NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

September 4, 2019

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

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

Dear Ms. Fulmore:

Enclosed for filing is the Partial Joint Proposed Order of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (with DEC, "Duke"), and the Public Staff, filed on behalf of Duke and the Public Staff. The partial Joint Proposed Order contains Finding and Conclusions on the topics to which the Public Staff and Duke have either stipulated to or do not have issues in dispute. As noted in the document, however, the Partial Joint Proposed Order contains general placeholders for additional findings, evidence, and conclusions of law to be filed separately by the Public Staff and Duke to reflect their individual positions on remaining issues.

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

Sincerely,

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

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))))))	**PARTIAL JOINT PROPOSED ORDER OF DUKE ENERGY CAROLINAS, LLC; DUKE ENERGY PROGRESS, LLC; AND PUBLIC STAFF 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

Tuesday, July 16, 2019, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, July 17, 2019, at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Thursday, July 18, 2019, at 11:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Friday, July 19, 2019, at 9:30 a.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:

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BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under North Carolina General Statute ("G.S." or "N.C. Gen. Stat.") § 62-156(b) to establish rates for small power producers as that term is defined in 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 prescribe 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. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards and 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 established in accordance with Section 210 of PURPA.

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. The relevant 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 has implemented Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. 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.

This proceeding also results from the mandate of N.C. Gen. Stat. § 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 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 has recently amended N.C. Gen. Stat. § 62-156 in 2017 through enactment of Session Law 2017-192 ("HB 589") and again in 2019 through enactment of Session Law Session Law 2019-132 ("HB 329"). As further addressed in this Order, the Commission takes judicial notice of HB 589 and HB 329, which establish the current framework for North Carolina's implementation of PURPA's mandatory purchase obligation.

On June 26, 2018, the Commission issued its *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") (collectively, "Duke" or the "Companies"), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC"), Western Carolina University ("WCU"), and New River Light and Power Company ("New River") (collectively with Duke and DENC, the "Utilities") were made parties to the proceeding. The *2018 Scheduling Order* specifically directed DEC, DEP and DENC to address issues as directed in Ordering Paragraph No. 16 of the Commission's October 11, 2017 Order in

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 specifically established The Commission established January 7, 2019, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; February 15, 2019, as the deadline for reply comments; and March 8, 2019, as the deadline for proposed orders. The Scheduling Order also scheduled a public hearing for February 19, 2019, solely for the purpose of taking non-expert public witness testimony. Finally, the 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. Gen. Stat. §

62-15(d) and Commission Rule R1-19(e). Participation of the North Carolina Attorney General's Office is recognized pursuant to N.C. Gen. Stat. § 62-20.

On November 1, 2018, Duke filed the Joint Initial Statement and Exhibits of DEC and DEP; DENC filed its Initial Statement and Exhibits; and WCU and New River jointly filed their proposed avoided cost rates. DENC subsequently revised its proposed standard offer rate schedules on March 7, 2019, and March 14, 2019.

On November 13, 2018, Duke filed a motion for approval to implement temporary variable rate credits**.** On December 3, the NCUC granted the motion.

On December 31, 2018, the Public Staff filed a Motion for Extension and Revised Procedural Schedule, asking the Commission to extend certain filing deadlines established in the Procedural Order and to grand Duke's request for an evidentiary hearing on the proposed rate design and integrations services charge. The Public Staff proposed that initial comments be due February 8, 2019; Utilities' testimony on rate design and integration charges be due February 15, 2019; reply comments on issues other than rate design and integration charges be due March 15, 2019; intervenors' responsive testimony on rate design and integration charges be due March 15, 2019; rebuttal testimony on rate design and integration charges be due April 8, 2019; and an evidentiary hearing begin April 29, 2019. On January 4, 2019, the Commission granted the Public Staff's motion.

On January 4, 2019, NCSEA filed a motion for a modified procedural order, asking the Commission to schedule a full evidentiary hearing on all issues in this docket and also to allow all parties to file initial, responsive, and rebuttal testimony. On January 10, 2019, Duke filed its response in opposition to NCSEA's motion.

On January 16, 2019, Duke filed a motion to establish discovery guidelines for the remainder of the proceeding. On January 23, 2019, SACE and NCSEA filed a joint response in opposition to Duke's motion.

On January 25, 2019, the Commission issued its *Order on Procedural Schedule*, allowing parties to file reply comments by February 22, 2019; suspending the March 8, 2019 deadline for proposed orders; and requiring Duke to file a report identifying (1) issues where agreement exists or could reasonably be expected to be reached; (2) issues in controversy that do not merit consideration at an evidentiary hearing, and (3) issues in controversy that merit consideration at an evidentiary hearing. The report on issues in controversy was due March 12.

On February 7, 2019, the Public Staff filed a motion for extension of filing deadlines. On February 8, 2019, the Commission granted the Public Staff's motion, making comments due February 12, 2019; reply comments due February 26, 2019; and the report on issues in controversy due March 12, 2019.

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

On or before February 20, 2019, all Utilities filed Affidavits of Publication of the Notice of Hearing, and the public hearing was held on February 19, 2019, in the Commission's hearing room, as scheduled. Three witnesses gave testimony.

On February 20, 2019, Duke filed a Motion for Extension of Time, which the Commission granted on February 22, 2019, making reply comments due March 20, 2019, and the report on issues in controversy due April 3, 2019.

On March 18, 2019, Duke and DENC filed a Joint Motion for Extension of Time, which the Commission granted on February 22, 2019, making reply comments due March 27, 2019, and the report on issues in controversy due April 10, 2019.

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

On April 10, 2019, Duke filed the report of issues in controversy.

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 Evidentiary Hearing and Establishing Procedural Schedule*, scheduling an evidentiary hearing to begin July 15, 2019, identifying issues in dispute, requiring direct testimony of the Utilities by May 21, 2019, and of the Public Staff and intervenors by June 21, 2019, and requiring rebuttal testimony by July 3, 2019.

On May 21, 2019, DENC filed 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 May 21, 2019, Duke also filed the Stipulation of Partial Settlement with the Public Staff Regarding Solar Integration Services Charge.

On June 14, 2019, the Commission issued an *Order Requiring Supplemental Testimony and Allowing Responsive Testimony*, requiring direct testimony of the Utilities by June 25, 2019, supplemental testimony of the Public Staff and intervenors by July 3, 2019, and supplemental rebuttal testimony by July 11, 2019; and requiring that parties specifically address the following question:

> what avoided cost rate schedule and contract terms and conditions apply when a QF adds battery storage to a facility that has (i) established a legally enforceable obligation ("LEO"), (ii) executed a purchased power agreement ("PPA") with the relevant utility, and/or (iii) commenced operation and sale of the facility's output to the 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 Glen 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 witness 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 its letter to the NC Small Hydro Group in response to their request to extend the 2.0 performance adjustment factor beyond the term of the Hydro Stipulation,[1] which expires at the end of 2020.

On July 15, 2019, the evidentiary hearing began, as scheduled, and continued through July 19, 2019. 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 pre-filed testimony of those witnesses who testified at the

[1] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014*, Stipulation of Settlement Among Duke Energy Carolina, LLC, Duke Energy Progress, LLC and North Carolina Hydro Group, Docket No. E-100 Sub 140 (filed June 24, 2014) ("Hydro Stipulation").

evidentiary hearing, as well as all other witnesses filing testimony in this docket with the exception of NCSEA witness Carson Harkrader, were copied into the record as if given orally from the stand. NCSEA witness Harkrader did not appear at the hearing, was not subject to cross-examination, and her pre-filed testimony was not accepted into the record by the Chair of the Commission. 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 pursuant to the requests of Commissioners Clodfelter and Brown-Bland during the evidentiary hearing.

On September 4, 2019, proposed orders and briefs were filed by the parties.

Various filings were made and orders were issued which are not discussed in this order but are included in the record of the proceeding.

Based on the foregoing, all of the parties' comments and other filings, and the entire record in this proceeding, 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 MW or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option 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. 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 ("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 April 18, 2019, Rate Design Stipulation between Duke and the Public Staff, are appropriate to incentivize QFs to better match the generation needs of the utilities and should be used in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding.

5. 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, and should be used in calculating DEC's and DEP's avoided capacity rates in this proceeding.

6. Duke's assumptions regarding the availability of demand-side management (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. It is appropriate for the Utilities to continue to 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.

8. It is appropriate to consider amendments to the requirements of Commission 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.

9. As a result of changes to the on- and off-peak hours being implemented in this Order, waiver of the current Rule R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) requirements is appropriate. Applicants for a certificate of public convenience and necessity (CPCN) should instead submit information regarding the projected annual production profile of the proposed generating facility, until such time as revisions to the rules are finalized.

10. The installed cost of a combustion turbine (CT) used by the Utilities is reasonable and appropriate for purposes of calculating avoided capacity rates in this proceeding.

11. It is appropriate for the Utilities in the next biennial proceeding to evaluate and apply, if appropriate, 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. It is not appropriate in this proceeding, however, to adjust the utilities' CT costs based upon hypothetical firm natural gas transportation costs.

12. 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.

13. 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.

14. It is appropriate for DEC and DEP to continue to include the line loss adjustments in their standard offer avoided energy calculations and 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. DEC and DEP should also 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.

15. It is appropriate to require DEC and DEP to utilize a 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 by further order of the Commission or in accordance with the Hydro Stipulation accepted by the Commission's December 31, 2014, Order in Docket No. E-100, Sub 140 ("Sub 140 Phase One Order").

16. It is appropriate to require DENC to utilize a PAF of 1.07 in its avoided cost calculations for all QFs, other than hydroelectric QFs without storage capability and to

utilize a PAF of 2.0 in its avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued by further order of the Commission.

17. The Utilities, in conjunction with the Public Staff, should consider the appropriateness of using other reliability indices, specifically the Equivalent Unplanned Outage Rate ("EUOR") metric, to support development of the PAF prior to the next biennial avoided cost filing.

18. DEC and DEP shall work in good faith and consistently with N.C. Gen. Stat. § 62-156 to maintain their commitment with respect to the PAF in the Hydro Stipulation until it expires on December 31, 2020.

19. DEC, DEP, and DENC have complied with amended N.C. Gen. Stat. § 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 for 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 undesignated capacity need.

21. Plant uprates do not constitute an undesignated and deferrable capacity need, as a utility should make plant uprates when it is reasonable and prudent to do so.

22. Beginning with the 2020 IRP, the Utilities shall include a specific statement addressing the utility's future capacity needs to be used determine the first year of capacity need in 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 five 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 terms 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 the QF's existing PPA, pursuant to the N.C. Gen. Stat. § 62-156(b)(3), as amended in HB 329.

24. For other types of QF generation, it is appropriate under PURPA and consistent with N.C. Gen. Stat. § 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 IRP.

25. The Utilities' current approach to the assumed January 2019 in-service date is reasonable for standard offer QFs, and the Commission declines to adopt NCSEA's hypothetical proposed in service date of December 31, 2021.

26. It 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 date of the QF project coming online.

27. DEC and DEP are incurring increased intra-hour ancillary services cost to integrate variable and intermittent solar generators. It is appropriate to recover these costs from the solar generators that are causing the cost through an Integration Services Charge.

28. The Astrapé Study's determination 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 is reasonable and should be approved.

29. 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. Upon a pre-existing solar QF not subject to the Integration Services Charge committing to sell to Duke under a new PPA in the future, the then-applicable Integration Services Charge shall be applied.

30. It is appropriate for Duke to apply the Integration Services Charge on an average, as opposed to incremental, basis, and to update the charge during each biennial avoided cost proceeding to most accurately reflect Duke's increased (or decreased) average ancillary services costs. It is further appropriate for Duke to cap the Integration Services Charge for each vintage in order to provide certainty for QFs.

31. It is not appropriate for Duke to impose the Integration Services Charge upon QFs or "controlled solar generators" that demonstrate that their facility is capable of operating, and contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility.

32. It is appropriate to require Duke to work with the Public Staff to establish guidelines for QFs to become "controlled solar generators" and properly avoid the Integration Services Charge.

33. The Solar Integration Services Charge ("SISC") Stipulation between the Public Staff and Duke to establish an Integration Services Charge is reasonable and appropriate.

xx. *[Placeholder for alternative findings of fact for remaining issues that will be filed separately by Duke and the Public Staff.]*

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

The evidence supporting these findings is contained in Duke's Joint Initial Statement on behalf of DEC and DEP ("JIS"), the Initial Statement of DENC, and the initial comments of the Public Staff.

Summary of the Evidence:

In their JIS, DEC and DEP 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 establish a legally enforceable obligation ("LEO") committing to sell the output of their QF generating facility to DEC or DEP on or after November 1, 2018. In order to be an eligible QF and receive energy credits under this Schedule, DEC and DEP indicated that the QF 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 QF with a Contract Capacity of one (1) MW or less. DEC and DEP further stated that, pursuant to N.C. Gen. Stat. § 62-156(b)(3), electric generation fueled by swine waste and poultry waste may be eligible for a different avoided capacity credit and rate if Seller sells the output of its facility, including renewable energy credits, to the Companies 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 and DEP Exhibits 1)

Similar to the avoided cost rate schedules filed in the 2016 Sub 148 proceeding, DENC in its Initial Statement 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. Gen. Stat. § 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.

DENC proposed to continue to offer QFs Schedule 19-LMP as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at avoided cost rates, as 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 MW per day from PJM's Base Residual Auction for the Dom

Zone. As in prior proceedings, DNCP 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 Initial Statement at 13, Exhibit DENC-3 at 5)

In its Initial Comments, the Public Staff reviewed and summarized the proposed rate schedules by the Utilities, but did not recommend any changes to the standard offer term and eligibility thresholds proposed by the Utilities.

Discussion and Conclusions

In the *2016 Sub 148 Order*, the Commission approved significant changes to the standard offer term and eligibility thresholds both as a result of changes in the marketplace for QF-supplied power in North Carolina, as well as legislative changes to the State's implementation of PURPA enacted in HB 589. 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."

In the current proceeding, no parties filed comments recommending further changes to the standard offer term and eligibility thresholds at this time. Based on foregoing and the entire record in this proceeding, 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 one 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 recognizes the enactment of the CPRE Program enacted pursuant to N.C. Gen. Stat. § 62-110.8, provides for a competitive procurement option for renewable energy facilities, but notes that Duke has not requested the Commission evaluate 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 concludes, based upon the foregoing and the entire record herein, that it is appropriate for DENC to 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, including the payment of capacity credits based on the PJM RPM, subject to the same conditions as approved in the Sub 106 Order and most recently restated in the *2016 Sub 148 Order*.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 7

The evidence supporting these findings is found in Duke's Joint Initial Statement; the Initial Comments of the Public Staff, NCSEA, and SACE; Duke's Joint Reply Comments, the Reply Comments of the Public Staff, NCSEA, and SACE; the testimony of Duke witnesses Snider and Wheeler, NCSEA witness Johnson, SACE witness James Wilson, and Public Staff witness Thomas and the April 18, 2019, Stipulation between Duke and the Public Staff addressing avoided energy and avoided capacity rate design between ("Rate Design Stipulation").

<u>Summary of the Evidence</u>

Duke's JIS stated its Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity is 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. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours.

In the *2016 Sub 148 Order*, the Commission held that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities," and, therefore, required the Utilities to consider refinements to the avoided capacity calculation and to address these refinements in the Sub 158 proceeding. (*2016 Sub 148 Order,* at 56) The Commission specifically ordered that the Utilities should consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." (Id.) The *2018 Scheduling Order* similarly directed the 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 proposed changes to its Schedule PP to eliminate the pre-existing Option A and Option B hours and developed 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 included 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 defined its energy pricing hours separately to account for the differences in each utilities' 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 PM hours in the summer, and AM and PM hours in the winter.

The JIS explained that Duke's initially-proposed updated Schedule PP rate design for energy and capacity reflected more narrowly defined seasons and hours compared to the former Option A and B definitions, and reflected higher energy payments during the Companies' 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 the Companies' 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 stated 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 recommended 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 recommended that Duke provide granular rate schedules that incorporate geographic granularity. NCSEA noted 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 stated 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 stated that the Utilities did not adequately recognize how costs vary across different times of day, despite having access to detailed avoided cost data for all 8,760 hours for the next ten years. NCSEA proposed that instead of the utilities' proposals, the Commission should adopt the time-of-day periods it proposed, as well as an optional, real-time pricing tariff for QFs. (Id. at 28) NCSEA witness Ben Johnson proposed specific energy rate design schedules, specifically: (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. (*See* NCSEA Affidavit of Ben Johnson at 64-76)

SACE in its Initial Comments also testified that by Duke allocating all or nearly all loss of load risk in the winter, Duke devalues the capacity contributions of solar QFs and almost completely eliminates consideration of the capacity benefits solar QFs provide during summer demand peaks. SACE provided the Report on the Research Adequacy Studies and Capacity Value Study prepared by James F. Wilson (Wilson Report), which raised the following four concerns:

- The representation of winter loads under extreme cold conditions, based on an extrapolation of the relationship between very cold temperatures and winter loads;
- The "economic load forecast uncertainty" layered on top of the weather-related load distributions;
- The assumptions regarding future winter demand response capacity; and

- The assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings. (SACE Initial Comments at 11-12)

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

The Public Staff in its Initial Comments stated its opinion 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 proposed its own seasonal energy rates and hours. Describing its proposal, the Public Staff stated that:

> 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 raised concerns regarding the Resource Adequacy Studies utilized by Duke, 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 recommended that the Commission direct Duke to rerun its 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 stated 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 used by Duke to capture the relationship between winter load and cold temperatures, Duke stated 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 recommended that the Commission reject the concerns raised by Mr. Wilson on this topic. (Id. at 62)

Similarly, with regard to the claims raised by Mr. Wilson that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions, Duke indicated that Mr. Wilson's statements regarding the operating reserves that are held back in the SERVM model are inaccurate, and should therefore 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 agreed with these assessments. Duke stated, however, that the levels of reduction proposed by NCSEA and characterized by NCSEA affiant Dr. Johnson as "conservative," are actually extremely optimistic and not reasonably achievable in the timeframe proposed, if at all. (Id. at 33) Duke stated that NCSEA failed to accurately support its proposal, and noted 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 noted that winter DSM programs raise different challenges than summer programs. Duke noted 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 recommended 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 noted 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 March. (Id. at 66)

Regarding its energy rate design, Duke stated 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 the Companies' 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 stated 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 indicated 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 argued that non-geographic specific pricing offers a fair rate to all generators committing to sell under the standard offer tariff and allows the Companies to adjust their system line loadings to maximize benefits for all customers, and that NCSEA's recommendation should therefore be rejected. (Id. at 73-74)

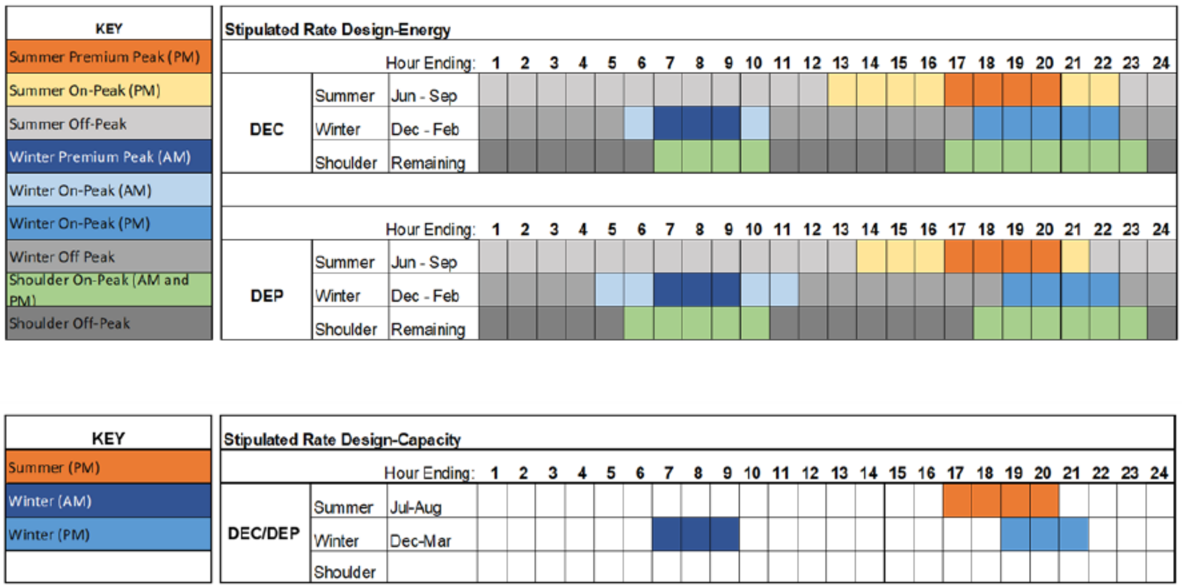
With regard to NCSEA's time of day pricing periods and optional real-time pricing tariffs, Duke agreed that this information could help align actual avoided costs to QF payments, but that the granular pricing periods proposed in this proceeding are sufficient at this time. Duke agreed to continue to investigate development of time-of-day and real-time pricing periods for standard offer QFs, but recommended 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 stated 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 noted 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 indicated 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 recommended 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* jointly filed by Duke and the Public Staff, 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 and 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 utilities' avoided cost based upon seasonal and time-of-day characteristics. (Tr. Vol. 2 at 65)

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



In support of the stipulated rate design, 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 the Companies 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, the 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 at 29)

Witness Snider also testified that contrary to SACE Witness Wilson's claim that the stipulated avoided capacity rate design focused on too narrow periods of time, 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, 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 at 76, 115)

Witness Snider also rebutted 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 indicated 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 indicated that such an approach would be inconsistent with 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. Mr. Snider indicated 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 the Companies' actual hourly marginal cost of energy. (Tr. Vol. 2 at 116-118)

Witness Snider also indicated that for the same reasons indicated in Duke's Reply Comments, the Commission should reject NCSEA's recommendation that Duke offer geographically differentiated avoided cost rates. (Tr. Vol. 2 at 119-120)

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 stated that NCSEA's criticisms are essentially the same arguments that were made in the Sub 148 proceeding and ignored the impact of continued increases in the amount of must-take solar generation on the utilities' loss of load risk. Mr. Snider noted that the Commission in its *2016 Sub 148 Order* rejected the arguments raised by NCSEA and instead recognized the significant impact high penetrations of solar were having on summer versus winter loads net of solar contribution. Mr. 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 Dr. 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 at 122-126)

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 noted 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. Mr. Snider further noted that the use of the loss of load risk values as allocation factors appropriately represent the seasonal capacity benefit provided by a QF, and also properly aligns with cost causation principles. Witness Snider also notes that the Companies 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 at 127-130)

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 LOLE is consistent with the general principles of PURPA and is technologically agnostic. He therefore states that non-dispatchable QFs are being fully compensated for the capacity value they provide. In addition, witness Snider notes that Dukes' methodology is fully consistent with Subsection (b)(3) of N.C. Gen. Stat. § 62-156, 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 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 noted 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 at 133-135)

Public Staff witness Thomas testified that the Public Staff largely agreed 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, Public Staff Witness Thomas noted that Duke's use of the LOLE metric is reasonable and protects ratepayers from overpaying for QF capacity and concluded that the proposed rate design sends the appropriate price signals to QFs. (Tr. Vol. 6 at 389-391)

<u>Discussion and Conclusions</u>

<u>Energy Rates:</u> The Commission's *2018 Scheduling Order* recognized the need to reconsider the continued appropriateness of the on- and off-peak time periods used in the Option A and Option B rate schedules accepted in prior proceedings, and also indicated its intention to establish more accurate price signals to incentivize QFs to better match the generation needs of utilities. These changes are appropriate in light of the substantial amount of QF development experienced in North Carolina.

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 the Utilities' highest production cost hours and loads, in order to increase the likelihood that the interests of ratepayers and developers of QF generators align. In addition, the modifications made through further discussions between the Public Staff and Duke to further refine this rate design approach, as memorialized in the *Rate Design Stipulation*, seek to further strike an appropriate balance between accurate avoided cost pricing, administrative efficiency, and the general acknowledgment that these factors will continue to change over time. 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 not sufficient evidence demonstrating that such an effort is appropriate for the standard offer tariff or would be cost beneficial at this time. As discussed in the Commission's June 14, 2019, *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony*, in Docket No. E-100 Sub 101, the benefits associated with developing detailed geographic guidance for smaller generating facilities seeking to select suitable interconnection locations may be outweighed by the costs, and similar information is already made available through other interconnection processes such as the Section 1.3 Pre-Application Reports. In addition, as noted by Duke witness Snider, the 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 is limited to small power producer QFs with a design capacity up to one MW under North Carolina law. N.C. Gen. Stat. § 62-156(b). 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 qualifying facilit[y] 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. Gen. Stat. § 62-156(c) and 18 C.F.R. 292.304(e)(vi). As such, the Commission finds that it is not necessary or appropriate to require further consideration of geographically granular rates for standard offer facilities at this time.

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 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.

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 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). 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. 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.

Capacity: As previously discussed in the *2016 Sub 148 Order,* the Commission finds that changes experienced in the marketplace for QF-supplied power in North Carolina continue to potentially obligate customers to pay for capacity in excess of what may actually be avoided. In addition, pursuant to N.C. Gen. Stat. § 62-156, the Utilities, in designing their avoided capacity rates, must consider the availability and reliability of QF power in evaluating whether the QF can help to avoid the utility's planned capacity addition. North Carolina's implementation of PURPA aligns fully with FERC's regulations implementing PURPA, which provide that states shall 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).

The Commission finds that Duke's reliance on loss of load expectation is appropriate in the context of determining when a QF can help a utility avoid or defer a planned capacity addition. The Commission further finds 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, to be responsive to the concerns raised. Similarly, the Commission finds

Duke's description of the consideration of operating reserves that are held back in the SERVM model as reasonable.

The Commission appreciates that Dr. Johnson's assessment of historical loads for the years 2006 to 2017 may have some relevance to Duke's proposed seasonal allocation of future capacity need; however, the Commission also reiterates its determination in the *2016 Sub 148 Order* that the high penetrations of solar in Duke's service territory are having today and will, in the future, have different impacts on summer versus winter loads net of solar contribution than in the past. 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 further agrees with Duke and the Public Staff that the use of the loss of load risk values to establish seasonal allocation factors is appropriate, and properly aligns with cost causation principles. In addition, the Commission 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.

The Commission does not agree with NCSEA witness Johnson that Duke's seasonal allocation is inconsistent with PURPA, and, to the contrary, finds that the seasonal allocation proposed by Duke and supported by the Public Staff provides full compensation to QFs for the capacity costs they enable the utilities to avoid. The Commission agrees that consistent with N.C. Gen. Stat. § 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 by Duke, a QF that can provide capacity during the identified need, as expressed by the loss of load expectation hours, is being more fully compensated under the proposed seasonal capacity allocations than under prior allocations. 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, can be avoided.

Turning to the assumptions made by Duke regarding the availability of winter DSM programs, the Commission agrees with 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. As discussed in the 2018 IRP proceeding, the Commission recommends that Duke should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winder demands. For purposes of this proceeding, however, the Commission finds Duke's assumptions regarding seasonal allocation to be reasonable and appropriate for purposes of inclusion in the avoided capacity rate.

In conclusion, the Commission finds the proposed energy and capacity rates presented in the April 18, 2019, *Rate Design Stipulation* between Duke and the Public Staff reasonable and appropriate. These stipulated rates send stronger price signals to incentivize

QFs to better match the generation needs of utilities and should be used in calculating DEC's and DEP's avoided energy and capacity rates in this proceeding. The Commission supports the methodology embodied in the Stipulation as reasonable, but as with other determinations in this case, notes that these assumptions can be dynamic and change in the future. Therefore, the Commission will be receptive to revisiting this issue in future proceedings, as appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 AND 9

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Thomas and the testimony of Duke witness Johnson.

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 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 at 395-397)

Duke witness David Johnson testified that Duke agrees with the Public Staff that the stipulated rate design is inconsistent with the rule requirements and therefore appropriate for revision. Duke indicated that other parties not currently participating in this proceeding may have an interest in the proposed rule revisions, and therefore believe that the Commission should address the proposed revisions in a separate rulemaking proceeding. Duke requested, however, 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. Duke indicated that it had discussed this proposal with the Public Staff and the Public Staff did not have any objection to Duke's proposal. (Tr. Vol. 2 at 282-285)

Discussion and Conclusions

In light of the changes to the energy and capacity rate designs being implemented in this proceeding, the Commission agrees 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 with the Public Staff 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 and 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 therefore a separate rulemaking proceeding to evaluate the proposed rule revisions is appropriate. The Commission therefore shall grant the limited waiver, as recommended by Duke and agreed to by the Public Staff, to allow CPCN applicants to substitute the information currently required in Commission Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) to instead be replaced with the following information:

> 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.

The Commission shall open a generic rulemaking proceeding within 60 days following the issuance of this order, and the limited waiver shall be in effect from the date of this Order until final revisions to Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) are approved by the Commission after the rulemaking.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 AND 11

The evidence supporting these findings of fact is found in Duke's Joint Initial Statement; the Initial Statement of DENC; the Initial Comments of the Public Staff; Duke's Joint Reply Comments; and the Reply Comments of DENC, the Public Staff, and NCSEA.

Summary of the Evidence

In its JIS, Duke stated 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 noted 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)

DENC in its Initial Statement indicated 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 Sub 148 Proceeding. DENC stated 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 is expected to become operational in December 2018. DENC stated that for the remaining costs, including construction and owner costs, that 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 indicated that it had also made several adjustments to the Brattle Study results, consistent with prior guidance from the Commission. (DENC Initial Statement at 12-14)

The Public Staff in its Initial Comments indicated that it had reviewed the capital cost inputs, line losses, and assumptions incorporated in the Utilities' avoided capacity calculations finds them reasonable for purposes of this proceeding (Public Staff Initial Comments at 12, 17). The Public Staff recommended, however, that the utilities in future avoided cost proceedings 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 noted 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 Mr. Thomas Beach advocated 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 CTs availability during winter peak hours when gas demand peaks and pipeline capacity is constrained. (NCSEA Initial Comments at 23-24)

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

DENC in its Reply Comments indicated that it has long advocated for the use of a brownfield CT to determine avoided capacity cost rates, and 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 indicated in its Reply Comments that the Companies are 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 stated that the Public Staff's proposal reflects an incremental improvement over the current methodology that will more accurately reflect the Companies' 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 opposed 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 pointed to the Public Staff's Initial Comments, which recognized that DEC and DEP included the cost of fuel oil as backup, which allows the Companies to exclude the securing firm pipeline capacity for CTs. (Public Staff Initial Comments at 7)

Duke also highlighted that this proposal would deviate from the Companies' 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 disputed NCSEA affiant Thomas 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 to NCSEA Initial Comments, at Attachment 2, at 18)

Discussion and Conclusions

In its *Order Setting Avoided Cost Parameters* issued on December 31, 2014 ("*Sub 140 Phase One Order"*), the Commission determined that:

> "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 p. 48).

Based on the evidence in this proceeding, the Commission finds that the Utilities adequately relied on publicly available industry sources for determining the installed cost of a CT per kW, 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 the DEC, DEP, and DENC, respectively, is reasonable and appropriate for purposes of calculating avoided capacity rates in this proceeding.

With regard to the Public Staff's recommendation that the utilities in future proceedings evaluate and apply, if appropriate, cost increments and decrements to the publicly available cost estimates based on brownfield sites and existing infrastructure that may be used to meet future utility capacity additions by the utility, the Commission agrees that such considerations may be 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 directs the utilities in the next avoided cost proceeding to evaluate these potential adjustments, and, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility, apply these adjustments to their avoided capacity calculations.

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 efforts by the Commission in recent proceedings to increase the transparency in these CT cost inputs to the avoided capacity rate calculations are not lost.

Finally, the Commission rejects NCSEA's recommendation to make an adjustment in this proceeding to increase the Utilities' winter avoided capacity costs to account for hypothetical natural gas pipeline transportation capacity costs. Comments filed both by Duke and the Public Staff suggest 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 actually reflect the utility's actual planned cost of building a CT in the Carolinas.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 14

The evidence supporting these findings of fact is found in Duke's Joint Initial Statement; the Initial Statement of DENC; the Initial Comments of the Public Staff; Duke's Joint Reply Comments; and the Reply Comments of DENC, the Public Staff, and NCSEA.

<u>Summary of the Testimony</u>

DENC in its Initial Statement noted that in its *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 indicated 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 stated 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 stated 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 or are expected to experience backfeed in the near future because of the recent growth in utility-scale solar QFs. As a result, DEP indicated that 50 out of 367 substations (approximately 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, or 26% of DEP's substations, are estimated to experience backfeed. Duke indicated that this lower percentage 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 indicated 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 indicated that it was appropriate for both DEC and DEP to retain a line loss adder for distribution-connected QFs eligible for Schedule PP at this time. Duke indicated, however, that for proposed distribution-connected QFs that are not eligible for the standard offer Schedule PP, the Companies plan to consider 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 on a case-by-case basis. (JIS at 23-25)

The Public Staff in its Initial Comments indicated that it agreed with the information filed by the Utilities related to line loss adders and back-feeding 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 recommended that in the next avoided cost proceeding, the Commission require DEC and DEP take into account the aggregate amount of renewable generation that will be, or is expected to be, interconnected by the end of Tranche 4 of the CPRE Program in their consideration of line loss impacts. (Public Staff Initial Comments at 72-73)

SACE in its Initial Comments indicated that it had 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 indicated that Synapse evaluated DENC's half-hour data associated with the 38 substations connected to QFs from August 16, 2017–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, and therefore DENC continues to benefit from solar QF line loss avoidance. SACE stated that complete elimination of the 3% line loss adder may not accurately reflect line loss avoidance benefits, and requested 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)

DENC in its Reply Comments indicated that it disagreed 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 noted that 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. Lastly, DENC noted that 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. Therefore, DENC recommended that the Commission reject SACE's analysis and find that it is appropriate for DENC to continue to not include the line loss adder in its avoided energy rates. (DENC Reply Comments at 42-45)

Discussion and Conclusions

In valuing the energy and capacity that a utility may avoid by purchasing power from a QF, FERC's regulations provide that a utility, to the extent practicable, should take into account "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 . . ." 18 C.F.R. 292.3.04(e)(4). As recognized by the Utilities, the Public Staff, and other parties to this proceeding, the Commission recognized in the *2016 Sub 148 Order* that variations in line losses may not exist if power purchased from a distribution connected QF is backfeeding the substation and 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 determines 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. Gen. Stat. § 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 filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 - 17

The basis for these findings of fact is found in the JIS, the Initial Statement of DENC, the Initial and Reply Comments of the Public Staff, NCSEA's Initial and Reply Comments, SACE's Reply Comments, and the Companies' Joint Reply Comments.

Summary of the Evidence

In their JIS, the Companies continued to recognize a 1.05 Performance Adjustment Factor ("PAF") in their calculation of avoided capacity cost rates to be paid to QFs (other than certain hydroelectric QFs) eligible for the standard offer, as approved by the Commission in its *2016 Sub 148 Order,* in which the Commission concluded that

> the availability of a [combustion turbine] CT is not determinative for calculating the PAF, and that calculation of the PAF should be based on a methodology that uses a system availability metric that represents the reliability of the system during peak demand periods.[2]

In other words, the Commission had agreed with the Companies 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.[3] Thus, the Companies compiled five years of historic equivalent availability data for the entire fleet during the Companies' critical peak season months of January, February, July and August. This critical peak season reflects the high load periods in which the Companies typically do not

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[2] *2016 Sub 148 Order* at 56.
[3] *Id*.

schedule planned maintenance outages for generating facilities. DEC's and DEP's respective equivalent availability during this timeframe averages 95%, which continues to support a PAF of 1.05. (Duke JIS at 15-16)

In its Initial Statement, DENC stated it was proposing to use the metric Equivalent Availability ("EA") to determine the PAF. DENC stated 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. Based on historical fleet-wide EA rates, DENC calculated a PAF of 1.07 that it used its calculation of the Schedule 19-FP capacity rates in this proceeding. (DENC Initial Statement at 32-33)

In its Initial Comments, the Public Staff generally agreed with the Utilities' base methodology for calculating the PAF, but it noted 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. Avoided costs are inherently forward-looking, therefore, the Public Staff stated that it is also appropriate to take a forward-looking approach when determining each Utility's EFOR for use in avoided cost calculations. 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 agreed that the Utilities had met the intent of the *2016 Sub 148 Order* with their filing of EFOR data, the Public Staff recommended that the Commission direct the Utilities to refile their fleet weighed 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 stated 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 requested the Commission to direct the Utilities to perform a revised PAF calculation that included June and December EFOR data.

NCSEA challenged Duke's 1.05 PAF multiplier to DEC's and DEP's avoided capacity rates, arguing that the historical equivalent availability data used to quantify the PAF narrowly defined January, February, July and August as "peak season." NCSEA indicated 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, NCSEA argued that historical data for both DEC and DEP does not support considering only January and February as winter peak months, while excluding December and March. Similarly, 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 attached to NCSEA's Initial Comments as Attachment 1, affiant Johnson stated 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 recommended that the Commission adopt a PAF between 1.08 and 1.10. (NCSEA Initial Comments, at 31-32; Johnson Affidavit at p. 36-37)

In their Reply Comments, Duke stated that it did not oppose the Public Staff's recommendation as an alternative quantification of the PAF for this proceeding, but clarified that a key distinction between the EFOR and the equivalent availability factor

("EAF") is the treatment of planned outages. Planned outages impact the EAF calculation but not the EFOR calculation. Because the Commission directed the Companies to use EAF as the metric to support the PAF and recognized that unit reliability should be evaluated during peak demand periods outside of planned maintenance intervals, the Companies believed that calculating the equivalent availability for critical peak season months of January, February, July, and August was appropriate under the *2016 Sub 148 Order.*

After the filing of initial comments, the Public Staff and Duke discussed the Companies' use of equivalent availability data, EFOR, and the Public Staff's proposed adjustments to the PAF calculation. Duke's Reply Comments explained that they supported 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 also argued that the more appropriate analysis of relative load data would be to evaluate peak demand net of solar capacity, identifying that DEC's and DEP's loss of load expectation ("LOLE") is zero in June and very small in December. Thus, while Duke did not necessarily agree that June and December represent appropriate months to use in determining the PAF, Duke agreed to include these months to quantify the PAF using the EFOR metric as planned outages that may be scheduled during these months would not impact the EFOR calculation. Duke's Reply Comments also supported excluding planned outages from impacting the PAF, by highlighting that the new rate structure would allow QFs seven months out of the year to conduct any routine or planned maintenance without incurring a reduction in the capacity payment. (Duke Reply Comments at 51-52)

Duke also reported that they calculated the PAF based on the Public Staff's recommendation to use EFOR and include the additional months of June and December and that the data would support a slightly lower PAF than the EAF data using the months proposed by the Companies. Accordingly, the Companies supported either approach; both approaches generally arrive at consistent results supporting a PAF of 1.05 or lower. (Duke Reply Comments at 53-54)

The Companies also noted in their Reply Comments that they appreciated 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 the Companies and would require them to make several assumptions that may not be readily accepted by the other parties. The Companies believe 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, the Companies believe 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 agreed that the Public Staff's recommended equivalent unplanned outage rate ("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 recommended that the Commission approve a PAF of 1.05 for QFs except for hydro QFs without storage, and noted that Duke 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)

DENC in its Reply Comments stated that including the months of March and December to the PAF calculation would run counter to the Commission's finding in the 2016 Sub 148 Order in that it could capture planned outages that are intentionally scheduled during off-peak shoulder periods when demand is low, and recommended that these months not be included in the PAF calculation. DENC also indicated its belief that continued use of the EA metric that DENC used to calculate the PAF is appropriate, and that its PAF of 1.07 was appropriate for this proceeding. DENC also noted that because of the lack of hydroelectric QF activity in its North Carolina service area, it took no position on the 2.0 PAF that was used in the 2014 stipulation. (DENC Reply Comments at 40-42)

In its Reply Comments, the Public Staff indicated that its Initial Comments did not recognize the complexity of comparing two separate metrics – EAF and EFOR – and the challenges of applying a prospective element. Therefore, the Public Staff proposed 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 suggested 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 outages (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 recommended 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 stated that the Companies had biased its current PAF calculations and that they had understated QFs contribution to capacity during peak months. NCSEA renewed its recommendation that the Commission reject the Companies' 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)

SACE in its Reply Comments agreed with both NCSEA's 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)

Discussion and Conclusions

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 peaking 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 has therefore ordered the Utilities to apply a PAF, or a simple capacity multiplier, in calculating avoided capacity rates paid by customers to QFs in previous avoided cost proceedings.

In the *2016 Sub 148 Order*, due to changing circumstances facing QFs and the Utilities, including the risk of customer overpayment to QFs, the Commission found that the methodology used to calculate the PAF should include greater precision than in past proceedings. Therefore, the Commission 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 equivalent availability metric is also an appropriate peak season reliability indicator, and ordered the Utilities to support development of the PAF using the equivalent availability 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.

The Commission finds in this proceeding, similar to the Sub 148 proceeding, that the record 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. It is not in dispute that DEC and DEP have generally complied with the *2016 Sub 148 Order* to support development of the PAF using the equivalent availability metric. However, disagreement remains among the parties regarding the appropriate peak months to calculate the PAF when using either the equivalent availability or EFOR metric.

To reiterate, the purpose of the PAF is to allow QFs reasonable periods for unplanned outages, similar to the utilities' fleet during the year. Therefore, it follows that support for the PAF should not be impacted by the Companies' planned outage maintenance intervals during the year. Notably, under the new capacity rate design structure being approved in this Order, QFs have even more time—seven out of twelve months of the year—to schedule any planned facility inspections and maintenance without incurring a reduction in capacity payment.

Specific to the Companies' initial reliance upon the equivalent availability 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 equivalent availability calculation. The Commission therefore finds that Duke appropriately included the months of January, February, July and August in quantifying the PAF based upon equivalent availability, while the inclusion of additional months as recommended by NCSEA and initially by the Public Staff would introduce periods with planned outages which would have the effect of artificially increasing the equivalent availability and thereby overstating the PAF.

Turning now to the additional generating unit availability metrics raised in this proceeding, the Commission reads Duke's and the Public Staff's Reply Comments to represent these parties' consensus that the equivalent availability of the generation fleet or EAF metric does not properly account for planned outages, while the EFOR metric, more appropriately, is not impacted by planned outages. The Commission appreciates the Companies' calculation of equivalent availability and EFOR as recommended by the Public Staff, and agrees that use of either metric supports a PAF of 1.05 in this proceeding. To resolve concerns regarding the impact of planned maintenance on the reliability metric and to avoid future disputes over which months should be used to support the PAF, the Commission believes that it may be more appropriate for the Utilities to rely upon the EFOR calculation in future biennial avoided cost proceedings. The Commission also accepts the Public Staff's recommendation to consider other reliability metrics, specifically the equivalent unplanned outage rate, 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 explained by the Public Staff and supported by Duke, the EUOR metric appropriately excludes planned outages from calculation of the PAF. The Commission therefore requests that the Public Staff work with the Companies to evaluate the appropriateness of using EUOR as an alternative to EFOR in the next avoided cost proceeding to support development of an accurate and appropriate PAF. Finally, although the Public Staff initially advocated that the Utilities should begin to incorporate prospective data in applying the PAF metric, the Pubic Staff's Reply Comments suggest that further discussions with Duke supports the Commission's 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 the Companies' 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 since 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.

Based upon the foregoing and the entire record herein, the Commission concludes that a PAF of 1.05 should be utilized by DEC and DEP in their avoided cost calculations for all QFs except hydroelectric facilities without storage capability, and a PAF of 1.07 should be utilized by in their avoided cost calculations for all QFs except hydroelectric facilities without storage capability. The Commission further finds good cause for the Public Staff and the Utilities to consider the appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The basis for this finding of fact is found in the JIS, the Initial Comments of the Public Staff, the Initial and Reply Comments of the NC Small Hydro Group, and Duke's Joint Reply Comments. The Commission also takes judicial notice of Session Law 2019-132 ("HB 329").

Summary of the Evidence

In the previous avoided cost docket, Docket No. E-100, Sub 148, the Commission directed Duke to address whether the 2.0 PAF for hydroelectric QFs without storage eligible for the standard offer should continue for the standard offer in this biennial proceeding. *2016 Sub 148 Order* at 57. In their JIS, DEC and DEP proposed to retain the 2.0 PAF that the Commission had approved in previous avoided cost dockets. The Companies state they made this proposal due to the Hydro Stipulation that they entered into with the NC Hydro Group in Docket No. E-100, Sub 140. Under the terms of the Hydro Stipulation, the Companies agreed that they would continue to use a 2.0 PAF to calculate the avoided cost rates for hydroelectric QFs without storage that were five MW or less. Duke explained that DEC and DEP had 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 supported continuation of the 2.0 PAF for hydroelectric facilities without storage in their standard offer Schedule PP (DEC) and Schedule PP-3 (DEP). (JIS at 15-17)

In their initial comments, both the Public Staff and the NC Small Hydro Group supported the Companies' 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 one MW and five MW in size, the NC Small Hydro Group in its Reply Comments also supported Duke using a 2.0 PAF for hydroelectric QFs without storage up to five MW. The NC Small Hydro Group noted 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 argued that the General Assembly had recognized the need for hydroelectric QFs with a total capacity of five MW or less to have greater certainty in their future revenues by allowing those facilities between one MW and five MW to have fixed-term contracts that exceed five years. N.C. Gen. Stat. § 62-156(c)(ii). Thus, the NC Small Hydro Group claimed that there was no reason to treat these facilities differently with respect to the 2.0 PAF. (NC Small Hydro Group Reply Comments at 2-3)

On July 12, 2019, Duke filed a letter ("July 12 Letter") to counsel for the NC Small Hydro Group, which outlined the Companies' commitment to honor the Hydro Stipulation's provision for using 2.0 PAF for hydroelectric QFs without storage contracting to sell five MW and less until the expiration of the Hydro Stipulation on December 31, 2020. Duke explained, however, that their commitment was subject to any adverse regulatory decisions by the Commission finding that the Companies should not offer the 2.0 PAF to these small hydroelectric QFs.

Discussion and Conclusions

No party opposed the Companies' proposal to retain the 2.0 PAF for hydroelectric QFs without storage eligible for Duke's standard offer tariffs. Furthermore, the Commission is aware that only a limited and finite amount of hydroelectric capacity exists in North Carolina and that the North Carolina General Assembly has continued to provide for favorable treatment of small hydro facilities in both HB 589 and recent amendments to N.C. Gen. Stat. § 62-156. *See e.g*. HB 329, Section 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). Therefore, based on the foregoing, the Commission approves the use of a 2.0 PAF for calculating avoided cost rates for those hydroelectric QFs without storage that are eligible for Schedule PP.

The Commission further recognizes that the Companies have stated that they will continue to comply with the Hydro Stipulation with respect to offering the 2.0 PAF to small hydroelectric QFs without storage that are between one MW and five MW. Therefore, the Commission concludes that the Companies should work in good faith and consistently with N.C. Gen. Stat. § 62-156(b) to maintain that commitment, expressed in both the July 12 Letter and the terms and conditions of the Hydro Stipulation, to offer a 2.0 PAF to hydroelectric QFs without storage that are offering to sell the Companies five MW and less (but greater than one MW) of capacity until expiration of the Hydro Stipulation on December 31, 2020.

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

The evidence supporting these findings of fact is found in Duke's Joint Initial Statement, the Public Staff's Initial and Reply Comments, SACE's Initial and Reply Comments, NCSEA's Initial and Reply Comments, Duke's Joint Reply Comments, the NC Small Hydro Group's Reply Comments, and DENC's Reply Comments. The Commission takes judicial notice of all filings made in the 2018 Integrated Resource Plan ("IRP") Proceeding in Docket No. E-100, Sub 157, as they relate to the Utilities' respective determination of projected capacity need to serve system load.

Summary of the Evidence

In its JIS, Duke noted that in the *2016 Sub 148 Order*, the Commission had accepted the reasonableness of the overall Peaker Method, and found that avoided capacity value should be recognized beginning with the that the utility's IRP forecast shows a capacity need. This determination was consistent with N.C. Gen. Stat. § 62-156(b)(3), as amended by HB 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 . . .". (Duke JIS, at 12-13)

Duke indicated that their avoided capacity rates were consistent with the *2016 Sub 148 Order* and N.C. Gen. Stat. § 62-156(b)(3) in that they recognized each utility's next avoidable future capacity need based upon DEC's and DEP's most recent biennial IRP 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 did not take issue with DEC's and DEP's identified first avoidable capacity need, as presented in their 2018 IRPs. The Public Staff noted that pursuant to the 2018 IRPs, QFs located in DEC's service area that select a 10-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 10 years. The Public Staff also did not take issue with DENC's calculation of avoided capacity costs being consistent with the installed cost of a CT utilized in its 2018 IRP filed May 1, 2018, in Docket No. E-100, Sub 157, which shows the first deferrable capacity need in 2022. The Public Staff also indicated that if utility inputs change, such as the anticipated date of the first capacity need, the utility should update its avoided capacity calculations for negotiated contracts, as well as for CPRE Tranche 2. (Public Staff Initial Comments at 9-10, 17)

In its Initial Comments, SACE noted 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 stated that if capital investments are required in the near term, there could be a capacity need as early as 2019, and that capacity should be reflected in DEP's avoided capacity rates. (SACE Initial Comments at 14)

In regard to DEC's capacity need, NCSEA noted in its Initial Comments that while DEC contended that it had no capacity need until 2028, its IRP showed a 30 MW short-term market capacity purchase in 2020, and uprates at existing units in 2021, 2022, 2023, 2024, and 2025. NCSEA contended 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 and SACE's comments on DEC's and DEP's first avoidable capacity need, Duke explained in its Reply Comments that DEC and DEP determine their future (avoidable) generation need 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. When the annual planning reserve margin falls below the reserve margin (currently 17%), new capacity is required. As indicated by DEC's and DEP's most recent 2018 IRPs, DEC's and DEP's first avoidable capacity needs are in 2028 and 2020, respectively. Duke commented 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 indicated that the near-term planned nuclear uprates during 2019-2022 were 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, and include maintenance of system equipment including feedwater heaters and moisture separator reheater tubes. Duke concluded 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 indicated that the uprates were 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 agreed with Public Staff's recommendation that the Companies update their first year of avoidable capacity need in calculating avoided cost rates for future negotiated contracts as well as 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 calculations for negotiated contracts with larger QFs. (Duke Reply Comments at 41-42)

In its Reply Comments, the Public Staff restated that the year of capacity need should be determined by the IRP. It agreed with Duke that plant uprates should not constitute a deferrable capacity need, as they were essentially "sunk costs". The Public Staff pointed out that a utility should make plant uprates when it was 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.

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

In its Reply Comments, SACE indicated that it did not object to the Public Staff's recommendation that avoided capacity rates should be updated for negotiated contracts between biennial avoided cost proceedings to accurately reflect utility capacity needs, but SACE recommended 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 agreed with NCSEA that DEC's projected 30 MW short-term market capacity purchase in 2020 should be considered an avoidable capacity need. SACE noted its comments in Docket No. E-100, Sub 157 contending that Duke failed to evaluate the potential retirement of aging fossil plants in its modeling. SACE referenced its IRP comments which recommended 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 avoided cost Reply Comments, SACE recommended that if the Commission adopted this IRP recommendation, Duke should revise its avoidable capacity need to include any capacity need identified as a result of this modeling. (SACE Reply Comments at 7)

In regard to DENC, SACE contended 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 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 agreed with the Public Staff that the Commission should require a Utility Statement of Need in the IRP process. However, the NC Small Hydro Group recommended 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 noted that it refiled its 2018 IRP on March 7, 2019, as required by the VSCC. DENC pointed 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 argued that it had 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 stated that its reliance on a "No CO2" 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 responded 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 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 stated 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 2019-2021 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. Gen. Stat. § 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 need, 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 calculations for negotiated contracts, as well as for CPRE Tranche 2. As pointed out by NCSEA, planned wholesale power purchases are undesignated resources and thus, avoidable. However, the Commission agrees with the Public Staff and Duke that plant uprates should not constitute a deferrable capacity need, and that a utility should make plant uprates when it is reasonable and prudent to do so. Beginning with the 2020 IRP, the Commission finds it 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 NCSEA's Initial and Reply Comments, the NC Small Hydro Group's Initial and Reply Comments, Duke's Reply Comments, SACE's Reply Comments, the direct and rebuttal testimony of Duke witness Snider, the rebuttal testimony of DENC witness Petrie, the direct testimony of Public Staff witness Hinton, and the testimony of 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 HB 329, section 3, as recently enacted into law on July 19, 2019.

Summary of the Evidence

In its initial comments, NCSEA commented 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. Dr. 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 recommended 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 noted 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 contended that Duke's approach leads to reductions in capacity payments for QFs and rates lower than actual avoided capacity costs. They argued that Duke's approach penalizes these QFs that have provided energy and capacity for years, and suggested that it is inconsistent with PURPA. They distinguished their 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 contended that HB 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 in the future. (NC Small Hydro Group Initial Comments at 5-10)

In its Reply Comments, Duke stated 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 noted that it had been consistently using this approach for DEC and DEP in all IRPs since 2012. Duke explained that using this approach, the expiration of a wholesale contract can affect the timing of the Company's first capacity need. Duke contended that it was 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 recognized parties' interest in the timing of capacity additions and deficits, and agreed 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 found 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 stated its support for 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. SACE in its Reply Comments also agreed with the NC Small Hydro Group's position. (NCSEA Reply Comments at 10-11)

The NC Small Hydro Group in its Reply Comments agreed with NCSEA's position in its initial comments 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 pointed 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 reiterated 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 noted that it agreed 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 did not agree with the NC Small Hydro Group's conclusion that this approach will "reduce capacity payments to QFs."[4] The Public Staff pointed 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)

The Public Staff also noted 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 pointed 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

[4] Initial Comments of the NC Small Hydro Group at 7.

years, the Public Staff noted the importance of having the utilities file a formal Statement of Need as recommended by the Public Staff in the Sub 157 proceeding. (Id.)

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. Mr. 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. Mr. 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 at 52-55)

Public Staff witness Hinton reviewed Duke's assumptions regarding expiring PPAs. He noted that Duke's IRPs indicated a reduction in capacity from expiring biomass and hydro PPAs in the planning period, but an increase in capacity from solar facilities. Mr. Hinton stated that while this assumption regarding solar PPAs may be appropriate for planning purposes, it was inappropriate for determining the first year of capacity need as it could elongate the time before there is a capacity need. Mr. 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. Mr. 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, Mr. 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 at 311-314)

NCSEA witness Johnson argues 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 contends that contract renewals do not add new capacity, but maintain existing capacity. Dr. Johnson states 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 finds 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 warns the Commission against interpreting HB 589 to require taking the capacity of QFs without compensating them fairly, as unfair and discouraging investment in North Carolina. Dr. Johnson recommends 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 at 206-215)

In his rebuttal testimony, Mr. Snider indicated that the Commission's decision on this issue must be considered in accordance with HB 589's amendment of N.C. Gen. Stat. § 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. Mr. Snider noted that purchases of generation from swine and poultry waste were exempted, as the General Assembly, in HB 589, designated an immediate need for this generation to meet the requirements of the REPS Program. (Tr. Vol. 2 at 97-102)

Mr. 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, Mr. Snider contended that, actually, Dr. Johnson's approach was discriminatory in that it would favor existing QFs over new capacity resources, including new QFs. Mr. Snider explained that HB 589 directs the Commission to treat all small power producer QFs in a like manner, whether existing or new. In response to Dr. Johnson's contention that Duke's approach would result in a QF never being paid for capacity, Mr. Snider pointed to the DEP 2018 IRP's avoidable need in year 2 and the utilities' requests for proposals for new resources. Mr. Snider also rebutted Dr. 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. Mr. Hinton stated that Duke assumes solar PPAs are expected to be renewed or replaced by new solar capacity, in contrast to expiring contracts for other types of resources. (Tr. Vol. 2 at 102-109)

<u>Discussion and Conclusions</u>

The Commission finds HB 589's and HB 329's recent amendments to N.C. Gen. Stat. § 62-156(b)(3) to be controlling on this issue. HB 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 HB 589 adds to N.C. Gen. Stat. § 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 HB 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 HB 589 and HB 329 is to treat swine and poultry waste QF resources and legacy small hydro QF resources differently from other QFs in regards 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. Gen. Stat. 62-156, as amended by HB 589, specifically identifies the Utilities' statutorily-designated need to procure swine and poultry waste resources to meet REPS, while HB 329's specification that the small hydroelectric QF's PPA be in effect as of July 27, 2017 (the date that HB 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 pp 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, *[sic]* utilities purchase energy from particular sources of energy or for a long duration"), *reh'g* denied, 134 FERC ¶ 61,044 at 32 (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 itself 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. Gen. Stat. 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 and concludes 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 five 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. Gen. Stat. § 62-156(b)(3), as amended by HB 329. For other types of QF generation, it is appropriate under PURPA and consistent with N.C. Gen. Stat. § 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 and avoidable capacity need identified in DEC's, DEP's, or DENC's most recent IRP.

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

The evidence supporting these findings of fact is contained in NCSEA's Initial Comments; the Reply Comments of Duke, DENC, SACE, and the Public Staff; the direct testimony of Duke witness Snider, DENC witness Petrie, NCSEA witness Johnson, Public Staff witness Hinton; and the rebuttal testimony of Duke witness Snider, Duke witness Johnson, and DENC witness Petrie.

Summary of the Evidence

In its initial comments, NCSEA stated 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 utility's 2018 IRPs, NCSEA argued 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 for NCSEA, Dr. Ben Johnson states that the utilities treat 2019 as the starting point for calculating the biennial standard offer avoided cost rate calculations. (NCSEA Initial Comments, Attachment 1, pp 58-59) Affiant Johnson further stated 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.)

Dr. Johnson asserted that an unrealistic timeline distorts all of the avoided cost calculations, but has the most impact on the avoided capacity rates. 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). Dr. Johnson stated that DEP and DEC would have similar under-payments for capacity depending on their capacity need in certain years over the span of a 10-year contract. In Reply Comments, SACE agreed with

NCSEA's recommendation and stated 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 the Companies' avoided capacity credit calculation is 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) The Companies' Schedule PP rates are based upon an assumed 2019 in-service date and are available for an approximate two year period. Duke stated 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)

Additionally, Duke asserted 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. In fact, there are other uncertainties like the cost of natural gas which has resulted in obligations for Duke in excess of the utility's avoided cost. Lastly, Duke argued 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 stated that the Commission should reject NCSEA's proposed delayed hypothetical in-service date. (Id. at 49-50)

In Reply Comments, DENC argued 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 stated 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, recommended 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 stated that "[t]his period of time should be long enough to allow the QF to have sufficient information regarding its proposed rates in order 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 stated that the Companies do 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 at 281) An existing QF eligible for the standard offer would automatically have the right to enter into a new ten-year term PPA at the Companies' 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 Dr. Johnson also stated 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 at 59) The Public Staff agreed 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 North Carolina Interconnection Procedures (NCIP), which are routinely placed in service in less than a year. (Tr. Vol. 2, at 60). Moreover, witness Snider argued 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 who 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. DENC 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 at 30)

With regard to negotiated contracts, witness Petrie further stated that the proposal by Dr. 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 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. The Public Staff agreed 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. The Public Staff again recommended 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 at 314-5)

In 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 at 216, 222)

Dr. 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 at 217)

Dr. 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.)

With regard to 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. Dr. Johnson says 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 at 224)

Witness Hinton agrees 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 and believes it is consistent with N.C. Gen. Stat. § 62-156(c) and the Commission's March 6, 2015 *Order on Clarification* issued in Docket No. E-100, Sub 140 that it is appropriate for any party, in the course of negotiations, 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 and/or requiring the Utilities to publish and update multiple pricing schedules as recommended by NCSEA would inject uncertainty into the process. (Tr. Vol. 2 at 110)

DENC witness Petrie on rebuttal also stated that DENC agreed 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 at 45, 53)

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

Discussion and Conclusions

FERC's regulations implementing PURPA's mandatory purchase obligation expressly provide QFs the option to make a legally enforceable commitment to sell and deliver energy and capacity over a specified future term and to thereby obligate the utility and customers to purchase the QF's output. 18 C.F.R. 292.304(d)(2). FERC's regulations further provide the QF the option to elect for the utility's avoided costs to be calculated either at the time of delivery or based upon avoided costs calculated at the time the obligation is incurred. Id. at (i)-(ii). For QFs eligible for the Standard Offer, the General Assembly has also expressly required the Commission to biennially review and approve updated standard contract avoided cost rates, which are required to be made available in a tariff to all small QFs up to one MW that establish a LEO committing to sell to the Utilities during the biennial period. N.C. Gen. Stat. § 62-156(b). NCSEA has raised in this proceeding whether "delays" between the point in time that the QF elects to establish a LEO obligating the utility to purchase the QF's output and the point in time that the QF actually commences delivering power should be taken into account in calculating the avoided cost rates to be offered under either the standard offer tariff or otherwise offered to QFs not eligible through the standard offer tariff.

The Commission agrees with the Public Staff and the Utilities that the Utilities' consistent practice of calculating avoided costs for the current biennial period assuming an in-service date in the year following the biennial filing dates is reasonable and equitable to existing and new QFs, as well as to the Utilities and customers that are obligated to purchase the QFs' power at avoided costs. The Commission finds most persuasive Duke's and the Public Staff's argument that it is the QF that has the unilateral right under PURPA to elect when to commit to sell and deliver its power to the Utilities. Where a smaller QF is eligible for the Utilities' standard offer tariffs, the Utilities' avoided cost rates are transparently published and the QF may obligate itself to the utility at any point during the current biennial period or may elect to wait until new, updated avoided cost rates are filed for the next biennial period. For QFs not eligible for the standard offer, the Commission's process to establish a LEO is clear and the QF may take such action, at its option, at any point in time. In light of the fact that QFs, and not the Utilities, control the point in time that rates to be paid to the QF must be established under North Carolina's implementation of PURPA, the Commission rejects NCSEA's proposal to presume a delayed in-service date for QFs committing to sell and deliver their power under PURPA.

The Commission also specifically finds persuasive the Utilities' and Public Staff's testimony that it is not accurate that most small QFs are being delayed significantly during the interconnection process, since small QF projects eligible for the standard offer have access to the fast track and supplemental review processes of the NCIP. NCSEA witness Johnson even conceded that a reasonable in-service deadline for those projects may be earlier than his initial recommendation of December 31, 2021. Furthermore, the Commission agrees with the Public Staff that the use of a later in-service date, rather than in the year immediately following the biennial filing of avoided cost rates, would create a greater mismatch of payments made to QFs in relation to their expected avoided costs. The Commission also agrees with DENC that it would be arbitrary to choose a new presumed in-service date every avoided cost proceeding. Thus, for standard offer QFs, it is appropriate for the Utilities to continue to design rates to reflect the utilities' avoided cost assuming the QF's energy and capacity begins to avoid the utility's incremental cost of alternative energy during the biennial period. Because QFs can commit themselves to commence delivering power under the new biennial avoided cost rates as soon as such rates are filed with the Commission, the Commission finds and concludes that assuming the QF commences delivering power during the first year of the biennial period is reasonable and most accurately reflects the utility's costs to be avoided by purchasing from the QF.

With regard to negotiated contracts, the Commission finds it is appropriate to allow limited flexibility 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 extended timelines that may affect the project coming online. The Commission finds that it is consistent with N.C. Gen. Stat. § 62-156(c) and the Commission's March 6, 2015 *Order on Clarification* Docket No. E-100, Sub 140, which states that it is appropriate for any party, in the course of negotiations, to identify specific characteristics that merit consideration in the calculation of avoided cost rates. At the Hearing, Duke stated that using the actual in-service date for negotiated QFs is its current practice. However, the Commission also recognizes the risk that the Utilities' future capacity needs and energy costs that are forecasted to be accurate based upon an assumed future delivery term may differ from the utility's avoided costs that will be more clearly known and quantified as of the date that the QF establishes a LEO and obligates itself to sell power to the utilities. Recognizing that negotiated avoided cost rates under N.C. Gen. Stat. § 62-156(c) should be based upon the "Commission-approved avoided cost methodology" and the "utility's most recent biennial integrated resource plan"—both of which are reviewed every two years—the Commission cautions that the utilities should not be assuming QF delivery dates out farther than two years into the future for purposes of calculating avoided costs for negotiated QF contracts. As noted above, a QF has the unilateral right under PURPA's mandatory purchase obligation to either delay committing itself to closer in time to the QF's actual delivery date or the QF may elect to accept Duke's avoided cost based upon a delivery date assumed to be up to two years into the future.

Furthermore, the Commission notes the Public Staff's recommendation 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 Commission agrees with the Public Staff that this period of time should be long enough to allow the QF to have sufficient information regarding its proposed rates in order 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.

Duke stated that it currently allows a QF to submit a new Notice of Commitment no earlier than 12 months prior to the end of the QF's exiting PPA term. Duke explained that this period of time allows the QF more than the six months provided for in the Notice of Commitment form to execute a PPA, while ensuring that the QF will be paid reasonably accurate avoided cost rates at the time of delivery. The Commission finds this timeline is appropriate for this proceeding. With the filing of the Utilities' next avoided cost biennial rate application, the Utilities shall provide further justification for the timeline of the delivery of the Notice of Commitment to existing QFs and the Commission may further consider the issue in the next proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 - 33

The evidence supporting these findings of fact are found in Duke's Joint Initial Statement and Reply Comments, the direct and rebuttal testimony of Duke witnesses Snider, Wheeler, and Wintermantel, SACE's Initial and Reply Comments and the testimony of SACE witness Kirby, NCSEA's Initial Comments and the testimony of NCSEA witness Beach, the Public Staff's Initial and Reply Comments and the testimony of Public Staff witness Thomas, as well as the Solar Integration Services Charge Stipulation ("SISC Stipulation") between Duke and the Public Staff.

Duke's JIS, Direct Testimony, and Stipulation in support of Integration Services Charge

The Companies' JIS identified 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 the Companies' incremental costs of alternative energy to be avoided from purchasing power from a QF. The JIS further identified that 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. (Duke JIS at 30-31)

In accordance with these Commission directives, the JIS and Duke witness Snider explained 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, the JIS explained that Duke has included an Integration Services Charge in the Companies' rate design to reflect the impact on operating reserves, or generation ancillary requirements, for new variable and non-dispatchable solar capacity. (Duke JIS at 30-31; Tr. Vol. 2 at 38)

The JIS and Duke witness Snider further explained that meeting the Companies' obligation to provide reliable electric service to their 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 further explained that the energy output from solar resources is variable, and 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 explained that this additional uncertainty and volatility requires the Companies 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. (Duke JIS at 32-33, Tr, Vol. 2, at 78-81)

To quantify the increasing costs of integrating solar generation into the DEC and DEP systems, witness Snider explained that Duke had commissioned Astrapé Consulting ("Astrapé") in late 2017 to analyze the impacts of integrating solar into the Companies' 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, at 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 increase on the utilities' systems. As solar penetration increases, the uncertainty and intra-hour volatility in net load increases, meaning 5-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 at 51-56)

Witness Wintermantel then provided an overview of the Study explaining how Astrapé's Strategic Energy Risk Valuation Model ("SERVM") 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 the Companies' Commission-approved 2012 and 2016 Resource Adequacy studies, modeled the Companies' system reliability with and without solar at various penetration levels. Witness Wintermantel's direct testimony as well as the Companies' JIS explained 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 last, the additional Plus 1,500 MW of solar scenario (3,020 MW in DEC and 4,610 in DEP). Once the ancillary services required were determined, the costs of the ancillary service were also computed through the SERVM model. (Duke JIS at 32-33; Tr. Vol. 4 at 56-59, 65-66)

Witness Wintermantel explained that an important aspect of the Study is that SERVM 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. In order 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 Study used historical five minute load and solar data from the 12 month period between October 2016 – September 2017. Mr. Wintermantel explained 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 for each penetration analyzed. (Tr. Vol. 4 at 58-61)

After providing background on the Astrapé Study's inputs and modeling framework, witness Wintermantel explained that the underlying premise of the 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 the Companies' 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. Mr. Wintermantel explained 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. In order to maintain the same reliability on the system as before the solar was added, load following reserves needed to be increased. Witness Wintermantel testified that the 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 $\text{LOLE}_{\text{FLEX}}$ events and ACE deviations are not synonymous. (Tr. Vol. 4 at 62-66)

As also detailed in the JIS, witness Wintermantel testified that at the Existing plus Transition solar penetration level for DEC, the Study determined that an additional 26 MW of load following reserves were required to integrate 840 MW of solar. For DEP, the Study identified that 166 MW of additional load following reserves were required in order to integrate 2,950 MW of solar. He then explained the Companies’ 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. Mr. Wintermantel presented the Astrapé Study’s modeling results for DEC and DEP in Figures 4 and 5, 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. Mr. Wintermantel concluded that in his expert opinion, the Companies had appropriately used the results of the Astrapé Study to establish a reasonable Integration Services Charge. (JIS at 33; Tr. Vol. 4 at 66-74)

Duke and the Public Staff (“Stipulating Parties”) also entered into the SISC Stipulation, which addressed the quantification of DEC’s and DEP’s ancillary services costs as well as the Integration Services Charge rate design. The Stipulating Parties agreed in the SISC Stipulation that the Astrapé Study’s data, methodology, results, and conclusions are reasonable for purposes of quantifying the Companies' "average" and "incremental" ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating the Companies' respective Integration Services Charges. *SISC Stipulation*, at III. The *SISC Stipulation* also provided 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*, at IV.D.

Duke's JIS and Duke witness Wheeler supported the rate design for the Integration Services Charge. Witness Wheeler explained that Duke proposed to calculate 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 explained 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 legally enforceable obligation ("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's JIS also proposed to update the Integration Services Charge every two years as part of the biennial avoided cost proceeding. The Companies stated that they planned 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 the Companies' future portfolios. These proposals were agreed to by the Public Staff and memorialized by the Stipulating Parties in Sections IV of the *SISC Stipulation*. (JIS at 33-34; Tr. Vol. 2 at 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 also testified that he viewed 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, Mr. Wheeler explained that QF Sellers 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 at 230-233)

Witness Wheeler also 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 explained that the Integration Service Charge rate design recognizes that the Companies' 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 the Companies' 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. Therefore, Witness Wheeler explained that Duke supported 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 tariff. (Tr. Vol. 2 at 230-233)

Witness Wheeler also testified in support of a cap on future increases to the Integration Services Charge, as agreed to in Section VI of the *SISC Stipulation*, in order to mitigate 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 the Companies' systems during the term of Sub 158 Vintage PPAs. Witness Wheeler testified that while a cap to limit future adjustments to the Integration Services Charge was not consistent with how other costs incurred to serve distributed generation are treated, Duke agreed to cap future adjustments to the Integration Services Charge as a reasonable approach to address the Public Staff's concerns, discussed *infra*, and to offer QFs limited price certainty during their contract term. Witness Wheeler also testified that inclusion of a 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 at 228)

Duke witness Wintermantel quantified the cap consistent with the methodology used in the Astrapé Study to quantify the Integration Services Charge and as detailed in Section IV of the *SISC Stipulation.* Witness Wintermantel explained that at the direction of the Companies and in support Section of the *SISC Stipulation*, Astrapé performed additional modeling simulations to calculate the incremental ancillary service cost impact of the last 100 MW of solar 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 at 78-80)

Witness Wheeler explained that the cap amount would be incorporated into Schedule PP to prescribe that "In 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 at 229-230)

Section II of the *SISC Stipulation* also provided 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 the Companies) 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 reduces or eliminate the intermittency of the output from the operating solar generator. Witness Wheeler also clarified, however, in addition to demonstrating its capability to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements, the *SISC Stipulation* provides that solar QFs 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 at 229)

Witness Snider also testified in support of the *SISC Stipulation's* Controlled Solar Generator proposal explaining that the 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 did, however, testify 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 in order to avoid the Integration Services Charge. In support of this statement, Witness Snider provided several figures to illustrate how storage devices can be operated to smooth a facility's delivered energy output and ultimately reduce both the volatility of the facility's energy output and the need for the utility to provide increased ancillary services in response to solar volatility. Finally, Witness Snider explained 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 the Companies' cost of providing additional ancillary services to address the solar generator's volatility. (Tr. Vol. 2 at 147-158)

The Public Staff's Position

In the Public Staff's initial comments, the Public Staff agreed that DEC and DEP face operational challenges due to the intermittent nature of solar resources and due to the requirement to meet real time load on a minute to minute basis, online dispatchable resource should have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Furthermore, the Public Staff agreed 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 identified certain concerns with the Astrapé Study's modeling approach, which were ultimately resolved as further described in the direct testimony of Public Staff witness Thomas.

Public Staff witness Thomas began by noting how Public Staff witness Dustin Metz testified on the issue of integrating significant solar QF capacity in the 2016 Sub 148 docket, 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." Witness Thomas then stated that the Public Staff agrees that integrating intermittent, non-dispatchable energy sources cause system operators to make decisions and deploy the fleet of utility-owned generation assets in ways that can increase costs to customers, and further stated that this concept is generally uncontroverted within this proceeding. Specifically, witness Thomas explained that the increased system costs were 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 North American Electric Reliability Cooperation ("NERC") balancing requirements. (Tr. Vol. 6 at 356-358)

Next, witness Thomas re-introduced the Public Staff's technical concerns with the Astrapé Study that were first identified in the Public Staff's initial comments. He explained that, as stated in the Public Staff's reply comments, the Public Staff later withdrew some of these concerns based upon additional discovery and ongoing technical discussions with Duke and Astrapé. Specifically, the Public Staff's initial technical concerns regarding the SISC focused on the following: (1) the Astrapé model portrayed DEC and DEP as load islands; (2) the justification for the Study's No Solar "base case" excluding utility-owned solar resources; (3) the limited amount of data used to quantify solar volatility on five minute intervals, and the potential for inaccuracy of the Study's estimates of solar volatility, and therefore the integration costs, due to the geographical diversity of future solar generation facilities; (4) the model's addition of "load following up" reserves and the exclusion of other types of ancillary services that are capable of meeting intra-hour fluctuations in real time; and (5) the assertion, based on the analysis of SACE witness Kirby, that if Duke used a reliability standard that was too stringent, it would drive up the amount of ancillary reserves required to meet intra-hour fluctuations in solar output, thus resulting in integration cost estimates that are higher than actual costs incurred. (Tr. Vol. 6 at 358-361)

Public Staff witness Thomas next explained that Duke and Astrapé made technical staff available for multiple conference calls, responded to multiple data requests, and provided additional analysis, which ultimately resolved the Public Staff's concerns with the Astrapé model and study methodology. Therefore, the Public Staff supported the Companies' solar integration charge. Further, witness Thomas explained that the Public Staff had additionally performed a review of seven integration studies from other utilities to compare methodologies, assess how the studies were conducted, 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 indicated that Duke's proposed Integration Services Charge is generally reasonable and within the other range of studies. In sum, witness Thomas testified that the he believed that the methodology used to quantify the Integration Services Charge is reasonable and that assessing this charge on solar QFs is appropriate, and cited the Stipulation between the Public Staff and Duke in support of his viewpoint. (Tr. Vol. 6 at 361-367; Thomas Direct, Exhibit B)

Witness Thomas then explained how Duke had proposed to administer the Integration Services Charge by employing an "average cost" rate design, to be updated biennially. He explained that the Public Staff had issues with Duke's proposal to update the charge biennially, and to lessen these concerns the Public Staff proposed to either (1) charge solar facilities the incremental SISC (which is higher than the average SISC) and eliminate the biennial update or (2) charge solar facilities the average SISC and allow a biennially update, but implement a reasonable cap on the amount by which the SISC could change to provide certainty to QFs. He explained that through the *SISC Stipulation*, Duke agreed to apply a cap on potential future increases of the Integration Services Charge, as explained in Section VI of the *SISC Stipulation*. In support of the cap, he reiterated Duke witness Wheeler's statements that inclusion of a cap might result in some level of subsidization of QFs, but that the Public Staff believes that is important to ensure that the majority of costs imposed on intermittent solar QFs is recovered from intermittent solar QFs, and stated that the cap provided a reasonable balance between reducing uncertainty for QFs and refunding ratepayers for the cost of integrating intermittent QFs. (Tr. Vol. 6 at 368-372)

Next, witness Thomas testified concerning NCSEA and the Public Staff's proposals related to differing ancillary services costs for innovative QFs. He began by stating that although he is not a lawyer, it is his understanding that PURPA does not obligate the utility to purchase ancillary services from QFs. However, he stated that he agreed 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, which has the potential to reduce costs to ratepayers and facilitate the cost-effective. Witness Thomas also explained 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; (3) that the additional ancillary services needed, as identified by the Astrapé Study, is limited (192 MW), and therefore, that 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 facility unnecessary. He explained 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 QFs under the standard offer, per 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 at 376-381)

SACE's Position

SACE's Initial Comments presented an expert report by Mr. Brendan Kirby critiquing the Astrapé Study that Duke relied upon to quantify the Integration Services Charge. Arguing that the Astrapé Study was flawed in a number of respects, Mr. Kirby also sponsored direct testimony on behalf of SACE repeating many of the same concerns and arguments in opposition to the Astrapé Study. 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:

- The $LOLE_{FLEX}$ reliability metric is not related to mandatory NERC reliability requirements and is inappropriate for an integration cost analysis
- The production cost modeling assumption that DEC and DEP are "islanded" systems, disconnected from the Eastern Interconnection is wrong.
- Linear scaling of expected short-term variability from new solar generators as solar penetration rises is physically incorrect.

<u>$LOLE_{FLEX}$</u>

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 in his affidavit and testimony 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, Mr. 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 5-minute balancing that is the basis of the Astrapé Study. (SACE Initial Comments, Attachment A ("Kirby Report") at 3; Tr. Vol. 5 at 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 Mr. Kirby acknowledged that an LOLE of 0.1 is an appropriate and accepted standard for long-term planning of reserve capacity, he believed it was inappropriate in this matter, unrequired by NERC, and "excessively expensive" when applied to actual operations. He expanded his explanation in his direct testimony when he stated that the 0.1 $LOLE_{FLEX}$ requirement was inappropriate because a 5-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. He further criticized use of the 0.1 $LOLE_{FLEX}$ because it was unrelated to NERC requirements, and concluded it was an unreasonable proxy for actual balancing and reliability requirements. Witness Kirby elaborated that the applicable NERC reliability standard is BAL-001-2, the Real Power Balancing Control Performance. It establishes two reliability metrics that apply during normal operations: Control Performance Standard 1 ("CPS1") and the Balancing Authority ACE Limit ("BAAL"). (Kirby Report at 3-5; Tr. Vol. 5 at 178-182)

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 had been replaced in July 2016 with the BAAL requirement BAL-001-02. He characterized CPS2 has a much laxer balancing requirement than the 0.1 $LOLE_{FLEX}$ requirement because CPS2 measured balancing over 10-minute intervals and required compliance only 90% of the time. According to Mr. 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, overgeneration helps to raise frequency and aids reliability. Conversely, when interconnection frequency is above 60Mz, undergeneration 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. Witness Kirby further criticized the Astrapé Study because, in addition to CPS1, it referenced the CPS2standard that was replaced in July 2016 with the BAL-001-02 requirement. He also characterized the CPS2 standard as less stringent than the $LOLE_{FLEX.}$ Witness Kirby also remarked that Duke had recently given a presentation to the NERC Operating Committee where it had shown Duke's operational focus to be on integrating solar based on actual NERC balancing metrics BAAL and CPS1 instead of the $LOLE_{FLEX}$. Therefore, witness Kirby concluded that the Astrapé Study used an unnecessarily stringent standard that resulted in an inflated SISC. (Tr. Vol. 5 at 181-185)

Islanded Systems

Witness Kirby also disagreed with the Astrapé Study's 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 the Companies operate. (Tr. Vol. 5 at 185-189)

Witness Kirby also cited DEC's and DEP's participation in the VACAR Reserve Sharing Group, which, he asserted, enabled 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 at 190-191)

Unsupported Assumption that Solar Variability Scales Linearly

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 Study's linear scaling of existing solar plant output data to represent new solar plants at higher penetrations. Witness Kirby had reviewed the historic solar output of DEC and DEP, which he asserted showed an expected trend of short-term variability increasing more slowly than solar capacity as solar penetration increases. Thus, witness Kirby believed that the assumption of linear scaling is unjustified. He also faulted the Astrapé Study as using unrealistic geographic locations, lead to an increased short-term variability. (Tr. Vol. 5 at 192-194)

Idaho Power Integration Cost Study

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 employed 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 5-minute deviations of solar output. He emphasized that the Idaho Study allowed a cumulative 90 hours per year of deviations rather than one-event-in-ten-years, like the Astrapé Study relied upon by Duke. Mr. 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. Mr. Kirby also testified that he disagreed with Duke witness Wintermantel's direct testimony in which witness Wintermantel noted that the Idaho Study's incremental load following reserves were comparable to the load following reserves required by the Astrapé Study. Instead, witness Kirby plotted integration requirements based on solar penetration percentages. His graph illustrated that Idaho Power had higher rates of renewable penetration, but DEC's and DEP's additional operating reserves far exceeded Idaho Power's as a function of renewable generation penetration. (Tr. Vol. 5 at 200-205)

NCSEA's position

In its initial comments, NCSEA alleged that the imposition of an Integration Services Charge as proposed by the Companies was inconsistent with previous Commission decisions in Sub 140 and Sub 148 because: (i) the Companies 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 argued 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 argued that the Companies' request and DNCP's similar request to implement a re-dispatch charge through this avoided cost proceeding is improper as it is single-issue ratemaking. As such, NCSEA indicated that any Integration Services Charge should be set during general rate cases. NCSEA agreed with the Companies that 18 C.F.R. § 292.304(e) allowed for the consideration of factors that may affect rates in determining avoided costs, but noted that ancillary services were not listed among the factors and that charging intermittent QFs for ancillary services was not allowed. (NCSEA Initial Comments at 47-49)

Moreover, NCSEA also contended that the Astrapé Study was deficient in several ways. First, the 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 argued 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)

NCSEA also attached to its initial comments the affidavit of R. Thomas Beach, who subsequently also filed direct testimony NCSEA's behalf. Witness Beach indicated that he agreed with the concerns about the Astrapé Study expressed by SACE witness Kirby, and he also raised several other deficiencies. In addition to supporting the potential for increased solar penetration and integration cost savings through adoption of an EIM, Mr. Beach argued that the Astrapé Study appeared 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 indicated that utility-scale projects have demonstrated the capability to provide ancillary services, including upward regulation and load following. He also faulted the Astrapé Study for not modeling the pairing of solar and storage projects. Mr. Beach asserted 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. (NCSEA Initial Comments Attachment 2, at 5)

Witness Beach additionally urged the Commission not to approve the Integration Service Charge, as proposed by Duke, arguing that the integration benefits of solar QFs outweigh the costs. He specifically suggested that the increased ancillary services costs identified in the Astrapé Study were offset by two other benefits. First, he argued that Duke failed to analyze and quantify proposed avoided transmission and distribution capacity costs associated with integrating QF solar onto the Companies' distribution systems. Mr. Beach suggested that QF generation can reduce peak loads on the utilities' transmission and distribution systems, allowing the utilities to avoided capacity-related transmission and distribution costs. Witness Beach also asserted 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 in to wholesale power markets can suppress market prices thereby benefiting utilities and customers. He also argued that the SISC should not be applied in any case when a solar project includes significant storage. (*Id.* at Exhibit 1, at 6, 19-21)

Duke's Response through Reply Comments and Rebuttal Testimony

In reply comments, Duke began by rebutting NCSEA's arguments that an Integration Services Charge, in general, is inconsistent with PURPA and prior Commission decisions. Duke explained that FERC's implementing regulations expressly acknowledge that standard avoided cost rates may differentiate among QFs using various technologies based on their supply characteristics in setting avoided costs. Additionally, as noted in the Companies' JIS, 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 responded that the Companies' 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 pointed out that other state commissions had similarly established wind and solar-only integration charges as separate charges from avoided energy rates. Duke also rebutted NCSEA's argument that establishing the Integration Services Charge in this proceeding violated the prohibition on single issue ratemaking, explaining that while Duke agreed that general rates charged by a utility should be set in a general rate case proceeding, this standard was irrelevant in this case where the rates to be established are rates paid by the utilities to QFs under PURPA. Duke argued that establishing the Integration Services Charge was well within the Commission's authority under N.C. Gen. Stat. § 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 Study, Duke's Reply Comments reiterated that the proposed Integration Services Charge is a conservative first step in incorporating the appropriate integration price signal for intermittent solar resources on the Companies' system. Specific to parties' concerns over the Study modeling DEC and DEP as islands, the Companies explained that the Public Staff's and Mr. Kirby's assumptions that the Companies can rely upon external market assistance from other BAs, VACAR Reserve Sharing Group members, or transfers of non-firm energy under the Companies' Joint Dispatch Agreement to meet regulation reserve requirements on a real-time, intra-hour basis is simply incorrect. In response to NCSEA's critique that the Study is flawed because intra-hour interchange of power could potentially be achieved through "regional cooperation" in the form of an EIM, Duke explained 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 noted that the Idaho Study identified by SACE and Mr. Kirby as a reasonably acceptable integration study, similarly does not assume regional cooperation exists to manage intra-hour volatility, despite Idaho Power participating in the Western EIM. Additionally, the Companies 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 Study model. In explaining the utilities' actual system operations and presenting these additional sensitivity analysis, the Companies' supported analyzing DEC and DEP as islands for purposes of the model, and illustrated 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 - September 2017 to quantify future volatility, Duke's reply comments explained that the 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 Mr. Kirby aptly characterized the Study as "model[ing] solar sites that do not yet exist and for which there is no actual data," the Companies explained 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 highlighted 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 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; and thus, Duke explained the Study is not unreasonable in that its most forward-looking scenario analyzed is the most uncertain scenario produced in the Study. (Duke Reply Comments at 102-105)

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 - September 2017, Duke's Reply Comments explained that Astrapé began the Study in the fall of 2017, meaning the data used was the best and most current data available at the time. The Companies did 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, the Companies advocated for 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, gas forecasts, etc., to ensure that the solar resource data is up to date and accurate. As discussed *supra*, 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 108-110)

As to the issue of applying the Integration Services Charge on an incremental or average basis, Duke's Reply Comments explained 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. The Companies then noted 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, the Companies contended that this was a risk faced by all business owners that can't control 100% of the factors impacting their business and 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. The Companies then emphasized that 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 102-108)

As to SACE expert Kirby's comments stating that the Astrapé Study inappropriately models contingency reserve requirements, the Companies' explained that his argument is flawed and incorrectly states that SERVM does not use contingency reserves where there is a loss of a generator or other reliability issues. The Companies' reply comments went on to provide additional clarifications in response to SACE expert Kirby's criticism of the model and $LOLE_{FLEX}$ metric, contending that Mr. Kirby had misunderstood the methodology of the model and therefore raised concerns inapplicable to the methodology actually used in the Study. Thus, the Companies dismissed SACE's criticisms of the Study, explaining that the criticisms were based upon an incorrect characterization of the $LOLE_{FLEX}$ metric used in the Study. In support of the reasonableness of the Astrapé Study, Duke presented 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 noted that Idaho Study suggests that the probability metric is "relatively immaterial" because the modeling objective of the Study is to maintain the system at the same level of reliability both before and after solar is added to the system. In sum, the Companies' Reply Comments exemplified that the Public Staff's and other intervenors' technical concerns should be dismissed by further explanation of the Study, and that the 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, 113-115)

Through rebuttal testimony, Duke also provided support for the *SISC Stipulation* and responded to critiques raised by intervenor witnesses. Witness Snider first 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 the Companies to incur increased ancillary services cost and and—absent an appropriate charge being established—such costs will continue to be recovered from customers. (Tr. Vol. 2 at 136-137)

In response to NCSEA witness Beach's advocacy that the Commission should recognize that future solar generators will be more controllable and that battery storage can reduce or eliminate integration costs, Mr. Snider explained 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 which 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 highlighted that the 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. Mr. 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 Mr. Beach's recommendation that the Integration Services Charge should not be approved without recognizing purportedly offsetting "benefits" of integrating solar generation (the lower overall wholesale market prices due to integration of zero-variable cost renewables; and avoided transmission and distribution capacity cost savings due to distributed solar). Referring to Duke's prior Reply Comments, Witness Snider testified that, unlike the reduced line losses actually avoided by distribution connected QFs (which the Companies continue to recognize in quantifying avoided energy costs), the two 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, Mr. Beach's reasoning for opposing the Integration Services Charge should be rejected. (Tr. Vol. 2 at 139-141, 146-147)

In response to NCSEA witness Beach's advocacy that the Commission should consider an ancillary services market like the Western EIM to enable QFs to provide ancillary services, as opposed to approving the Integration Services Charge, witness Snider opposed this recommendation. First he explained 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 the Companies 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. 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 at 142-145)

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 supported the methodologies and assumptions underlying the Astrapé Study, as agreed in the *SISC Stipulation*. He then responded to SACE witness Kirby, who continued to argue that the $LOLE_{FLEX}$ metric inappropriately requires the system to maintain enough ramping capability to match 5-minute load ramps in all but one period every 10 years, meaning that the simulations are solving for a system that will only have one 5-minute balancing deviation every 10 years. Witness Wintermantel explained, as he had previously done in his direct testimony (and Duke had previously done through Reply Comments), that SERVM models the DEC and DEP systems assuming perfect foresight for the next 5-minute time step, meaning net load is frozen and generators are allowed to catch up to load. Given this perfect foresight, SERVM should attempt to carry enough reserves to match the 5-minute ramps in all but one period in 10 years; however, in reality, operators never have perfect foresight, so many 5-minute balancing deviations are expected to occur every year. He explained further that, if Astrapé had added reserves consistent with the largest 5-minute unexpected solar deviation in 10 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 through SERVM for DEC and DEP. (Tr. Vol. 4 at 86-88)

Moreover, witness Wintermantel explained that SERVM is not even capable of identifying the frequency of 5-minute balancing deviations, and that the balancing requirements imposed by the NERC CPS1 and BAAL standards do not conflict with the 0.1 $\text{LOLE}_{\text{FLEX}}$ metric. Thus, the 0.1 $\text{LOLE}_{\text{FLEX}}$ metric is not designed as a measure of a system's compliance with NERC CPS1 and BAAL standards. However, the NERC balancing standards and $\text{LOLE}_{\text{FLEX}}$ metric should correlate, meaning that if $\text{LOLE}_{\text{FLEX}}$ is allowed to increase substantially, it is expected that the NERC CPS1 and BAAL standards would be violated more often. To further rebut Mr. Kirby's arguments, witness

Wintermantel explained that Astrapé performed additional calculations at the request of the Public Staff, which demonstrated that if the flexibility reliability were measured at 1.0 events per 10 years—*i.e.* the metric was "relaxed" to be "less stringent" by being increased 10-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, witness Wintermantel testified that Mr. Kirby's objection to the subjective nature of the $LOLE_{FLEX}$ metric was overstated, and explained that even the Idaho Study supported by Mr. Kirby similarly recognized that the selected reliability level is "relatively immaterial" in terms of quantifying integration cost since both the base case and change case are subject to the same metric. Further, Mr. Wintermantel explained that Astrapé compared the results of the Idaho Study to the Astrapé Study, and the results were reasonably similar. Last, concerning the Idaho Study, witness Wintermantel explained that Mr. Kirby's alternative comparison of operating reserves based on a function of solar penetration is an inappropriate comparison and should therefore be ignored, since the studies employ two different modeling approaches. (Tr. Vol. 4 at 88-97)

Next, witness Wintermantel explained that Mr. Kirby additionally incorrectly compared the need for load following reserves to 1-minute net volatility, since load following reserves are intended to cover volatility over longer 5-minute time steps. He further explained that Mr. 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. He further explained that SERVM implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves. Witness Wintermantel additionally explained that 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 Mr. Kirby's concerns that an automatic generation control ("AGC") tuning effort undertaken by Duke Energy's system operations staff conflict with the assumptions made in the Study, he explained that there is no conflict because the Astrapé Study does not penalize solar for one-minute movements since it is conducted on a 5-minute basis with perfect foresight, and cited Mr. Kirby's own statements explaining that it is infeasible to actually model NERC BAAL standards in real time. Witness Wintermantel then explained that Mr. Kirby's formula supporting his statement that intra-hour volatility declines according to a specific formula lacks empirical evidence, and contended that given the uncertainty in an actual diversity benefit of solar, 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 data is most accurate. (Tr. Vol. 4 at 97-103)

In response to NCSEA witness Beach, witness Wintermantel disagreed with his 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," and cited to CAISO's 2016 Annual Market Performance Report stating that ancillary service costs had nearly doubled from 2015. Witness Wintermantel next rebutted NCSEA witness Johnson's claims that Astrapé modeled one site per grid zone, which he argued potentially misses diversity across the fleet. Witness Wintermantel explained that Astrapé was concerned with the intra-hour diversity which would not be captured in the hourly solar profiles that were developed with NREL data, so the number of sites modeled would not have a significant impact on the Study. In conclusion, witness Wintermantel disagreed with Mr. 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 at 103-107)

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 Stipulating Parties. Mr. 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 the Companies' 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. Therefore, the Integration Service 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 at 240-241)

Hearing

During the hearing, interveners 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 interveners in November of 2018, providing 8 months of review opportunity, 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 interveners 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 solar Integration Services Charge. Duke witness Wintermantel also testified that typically the technical studies that his consulting firm conducts for utilities and state public utility commissions 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, that 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. Public Staff Witness Thomas 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 now. (Tr. Vol. 3 at 11-14; Tr. Vol. 4 at 204-205; Tr. Vol. 6 at 433; Tr. Vol. 7 at 105)

In response to questions from NCSEA, Duke witness Wheeler explained that the Companies' 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. At the end of the hearing, Commissioner Clodfelter inquired as to what the Public Staff's position was as to whether the solar Integration Services Charge would apply to the CPRE and GSA programs, since the Duke witnesses had indicated that the solar integration charge would likely impact the CPRE and GSA programs. Public Staff witness Thomas stated that if an uncontrolled solar generator is participating in those proceedings, then, yes, that charge would be considered, but noted that there were complexities in implementing the charge under the CPRE program and that the Integration Services Charge had not been previously discussed in the GSA Program proceeding. (Tr. Vol. 2 at 290-291; Tr. Vol. 7 at 131-135; *see also* Tr. Vol. 2 at 350-351)

DISCUSSION AND CONCLUSIONS

As the *SISC Stipulation* has not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998) (CUCA I), and State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000) (CUCA II). In CUCA I, the Supreme Court held that

> a stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence

> presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.
>
> 348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit a court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. CUCA II, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court held that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id*. at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of the Public Staff and the Duke witnesses regarding the issues addressed in the Stipulation. The Commission concludes that the Stipulation is the product of the "give-and-take" of settlement negotiations between Duke and the Public Staff, in an effort to appropriately balance these parties' interests in reasonably and accurately quantifying the increased ancillary services costs being incurred by Duke and customers as a result of the growing solar generation being installed on the DEC and DEP systems, as well as establishing a fair and reasonable rate design to prospectively apply the Integration Services Charge to all future uncontrolled solar generators proposing to deliver power into to the DEC and DEP systems.

Thus, the *SISC Stipulation* generally strikes a fair balance between the interests of the Stipulating Parties as well as solar generators that will be subject to the Integration Services Charge. As discussed above, and further detailed in the Commission's findings of fact and subsequent discussions and conclusions, the Commission has fully evaluated the provisions of the *SISC Stipulation* and concludes, in the exercise of its independent judgment, that the provisions of the *SISC Stipulation* are just and reasonable to all parties to this proceeding in light of the evidence presented and serve the public interest.

a. <u>The Proposed Integration Services Charge Conforms to the Commission's Prior Orders</u>

In the 2014 Sub 140 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. In that proceeding, 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 PV penetration should be taken into account in calculating Duke's avoided energy cost rates. *2014 Sub 140 Phase I Order*, at 57. After extensive review and discussion by the parties to that proceeding, the Commission ultimately determined that it was premature for the utilities to include integration costs associated with increasing levels of solar integration in their calculation of avoided cost rates. *Id.* at 60. 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, Finding of Fact 10.

In the 2016 avoided cost proceeding, the Commission identified 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," specifically highlighting 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 in the 2016 Sub 148 proceeding. The Commission's *2016 Sub 148 Order* also announced certain directives for the Utilities to follow in developing their avoided costs to be filed in this instant proceeding, including directing 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. *2016 Sub 148 Order*, at 98. In the Commission's *Scheduling Order* initiating this proceeding, 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 the Companies' incremental costs of alternative energy to be avoided from purchasing QF power.

Duke's JIS presented the Integration Services Charge as responsive to these directives and as necessary to recognize integration costs that Duke is now incurring in order to appropriately value the energy and capacity provided by QFs eligible for Schedule PP. Duke highlighted that installed utility-scale QF solar capacity in DEC and DEP had 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. Based on Duke's recent experience integrating surging levels of variable and intermittent solar QF power, the JIS explained that Duke included the Integration Services Charge in the Companies' rate design to reflect the impact on operating reserves, or generation ancillary requirements, as increasing levels of variable and non-dispatchable solar capacity continued to be installed on the DEC and DEP systems.

The Commission finds that Duke's proposed Integration Services Charge is reasonable and responsive to the Commission's directives in the *2016 Sub 148 Order* and the Commission's *Scheduling Order* initiating this proceeding, and appropriately evaluates the unique cost characteristics of intermittent and non-dispatchable QF-supplied power. Moreover, the Commission finds that the Astrapé Study relied upon by Duke to develop the Integration Services Charge is appropriately responsive to the Commission's directive in the *2014 Sub 140 Phase I Order* to develop detailed integration cost studies to support any future adjustment to avoided cost rates to reflect costs being incurred by the Utilities to integrate QFs.

The Commission also finds that the proposed Integration Services Charge appropriately reflects the current regulatory framework under North Carolina's Public

Utilities Act and agrees with Duke witness Snider that NCSEA witness Beach's generalized discussion of the benefits of an EIM structure are beyond the scope of this current biennial proceeding to implement PURPA in North Carolina.

b. <u>NCSEA's Arguments Regarding the Appropriateness and Lawfulness of the Integration Services Charge are Rejected</u>

NCSEA puts forward a number of arguments and legal theories to suggest that Duke's Integration Service Charge is either inappropriate under prior Commission Orders or legally deficient and, therefore, should not be approved. The Commission finds each of these arguments without merit. First, NCSEA alleges that Duke failed to fully consider both the costs and benefits of integrating solar, citing to language from the *2014 Sub 140 Phase I Order*, discussing potential additional factors to be considered in quantifying the Utilities' avoided costs including "the potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support." *2014 Sub 140 Phase I Order*, at 60. In this proceeding, Duke witness Snider testified that the Companies retained Astrapé Consulting to evaluate the ancillary services costs associated with integrating solar QFs and independently determined that it was appropriate to continue to recognize the benefit of reduced line losses associated with distribution connected QFs. Duke determined that both of the factors appropriately reflected real and measurable costs being incurred or avoided, while Witness Snider further explained that no other known or measurable costs or benefits exist that should be included in the Companies' avoided costs at this time. (Tr. Vol. 2 at 373-374) The Commission finds that the record supports Duke's conclusion and, as noted above, finds Duke's decision to undertake a detailed integration cost study focusing on the increased intra-hour ancillary services costs specific to solar QFs providing intermittent and non-dispatchable QF-supplied power to be reasonable and responsive to the Commission's *2016 Sub 148 Order*. Notably, NCSEA through the testimony presented by Mr. Beach independently proposed two other potential "benefits" of integrating QF solar: (i) avoided capacity-related transmission and distribution costs; and (ii) wholesale market price suppression benefits associated with increasing renewable QF power. The Commission addresses these recommendations in other parts of this order and finds that the record has allowed the Commission to satisfactorily assess the avoided costs and potentially offsetting benefits of integrating QFs in to the DEC and DEP systems.

The Commission also rejects NCSEA's arguments that the Integration Services Charge is not encompassed within the Commission's authority to establish a "rate" for utility purchases of QF energy and capacity under FERC's implementing regulations. *See* 18 C.F.R. § 292.101(b)(5). The Commission finds this definition broader than characterized by NCSEA, and specifically allowing the Commission, as part of its broad authority to implement PURPA, to establish ". . . any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity." Recognition of differences in costs avoided or incurred by a utility as a result of purchasing power from a QF is fully consistent with FERC's regulations which provides that the Commission should take into account, to the extent practicable, factors specifically related to the purchase from the QF at issue. *See* 18 C.F.R. § 292.304(c)(3)(i). FERC's regulations establishing rates for purchases from QFs further provide that the "individual and aggregate value of energy and capacity from [QFs] on the electric utility's system" should be taken into account in quantifying the costs to be avoided by utilities in making purchases from

QFs under PURPA. 18 C.F.R. § 292.304(e)(2(vi). The Commission, therefore, finds that Duke's proposed Integration Services Charge is a reasonable charge within the Commission's authority to adopt in this proceeding, and that the Charge appropriately recognizes the ancillary services cost of integrating the energy produced by solar QFs onto the Companies' systems.

The Commission also rejects NCSEA's argument that the solar Integration Services Charge is a "compensation or charge" under the Public Utilities Act that must be set a during general rate case pursuant to the requirements of N.C. Gen. Stat. § 62-133. As recognized by Duke, the Public Utilities Act's definition of "rate," as set forth in N.C. Gen. Stat. § 62-3(24), applies to charges made "by ***any public utility***, for any service product or commodity offered by it to the public." The Commission agrees with Duke that this provision of the Public Utilities Act is not relevant or controlling in this case where the rates to be established are rates *paid* by the utilities to QFs under the Commission's delegate authority to implement PURPA. *See* 16 U.S.C. § 824a-3(f)(1). Notably, the Public Staff did not raise concerns similar to NCSEA's and, in fact, advocated that DENC should similarly collect and administer these costs separately from the avoided energy rate that is paid to these QFs. The Commission finds that Duke's proposed solar Integration Services Charge does not fall under the purview of N.C. Gen. Stat. § 62-133, which governs the fixing of rates to recover the utility's cost of providing utility service to retail customers; rather, it is appropriately developed and analyzed in the context of a proceeding to examine a utility's avoided cost rates for purchase from QFs under N.C. Gen. Stat. § 62-156. Accordingly, NCSEA's single-issue ratemaking argument should be rejected.

The Commission also finds Duke's approach to designating the Integration Services Charge as a separate cost or charge to be established in Schedule PP and through negotiated PPAs entered into by DEC or DEP—similar to an administrative sellers charge—to be appropriate. The Commission further finds that Section IV.D of the *SISC Stipulation* appropriately 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.

c. Quantification of DEC's and DEP's Integration Services Charge

Throughout this proceeding, the accuracy and appropriateness of the Astrapé Study's quantification of DEC's and DEP's ancillary services costs attributable to integrating intermittent solar QFs has received much interest and discussion. Duke witnesses Snider and Wintermantel, Public Staff witness Thomas, and SACE witness Kirby each testified extensively regarding the Astrapé Study, and provided the Commission their expert perspectives on its technical merits. Consistent with the provisions of the *SISC Stipulation* agreed to between Duke and the Public Staff, the Commission finds that the data, methodology, results, and conclusions of the Astrapé Study are reasonable for purposes of quantifying the Companies' "average" and "incremental" ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating the Companies' respective Integration Services Charges at this time.

In arriving at this conclusion, the Commission initially finds persuasive Duke witness Snider's testimony that no expert witness in this proceeding disputes the basic premise of the Study—that Duke is incurring increased intra-hour ancillary services cost to integrate the already very significant "Existing plus Transition" level of QF solar into the DEC and DEP systems. The Commission finds persuasive the detailed testimony by Duke witness Wintermantel and Public Staff witness Thomas that the uncertainty and intra-hour volatility of managing "net load" as solar is integrated in to each utility's system is greater than the volatility of load alone, and that reliably integrating the increased levels of uncontrolled must-take solar generation requires Duke to maintain increased real-time system operating reserves. Operating the conventional generation fleet to provide these increased load following operating reserves results in increased system costs due to higher fuel and maintenance costs as thermal fleet generating units are required to operate outside their optimal output range, and dispatchable units are required to start more frequently causing additional startup and maintenance costs.

In addition to generally accepting the basic premise of the Study, no party challenged Duke's objective of quantifying the near-term projected Existing plus Transition level of solar to be installed on the DEC and DEP systems based upon modeling a projected 2020 study year. Based upon the evidence in the record, the Commission finds that it was appropriate to quantify the increased ancillary services costs to integrate 840 MW of solar in DEC and 2,950 MW of solar in DEP for purposes of quantifying the Integration Services Charge.

The Commission also generally finds Mr. Wintermantel's testimony in support of the Study methodology to be persuasive. Mr. Wintermantel's testimony and the Astrapé Study itself provide a detail description of the data and assumptions inputted into the SERVM Model, the methodology that Astrapé undertook to develop the Study, and provides a reasonable explanation of the results of the modeling and summarizes the overall findings of the Study. However, the Commission also recognizes that the Study's quantification of Duke's increased ancillary services costs presented novel and complex issues that warranted (and appropriately received) extensive evaluation and investigation from the parties to this proceeding. Therefore, further consideration of the appropriateness of the study methodology and conclusions is warranted.

The Commission recognizes that the Public Staff's position in this proceeding has evolved from initially identifying certain concerns with the Astrapé Study in the earlier comment phase of the proceeding to subsequently determining after further investigation that the Study methodology and results were reasonable and appropriate. The record reflects that the Public Staff invested significant time to investigate the Astrapé Study through discovery, technical discussions with Duke and Astrapé personnel, requests for further post-Study analyses and validation, as well as through independently evaluating the Astrapé Study compared to other recent integration studies across the Country. (Tr. Vol. 6 at 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 review of seven integration studies from other utilities to compare methodologies, assess how the studies were conducted, whether the utilities were modeled as load islands, and what metrics were used to evaluate the system impact of intermittent resources, indicated that Duke's proposed Integration Services Charge is generally reasonable and within the range of other studies.

The Commission has similarly invested significant time and effort in its review of the testimony and other evidence in the record with regard to the continuing disagreements as to the validity of certain aspects of the Astrapé Study between Duke witness Wintermantel and Public Staff witness Thomas on the one hand and SACE witness Kirby on the other.

As to Witness Kirby's critique that it was inappropriate for Astrapé to model the DEC and DEP systems as standalone BAs or "islands" disconnected from the Eastern Interconnection, the Commission finds persuasive witness Wintermantel's testimony that the SERVM model implicitly does recognize the benefits of participating in an interconnected system by modeling reserves in the No Solar case that are comparable to historical reserves during interconnected operations. The Commission also agrees with Duke that while each BA is interconnected with other BAs in the surrounding regions, it is inappropriate to assume that Duke will be able to rely upon surrounding BAs to incur additional costs to provide the system flexibility needed to respond to the increased volatility caused by solar on the Duke systems. Both witness Wintermantel and witness Kirby agreed that a fundamental objective of integration cost modeling is to quantify the additional costs of managing solar volatility while maintaining the same level of reliability on the system that existed before the solar was added. Therefore, the Commission agrees with Duke witness Wintermantel that it would be unreasonable for the integration cost modeling to assume a larger burden can be imposed on other BAs across the Eastern Interconnection after adding solar than what was assumed prior to adding solar.

The Commission also finds persuasive Mr. Thomas' concurrence with Duke that DEC and DEP operate independently of each other and that, while the Joint Dispatch Agreement between DEC and DEP allows for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra-hour ancillary services needed to manage the variability in solar output. Further, Mr. Thomas identified the Public Staff's investigation of other integration cost studies across the Country suggested that modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-time solar and wind output fluctuations is not uncommon. For example, the record supports that the Idaho Study similarly modeled that utility's operations as an islanded power system for purposes of evaluating solar integration costs. (Tr. Vol. 5, at 136, Tr. Vol. 6, at 363) Accordingly, the Commission finds this aspect of the Study to be reasonable and rejects Mr. Kirby's critique.

With regard to Witness Kirby's critique of the 0.1 $LOLE_{FLEX}$ metric as being inappropriate and overly stringent, the Commission is challenged to reconcile Mr. Kirby's extensive discussion of the NERC balancing standards with his recognition that it is currently an infeasible modeling exercise to directly model the NERC balancing standards. While it is undisputed the Duke BAs are required to maintain operational compliance with the NERC balancing standards, the record clearly supports that other modeling processes and methodologies may be relied upon to model solar integration costs. The Idaho Study, for example, is based upon a more simplified modeling approach designed to quantify additional operating reserve requirements outside of a production cost model through statistical analysis of 5-minute solar deviations, while Astrapé modeled both the increased operating reserves as well as the total system production cost in the model. (Tr. Vol 4, at 65, 92)

The Commission also recognizes Mr. Wintermantel's testimony that the $LOLE_{FLEX}$ metric, while not a direct measure of a BA's compliance with the NERC balancing standards, is correlated with the NERC balancing standards such that if $LOLE_{FLEX}$ is allowed to increase substantially, it is expected that NERC CPS1 and BAAL standards would be violated more often. The Commission further understands that a fundamental difference between real world operations discussed by Mr. Kirby—where Duke's system operations have imperfect knowledge of solar volatility and net load and must make generation commitment decisions in real-time—and Astrapé's modeling of $LOLE_{FLEX}$ in SERVM measures the system's ability to satisfy net load obligations assuming the net load is known five minutes before it materializes. This "perfect foresight" in the model is significant and supports Mr. Wintermantel's explanation that a $LOLE_{FLEX}$ event represents a considerably more extreme violation of a system's obligation to manage its own load as compared to short term Area Control Error ("ACE") frequency deviations which are not violations of the NERC balancing standards. The Commission further finds that Mr. Kirby's comparison of the reliability metric used in the Idaho Study and the Astrapé Study is not a valid comparison. While the Astrapé Study is uncertain of the net load until five minutes before it materializes, the production cost model used in the Idaho Study does not incorporate stochastic modeling techniques as does the Astrapé Study. It is therefore impossible to directly compare the reliability metrics between the two studies. Accordingly, the Commission rejects Mr. Kirby's assertion that the 0.1 $LOLE_{FLEX}$ metric is draconian and overly stringent. (Tr. Vol. 4, 58, 64, 87, 89, 101; Tr. Vol. 5, at 317-318; Tr. Vol. 6, at 50)

The Commission also finds persuasive Mr. Wintermantel's testimony and Public Staff witness Thomas' concurrence that reserves held in the 0.1 $LOLE_{FLEX}$ base case compare reasonably well with historical reserves. (Tr. Vol. 6, at 21, 410; Tr. Vol. 7, at 2021) The Commission also agrees with Mr. Thomas' testimony that the post-processing analysis undertaken by Duke at the Public Staff's request to increase 0.1 $LOLE_{FLEX}$ metric ten-fold to 1.0 $LOLE_{FLEX}$ thereby loosening the reliability standard did not have the significant effect that was anticipated by the Public Staff. Mr. Thomas further concluded the quantity of incremental load following reserves appears to be reasonable compared to the capacity of solar generation resources on the system. (Tr. Vol 6, at 367)

Finally, the Commission finds persuasive that Duke witness Wintermantel's comparison of the operating reserves identified in the Astrapé Study and the Idaho Study as a function of installed solar capacity to be persuasive. While the record is clear that the Astrapé Study and the Idaho Study relied upon differing methodologies, the close correlation between the reserves required by the two studies at increasing penetration levels refutes SACE witness Kirby's testimony that the 0.1 $LOLE_{FLEX}$ metric requires balancing that is over 10,000 times stricter than the 99% confidence level used in the Idaho Study. (Tr. Vol 4, at 78, Tr. Vol. 5, at 204) Based upon the foregoing, the Commission finds and concludes that the 0.1 $LOLE_{FLEX}$ metric relied upon in the Astrapé is reasonable and Mr. Kirby's critiques should be rejected.

The Commission further finds that the Public Staff's and Mr. Kirby's concerns about the solar volatility assumptions at higher penetration levels in the Study should be prospectively reviewed in the next biennial review of Duke's integration costs, but do not impact the reasonableness of the Integration Services Charge before the Commission in this proceeding. The Commission specifically notes Mr. Thomas' testimony that that the Public Staff continues to have concerns regarding linear scaling of solar volatility in the higher penetration scenarios, but that the Public Staff expects this issue to generally resolve itself as Duke continues to update their integration cost studies, new solar facilities are constructed and connected to the grid, and additional granular solar output data is collected. Accordingly, the Commission will not take any action on this recommendation at this time. (Tr. Vol. 6, at 365)

In summary, based upon all of the evidence in the record, the Commission finds and concludes that the Astrapé Study's determination 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 and should be approved.

d. Integration Services Charge Average Cost Rate Design and Proposed Cap

In approving the *SISC Stipulation*, the Commission agrees with Duke and the Public Staff that the Integration Services Charge appropriately assigns ancillary services costs on an average basis to all uncontrolled solar generators that impose such additional costs on the Companies' systems. First, the Commission finds persuasive the fact that the Public

Staff's initial concerns with the Companies' average cost rate design and biennial update as opposed to fully assigning the costs to new entrants on an incremental, basis were resolved through the Companies' agreement to apply a cap to the charge in the *SISC Stipulation*. Second, the Commission agrees with Duke witness Wheeler's testimony that the higher ancillary services costs are caused by all intermittent solar QFs, not just new solar QFs, and that imposing the charge on an incremental basis would result in preferential pricing for the early solar generators while unfairly shifting the full cost burden to new solar generators in the future. Third, the Commission agrees with Duke witness Wheeler that collecting the incremental integration cost will require creation of vintage years for each participant, which could result in an administrative burden as new projects are delayed or old projects opt to enter into new contracts. Last, the Commission agrees that adopting a rate based upon incremental cost fixes the rate for the long-term contract term and fails to recognize that ancillary services cost change over time.

In contrast, applying the Integration Services Charge on an average basis most fairly allocates the costs caused to the cost causers. Application of an average rate design also reduces additional administrative burden on Duke to apply the charge differently based upon the solar QF's specific vintage. Further, Duke's and the Public Staff's agreement to cap future adjustments to the Integration Service Charge reasonably address the Public Staff's and intervenors concerns regarding Seller's ability to properly finance their facilities, as the cap establishes a quantifiable limit on future adjustments of the charge to be fixed by the Commission in future biennial proceedings.

Sections II.B of the *SISC Stipulation* adopts Duke's initial proposal not to apply the Integration Services Charge to existing solar generators that committed to sell and deliver power to DEC or DEP prior to the current biennial avoided cost proceeding for the duration of their existing PPA. After the term of the QF's existing PPA concludes, Section II.C provides that upon the solar QF committing to sell to Duke under a new PPA in the future, the then-applicable Integration Services Charge shall be applied. As Duke witness Wheeler testified, a QF has no obligation or commitment to sell its generation output to the host utility once its initial PPA expires; therefore, all changed cost parameters, including the Integration Services Charge, updated avoided cost rates, and updated rate designs, should be evaluated by the QF to determine whether to enter into a new PPA and sell to the Companies in the future. The Commission finds these provisions to be reasonable, and to reasonably balance the interests of existing QFs that committed to sell to DEC or DEP before the charge was quantified with the interest of ratepayers that will continue to subsidize the integration costs imposed by these existing QFs until their existing PPA expires.

The Commission finds that Section V of the *SISC Stipulation* reasonably and appropriately provides for the average Integration Services Charge to be updated on a biennial basis. As explained by Duke witness Wheeler, this Commission has previously allowed the Companies' to update the Seller or Administrative Charge included in Schedule PP during each biennial proceeding, to most accurately reflect the billing-related costs applied to QFs. For similar reasons, the Commission finds persuasive Duke witness Wheeler's and Snider's testimony that it is appropriate for the Companies to biennial update and review the Integration Services Charge to most accurately reflect the ancillary services costs that the Companies are incurring. This will help to ensure that ratepayers do not subsidize Sellers causing an increase in Duke's ancillary services costs, while Sellers are not unfairly paying for a level of increased ancillary services costs that they may, in the future, no longer be imposing on the system.

e. The Stipulation's Recognition of "Controlled Solar Generators" Appropriately Incentivize Innovative QFs to Mitigate their Ancillary Services Impact to the System

The Commission also approves Section II.A of the Stipulation allowing "controlled solar generators" the opportunity to avoid the solar 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. The Commission agrees with the Public Staff and NCSEA's 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, and exemplifies good faith negotiations reached between the Public Staff and Duke in response to intervenors' recommendations.

Further, as evidenced by Duke witness Snider's testimony, inclusion of this section of the Stipulation 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 additionally create a disincentive for QFs to seek to avoid the charge. Correspondingly, inclusion of this provision incentivizes the deployment of battery storage amongst QFs and other technologies that can benefit the Companies' system operators and customers through more coordinated dispatch and operational control of intermittent QFs, which, in turn, benefits customers by increasing system reliability. The Commission also finds persuasive the fact that this provision will 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 Commission finds NCSEA witness Beach's proposal to allow solar QFs that install "significant storage" to unilaterally avoid the solar Integration Services Charge inappropriate. As exemplified throughout this proceeding by evidence presented by Duke and the Public Staff, the mere existence of a battery storage system does not provide additional benefits to customers or, specifically, reduce the Companies' need for increased ancillary services by reducing a QF's intermittency. As provided for in the *SISC Stipulation*, the Integration Services Charge should be avoidable only where a solar generator designs its facility and then contractually commits to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility. Accordingly, NCSEA witness Beach's recommendation is rejected.

Based upon the foregoing, the Commission approves the provision in Section II.A of the Stipulation allowing "controlled solar generators" the opportunity to avoid the solar Integration Services Charge. The Commission appreciates Duke's commitment to work with the Public Staff and solar QF generators proposing to enter into a negotiated PPA to establish reasonable and appropriate design specification and operating protocols that would enable the solar generator to qualify as a Controlled Solar Generator, and hereby directs require Duke to work with the Public Staff and renewable developers to develop clear parameters for implementing the "controlled solar generator" provision within the Stipulation to that will enable solar QFs to avoid the solar Integration Services Charge where applicable.

Based upon the foregoing and the entire record in this proceeding, the Commission approves the provisions of the 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 Section V of the *SISC Stipulation*, the Commission finds and concludes that Duke shall review and update the Companies' 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.

f. Applicability of Integration Services Charge to CPRE Tranche 2 and GSA Programs

The Commission notes that Duke and the Public Staff in Section II.B of the Stipulation agreed that "it is appropriate to consider the ancillary services costs of adding incremental solar, and the potential applicability of the Integration Services Charge to solar generation solicited in CPRE Tranche 2 and other future CPRE Tranches," and agrees that that the same rationale that applies to the application of the Integration Services Charge to solar QFs in this proceeding is equally applicable in the context of the CPRE Program, which will result in significant amounts of additional intermittent solar generation being added to DEC's and DEP's systems over the next five years. The Commission also recognizes that similar logic applies to renewable energy generators that choose to participate in the GSA Program in Docket Nos. E-2, Sub 1170 and E-7, Sub 1169. Similarly, the Commission finds that it is appropriate for projects participating in those programs to have the opportunity to avoid the application of an 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." The Commission acknowledges the level of interest amongst the parties as to the application of the Integration Services Charge to projects participating in these programs, but also notes that parties were not asked to provide testimony on these issues, nor are all parties participating in the CPRE dockets or GSA dockets parties to this proceeding. Therefore, the Commission shall address the application of an integration services charge to those proceedings, through separate orders in those dockets. The Commission also recognizes the urgency of the matter, as the CPRE Tranche 2 is scheduled to open on October 15, 2019, and therefore urges Duke, the Public Staff, and other interested stakeholders to consider how the integration services charge might best be applied to the CPRE and the GSA Program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS.

[Placeholder for alternative evidence and conclusions for remaining issues, to be filed separately by Duke and the Public Staff.]

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 one 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 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. DEC and DEP should 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. 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. 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. Prior to the next biennial avoided cost proceeding, Duke should 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. The Commission shall open a generic rulemaking proceeding addressing revisions to Rules R8-64(b)(6)(iii) and R8-71(k)(2)(iii)(6) within 60 days following the issuance of this order.

9. Until such time as revisions to the rules are approved by the Commission after the rulemaking, applicants for a certificate of public convenience and necessity pursuant to Commission Rules R8-64 and R8-71(k) should, instead of the information currently called for in 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."

10. The Utilities in the next biennial proceeding shall evaluate and apply, if appropriate, 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.

11. That DEC, DEP, and DENC shall continue to calculate avoided capacity rates 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. Gen. Stat. 62-156(b)(3).

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

13. That the Utilities 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.

14. The Utilities, with input from the Public Staff, shall evaluate appropriateness of using other reliability indices, specifically the Equivalent Unplanned Outage Rate ("EUOR") metric, to support development of the PAF prior to the next biennial avoided cost filing.

15. That DENC shall eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network.

16. 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.

17. 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.

18. Beginning with the 2020 IRP, the Utilities shall include a specific statement of capacity to be used determine the first year of capacity need in next biennial avoided cost proceeding.

19. The Utilities shall amend their standard offer rate schedules to recognize that the avoided capacity rates for a swine or poultry waste generator or a legacy small hydroelectric facility five MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, as avoiding a designated future capacity need in the first year of these QF resources' existing purchase power agreement pursuant to the N.C. Gen. Stat. § 62-156(b)(3), as amended in in HB 329. 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.

20. 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 to the future.

21. The solar Integration Services Charges proposed by DEC ($1.10/MWh) and DEP ($2.39/MWh) and agreed to in the *SISC Stipulation* are reasonable and shall be approved. These Integration Services Charges shall be applicable to all QFs committing to sell and deliver power under DEC's and DEP's standard offer tariffs or a negotiated avoided cost PPA on or after November 1, 2018 for the duration of this biennial period, subject to the QF contracting to design and operate its generating facility as a Controlled Solar Generator. The Commission also specifically approves the cap on the Integration Services Charge for all QFs that commit to sell and deliver power during this biennial period in the amounts of $3.22/MWh for DEC and $6.70/MWh for DEP. Duke shall add language to the standard offer tariffs and any future negotiated PPA where the QF is subject to the Integration Services Charge addressing this cap on the Charge. Duke shall also file an updated study of DEC's and DEP's integration costs at the time updated avoided cost rates are filed at the outset of the next biennial avoided cost proceeding.

22. That WCU 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 ten-year long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed ten-year avoided energy and capacity rates.

23. That the Utilities, within 30 days after the date of this Order, are required to 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.

xx. [Placeholder for alternative ordering paragraphs for remaining issues that will be filed separately by Duke and the Public Staff.]

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of _________, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Kimberly A. Campbell, Chief Clerk