Id.* at 37.

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 need 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 real-time pricing rates consistent with NCSEA's proposal at least six months before the next biennial proceeding. Tr. vol. 6, 231-36.

Public Staff witness Thomas testified that the Public Staff agrees with DENC's proposed rate design modifications. He further noted that while the rate design proposals for DENC and Duke agreed to by the Public Staff were nearly identical, the Public Staff supports continued consideration of the unique characteristics for each utility in rate design. At the hearing, witness Thomas confirmed that the Public Staff agrees in principal with the energy and capacity rate design presented in DENC witness Petrie's rebuttal testimony. Tr. vol. 6, 394; tr. vol. 7, 100.

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," and 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, 47-48.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, 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 by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission therefore will require DENC to 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 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 calculated either at the time of delivery or 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 its Schedule 19-LMP as an alternative to avoided cost rates derived using the Peaker Methodology, with rates 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 further finds that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in weighting capacity value between seasons, as these weightings continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder for capacity, and should be used in calculating DENC's avoided capacity rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 45

The evidence supporting this finding of fact is found DENC's verified Initial Statement and in the affidavit of NCSEA witness Beach.

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC states that it used the PROMOD production cost model to derive avoided energy costs for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in DENC's North Carolina service area where QFs are located, plus a fuel hedging benefit and a re-dispatch charge. DENC Initial Statement at 7. DENC states that it used the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates under Schedule 19-FP. *Id.* at 8.

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the 2016 Sub 148 Proceeding. *Id.* at 8-9.

DENC explains that consistent with the Commission's conclusions in the 2016 Sub 148 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs, and states that it included the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy rates. *Id.* at 9-11.

DENC also notes that in the Sub 140 Phase One Order the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC explains that in the Sub 140 Phase Two Order the Commission required the Utilities to utilize the Black-Scholes Model, or a similar model, to determine the fuel price hedging value of renewable generation. Consistent with its proposal in the 2016 Sub 148 Proceeding, DENC proposes to continue to use the same Black-Scholes Option Pricing Model to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 Sub 140 Proceeding, with a resulting fuel price hedging value of $0.30/MWh, which was assumed constant for all years of the Schedule 19-FP contract. *Id.* at 11.

In its Initial Comments the Public Staff confirms that DENC used the same method for calculating its avoided energy costs for Schedule 19-FP as it did in the 2016 Sub 148 Proceeding, and states that it reviewed DENC's PROMOD inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs in this proceeding. Public Staff Initial

Comments at 19. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices, and states that DENC's calculation of the fuel hedge value is reasonable. *Id.* at 28.

In its Initial Comments NCSEA states that QFs displace natural gas-fired generation, decrease exposure to volatility in natural gas prices, and provide a long-term physical hedge for the term of the PPA. NCSEA contends that renewable generation provides a hedge not otherwise available in financial markets. NCSEA asserts that the Black-Scholes Model assumes displaced gas is re-priced at the prevailing market price five or ten times over a ten-year period, which does not provide as effective a hedge as the hedge actually provided by a 10-year PPA. NCSEA cites studies performed in 2013 for Xcel Energy's Public Service of Colorado, which arrived at a $6.60/MWh hedge benefit of distributed solar (Xcel Study) and to the 2015 Maine Public Utilities Commission's Distributed Solar Valuation Study (Maine Study). NCSEA uses the Maine Study's method to calculate a ten-year hedging benefit of renewable PPAs in North Carolina using NCSEA's proposed gas forecast, current U.S. Treasury yields as the risk-free investments, the Utilities' weighted average costs of capital, and a marginal heat rate of 7,250 Btu/kWh. With this method, NCSEA calculates an avoided fuel hedging cost of about $0.007/kWh. NCSEA Initial Comments at 21-23. In his affidavit, NCSEA witness Beach reiterates that renewable QF generation provides a long-term physical hedge to natural gas prices, and he argues that the natural gas hedging costs used in the avoided cost rates in the past are too low because they only represent the cost to fix gas prices for one or two years rather than the ten-year hedge provided by renewable QF PPAs. Witness Beach also supports the Maine Study's method to calculate hedging costs. Beach Affidavit at 4.

NCSEA asserts that a balanced fundamentals forecast should be based on (1) the ICF forecast utilized by DENC, and (2) the new 2019 forecast from EIA. In the alternative, NCSEA states that it "would not object to the use of DENC's similar forecast methodology" of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities. NCSEA Initial Comments at 19. In his affidavit, witness Beach expresses support for a forecasting approach similar to that of DENC, using forward market prices as the forecast for no more than the first two years and then transitioning to the average of a set of fundamental forecasts by year five and using fundamentals forecasts from several sources to avoid over-reliance on one approach. Beach Affidavit at 3-4.

In its Reply Comments SACE does not specifically critique DENC's calculated hedge value and acknowledges that the Black-Scholes Model is an industry-accepted methodology for calculating fuel hedging costs, but advocates that Utilities use a methodology such as that used in the Maine Study to the extent they are able. SACE Reply Comments at 4-5.

No party objected to DENC's continued application of the LMP adjustment to its avoided energy rates.

In its Reply Comments DENC states that the use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 Sub 136 Proceeding and that DENC believes the method remains appropriate. In particular, DENC notes that ICF forecasts are reputable and respected in the industry, and the EIA forecast recommended by NCSEA does not provide tailored forward pricing for the mid-Atlantic region in which DENC operates, as do the ICF forecasts. DENC Reply Comments at 4-5.

With regard to hedging, DENC details that use of the Black-Scholes Option Pricing Model to determine fuel hedging benefits was thoroughly reviewed and proposed by the Public Staff in the 2014 Sub 140 Proceeding. In response to NCSEA and witness Beach's recommendation that the value of hedging should be calculated based on the cost of executing hedges over the full ten-year PPA horizon, DENC references the Commission's finding in the Sub 140 Phase Two Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities which, in DENC's case, is approximately 18 to 24 months in the future. DENC explains that the Xcel Study is inappropriate for use in this proceeding because the results are inflated as it looked 20 years into the future using relatively stale high gas prices. DENC further states that when the Xcel Study was conducted in 2013, the forecasted natural gas price for 2025 was approximately $7.50/MMBtu, while the current forecasted price for 2025 is $4.00/MMBtu. DENC also notes that it is not clear if the Xcel Study used the cost of call options to determine the hedge value, and that it appears instead to be a cash flow discounting exercise that does not accurately represent the value of reduced natural gas pricing volatility in the future. DENC notes that the Maine Study is similarly outdated, its authors note difficulties with the method and how it required "some simplifying assumptions," and it does not include the possibility of future downward movements in natural gas prices. The resulting hedge value would lead to unreasonably high energy rates paid to QFs. *Id.* at 6-8.

In its Reply Comments the Public Staff states that in the Sub 140 Phase One Order the Commission found that renewable generation provides fuel price hedging benefits and that these benefits should be valued over terms that are comparable to the Utilities' hedging terms. The Public Staff also notes that in compliance with the Commission's directive from that order, DENC included the avoided fuel hedging values in its avoided energy calculations. The Public Staff disagrees with witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term because the Utilities rely on hedge terms that are significantly shorter. The Public Staff states that the value of the hedge should be calculated over a term comparable to the Utilities' actual natural gas hedge contracts that can be avoided, as proposed by DENC. Public Staff Reply Comments at 8.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that DENC's proposed avoided energy inputs are reasonable for the purposes of this proceeding. Therefore, the Commission concludes that these energy inputs should be approved. With respect to the fuel forecast DENC used in its modeling, the Commission agrees that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings, which the Commission has accepted since the 2012 Sub 136 Proceeding, continues to be appropriate. No party raised specific objections to DENC's approach, and the Commission declines to require DENC to adopt witness Beach's proposed method for the reasons discussed in DENC's Reply Comments.

With regard to hedging, in the Sub 140 Phase One Order the Commission concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. Sub 140 Phase One Order at 8, 42. In the Sub 140 Phase Two Order the Commission found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. Sub 140 Phase Two Order at 7, 30-31. Based on the record in this proceeding, the Commission finds that the Black-Scholes Model or a similar method continues to be appropriate to reflect hedging benefits in avoided cost rates. The Commission therefore concludes that DENC has appropriately calculated avoided hedging costs using the Black-Scholes Model, and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.30/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The Commission declines to accept witness Beach's recommendation that the benefit of the hedge should be calculated to approximate the hedge value over a ten-year term. The Commission continues to find, as it did in the Sub 140 Phase Two Order, that hedging benefits should only be valued over the hedging terms actually used by the Utilities, and DENC relies on an 18- to 24-month hedge term. Because the Commission continues to find the Black-Scholes Model or a similar method to be reasonable for calculating hedge value, and for the reasons stated by DENC, the Commission concludes that the Xcel and Maine Studies are not appropriate for use in determining avoided hedging values for avoided cost rates in North Carolina.

Finally, based on the evidence presented by DENC updating the continued disparity in LMPs in its service territory, which no party contested here, the Commission finds that it continues to be appropriate for DENC to include the historical average congestion differentials for on- and off-peak periods in its calculation of proposed energy costs for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 46

The evidence supporting this finding of fact is contained in DENC's verified Initial Statement and in the testimony of DENC witness Petrie, Public Staff witness Thomas, NCSEA witnesses Beach and Johnson, and SACE witness Kirby.

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." *Id*. at 110-11. The 2018 Scheduling Order reiterated that directive.

In its Initial Statement DENC notes that the addition of new QF generation can have an impact in two distinct areas: ancillary services and integration costs. DENC proposes to adjust the avoided energy cost payments to new QFs to reflect the increase in system supply costs, or re-dispatch costs, caused by these generators. DENC defines 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. DENC states 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 the unpredictable output of these types of units caused by changes in cloud cover or changes in wind speed. DENC clarifies that it is 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 Initial Statement at 12-13.

To calculate the re-dispatch cost, DENC explains 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 currently interconnected to its system to develop generation profiles for these facilities. DENC performed the study at three levels of solar penetration to provide a range of results. It used the PLEXOS model to determine an overall system cost impact, which it calculated to be approximately $1.78/MWh, and proposes to adjust avoided energy payments made to QFs under Schedule 19-FP by that amount. *Id.* at 13.

In its Initial Comments the Public Staff does not oppose the concept of a re-dispatch charge but makes a number of recommendations and raises certain concerns. First, the Public Staff argues that the avoided energy rate should not be reduced by separately calculated charges, and states 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 recommends that DENC collect and administer the re-dispatch costs separately from the avoided energy rate, similar to Duke's approach for the integration services charge. Second, while the Public Staff agrees that it is reasonable to calculate the re-dispatch charge using solar resource data, as solar is the dominant type of intermittent, non-dispatchable QF, it suggests 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 30-32, 43-46.

As for its concerns, the Public Staff states that DENC's calculation of the charge, which reflects equal weighting of multiple cost categories and solar penetration scenarios, may not be reasonable. More generally, the Public Staff notes the Commission's conclusions in the Sub 140 Phase One 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 Sub 140 Phase One Order at 60-61). The Public Staff acknowledges that some costs of QF energy and capacity are less discernable than others, and states 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 32-33.

In its Initial Comments NCSEA asserts as it did with respect to Duke's integration services charge that the re-dispatch charge is inconsistent with previous Commission decisions and does not comply with PURPA. NCSEA points to the Commission's recognition in the Sub 140 Phase One Order that it may be appropriate to reflect the costs and benefits of integrating solar resources into the Utilities' avoided cost calculations. NCSEA Initial Comments at 32-33. NCSEA contends that DENC's proposed re-dispatch charge fails to comply with the 2016 Sub 148 Order because the charge does not take the form of a separate rate schedule. NCSEA also asserts that the proposal is inappropriately based on generation technology rather than QF characteristics, and that DENC admits such noncompliance in its Initial Statement. NCSEA also argues that the re-dispatch charge represents single-issue ratemaking because it is a "rate" under N.C.G.S. § 62-3(24) and should be set during a general rate case. NCSEA argues 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). *Id.* at 34-35, 47-48. NCSEA also claims that the Utilities fail 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, thereby reducing market prices. *Id.* at 43-45.

In his affidavit NCSEA witness Johnson states that refining avoided cost rates to consider the costs and benefits associated with integrating solar resources is "not objectionable, per se," but takes issue with how the Utilities conducted their respective analyses. He claims, among other things, that the Utilities fail to take an unbiased approach, only consider negative impacts imposed by solar QFs, and ignore the geographic diversity of solar QFs that avoids T&D costs. With regard to DENC's re-dispatch charge, in contrast to NCSEA's own position he does 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." Johnson Affidavit at 17-18. He asserts, 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 cost and solar penetration scenarios. He presents his own calculation of a re-dispatch charge of $0.69/MWh, based on removal of the PJM and generation-only cost categories of DENC's re-dispatch analysis and the 80-MW solar penetration scenario. *Id.* at 18-20.

In his affidavit NCSEA witness Beach similarly claims that the re-dispatch charge does not consider the benefits of integrating QF resources into the system. Witness Beach also asserts that appropriately located QFs will allow T&D costs to be avoided, citing 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 asserts a potential market suppression benefit of integrating QF power and recommends that the Commission direct the Utilities to study the ability of their T&D system to host distributed generation and storage resources. Beach Affidavit at 6-7.

In its Initial Comments SACE disagrees 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 flaws, SACE concludes that DENC fails to adequately support its re-dispatch charge and that the Commission therefore should reject it. SACE Initial Comments at 17-18.

In its Reply Comments DENC reiterates the basis for its re-dispatch proposal and states 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 explains that in the analysis providing the basis for the proposed charge, it gave equal weight to each of the cost categories considered, which included all costs, PJM purchases/sales, pumped storage costs/revenues, and generator costs only. DENC states that it chose solar penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the analysis, and describes the process it used to calculate the charge based on those levels. DENC Reply Comments at 8-11.

DENC states that while it proposes 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 states that it is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases. *Id.* at 9-10.

DENC states that it discussed its proposal with the Public Staff and addressed a number of the Public Staff's questions and concerns. DENC also states 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 describes these points as representing the Public Staff's remaining concerns with the re-dispatch proposal. DENC states that it continues 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 provides arguments in support of those aspects of its original approach to calculating the charge. DENC states that it believes it is appropriate to weight each category equally, as each plays a major role in the total re-dispatch cost related to distributed solar generation. DENC also explains the rationale for including each of the solar penetration levels and for weighting each level equally in the charge calculation. DENC concludes, however, that in the interest of reaching compromise on the issue and narrowing down the areas of dispute, it is 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. *Id.* at 12-14.

In response to NCSEA, DENC first clarifies that its presentation of the re-dispatch proposal does not constitute an admission of noncompliance with the 2016 Sub 148 Order, but rather makes clear that the proposal is 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 states 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 acknowledges 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 states 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 states 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 notes, 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 15-17.

DENC further explains 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 notes 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 non-dispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." DENC concludes that, practically, these terms present a distinction without a difference. DENC notes its willingness to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, non-dispatchable QFs in a future proceeding. *Id.* at 17.

DENC also addresses NCSEA's contention that the re-dispatch charge is a "rate" under N.C.G.S. § 62-3(24) that should be set during general rate cases pursuant to N.C.G.S. § 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 shows 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 notes that taken to its logical end NCSEA's argument would nullify N.C.G.S. § 62-156. As to the latter, DENC states that the charge is valid regardless of whether it qualifies as a "rate" under 18 C.F.R. § 202.101(b)(5) and explains that it is also consistent with the Section 202.304(e) because it properly considered the enumerated factors listed in the FERC regulations. *Id.* at 17-19.

In response to NCSEA's and witness Johnson's contentions regarding costs and benefits, DENC explains that due to their intermittent nature and concentration in its small North Carolina service territory, non-dispatchable QFs do not allow DENC to avoid T&D costs; due to the potential for additional line losses resulting from backfeeding, the opposite is more likely true. *Id.* at 19-21.

DENC further states that its willingness to recalculate the re-dispatch charge consistent with the Public Staff's recommendations should address SACE's concerns with the proposal. *Id.* at 21-22.

In its Reply Comments the Public Staff presents a summary of DENC's proposed charge and states that it is not convinced that DENC considered the appropriate cost and solar scenarios in its re-dispatch charge calculation. The Public Staff disagrees with the "no PJM," "no pumped storage," and "generator cost only" scenarios because those categories do not represent DENC's current operations. The Public Staff states that while these scenarios may be illustrative of the impact solar "might" have on system costs were DENC to leave PJM or decommission its Bath County pumped storage facility, they are not appropriate for use in specifying a charge to apply to non-dispatchable QFs today. The Public Staff notes that the higher re-dispatch charge associated with a "No PJM" scenario indicates the value of being able sell excess energy into the PJM market. The Public Staff also finds the 80-MW solar penetration scenario to be inappropriate because DENC already has several hundred megawatts of solar capacity installed — the 2,000 MW scenario is more likely in the future due to the higher probability that DENC's total system will realize this level of intermittent capacity, and 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 proposes that DENC give 100% weight to the "all costs" category and no weight 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 notes that the re-dispatch charge and Duke's proposed integration services charge may result in recovery of overlapping costs, and states 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 20-23.

In its Reply Comments NCSEA agrees with SACE's position that DENC inappropriately averages costs associated with multiple solar penetration levels and combinations of assumptions, which results in an inflated charge. NCSEA also echoes some of the questions raised by the Public Staff in its Initial Comments. NCSEA states 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. NCSEA Reply Comments at 17-18.

In its Reply Comments SACE contends that the Utilities fail to analyze the potential benefits of solar integration, and therefore do not comply with the Commission's previous orders. SACE also agrees 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 recognizes 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 supports DENC's approach of applying the re-dispatch charge, if approved, as a decrement rather than as a stand-alone charge. SACE suggests 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 13-16.

In his direct testimony DENC witness Petrie stated that in the 2016 Sub 148 Order and the 2018 Scheduling 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. 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 integration services charge, 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, 15-18.

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. He testified 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, which 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, as it notes in its Reply Comments DENC is willing to re-calculate the re-dispatch charge with modified cost categories and solar penetration scenarios as recommended by the Public Staff, resulting in a $0.78/MWh re-dispatch charge. Tr. vol. 5, 19-22.

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. However, 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, 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. Tr. vol. 5, 22-24.

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. Tr. vol. 5, 24-25.

Witness Petrie also responded to NCSEA 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 stated 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 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, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost. Tr. vol. 5, 25-26.

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. 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 generation onto its system, which was first addressed in the 2012 Sub 136 Proceeding. 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 27-28.

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 stated 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 least-cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs that are passed on to ratepayers. He also noted that unlike Duke's method of calculating the integration services charge, DENC's method of calculation does not measure system reliability. Tr. vol. 6, 373-74.

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 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 inappropriately excludes 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 integration services charge 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. *Id*. at 374-76.

In their comments filed in this proceeding, the Public Staff and NCSEA discuss whether or not solar QFs with battery storage capability should be subject to Duke's proposed integration services charge. The SISC Stipulation provides, in part, that certain QFs would be exempt the integration services charge if they can operate the facility in a manner that "materially reduces the need for additional ancillary service requirements," as determined by Duke, to include battery storage, dispatchable contracts, or other mechanisms. In his testimony, Public Staff witness Thomas testified that the Public Staff believes 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 integration services charge or, "to a lesser extent," the re-dispatch charge. *Id*. at 376-81.

NCSEA witness Beach testified generally on the re-dispatch charge together with the Duke integration services charge. 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, 112.

In his testimony SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations, and he 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, 208-10.

In his rebuttal testimony, DENC witness Petrie testified that DENC remains 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 recommends rejection of the re-dispatch charge, he does 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, 37-40.

Witness Petrie also disagreed with any characterization of the charge as a "penalty." He stated 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, 37-39.

Finally, witness Petrie addressed the Public Staff's suggestion 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 stated that although the addition of battery storage may potentially smooth the QF's output during certain hours, the shape of the energy 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 has 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. He therefore argued that the recalculated $0.78/MWh charge should apply to all solar QFs in this biennial period and be 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, 40-42.

At the hearing, SACE witness Kirby recommended rejection of the re-dispatch charge until it is recalculated based on both the cost and benefits of integrating solar. 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 integration services charge 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. He also testified, and reiterated upon questioning by the Commission, 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. Witness Petrie also agreed in response to questions by counsel for the Public Staff that the re-dispatch charge could decline in the future. 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, 80-82, 92-94, 100-03, 215.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, and for reasons similar to those discussed in other sections of this Order with respect to Duke's proposed integration services charge, the Commission finds that DENC's proposed re-dispatch charge, as modified to be $0.78/MWh, is reasonable for purposes of this proceeding.

As with Duke's proposed integration services charge, 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 recommendations. Given the evidence presented, the Commission concludes that the charge, modified as agreed to by DENC, should be accepted for purposes of this proceeding.

For reasons similar to those details above, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations implementing PURPA, N.C.G.S. § 62-156, and the Commission's orders issued in biennial avoided cost proceedings. 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 is 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. The Commission finds DENC's filings and particularly witness Petrie's testimony highly persuasive on this point. DENC has already reflected certain benefits of solar, including hedging value, in the underlying avoided energy cost rate. Moreover, 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, DENC provided data supporting the charge based on solar generation located on its own system. Evidence presented relating to the New England ISO, for example, is not relevant to this proceeding. For the reasons stated above, the Commission also declines to accept witness Beach's suggestion to direct the Utilities to study the ability of their T&D system to host distributed generation.

In addition, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations because the re-dispatch charge reasonably approximates utility indifference. With regard to DENC's approach to calculating the re-dispatch charge, the Commission concludes that the use of 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 resulting $0.78/MWh charge is close to the $0.69/MWh charge that witness Johnson calculated as an illustrative alternative. DENC has indicated that the charge represents its first step in quantifying the costs of integrating 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 acknowledges that it could decline in future proceedings. The Commission therefore agrees with witness Petrie that for purposes of this proceeding 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 avoided costs.

The Commission recognizes the discussions regarding a potential overlap between the costs being borne by each utility that DENC's re-dispatch charge and Duke's integration services charge 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, the Commission will evaluate the reasonableness of such a charge at that time. 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. As with Duke, the Commission finds it is appropriate to require DENC to file with the Commission a proposed protocol for avoidance of the re-dispatch charge.

In conclusion, the Commission finds that DENC's proposed re-dispatch charge of $0.78/MWh is reasonable for purposes of this proceeding. 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, consistent with the decisions relevant to Duke's proposed integration services charge included in this Order, to the extent possible. In addition, the Commission will direct DENC to file a proposed protocol for avoidance of the re-dispatch charge similar to those protocols required from Duke.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 47

The evidence supporting this finding of fact is found in DENC's verified Initial Statement and in the affidavit of NCSEA witness Johnson.

Summary of the Evidence

In its Initial Statement DENC proposes to apply annual capacity payment caps that reflect the characteristics of intermittent non-dispatchable resources. DENC notes the 2016 Sub 148 Order directive that the Utilities only offer avoided capacity payments in years in which the utility's IRP shows a need for capacity and that the Utilities should propose schedules demonstrating any "marked differences in the value of the energy and capacity provided by these QFs." 2016 Sub 148 Order at 98. DENC states that because solar and wind generation is intermittent in nature, the capacity benefit of these resources is not equivalent to the capacity benefit of a conventional CT unit. DENC provides data supporting the lower capacity value offered by solar and wind QFs on its system. Specifically, DENC presents data showing the hourly system loads of the PJM DOM Zone on the peak day from the summer of 2018 overlaid with the aggregate output from DENC's solar contracts. This data demonstrates that even under favorable sun conditions on a hot summer day, these units could not deliver output at their full nameplate capacity during the hours when the power was needed most, showing that they do not fully displace the operation of dispatchable CT units. DENC also presents data showing the hourly system loads of the PJM DOM Zone on the peak day from the winter of 2017/18 overlaid with the aggregate output from DENC's solar contracts. This data demonstrates that on a peak day in winter the capacity value of the solar facilities was nearly zero, again showing that these resources do not displace CT generation at the time of winter morning and evening peaks. DENC Initial Statement at 20-21.

Based on this data, DENC proposes an annual payment cap reflecting the capacity value of intermittent QFs relative to fully dispatchable CT facilities. DENC clarifies that all QFs, regardless of technology, would continue to receive the same capacity rates, but the payments would be capped on an annual basis for QF resources at levels reflecting the operating characteristics and capacity value of these resources. DENC determined those levels by first calculating the levelized annual capacity value of a new CT, which it explains represents the maximum amount that a QF could receive for capacity if it generated at its rated capacity during all of the seasonal capacity on-peak hours, and which it based on 100% of the fixed costs of a new CT during the year that DENC has a capacity need. DENC then multiplied that benchmark capacity value of a fully dispatchable CT by percentage factors representing the capacity value relative to a CT for solar-tracking, solar-fixed tilt, and wind. These percentage factors — 23%, 16%, and 13%, respectively — were based on the average output from each of these types of resources during the critical peak winter and summer hours. The result is proposed capacity caps of $8.55, $5.95, and $4.83/kW per year for solar-tracking, solar-fixed tilt, and wind, respectively. DENC states that once an intermittent QF reaches the applicable limit for capacity payments on an annual basis, the cap would be triggered and the QF would receive no further capacity payments during that year of the contract term. Capacity payments would resume at the beginning of the next year of the contract term and continue through that contract year unless and until the point at which the annual cap is again reached. *Id.* at 22-24.

DENC notes that these caps are consistent with DENC's 2018 IRP and conform to the expected value of such facilities in PJM's capacity market. It also argues that they are consistent with FERC regulations that allow for the consideration of specific QF characteristics in determining avoided cost rates and with the complementary provisions of N.C.G.S. § 62-156. DENC explains that by having a single set of capacity rates, all QFs will see the same price signal, but application of the caps will allow capacity payments to be tailored to individual QF operating characteristics. DENC states that this would help ensure that rates paid to intermittent QFs reflect their actual capacity value and that customers not overpay for these QFs' output. DENC posits that this approach achieves the intent of the Commission's directive to consider establishing separate rate schedules for intermittent QFs, which is to recognize the limited capacity value of these QFs. DENC notes in addition that this approach will result in efficient administration of QF contracts by retaining a single set of standard seasonal capacity rates, with the cap applied only to intermittent QFs. *Id.* at 24-26.

In its Initial Comments the Public Staff objects to DENC's proposed cap. The Public Staff notes the steps taken by the Commission and General Assembly in 2017 to reduce the risk of overpayment for capacity to QFs. It also argues 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 states that it reviewed generation data from 61 solar facilities representing over 430 MW in DENC's 2018 fuel factor proceeding, Docket No. E-22, Sub 558, and found that the average capacity factor during the twelve months ending June 2018 was 18.2%, with a maximum of 25.1%. The Public Staff also states that information DENC provided in discovery indicates that the capacity cap would affect tracking solar facilities with a capacity factor above 25.8%, which suggests that few QFs would actually hit the capacity cap. The Public Staff cautions, however, that this information is based on existing facilities that may have different efficiencies and operating characteristics than newer facilities eligible for these rates that may be constructed with more efficient inverters, more efficient panels, or other factors that may increase the output of their system relative to existing facilities. Public Staff Initial Comments at 60-62.

The Public Staff also questions DENC's approach of defining its seasonal allocation of capacity need to be consistent with its membership in the PJM market, when the capacity needs of the PJM market as a whole are different from the capacity needs of a utility operating in North Carolina. The Public Staff recommends that instead of the cap on capacity payments, DENC should evaluate alternative seasonal allocation and capacity payment hours that align more directly to DENC's system as opposed to the PJM system as a whole. *Id.* at 62-64.

In his affidavit, NCSEA witness Johnson claims that adopting more accurate price signals as he proposes would eliminate the potential that a QF will be over-compensated for capacity and therefore make DENC's proposed annual capacity payment cap unnecessary. Johnson Affidavit at 78.

In its Reply Comments, DENC explains that the proposed annual cap on capacity payments is an administratively efficient way to accomplish two goals. First, DENC argues that it links IRP principles to avoided cost payments. DENC states that it values solar capacity at 23% of nameplate capacity in its IRP, and that the cap accounts for that solar capacity value. Second, the cap provides a useful and reasonable way to reduce the risk that customers overpay for capacity beyond DENC's actual avoided costs. DENC acknowledges the progress made by House Bill 589 and the 2016 Sub 148 Order toward reducing the risk of customer overpayment, but states that that progress did not eliminate the need for the cap as a useful stopgap to prevent overpayment that could still occur due to potential imperfections in the rate design, peak hours selection, and CT seasonal cost allocations. DENC Reply Comments at 38.

In addition, noting the Public Staff's recognition that its calculated historical average solar capacity factor was based on existing solar facilities, DENC states that solar technology is advancing, and the lower historical capacity factors associated with existing units, many of which are fixed tilt, may not accurately represent future performance of solar resources, which could be tracking solar units. Given this uncertainty of new solar QF capacity factor performance in the future and the likelihood that new units will utilize tracking solar technology with higher capacity factors, DENC argues that the capacity payment cap would provide a good safeguard to protect customers from overpaying for capacity. *Id.* at 38-39.

Discussions and Conclusions

Based upon the foregoing and the entire record herein, the Commission agrees with the Public Staff that DENC's proposed capacity cap, which acts as 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. Therefore, the Commission finds that it is inappropriate to approve DENC's proposed capacity cap for the purposes of calculating rates in this proceeding, and the Commission will direct DENC to appropriately revise its Schedule 19-FP rates to remove the capacity payment limits.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 48

The evidence supporting this finding is contained in DENC's verified Initial Statement and NCSEA witness Johnson's affidavit.

Summary of the Evidence

In its Initial Statement DENC acknowledges that in the 2016 Sub 148 Order the Commission ruled that it would require the Utilities to "address the PAF and to support their recommendations for PAF calculations based on their evidence of peak season equivalent availabilities for the utility fleets in total in [their] initial filings" in this proceeding. DENC proposes to use the fleet EA to determine the PAF, which it calculated to be 1.07 and applied to its proposed Schedule 19-FP capacity rates. DENC states that the EA represents the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages. DENC notes that it assumed peak seasons of June, July, August, and January-February in its PAF calculation, which PJM considers the critical months when system emergencies and performance assessment hours are expected. DENC Initial Statement at 32-33.

In its Initial Comments the Public Staff asserts that each utility's PAF should incorporate the respective utility's prospective EFOR, and not be based solely on historical availability data. It recommends that the Commission direct the Utilities to refile their fleet weighted average peak month EFORs using five years of historical data and at least five years of prospective data. The Public Staff asserts that the Utilities' historical data supports the use of June through August as summer peak months and December through February as winter peak months (and notes that DENC excluded December from its winter peak months). The Public Staff acknowledges, however, that DENC's proposed PAF of 1.07 based on historic operational data is an increase from DENC's 1.05 PAF approved by the Commission in the 2016 Sub 148 Order. Public Staff Initial Comments at 69-70.

In its Initial Comments NCSEA states that a PAF is used to ensure that QFs are not discriminated against in favor of rate-based generation and that the PAF should consider the availability of rate-based generation during all critical peak hours. NCSEA notes that the Commission states in its 2016 Sub 148 Order that the availability of a CT is not determinative for the purpose of calculating a PAF. NCSEA and witness Johnson, in his affidavit, also state that the Commission in that order discussed alternatives for calculating the PAF in future proceedings and indicates a preference for consistency between avoided cost filings and other routine filings. Witness Johnson notes the peak months used by the Utilities in their respective PAF calculations, but he does not oppose DENC's calculation or make a recommendation to the Commission specifically regarding DENC's PAF. NCSEA Initial Comments at 30-32.

In its Reply Comments the Public Staff states that although it initially advocated for the use of at least five years prospective EFOR data to bring to the forefront the "peak season" concept, subsequent to filing its Initial Comments the Public Staff better recognized the fundamental differences between EA and EFOR and the challenges associated with comparing the two separate metrics. The Public Staff also recognizes the difficulty of adding a prospective element to the PAF calculation as it would introduce subjectivity. As a result, the Public Staff proposes that if a rate-based metric is applied, the use of three to five years of historic data is appropriate. The Public Staff also asserts that an EFOR metric does not properly address other types of outages that can occur during a peak season and suggests that other reliability metrics used by NERC such as the EUOR or WEUOR could be an appropriate metric that takes into account outages that can occur during peak periods such as forced outages, maintenance outages, and derates. The Public Staff states that EUOR removes planned outages from the base calculation and therefore would not give a negative indication of utility unit performance during the critical peak seasons. Based on discussions with the Utilities, however, the Public Staff recommends that the Commission approve the initial PAF calculations proposed by the Utilities in their respective Initial Statements, but also direct the Public Staff, Utilities, and parties in this proceeding to discuss whether another metric, such as EUOR, may be a more appropriate reliability metric to support quantification of the PAF in future avoided cost proceedings. Public Staff Reply Comments at 14-16.

In its Reply Comments DENC opposes the Public Staff's suggestion of the weighted equivalent unplanned outage rate (WEUOR) to determine the PAF. DENC states that the WEUOR is an obscure metric that DENC does not calculate and that the EA metric DENC used is more appropriate based on the 2016 Sub 148 Order. DENC argues that the PAF should be determined based on three years of EA history as that measure provides the most meaningful information because it is actual, observable, and recent as opposed to five years of data which is less relevant due to generation unit changes such as unit fuel conversions. Prospective EA data, DENC details, would add subjectivity and unnecessary complication to the PAF calculation. DENC supports the Public Staff's shift away from using a prospective component in the PAF calculation. DENC Reply Comments at 39-40.

DENC also states that the peak periods it used in its PAF calculation correspond with the months PJM considers to be the peak months from a system operations perspective, when system emergencies would likely occur, and when planned outages would not be scheduled. DENC states that including December or March in its calculation would mean the majority of months in a year would be "peak" months, and that DENC uses these months for planned outages in order to spread out the spring and fall outages. DENC argues that including December or March data would increase the PAF and unfairly burden electric customers with increased QF capacity costs due to the Company's efforts to efficiently plan outages for its generation units. DENC states that including March and December would also run counter to the Commission's finding in the 2016 Sub 148 Order where the Commission states that "Public Staff's witnesses use of availability factor is flawed because it includes planned outages that a utility intentionally schedules for off-peak shoulder periods when electricity demand is low." DENC Reply Comments at 41-42 (quoting 2016 Sub 148 Order at 55).

In its Reply Comments NCSEA states that the calculation of the PAF should be forward-facing to account for technological improvements. NCSEA Reply Comments at 12. In its Reply Comments SACE asserts that based on historical data, the Utilities should include June and September in their summer peak months and March and December in their winter peak months. SACE Reply Comments at 8.

Discussion and Conclusions

In the 2016 Sub 148 Order the Commission directed the Utilities to address the PAF and support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for their fleets in total in their initial filings in this proceeding.

Based upon the foregoing and the entire record herein, the Commission finds that DENC has satisfied this directive, and that its proposed PAF of 1.07 is appropriate for use in calculating its avoided capacity costs in this proceeding. Therefore, the Commission concludes that DENC's PAF of 1.07 should be approved for the reasons articulated by DENC and the Public Staff. The Commission finds persuasive the comments of DENC and the Public Staff as to the value of basing the PAF calculation on historical as opposed to prospective data. The Commission also finds that DENC's rationale for its assumed peak seasons to be reasonable, as those seasons represent the critical months that PJM considers to be the peak months from a system operations perspective when system emergencies would likely occur and when planned outages would not be scheduled.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49 – 52

The evidence supporting these findings of fact is found in Duke's verified JIS and in the testimony of Duke witnesses Snider and Johnson, Public Staff witness Hinton, and SACE witness Glick.

Summary of the Evidence

A part of its Initial Statement Duke includes an amended Schedule PP PPA and Terms and Conditions to address modifications to a QF Facility that seeks to install battery storage or otherwise increase its energy output. Duke amends the Terms and Conditions for new PPAs to state that it may terminate or suspend purchases of electricity from the QF 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." JIS DEC Exhibit 4 and DEP Exhibit 4. The Terms and Conditions do not specifically define the term "material modification." A material modification is, however, a term defined in the NCIP.

Duke states that the right to sell power under the pre-existing PPA and standard offer rates should be limited to the QF as configured when it established a LEO and originally entered into the PPA. Duke states that adding batteries or other technologies for the storage and later injection of energy to an existing QF 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 Duke's election. JIS at 35. Amendments to Section 1.4 of the Schedule PP PPA and Section 4 of the Terms and Conditions propose to clarify that modifying a QF to increase the AC energy output or the delivered DC capacity of the facility would be an event of default. *Id.* at 38.

Duke specifically amends the terms and conditions to clarify the term “Contract Capacity” to include the estimated annual energy production of the facility. Duke further states 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 “stale and significantly higher avoided cost rates.” *Id.* at 35. Duke believes 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. Acceptance of such modifications would materially increase the financial obligations of Duke’s customers at rates significantly above the current avoided cost.

In its Initial Comments the Public Staff agrees with Duke that the increased energy output of a QF 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 states that allowing a QF to increase its 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 74, fn. 111. The Public Staff is concerned, however, 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 QF 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 74, fn. 112.

The Public Staff agrees with Duke that 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 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 notes, however, 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*. at 77-78.

The Public Staff proposes 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 states “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 is 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.

In its Initial Comments NCSEA states 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 states that the annual production number, which Duke proposed to use as the Contract Capacity, is an estimate that will vary up and down due to a variety of circumstances. *Id*. NCSEA asserts that it is commercially unreasonable to require that a QF never exceed its estimated annual energy production without risking termination of the PPA.

NCSEA argues that Duke's proposal violates PURPA's requirement that a utility purchase all of a QF's output provided that the QF does not exceed its nameplate capacity. *Id*. NCSEA disagrees 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 states 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 states 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 states that Duke's barriers to storage deployment discriminate against QFs, create economic inefficiencies, and miss opportunities to add value to the grid. *Id*.

In its Initial Comments NC WARN disagrees with Duke's changes to the Terms and Conditions that provide for early contract termination for changes in Contract Capacity or energy output, and states that the proposed amendments would give Duke 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 Initial Comments at 4.

In its Reply Comments Duke maintains 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 clarifies 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 capacity (known as "over-paneling"), or proposing to co-locate battery storage at a facility, and represent what Duke believes is already the case under the existing language — that Duke will not agree to modifications that will increase its and its customers' obligations to purchase energy at prior avoided cost rates. Duke Reply Comments at 134. Duke provides a chart depicting various scenarios and the overpayment risk to installing storage at existing QFs. *Id*. at 135, fig. 11.

Duke proposes to add the following new defined term “Material Alteration” to its amended Terms and Conditions to more clearly define what constitutes a material change to a facility:

> (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.*

Id. at 139 (emphasis added). The proposed definition will allow the repair or replacement of equipment at a facility with “like-kind equipment” to clarify that developers and owners may undertake routine operations and maintenance and replace equipment if the facility is impacted by storm damage. *Id*. at 139-40.

Regarding the Public Staff’s recommendation in its Initial Comments to explore separately metering battery storage and compensating additional output at the current avoided cost rate, Duke states 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 a facility would require the consent of utility, and the failure to obtain consent would be a material breach of the contract. Second, from a technological perspective, Duke states that its current metering system does not have the capability to segregate or estimate the production of a solar QF separate from a co-located battery storage facility. Furthermore, if the battery is shifting the time of energy delivered it could result in inequities. For example, under the levelized rate concept, there would be overcompensation being paid to the QF because there would be higher deliveries and payments in the early years prior to the installation of battery storage when levelized rates are artificially high. Third, 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 energy or to shift energy output in ways that were not contemplated when the contract was entered. *Id*. at 145-46. Finally, Duke states 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 adding generation that will increase nameplate capacity of the facility as a whole and the potential violation of the half-mile rule. *Id*. at 147-48.

In its Reply Comments NCSEA states that energy storage is now cost-competitive and that 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 agrees 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 disagrees with the Public Staff's suggestion that increased energy output be separately metered and compensated at the most recently effective avoided cost rate. NCSEA asserts 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 states in its Reply Comments that it agrees with the positions of the Public Staff, NCSEA, and NC WARN that a number of Duke's 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 states that it does not 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 capacity, to enter into new contracts with new avoided cost rates." *Id*. at 18. SACE believes "[r]equiring 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 agrees with the Public Staff that "material modification" is undefined and that the term should be defined further with stakeholder input for the purposes of avoided cost contracts. SACE agrees with NCSEA that material modification is more appropriately addressed in the interconnection proceeding and believes that to the extent material modification is used in avoided cost contracts that Duke's definition is overly broad. *Id*.

On June 14, 2019, the Commission directed the parties to file testimony specifically addressing 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 a utility, (ii) where a QF has executed a PPA with a utility 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.

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, 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 avoided cost proceeding, Docket No. E-100, Sub 127. *Id*. In quantifying the potential impacts to customers, witness Snider stated that Duke is committed to purchasing 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 testified that Duke is not making any further changes to the proposed PPA and Terms and Conditions than those modifications proposed in Duke's Reply Comments. *Id*. at 261. He reiterated that Duke added the defined term "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*.

In response to the scenarios presented in the Commission's June 14, 2019 Order, witness Snider testified 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, 162-63. He further 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 No. 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.

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, 58. DENC's position regarding all three scenarios presented in the Commission's June 14, 2019 Order is that a QF that seeks to add storage to a proposed or existing facility that has established a LEO or entered into a PPA would be required to establish a new LEO or execute a new PPA at current avoided cost rates. *Id*. Witness Billingsley testified that a QF that seeks to expand its maximum capacity or energy production, or to shift its hours of production under existing 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 battery storage 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, and that those hours no longer represent the utility's highest capacity value hours. Allowing existing QFs 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. Witness Billingsley, when asked whether some of DENC's concerns would be alleviated if existing QFs were incentivized to produce energy during the newly proposed peak periods, agreed that DENC would like to send price signals during peak hours. *Id*. at 89.

Public Staff 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 they addressed earlier concerns raised by the Public Staff and NCSEA. He stated that the Public Staff is generally supportive of Duke's modifications but emphasized that a "degree of reasonableness" is appropriate regarding equipment replacement and repairs made by QFs. Witness Hinton 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, 321.

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, 349. He further 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 330. He stated 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 331. 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 333. However, witness Metz 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 334-35. 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. In response to questions by the Commission, witness Metz stated that it was possible to add energy storage without increasing the overall output of the facility, 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 of co-located batteries, but that it would likely require further restrictions of commercial terms and conditions and may prove uneconomical. Witness Metz stated 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, 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.

Ecoplexus 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. Tr. vol. 5, 347. He stated that 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[ing] 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 347-48. In the second option, 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 stated that there "are no ANSI or IEEE standards in place for DC-meters," there are companies "that can meet [the] ANSI C12.1 accuracy specification." *Id*. Witness Wallace testified that if DC energy can be measured with revenue grade accuracy, a "simple ratio can be calculated and used at the [utility's] 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. Lastly, he noted two outstanding issues that would need to be discussed and considered collaboratively: (1) a metering and communications standard, and (2) commercial PPA terms, and suggested a stakeholder process with a formal proposal to be submitted to the Commission within 150 days. *Id*. at 351.

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, 124. He stated 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 it 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. Witness Norris testified that "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. He stated 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. However, the avoided cost rate sought by NCSEA is the ten-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 five-year avoided cost rate would "undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable." *Id*. at 147.

Witness Norris testified that the 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*. at 151. He 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 that the addition of battery storage could smooth the production curve in a way that could obviate the need for the integration services charge. *Id*. at 177.

Witness Norris disagreed with DENC witness Billingsley's assertion that a QF with a LEO under the Sub 136 or Sub 140 tariffs 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 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 recertified by the FERC without voiding the established LEO.

In his testimony 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 integrate battery storage, and develop a modified rate design proposal for existing QFs that seek to integrate battery storage. *Id*. at 287-88. 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 integrate energy storage should not be able to do so without the utility's consent and should enter into a new PPA at current avoided cost rates. Tr. vol. 2, 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 181-82. Witness Snider stated that 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, 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 further testified that if the Commission accepts the compromise, 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 184-85. 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 ten years, witness Snider stated that this is a deviation from the express requirements of House Bill 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 147-48. First, it is Duke's business practice to install metering exclusively on the utility's side of the point of interconnection; if it is installed on the QF side, the QF would have the opportunity to change the operation of the equipment without the utility's knowledge or control. Second, as witness Wallace admits, no ANSI standards currently exist to judge the accuracy of the meter data logger proposed in witness Wallace's testimony. Tr. vol. 2, 147-49.

Duke witness Johnson testified that he disagrees with NCSEA's assertion that energy shifting is currently allowed under Duke's avoided cost tariffs. *Id*. at 202-04. He stated that a unilateral change such as adding storage to a committed facility without obtaining Duke's 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 a decrease of only 5% would not be considered a material alteration whereas any increase would be a material alteration. Tr. vol. 5, 338, fn. 22. Witness Johnson testified that Duke has no objection to witness Metz's recommendation for the grammatical clarification. Tr. vol. 2, 204.

In supplemental rebuttal testimony, DENC witness Billingsley stated, "[T]he 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, 69. He also stated that DENC would be willing to participate in a working group to address various technological and commercial challenges, and that 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 the 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 energy storage is a material change that can trigger default of the existing PPA. Duke in 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 that 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 the Public Staff regarding the term "Material Alteration." The Commission agrees with the Public Staff that QFs 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, and that this type of maintenance should not trigger a default of the existing PPA. The Commission concludes that Duke has adequately addressed these concerns with the defined term "Material Alteration" which expressly allows replacement of "like-kind" equipment and provides that material alterations will be evaluated by DEC and DEP in a "commercially reasonable manner."

The Commission also agrees with Duke, DENC, and the Public Staff that the right to sell power under a pre-existing PPA and standard offer rates should be limited to the facility that originally entered into the PPA. The Commission finds the evidence and positions in opposition to Duke and the Public Staff's view to be unpersuasive. 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 has approved amendments to CPCNs without voiding the facility's LEO. As NCSEA argues, those amendments are usually limited in scope and do not involve changes to the facility that would require reconsideration of the facility's interconnection study or substantially increase the lifetime energy output or revenue potential of the facility.

For existing PPAs, material changes to the capacity of the QF 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 agrees that regular maintenance and repair of a 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 be considered a change that would allow the utility to void the existing PPA. For the reasons articulated by the Public Staff, the Commission finds that this modification to the Terms and Conditions is reasonable. Therefore, the Commission will approve the use of these revised Terms and Conditions.

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 under contracts that do not reflect current avoided costs and do not align price signals with the highest needed capacity windows. However, the Commission recognizes the concerns raised by several intervenor-parties and the Public Staff that requiring existing or "committed QFs" to enter into a new PPA and forfeit prior, higher avoided cost rates will discourage 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 its ratepayers.

The Commission finds persuasive NCSEA's argument that removing barriers to energy storage is particularly important in North Carolina because the amount of utility-scale solar that is already installed surpasses that of any other state except California. The Commission also notes the testimony of NCSEA's witnesses that energy storage is now a cost-competitive option, that 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. NCSEA's witnesses further testified that NCSEA 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 time and that the Commission would need to ensure that those QFs received the ten-year avoided cost rate for the additional output. The Commission determines that it is premature to resolve this issue at this time. Instead, for reasons discussed further below, the Commission will seek more detailed discussion on this issue through the stakeholder process required by this Order.

The Commission disagrees, however, with SACE that a QF should be allowed to add energy storage and be compensated at prior avoided cost rates for the additional energy added to the system not contemplated in the original PPA. As stated above 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. Allowing a QF to modify its facility to substantially increase energy output and be compensated at prior avoided cost rates would result in significant overpayment beyond the current avoided cost, which 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, including 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 also 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 to properly encourage the addition of battery storage in a manner that is fair to ratepayers.

The Commission is encouraged by Duke and DENC's willingness to enter a new PPA or negotiate a modified PPA if an existing QF proposes adding storage. The compromise appears to be a reasonable approach to resolve the various technological and commercial challenges. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for the parties to further discuss how to integrate storage with solar through a stakeholder process that would specifically address the complexities of modifying existing facilities that request to add capacity through the co-location of batteries. Therefore, the Commission directs Duke to organize a stakeholder group and will require Duke and DENC to report to the Commission on the results of the process on or before September 1, 2020.[6] The Commission directs the Public Staff to report on the organization of the stakeholder process, as well as the schedule, through an appropriate filing in this docket within 30 days of the date of this Order. The Commission's goal for the stakeholder process is to create a 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, (c) further identify specific challenges that prevent the commercial viability, and (d) provide certainty to QFs that are considering the addition of an energy storage component to their electric generating facilities. The stakeholder process should be comprehensive in its consideration of all use cases for adding an energy storage component to a committed QF's electric generating facility. The report shall address, at a minimum, the following categories:

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[6] In light of the present public health emergency resulting from the impacts of COVID-19, the Commission directs Duke to conduct the stakeholder group virtually.

I. Technology
   (a) Identify the metering challenges for AC and DC measured systems.
   (b) Propose solutions for AC and DC measured systems.
   (c) Analyze cost of design and implementation for both the facility and utility.
   (d) Identify and quantify specific ancillary services that can be provided by QFs coupled with energy storage.

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) Report on how to accomplish billing and payment for separately metered systems.

III. Regulatory
   (a) Identify and propose solutions to regulatory barriers, including without limitation whether the addition of energy storage to an existing QF requires an amendment to the QF's CPCN or a wholly separate CPCN for the energy storage facility.
   (b) Propose the appropriate avoided cost rates and terms of the PPA applicable to the energy storage element of an existing QF coupled with energy storage.
   (c) Propose how costs should be recovered (or payment made) for identifiable and quantifiable specific ancillary services provided by the QF coupled with energy storage.

The report shall identify the areas of consensus reached among the stakeholders, and with respect to those areas where the stakeholders fail to reach consensus, the Commission will require Duke to provide the Commission with a recommended resolution. To the extent the Public Staff does not agree with any of the recommendations in the report, the Commission directs the Public Staff to file a separate report setting forth its recommendation(s) and basis therefor on September 1, 2020. The Commission will proceed as appropriate in considering the report(s) of the stakeholder group's activity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

The evidence supporting this finding of fact is found in the verified Joint Comments and Proposed Rates of WCU and New River and the entire record herein.

In their Joint Comments WCU proposes to continue to pay variable rates based on its wholesale cost of power; New River proposes to continue to offer variable rates based on DEC's Schedule PP, but will not recover the administrative charge to suppliers found in Schedule PP. WCU and New River each further propose to offer long-term fixed price rates approved for DEC's Schedule PP, but again, New River will not recover the administrative charge found in Schedule PP. DEC is WCU's all requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation (Blue Ridge). Joint Comments at 2-3.

For both WCU and New River this is the same approach approved by the Commission in the 2016 Sub 148 Proceeding. As further provided in the 2016 Sub 148 Proceeding, N.C.G.S. § 62-156, as amended, provides for long-term contracts of up to ten years under the standard offer, as implemented by DEC in that docket and found above to be appropriate for use in this proceeding No parties filed any comments or objections to WCU's and New River's proposals.

The Commission therefore concludes, based upon the foregoing and the entire record herein, that WCU's and New River's rate proposals based on DEC's Schedule PP should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DENC shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell 1 MW or less capacity. The standard ten-year levelized rate option should include a condition making contracts renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration;

2. That DENC shall continue to offer, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's 2006 Sub 106 Order and most recently restated in the 2016 Sub 148 Order;

3. That DEC, DEP, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed

that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding;

4. That DEC and DEP shall file revised Schedule PP tariffs reflecting the energy and capacity rate design consistent with the April 18, 2019, Rate Design Stipulation between Duke and the Public Staff;

5. That, for the purposes of calculating avoided capacity rates in this proceeding, DEC should use seasonal allocation weightings of 90% for winter and 10% for summer, and DEP should use seasonal allocation weightings of 100% for winter.

6. That Duke's assumptions regarding the availability of DSM programs for reducing winter peak demand are reasonable and appropriate for the purposes of calculating avoided capacity rates in this proceeding, but Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands;

7. That Duke shall evaluate methods to better align the Utilities' avoided cost rates with actual real-time system conditions to enable QFs to maximize their facilities' value to ratepayers through real-time pricing or other tariffs that provide more granular rate structures and price signals, and if found to be appropriate, should offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding;

8. That the requirements of Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) shall be waived, and that until such time as the Commission adopts revisions to these Rules applicants for a certificate of public convenience and necessity pursuant to Rules R8-64 and R8-71(k) should, instead of the information currently called for in Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6), submit the "projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output";

9. That in the next biennial avoided cost proceeding, the Utilities shall evaluate and apply, consistent with the conclusions reached in this Order, cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility;

10. That DEC, DEP, and DENC shall continue to calculate avoided capacity costs using the Peaker Method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3);

11. That DEC and DEP shall use a PAF of 1.05 and DENC a PAF of 1.07 in their respective avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation.

12. That DEC and DEP shall use a PAF of 2.0 in their avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation;

13. That the Utilities, with input from the Public Staff, shall evaluate appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing;

14. That DENC shall continue to calculate rates that reflect the elimination of the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

15. That DEC and DEP shall continue to include a line loss adder in their standard offer avoided cost calculations for distribution-connected QFs, but shall study the effects of QFs on their distribution grid to determine the extent of backflow at substations prior to the next biennial avoided cost proceeding;

16. That the Utilities, for purposes of determining the first year of capacity need for negotiated contracts and for CPRE Tranche 2, shall update their avoided capacity calculations to reflect any changes in the utility's first year of undesignated capacity need as presented in their next IRP;

17. That beginning with the 2020 IRP, the Utilities shall include a specific statement of capacity to be used to determine the first year of avoidable capacity need in the next biennial avoided cost proceeding;

18. That the Utilities shall amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended. For other types of QF generation, the Utilities shall recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRP;

19. That the Utilities shall continue to assume an in-service date in the first year following the filing of new avoided cost tariffs for standard offer QFs. A utility and QF negotiating a PPA may agree to a presumed in-service date for rate calculation purposes that takes into account the future in-service date of the QF generator, not to exceed two years in the future;

20. That DEC and DEP shall continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using the fundamental forecast data for the remainder of the planning period, and DENC shall use its proposed fuel forecasting methodology in calculating avoided energy costs in this proceeding;

21. That DEC and DEP shall consider site- and project-specific characteristics during contract negotiations with QFs not eligible for the standard offer contract and include a T&D capacity adder if a project can provide real and measurable avoided transmission benefits;

22. That the integration services charges proposed by DEC ($1.10/MWh) and DEP ($2.39/MWh) shall be used in calculating rates in this proceeding as a decrement to DEC and DEP's avoided energy rates, which shall apply prospectively for the duration of the contract, consistent with the conclusions reached in this Order;

23. That DEC and DEP shall not apply the integration services charge to a QF that qualifies as a "controlled solar generator";

24. That Duke shall include in its initial filings in the next biennial avoided cost proceeding an evaluation of whether a QF that can sufficiently demonstrate its ability, and contractually obligates 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, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide;

25. That Duke shall submit the Astrapé Study methodology to an independent technical review as described in this Order and include the results of that review and any revisions to that methodology that is supported by the results of that review in its initial filing in the 2020 avoided cost proceeding;

26. That DENC's proposed rate design shall be used in calculating DENC's rates in this proceeding;

27. That DENC's proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons shall be used in calculating DENC's rates in this proceeding;

28. That DENC's proposed input assumptions to be used in determining its proposed energy rates, including those related to fuel hedging activities and the LMP adjustment shall be used in calculating DENC's rates in this proceeding;

29. That DENC's proposed re-dispatch charge of $0.78/MWh shall be used in calculating DENC's rates in this proceeding;

30. That Duke's proposed modifications to its Terms and Conditions are approved;

31. That, Duke shall organize a virtual stakeholder process to address issues related to the addition of energy storage at an existing QF as described in this Order. The Public Staff shall make a filing, within 30 days of the date of this Order, on the organization and schedule for this stakeholder process. The Utilities, and Public Staff as necessary, shall report the results of the stakeholder process to the Commission through an appropriate filing in this docket on or before September 1, 2020;

32. That WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved avoided cost rates for QFs interconnected at distribution are approved; and

33. That, within 30 days after the date of this Order, the Utilities shall file revised versions of their rate schedules and standard contracts in redline and clean versions that comply with the rate methodologies and contract terms approved in this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations, except to the extent that filings previously submitted in response to the Notice of Decision and Supplemental Notice of Decision accurately reflect the conclusions reached in this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 15th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Joann R. Snyder

Joann R. Snyder, Deputy Clerk