STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

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

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

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

APPEARANCES:

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

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For North Carolina Sustainable Energy Association:

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

For Carolina Utility Customers Association, Inc.:

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For Cube Yadkin Generation LLC:

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

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For North Carolina Small Hydro Group:

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For NC WARN, Inc.:

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For Southern Alliance for Clean Energy:

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For the Using and Consuming Public:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FINDINGS OF FACT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

28. It is appropriate to require DEC and DEP to recalculate their avoided energy costs to include the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

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

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

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

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

Summary of the Evidence

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

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

In response to the Commission's directives Duke proposes changes to its Schedule PP to eliminate the pre-existing Option A and Option B hours and to develop updated, more granular rate designs that better recognized the value of QF energy and capacity. JIS at 27. Duke's initially proposed Schedule PP rate structure for energy payments defines the summer period as May through September and the non-summer period as October through April. The energy pricing includes five distinct pricing periods, each of which has an independent price block to better reflect the value of QF energy during the different periods. Each utility defines its energy pricing hours separately to account for the differences in each utility's load profile net of solar generation.

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

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

In its Initial Comments NCSEA states that Duke's proposed allocations are inappropriate due to flaws in the loss of load analysis that underlies the proposed allocations, underestimates of winter DSM assumptions, a failure to consider imports, and flawed solar modeling. NCSEA recommends that the Commission instead require Duke to utilize the allocation ratios previously approved by the Commission in the 2016 Sub 148 Order. NCSEA Initial Comments at 13-14. NCSEA further recommends that Duke provide granular rate schedules that incorporate geographic granularity. NCSEA notes that without such geographic granularity, there is no incentive for QFs to locate in areas where transmission and distribution costs can be avoided. *Id.* at 26-27. NCSEA further states that the Utilities failed to adequately recognize how costs vary by seasons and that Duke's proposal not to differentiate a winter season did not appropriately consider the different patterns of electrical usage, net system load, marginal production costs, and avoided costs that occur during winter as opposed to spring and summer. NCSEA also states that the Utilities did not adequately recognize how costs vary across different times of day, despite having access to detailed avoided cost data for all 8,760 hours for the next ten years. NCSEA proposes that instead of the Utilities' proposals, the Commission should adopt the time-of-day periods it proposes, as well as an optional real-time pricing tariff for QFs. *Id.* at 28. NCSEA witness Johnson supports this proposal by detailing the following specific energy rate design schedules: (i) a 12 month by 24 hour rate design (12x24 Design), and (ii) a fixed tariff with a set number of real time pricing (RTP) high and low cost hours (Hybrid Tariff), both of which would provide additional granularity to avoided energy rates. Johnson Affidavit at 64-76.

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

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

In its Initial Comments the Public Staff states that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believes that energy rate mismatches were still likely and could result in QFs potentially being over- or under-paid for the energy generated. As a result, the Public Staff proposes its own seasonal energy rates and hours:

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

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

Public Staff Initial Comments at 54.

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

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

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

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

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

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

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

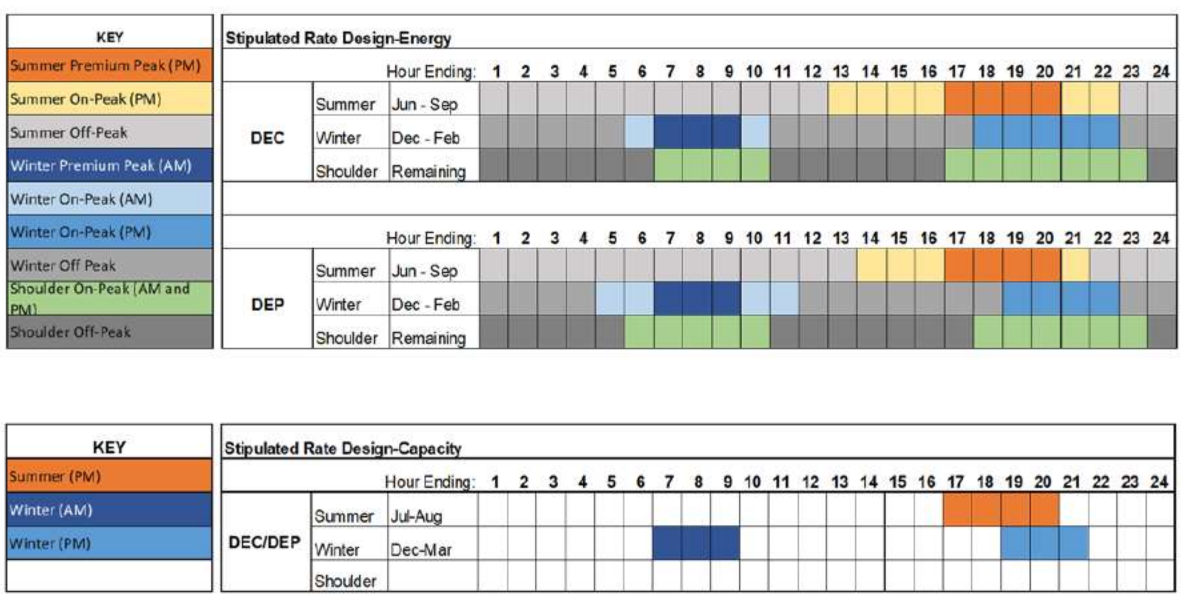
In response to NCSEA's proposed rate design changes, the Public Staff in its Reply Comments states that hourly pricing for each month, as proposed in the

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

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

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

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



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

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

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

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

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

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

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

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

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

Discussion and Conclusions

Avoided Energy Rates

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

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

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

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

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

Finally, the Commission agrees with Duke, NCSEA, and the Public Staff that real-time pricing rates for QFs could better align the Utilities' avoided cost rates to QF payments, but recognizes that such an option must be balanced with the Utilities' obligations under PURPA to provide a QF with the option to commit to deliver its power

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

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

at the utility's avoided cost, either calculated at the time of delivery or calculated at the time the QF makes its legally enforceable commitment to deliver energy and capacity. 18 C.F.R. § 292.304(d)(2). Therefore, consistent with the recommendation of the Public Staff, the Commission directs Duke to evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding.

Avoided Capacity Rates

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

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

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

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

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

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

Conclusion

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

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

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

Summary of the Evidence

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

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

Discussion and Conclusions

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

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

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

Sub 140 Phase One Order at 48.

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

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

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

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

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

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

Summary of the Testimony

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

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

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

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

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

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

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

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

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

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 27

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

Summary of the Evidence

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

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

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

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

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

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

In its Reply Comments SACE indicates that it considers the proposals of both the Public Staff and NCSEA be more appropriate than the natural gas forecast methodology proposed by Duke. SACE Reply Comments at 3. The Small Hydro Group indicates that it agrees with the Public Staff that the Commission should require Duke to use no more than five years of forward market data before transitioning to its fundamental forecast. Small Hydro Group Reply Comments at 3.

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

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

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

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

Discussion and Conclusions

The evidence in this proceeding demonstrates continued declines in the price of natural gas. In addition, the evidence demonstrates that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and that changes in the liquidity and trading prices in the natural gas markets over the long term are being incorporated into long-term forecasts. In the 2016 Sub 148 Proceeding the parties advocated for many of the same positions as in this proceeding. In the 2016 Sub 148 Order the Commission found merit in some of the arguments raised by each party, and in its expert judgment adopted a method for the purposes of that proceeding that authorized Duke to rely on market data for eight years and fundamental forecasts thereafter. The Commission also indicated that it would continue to monitor the liquidity of the market in future avoided cost proceedings.

In this proceeding the Commission again recognizes the important relationship that exists between the Commission's biennial avoided cost proceeding and the Commission's review of IRPs, as well as the importance of maintaining internal consistency between these proceedings. In this proceeding and in the IRP proceeding, the Public Staff argues that Duke's reliance on ten years of forward market price data tends to lead to gas price forecasts lower than is appropriate, which may lead to an excessive reliance on natural gas-fired generation relative to other forms of generation — such as solar and battery storage. The Public Staff instead proposes the use of forward prices for no more than five years, combined with a fundamental forecast, arguing that after year five the current market is not sufficiently robust to supplant the predictions of market analysts. The Commission finds somewhat persuasive the Public Staff's evidence demonstrating that Duke's other operating utilities do not use ten years of forward prices and that the practice proposed by Duke is highly uncommon in the electric utility industry. NCSEA and SACE argue in favor of less reliance on forward market price data, or in support of the Public Staff's position.

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 28

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

Summary of the Evidence

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

In its Initial Comments the Public Staff disagrees with Duke’s argument, stating that Duke’s position “would essentially require QFs to compensate utilities for the right to sell their generation.” Public Staff Initial Comments at 28. The Public Staff states that renewable generation provides additional fuel price stability that has value, as evidenced by the Utilities’ ongoing hedging programs, and that it is reasonable to expect that the utility will be able to reduce its volume of hedged natural gas and coal fuels as a result of renewable generation. The Public Staff reiterates its support for inclusion of a hedging value for renewables, consistent with the Commission’s findings in the Sub 140 Phase One Order, and recommends that the Commission require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing Model or similar method. *Id.* at 29.

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

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

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

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

Discussion and Conclusions

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

The Commission is not persuaded that Duke's argument that QFs are inappropriately being granted a "put option" without any obligation to sell is consistent with the requirements of 18 C.F.R. § 292.304(d)(2), which provides that a QF may choose to sell energy or capacity pursuant to a LEO for delivery "over a specified term," with rates determined at the time the obligation is incurred. Further, pursuant to N.C.G.S. § 62-156(b)(2):

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

The Commission is likewise not persuaded that Duke's view is consistent with this direction, nor is the Commission persuaded by Duke's position that paying QFs for the value of reduced volatility with fuel prices subjects its customers to additional overpayment risk. Instead, based upon the foregoing and the entire record herein, the Commission finds, consistent with the Public Staff's arguments, that DEC and DEP should be required to recalculate their avoided energy rates to include an appropriate fuel hedging value utilizing the Black-Scholes Model or a similar model to determine the hedging value of renewable generation, and that the fuel hedge value should be included for each year of the entire term of the QF PPA.

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

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

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

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

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

Public Staff Reply Comments at 10.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

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

Summary of the Evidence

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

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

Discussion and Conclusions

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

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

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

Summary of the Evidence

Duke's JIS provides that the 2018 Scheduling Order directed the Utilities to consider factors relevant to the characteristics of QF-supplied power — specifically intermittent and non-dispatchable power — in designing rates to meet PURPA's objectives of appropriately valuing Duke's incremental costs of alternative energy to be avoided from purchasing power from a QF. Further, the 2016 Sub 148 Order similarly emphasized that it would be appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power if the Utilities' cost data "demonstrates marked differences" in the value of the energy and capacity provided by these QFs. JIS at 30-31 (quoting 2016 Sub 148 Order).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

In the Sub 140 Phase One Order the Commission stated:

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

Sub 140 Phase One Order at 60.

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

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

accuracy has been attained. Accordingly, the Commission concludes that it is premature for DEC, DEP and DENC to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Commission also finds merit in the Public Staff's recommendation that Duke should be required to continue to evaluate the potential benefits provided by QF resources, particularly as new technologies such as energy storage and smart inverters are incorporated into QF projects in North Carolina, as well as those existing technologies

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

such as small hydroelectric QFs that may have dispatch capability. Therefore, the Commission will direct Duke to provide the Commission, in its initial filing made in the 2020 biennial avoided cost proceeding, with an evaluation of whether a QF that can sufficiently demonstrate and contractually obligates itself to operate in a manner that not only eliminates the need for additional ancillary service requirements, but also has the capability to provide those benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits.

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

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

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

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

Summary of the Evidence

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

In response to the Commission's directives DENC in its Initial Statement proposes changes to the rate schedules for both energy and capacity that offer additional granularity and improved price signals to QFs to better match DENC's generation needs. DENC proposes a revised rate structure that includes seasonal capacity rates and non-seasonal on- and off-peak energy rates. DENC Initial Statement at 29.

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

Consistent with its comments regarding Duke's proposed rate design changes, the Public Staff in its Initial Comments states that the pricing periods proposed in this proceeding are an improvement over the current Option B hours in terms of being reflective of historical marginal energy costs. Nevertheless, the Public Staff believes that energy rate mismatches are still likely that could result in QFs potentially being over- or under-paid for the energy generated. Public Staff Initial Comments at 47-48. As a result, the Public Staff proposes its own seasonal energy rates and hours.

Regarding DENC's proposed seasonal allocation of capacity payment costs and its selection of Capacity Peak Hours, the Public Staff finds them to be reasonable, but states that the reliance on the broader characteristics of the PJM region results in a misalignment of DENC's system with the seasonal allocation and Capacity Peak Hour, and recommends that DENC evaluate alternative seasonal allocation and Capacity

Payment Hours that align more directly to its system (as opposed to the PJM system as a whole, which has different capacity needs from a utility operating in North Carolina). *Id.* at 60, 64.

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

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

DENC further states that it continues to believe that its original proposed energy seasons and peak hours designations are reasonable and appropriate, particularly for the purposes of the standard offer. It also states that in subsequent discussions with the Public Staff on this issue, the Public Staff has recognized that September is appropriately included in DENC's summer peak season. In addition, DENC notes that in those discussions the Public Staff has proposed expanding the "premium peak" summer and winter hours such that there are four premium peak summer hours in the afternoon and four premium peak winter hours, two in the morning and two in the evening. As a result of these discussions, DENC indicates that it is willing to accept the Public Staff's proposal, as modified, in the interest of achieving consensus on this issue. DENC notes that its initial proposal included the afternoon hours on weekdays and weekends in the Energy Peak Hours, but under the modified proposal, it will pay on-peak and premium peak avoided energy rates on weekdays only. *Id.* at 22-24. With regard to capacity, DENC states it is willing to use a 45/40/15 seasonal allocation of CT costs, which would continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder season for capacity. *Id.* at 37.

NCSEA witness Johnson testified in favor of real-time pricing during "extreme conditions." He acknowledged the Utilities' reply comments on this topic and agreed that the Utilities raised practical considerations that need to be considered, but asserted that those considerations do not justify rejection of his proposal. He further stated that DENC's LMP tariff is not as good a solution as NCSEA's proposal because of its linkages to volatile natural gas and other energy markets, and instead recommended that the Utilities submit proposed real-time pricing rates consistent with NCSEA's proposal at least six months before the next biennial proceeding. Tr. vol. 6, 231-36.

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

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

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that the revised rate design changes proposed by DENC and agreed to by the Public Staff are responsive to the Commission's directives in the 2016 Sub 148 Order and the 2018 Scheduling Order by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission therefore will require DENC to file updated rate schedules consistent with the energy and capacity rate design described in DENC witness Petrie's rebuttal testimony.

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

The Commission further finds that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons are appropriate for use in weighting capacity value between seasons, as these weightings continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder for capacity, and should be used in calculating DENC's avoided capacity rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 45

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

Summary of the Evidence

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

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

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

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

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

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

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 46

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

Summary of the Evidence

In the 2016 Sub 148 Order the Commission concluded that "it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity." 2016 Sub 148 Order at 98. The Commission directed that with their initial filings in this proceeding the Utilities address, among other issues, "consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable." *Id*. at 110-11. The 2018 Scheduling Order reiterated that directive.

In its Initial Statement DENC notes that the addition of new QF generation can have an impact in two distinct areas: ancillary services and integration costs. DENC proposes to adjust the avoided energy cost payments to new QFs to reflect the increase in system supply costs, or re-dispatch costs, caused by these generators. DENC defines re-dispatch costs as the additional fuel and purchased energy costs incurred due to the unpredictability of events that occur during a typical power system operational day. DENC states that as more and more intermittent generation such as solar or wind is added to the grid, the level of uncertainty regarding re-dispatch costs increases due to the unpredictable output of these types of units caused by changes in cloud cover or changes in wind speed. DENC clarifies that it is not proposing to adjust avoided cost rates to specifically account for the potential costs or benefits related to changes in ancillary services requirements that occur due to increased levels of new QF generation on the system. DENC Initial Statement at 12-13.

To calculate the re-dispatch cost, DENC explains that in conjunction with the development of its 2018 IRP, it performed a simulation analysis to determine the cost impact on generation operations. It used hourly generation data from 26 solar sites currently interconnected to its system to develop generation profiles for these facilities. DENC performed the study at three levels of solar penetration to provide a range of results. It used the PLEXOS model to determine an overall system cost impact, which it calculated to be approximately $1.78/MWh, and proposes to adjust avoided energy payments made to QFs under Schedule 19-FP by that amount. *Id.* at 13.

In its Initial Comments the Public Staff does not oppose the concept of a re-dispatch charge but makes a number of recommendations and raises certain concerns. First, the Public Staff argues that the avoided energy rate should not be reduced by separately calculated charges, and states that a consolidated charge would present difficulties for tracking costs of compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). The Public Staff recommends that DENC collect and administer the re-dispatch costs separately from the avoided energy rate, similar to Duke's approach for the integration services charge. Second, while the Public Staff agrees that it is reasonable to calculate the re-dispatch charge using solar resource data, as solar is the dominant type of intermittent, non-dispatchable QF, it suggests that in the future DENC separately calculate the charge specific to each type of intermittent, non-dispatchable QF seeking to interconnect to its system. Public Staff Initial Comments at 30-32, 43-46.

As for its concerns, the Public Staff states that DENC's calculation of the charge, which reflects equal weighting of multiple cost categories and solar penetration scenarios, may not be reasonable. More generally, the Public Staff notes the Commission's conclusions in the Sub 140 Phase One Order that inclusion of costs and benefits related to solar integration in the Utilities' avoided cost calculations would be "appropriate only when both costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained." *Id.* at 32 (quoting Sub 140 Phase One Order at 60-61). The Public Staff acknowledges that some costs of QF energy and capacity are less discernable than others, and states that it may be appropriate for the Commission to consider evidence from other parties regarding what additional costs or benefits can be sufficiently known and verifiable such that they should be included in avoided cost rates. *Id.* at 32-33.

In its Initial Comments NCSEA asserts as it did with respect to Duke's integration services charge that the re-dispatch charge is inconsistent with previous Commission decisions and does not comply with PURPA. NCSEA points to the Commission's recognition in the Sub 140 Phase One Order that it may be appropriate to reflect the costs and benefits of integrating solar resources into the Utilities' avoided cost calculations. NCSEA Initial Comments at 32-33. NCSEA contends that DENC's proposed re-dispatch charge fails to comply with the 2016 Sub 148 Order because the charge does not take the form of a separate rate schedule. NCSEA also asserts that the proposal is inappropriately based on generation technology rather than QF characteristics, and that DENC admits such noncompliance in its Initial Statement. NCSEA also argues that the re-dispatch charge represents single-issue ratemaking because it is a "rate" under N.C.G.S. § 62-3(24) and should be set during a general rate case. NCSEA argues further that the charge is not a "rate" under 18 C.F.R. § 292.101(b)(5) because it does not involve the sale or purchase of electric energy or capacity, and that even if it is a rate under FERC rules it is not appropriate under 18 C.F.R. § 292.304(e). *Id.* at 34-35, 47-48. NCSEA also claims that the Utilities fail to accurately capture the effect that wind and solar resources have on market prices by reducing demand on regional markets for electricity and natural gas, thereby reducing market prices. *Id.* at 43-45.

In his affidavit NCSEA witness Johnson states that refining avoided cost rates to consider the costs and benefits associated with integrating solar resources is "not objectionable, per se," but takes issue with how the Utilities conducted their respective analyses. He claims, among other things, that the Utilities fail to take an unbiased approach, only consider negative impacts imposed by solar QFs, and ignore the geographic diversity of solar QFs that avoids T&D costs. With regard to DENC's re-dispatch charge, in contrast to NCSEA's own position he does not oppose the concept of a re-dispatch charge itself, acknowledging that "[i]t is reasonable to expect solar generation to increase re-dispatch costs somewhat, at least under some circumstances, because solar generation varies with cloud cover which cannot be forecast with perfect accuracy." Johnson Affidavit at 17-18. He asserts, however, that the proposed $1.78/MWh is too high because DENC (1) only partly considered the benefits of geographic diversity by only relying on 26 individual sites for its analysis, and (2) improperly weighted the average of multiple cost and solar penetration scenarios. He presents his own calculation of a re-dispatch charge of $0.69/MWh, based on removal of the PJM and generation-only cost categories of DENC's re-dispatch analysis and the 80-MW solar penetration scenario. *Id.* at 18-20.

In his affidavit NCSEA witness Beach similarly claims that the re-dispatch charge does not consider the benefits of integrating QF resources into the system. Witness Beach also asserts that appropriately located QFs will allow T&D costs to be avoided, citing an example using Duke's distribution substations to show how avoided T&D costs can be allocated to hours of the year using peak capacity allocation factors. Witness Beach also asserts a potential market suppression benefit of integrating QF power and recommends that the Commission direct the Utilities to study the ability of their T&D system to host distributed generation and storage resources. Beach Affidavit at 6-7.

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

In its Reply Comments DENC reiterates the basis for its re-dispatch proposal and states that applying the re-dispatch charge will help ensure that its customers pay for accurate avoided costs, since without the charge customers would overpay for QF output. DENC explains that in the analysis providing the basis for the proposed charge, it gave equal weight to each of the cost categories considered, which included all costs, PJM purchases/sales, pumped storage costs/revenues, and generator costs only. DENC states that it chose solar penetration levels of 80 MW, 2,000 MW, and 4,000 MW for the analysis, and describes the process it used to calculate the charge based on those levels. DENC Reply Comments at 8-11.

DENC states that while it proposes to apply the re-dispatch charge as a reduction to the avoided energy rate for purposes of administrative efficiency, if the Commission agrees with the Public Staff that it should be separated from the avoided energy rate, DENC could modify the administration of the charge to occur as a separate line item on a QF invoice. DENC also states that it is willing to evaluate the potential for calculating separate re-dispatch charges for other generation types in future cases. *Id.* at 9-10.

DENC states that it discussed its proposal with the Public Staff and addressed a number of the Public Staff's questions and concerns. DENC also states that in those discussions, the Public Staff recommended re-calculating the re-dispatch charge without considering an 80-MW solar penetration level and allocating 70% to the 2,000-MW scenario and 30% to the 4,000-MW scenario. DENC describes these points as representing the Public Staff's remaining concerns with the re-dispatch proposal. DENC states that it continues to believe that the approach it took in the simulation analysis with respect to cost category and solar penetration level selection and weighting to be reasonable and provides arguments in support of those aspects of its original approach to calculating the charge. DENC states that it believes it is appropriate to weight each category equally, as each plays a major role in the total re-dispatch cost related to distributed solar generation. DENC also explains the rationale for including each of the solar penetration levels and for weighting each level equally in the charge calculation. DENC concludes, however, that in the interest of reaching compromise on the issue and narrowing down the areas of dispute, it is willing to recalculate the re-dispatch charge for purposes of this proceeding with modified cost category and solar penetration scenario weightings, resulting in a re-dispatch charge of $0.78/MWh. *Id.* at 12-14.

In response to NCSEA, DENC first clarifies that its presentation of the re-dispatch proposal does not constitute an admission of noncompliance with the 2016 Sub 148 Order, but rather makes clear that the proposal is intended to quantify the added costs due to re-dispatching of units caused by the intermittency of solar QF output, and not to specifically account for potential costs or benefits related to changes in ancillary service requirements. DENC also states that in preparing the initial filing and developing the re-dispatch charge proposal, it carefully evaluated the Commission's directives in the 2016 Sub 148 Order. DENC acknowledges the Commission's directive for the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity. DENC states that in developing its proposal DENC determined that it would be more efficient, and therefore benefit both the QF and DENC, to include the re-dispatch proposal in the existing rate schedule rather than to propose a separate rate schedule only for intermittent QFs. DENC states its belief that QF developers are generally sophisticated entities that can determine which parts of a standard avoided cost tariff apply to them. DENC also notes, however, that it will comply with any Commission determination that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule. *Id.* at 15-17.

DENC further explains that the charge was derived based on data associated with the intermittent, non-dispatchable QFs in its service area, all of which at this point in time are in fact solar QFs. DENC notes that while the proposed charge is actually "based upon a consideration of the characteristics of the power supplied by" these QFs (those characteristics being intermittency and unreliability), for purposes of North Carolina, where almost all intermittent non-dispatchable QF generation is solar, there is inevitably an overlap between the concepts of "generation technology" and "QF characteristics." DENC concludes that, practically, these terms present a distinction without a difference. DENC notes its willingness to evaluate the potential to calculate a re-dispatch charge for other types of intermittent, non-dispatchable QFs in a future proceeding. *Id.* at 17.

DENC also addresses NCSEA's contention that the re-dispatch charge is a "rate" under N.C.G.S. § 62-3(24) that should be set during general rate cases pursuant to N.C.G.S. § 62-133, and that it is not a "rate" under FERC rules implementing PURPA because it does not involve the sale or purchase of electric energy or capacity. As to the former, DENC shows that the re-dispatch charge is not a "rate" as that term is contemplated by Section 62-3(24), which contemplates charges for services or commodities offered by the utility to the public, as the charge is not so related, but instead reflects the impact to DENC's system of intermittent, non-dispatchable QFs from which

DENC is required by law to purchase energy. DENC notes that taken to its logical end NCSEA's argument would nullify N.C.G.S. § 62-156. As to the latter, DENC states that the charge is valid regardless of whether it qualifies as a "rate" under 18 C.F.R. § 202.101(b)(5) and explains that it is also consistent with the Section 202.304(e) because it properly considered the enumerated factors listed in the FERC regulations. *Id.* at 17-19.

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

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

In its Reply Comments the Public Staff presents a summary of DENC's proposed charge and states that it is not convinced that DENC considered the appropriate cost and solar scenarios in its re-dispatch charge calculation. The Public Staff disagrees with the "no PJM," "no pumped storage," and "generator cost only" scenarios because those categories do not represent DENC's current operations. The Public Staff states that while these scenarios may be illustrative of the impact solar "might" have on system costs were DENC to leave PJM or decommission its Bath County pumped storage facility, they are not appropriate for use in specifying a charge to apply to non-dispatchable QFs today. The Public Staff notes that the higher re-dispatch charge associated with a "No PJM" scenario indicates the value of being able sell excess energy into the PJM market. The Public Staff also finds the 80-MW solar penetration scenario to be inappropriate because DENC already has several hundred megawatts of solar capacity installed — the 2,000 MW scenario is more likely in the future due to the higher probability that DENC's total system will realize this level of intermittent capacity, and the 4,000-MW scenario might be achieved in the more distant future due to Virginia's mandate of increased deployment of solar resources through the Grid Transformation and Security Act of 2018. To address these concerns, the Public Staff proposes that DENC give 100% weight to the "all costs" category and no weight to the other cost categories, and give 70% weight to the 2,000-MW solar penetration scenario, 30% weight to the 4,000-MW scenario, and none to the 80-MW scenario. The Public Staff also notes that the re-dispatch charge and Duke's proposed integration services charge may result in recovery of overlapping costs, and states that to the extent the Commission approves the broader application of these calculations in future proceedings, it is appropriate for the costs to be fully delineated to reduce any overlap. Public Staff Reply Comments at 20-23.

In its Reply Comments NCSEA agrees with SACE's position that DENC inappropriately averages costs associated with multiple solar penetration levels and combinations of assumptions, which results in an inflated charge. NCSEA also echoes some of the questions raised by the Public Staff in its Initial Comments. NCSEA states its opposition to any fixed charge that “allegedly” offsets costs to the grid due to intermittent QFs, reiterating its position that distributed generation, including solar, causes a net benefit to the grid and rate payers. NCSEA Reply Comments at 17-18.

In its Reply Comments SACE contends that the Utilities fail to analyze the potential benefits of solar integration, and therefore do not comply with the Commission’s previous orders. SACE also agrees with NCSEA that QFs should be compensated for the full range of costs they allow the purchasing utility to avoid, including applicable T&D costs. SACE recognizes the Public Staff’s concerns regarding an integration charge’s potential impact on REPS and other programs’ administration if the charge is embedded in the avoided cost rate, but ultimately supports DENC’s approach of applying the re-dispatch charge, if approved, as a decrement rather than as a stand-alone charge. SACE suggests that the Commission could establish a procedure to remove any integration charge in the administration of the applicable REPS or other program to address this concern. SACE Reply Comments at 13-16.

In his direct testimony DENC witness Petrie stated that in the 2016 Sub 148 Order and the 2018 Scheduling Order the Commission found merit in the concept that evaluation of the Utilities’ avoided costs should consider factors such as a QF’s capacity, dispatchability and reliability, and the value of QF energy and capacity in establishing avoided cost rates. He clarified that DENC’s proposal to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP by \$1.78/MWh applied to both standard offer QFs and larger QFs with negotiated PPAs. He also clarified that while the re-dispatch charge is complementary to Duke’s proposed integration services charge, the charges are not the same, as DENC and Duke each analyzed a different aspect of the impact of resource intermittency on their respective systems. Tr. vol. 5, 15-18.

Witness Petrie noted that the Public Staff did not disagree with the re-dispatch charge in theory and responded to several of the Public Staff’s concerns and recommendations consistent with DENC’s Reply Comments. He testified that since the filing of initial comments, DENC and the Public Staff discussed the re-dispatch proposal, including how the generation portfolios were constructed, how the 85 PLEXOS model runs were used, and other issues raised by the Public Staff, which resolved most of the Public Staff’s concerns. With respect to Public Staff’s remaining concerns regarding the weighting of cost categories and selection of solar penetration weights, as it notes in its Reply Comments DENC is willing to re-calculate the re-dispatch charge with modified cost categories and solar penetration scenarios as recommended by the Public Staff, resulting in a \$0.78/MWh re-dispatch charge. Tr. vol. 5, 19-22.

Witness Petrie responded to NCSEA’s contention that the re-dispatch charge failed to comply with the 2016 Sub 148 Order. He stated that the re-dispatch charge is compliant with the 2016 Sub 148 Order’s statement to “consider and propose additional rate schedules” because DENC did consider proposing new rate schedules, but determined that in the interest of efficiency, the re-dispatch charge should be included in the existing rate schedule. However, if the Commission determines that the re-dispatch charge and other aspects of the proposed standard tariffs applicable to intermittent QFs should be reflected in a separate rate schedule, DENC will comply with that determination. With respect to NCSEA's assertions regarding the focus on generation technology, he stated that the re-dispatch charge is based on data associated with the intermittent, non-dispatchable QFs in DENC's service area, all of which are solar QFs. Therefore, there is an inherent overlap between the concepts of "generation technology" and "QF characteristics," and for DENC's purposes those terms present a distinction without a difference. Tr. vol. 5, 22-24.

Witness Petrie stated that NCSEA and SACE's concerns regarding the actual derivation of the re-dispatch charge should be addressed by DENC's willingness to recalculate the charge as recommended by the Public Staff. He also responded that DENC did account for both costs and benefits associated with distributed solar generation in its re-dispatch analysis as well as in the basic avoided energy rate. He testified that the macro benefits to new solar generation, including zero fuel cost for solar generation, displacement of DENC owned generation, and PJM purchases during daytime hours, and the related fuel price hedge benefit were reflected in the production cost modeling and in the separate hedge value adder to the energy rates. He noted that DENC has not observed any benefits with respect to system dispatch and minute-to-minute operational control of the grid from the addition of intermittent resources, such as solar QFs, to its system that are not already accounted for in the avoided energy costs. Tr. vol. 5, 24-25.

Witness Petrie also responded to NCSEA witness Johnson's contentions regarding geographic diversity, explaining that the QFs evaluated for the re-dispatch analysis are in fact geographically dispersed throughout DENC's service area, including North Carolina. He stated further, however, that the North Carolina portion of that service area is relatively small, with very limited geographic diversity as compared to the rest of DENC's footprint. He noted that as a result, the intermittency of solar QFs located in North Carolina is not mitigated by their geographic diversity throughout DENC's service area. Witness Petrie also clarified that PJM market purchases and sales are accounted for in the re-dispatch study, as the PLEXOS model assumed DENC would sell excess power into PJM during the peak hours with higher LMP costs and make market purchased at low prices. In calculating the re-dispatch cost, DENC netted market purchases and sales against each other, which resulted in a net benefit to the solar re-dispatch cost. Tr. vol. 5, 25-26.

Witness Petrie concluded by noting that there are 72 solar QFs operating in DENC's North Carolina service area, representing approximately 501 MW of solar capacity. Once all of the QFs with which DENC has executed PPAs come online, that total will rise to 691 MW, which significantly exceeds DENC's 2018 average on-peak load of approximately 525 MW. He stated that DENC's proposed re-dispatch charge represents the first step in quantifying the costs of integrating these large volumes of solar generation onto its system, which was first addressed in the 2012 Sub 136 Proceeding. He stated that DENC will continue to work on this issue, but for purposes of this biennial period believes that the re-dispatch charge is fair to both QFs and DENC's retail electric customers because it will provide energy payments to QFs that better reflect DENC's actual avoided energy costs. *Id*. at 27-28.

In his testimony Public Staff witness Thomas described the re-dispatch charge as reflecting the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. He stated that similar to the changes in dispatch order caused by load certainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of least-cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs that are passed on to ratepayers. He also noted that unlike Duke's method of calculating the integration services charge, DENC's method of calculation does not measure system reliability. Tr. vol. 6, 373-74.

Witness Thomas testified that the re-dispatch charge is a reasonable attempt to quantify the costs incurred by intermittent generators but noted that the Public Staff identified potential concerns with the charge as proposed. He noted the Public Staff's suggestion of an alternate set of weightings resulting in a re-dispatch charge of $0.78/MWh, which the Public Staff believes better reflects the DENC system and actual costs incurred. He argued that including cost scenarios such as the "no PJM" scenario inappropriately excludes benefits provided by solar QFs due to DENC's membership in PJM. He acknowledged DENC's willingness to recalculate the charge with the Public Staff's recommended weightings. He recognized that the re-dispatch charge and Duke's integration services charge attempt to quantify different aspects of integrating intermittent generation and use different approaches but based on the Public Staff's review of these proposals stated that there is likely some overlap between them. *Id*. at 374-76.

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

NCSEA witness Beach testified generally on the re-dispatch charge together with the Duke integration services charge. Witness Beach recommended that the Commission not adopt either of these proposed charges and asserted that any cost to integrate solar resources will be offset by benefits of these resources that he contended the Utilities have not recognized. Tr. vol. 5, 112.

In his testimony SACE witness Kirby asserted a lack of detail supporting the re-dispatch charge calculations, and he contended that DENC did not include an analysis of the benefits of solar projects. He also, however, testified that DENC's agreement to remove the 80-MW solar penetration scenario from its analysis and to solely use the "all costs" category for its re-dispatch charge analysis instead of averaging all four of its originally proposed cost categories helped alleviate his concerns on these fronts. Tr. vol. 5, 208-10.

In his rebuttal testimony, DENC witness Petrie testified that DENC remains willing to accept the Public Staff's recommended modifications to the re-dispatch charge calculation and resulting charge of $0.78/MWh for purposes of this proceeding. He noted that while NCSEA witness Beach generally recommends rejection of the re-dispatch charge, he does not offer any specific critiques of the charge itself. To the extent witness Beach's claims that the utilities did not properly consider and quantify the benefits of solar in presenting their proposed charges were made with respect to DENC, witness Petrie referenced his direct testimony and DENC's Reply Comments and testified that DENC has properly considered both costs and benefits in both the avoided cost rates and the re-dispatch charge. Tr. vol. 5, 37-40.

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

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

At the hearing, SACE witness Kirby recommended rejection of the re-dispatch charge until it is recalculated based on both the cost and benefits of integrating solar. DENC witness Petrie clarified in response to questions from counsel for SACE that in developing the re-dispatch charge, DENC focused only on re-dispatch costs and not ancillary services, and that he could not speak to whether Duke's integration services charge reflected some element of re-dispatch costs. He also clarified that DENC has no intention of double-counting re-dispatch costs, and that he expects DENC in the future to conduct a more comprehensive study that accounts for ancillary service costs. He also testified, and reiterated upon questioning by the Commission, that there are conceivable circumstances where it would be appropriate to not apply the re-dispatch charge to a QF that has installed battery storage. Witness Petrie also agreed in response to questions by counsel for the Public Staff that the re-dispatch charge could decline in the future. DENC witness Billingsley clarified in response to questions from SACE counsel that if approved the re-dispatch charge would apply prospectively only, including to QFs that renew their PPAs after the initial term has concluded. Tr. vol. 5, 80-82, 92-94, 100-03, 215.

Discussion and Conclusions

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

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

For reasons similar to those details above, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations implementing PURPA, N.C.G.S. § 62-156, and the Commission's orders issued in biennial avoided cost proceedings. As directed in the 2016 Sub 148 Order DENC has proposed an adjustment to its rates to account for the characteristics of intermittent, non-dispatchable QFs.

The Commission is not persuaded by the comments and testimony offered by NCSEA and SACE that DENC did not consider benefits as well as costs in developing the re-dispatch charge. The Commission finds DENC's filings and particularly witness Petrie's testimony highly persuasive on this point. DENC has already reflected certain benefits of solar, including hedging value, in the underlying avoided energy cost rate. Moreover, the re-dispatch charge does, as shown by DENC's testimony and other evidence presented, reflect benefits as well as costs. In contrast to intervenors who advocate for rejection of the re-dispatch charge, DENC provided data supporting the charge based on solar generation located on its own system. Evidence presented relating to the New England ISO, for example, is not relevant to this proceeding. For the reasons stated above, the Commission also declines to accept witness Beach's suggestion to direct the Utilities to study the ability of their T&D system to host distributed generation.

In addition, the Commission concludes that the re-dispatch charge complies with PURPA and FERC's regulations because the re-dispatch charge reasonably approximates utility indifference. With regard to DENC's approach to calculating the re-dispatch charge, the Commission concludes that the use of the re-dispatch analysis from the 2018 IRP was reasonable and appropriate. The analysis was based on actual historical data from solar facilities existing on DENC's system, which was analyzed over 85 model runs in various scenarios to develop the charge. In sum, the Commission finds that DENC has made a substantial and well-supported effort to comply with the Commission's directive, which is augmented by DENC's willingness to re-calculate the charge consistent with the Public Staff's recommendations. The resulting $0.78/MWh charge is close to the $0.69/MWh charge that witness Johnson calculated as an illustrative alternative. DENC has indicated that the charge represents its first step in quantifying the costs of integrating large volumes of solar PV generation onto its system, and that it will continue to evaluate these costs and benefits going forward. The calculation was made using the best information available at the time, but with further evaluation and refinements, as well as further changes in the development of QF projects, DENC acknowledges that it could decline in future proceedings. The Commission therefore agrees with witness Petrie that for purposes of this proceeding the re-dispatch charge is fair to both QFs and DENC's retail electric customers because it will provide payments to QFs that better reflect DENC's avoided costs.

The Commission recognizes the discussions regarding a potential overlap between the costs being borne by each utility that DENC's re-dispatch charge and Duke's integration services charge are intended to recover. In this proceeding, each utility has taken its own approach to evaluating and quantifying the costs to its system from intermittent, non-dispatchable QFs. Should DENC propose a revised charge or charges in the next biennial proceeding to address other costs to its system resulting from such QFs, the Commission will evaluate the reasonableness of such a charge at that time. Finally, DENC acknowledged that there could be circumstances where a QF, due for example to the addition of a battery, could justify an exception from the re-dispatch charge. As with Duke, the Commission finds it is appropriate to require DENC to file with the Commission a proposed protocol for avoidance of the re-dispatch charge.

In conclusion, the Commission finds that DENC's proposed re-dispatch charge of $0.78/MWh is reasonable for purposes of this proceeding. In the filing of rate schedules that it makes in compliance with this Order, DENC should reflect the modified re-dispatch charge of $0.78/MWh in its Schedule 19-FP, consistent with the decisions relevant to Duke's proposed integration services charge included in this Order, to the extent possible. In addition, the Commission will direct DENC to file a proposed protocol for avoidance of the re-dispatch charge similar to those protocols required from Duke.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 47

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

Summary of the Evidence

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

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

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

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

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

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

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

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

Discussions and Conclusions

Based upon the foregoing and the entire record herein, the Commission agrees with the Public Staff that DENC's proposed capacity cap, which acts as a limit on payments, is unnecessary if DENC appropriately evaluates and adjust its seasonal allocation and capacity payment hours based on the specific characteristics of its system. Therefore, the Commission finds that it is inappropriate to approve DENC's proposed capacity cap for the purposes of calculating rates in this proceeding, and the Commission will direct DENC to appropriately revise its Schedule 19-FP rates to remove the capacity payment limits.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 48

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

Summary of the Evidence

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

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

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

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

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

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

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

Discussion and Conclusions

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

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

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

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

Summary of the Evidence

A part of its Initial Statement Duke includes an amended Schedule PP PPA and Terms and Conditions to address modifications to a QF Facility that seeks to install battery storage or otherwise increase its energy output. Duke amends the Terms and Conditions for new PPAs to state that it may terminate or suspend purchases of electricity from the QF for "any material modification to the Facility without the Company's consent or otherwise delivering energy in excess of the estimated annual energy production of the Facility." JIS DEC Exhibit 4 and DEP Exhibit 4. The Terms and Conditions do not specifically define the term "material modification." A material modification is, however, a term defined in the NCIP.

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

Duke specifically amends the terms and conditions to clarify the term "Contract Capacity" to include the estimated annual energy production of the facility. Duke further states that any such increase to the "Contract Capacity" will not be allowed if the QF seeks to retain its pre-existing standard offer PPA at "stale and significantly higher avoided cost rates." *Id.* at 35. Duke believes it would be inappropriate to compensate capital investment made today based "on stale avoided cost rates that were established many years in the past and which far exceed the currently-effective avoided cost rates." *Id.* at 35-36. Acceptance of such modifications would materially increase the financial obligations of Duke's customers at rates significantly above the current avoided cost.

In its Initial Comments the Public Staff agrees with Duke that the increased energy output of a QF that adds storage should be subject to the rates determined in the most recently effective avoided cost docket. Public Staff Initial Comments at 73. The Public Staff states that allowing a QF to increase its energy output by adding storage could significantly change the total cost of the QF's energy and capacity to the detriment ratepayers if, for example, the facility adds energy during on-peak periods as reflected in prior tariffs that do not reflect the utility's highest production cost hours today. *Id.* at 74, fn. 111. The Public Staff is concerned, however, that Duke's approach to requiring a new PPA at current avoided cost rates for the entire facility would disincentivize the adoption of new energy storage technologies at existing facilities, which also have the potential to benefit ratepayers by allowing the QF to operate it in such a way to provide energy and capacity during periods when the utility faces high production costs or critical demand. Further benefits could include operational controls that may also help to reduce the impacts associated with the intermittent, uncontrolled output from solar-only facilities. *Id.* at 74, fn. 112.

The Public Staff agrees with Duke that a QF seeking to add any new capability for energy output after execution of a System Impact Study (SIS) Agreement or execution of an Interconnection Agreement following the Fast Track Process or Supplemental Review pursuant to the NCIP should be required to receive authorization from the utility in order to ensure that the addition does not negatively impact the safe and reliable operation of the grid. *Id.* at 75. The Public Staff notes, however, that Duke does not specifically define the term "material modification" in its amendments to the Terms and Conditions. As that term is also used in the interconnection proceeding, the Public Staff recommends that Duke define the term explicitly. *Id*. at 77-78.

The Public Staff proposes an alternative approach to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its pre-existing PPA. *Id.* at 76. The Public Staff states "that designating the addition of energy storage at an existing facility as a new and separate facility may result in unintended consequences, including loss of eligibility as a standard offer QF or a FERC-certified QF." *Id.* The Public Staff is also concerned that having multiple PPAs at the same site may result in timeframes that do not align, potentially causing confusion regarding QF eligibility *Id*. at 76-77.

In its Initial Comments NCSEA states that Duke provides "no limitation or quantification" on its proposed "unilateral authority to void a PPA if a QF increases its annual energy production above an estimated production number stated in the PPA," and that that "occurs on a regular basis for QFs." NCSEA Initial Comments at 55. NCSEA further states that the annual production number, which Duke proposed to use as the Contract Capacity, is an estimate that will vary up and down due to a variety of circumstances. *Id*. NCSEA asserts that it is commercially unreasonable to require that a QF never exceed its estimated annual energy production without risking termination of the PPA.

NCSEA argues that Duke's proposal violates PURPA's requirement that a utility purchase all of a QF's output provided that the QF does not exceed its nameplate capacity. *Id*. NCSEA disagrees with Duke's assertion that the right to sell under PURPA should be limited to the facility that established a LEO and originally entered the PPA. NCSEA states that the CPCN requirement was not intended to lock QFs into construction of a facility exactly as described in the CPCN application. *Id*.

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

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

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

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

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

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

Regarding the Public Staff's recommendation in its Initial Comments to explore separately metering battery storage and compensating additional output at the current avoided cost rate, Duke states that it does not support the Public Staff's recommendation to allow amendments to prior standard offer PPAs to accommodate the addition of storage for contractual, technological, and regulatory policy reasons. First, contractually, Duke believes that a material alteration of a facility would require the consent of utility, and the failure to obtain consent would be a material breach of the contract. Second, from a technological perspective, Duke states that its current metering system does not have the capability to segregate or estimate the production of a solar QF separate from a co-located battery storage facility. Furthermore, if the battery is shifting the time of energy delivered it could result in inequities. For example, under the levelized rate concept, there would be overcompensation being paid to the QF because there would be higher deliveries and payments in the early years prior to the installation of battery storage when levelized rates are artificially high. Third, from a regulatory policy perspective, QFs and their investors have often selected the longest possible term of 15-year contracts in order to benefit from locking in higher avoided cost rates that are now projected to significantly exceed future avoided costs. Duke believes it would be inequitable to allow those facilities to leverage the current contractual relationship to sell more energy or to shift energy output in ways that were not contemplated when the contract was entered. *Id*. at 145-46. Finally, Duke states that it agrees with the Public Staff that there would be challenges in determining the eligibility for QF status as a small power production facility under PURPA. The potential co-location of battery storage with a solar facility raises federal and regulatory policy questions that have not fully been answered, including eligibility for 5-MW projects adding generation that will increase nameplate capacity of the facility as a whole and the potential violation of the half-mile rule. *Id*. at 147-48.

In its Reply Comments NCSEA states that energy storage is now cost-competitive and that there is likely to be substantial deployment before the next avoided cost biennial proceeding. NCSEA agrees with the Public Staff and SACE that the proposed additions to the PPA and Terms and Conditions regarding energy storage and increases to energy output are overly and unduly restrictive. NCSEA Reply Comments at 21-22. NCSEA agrees with SACE that the replacement of older solar panels with newer solar panels should not be considered a material modification that would require the QF to enter a new PPA. *Id*. at 22. NCSEA disagrees with the Public Staff's suggestion that increased energy output be separately metered and compensated at the most recently effective avoided cost rate. NCSEA asserts that the fact that a QF could increase its total revenue generated through the addition of energy storage is an insufficient reason "to violate the PURPA rights of QFs." *Id*. A QF that is already providing electricity to the grid has already met the requirements to establish a LEO and adding energy does not void the LEO. *Id*. at 22-23.

SACE states in its Reply Comments that it agrees with the positions of the Public Staff, NCSEA, and NC WARN that a number of Duke's proposed amendments to the Schedule PP Terms and Conditions will likely discourage QF development, including the addition of energy storage. SACE states that it agrees with the Public Staff that it is not appropriate for a QF that adds storage to forfeit its existing PPA or to characterize the addition of energy storage as a new and separate facility. SACE Reply Comments at 17-18. SACE states that it does not consider it "appropriate at this time to require existing QFs that add storage or replace existing solar panels, but which do not exceed their AC capacity, to enter into new contracts with new avoided cost rates." *Id*. at 18. SACE believes "[r]equiring QFs to enter into bifurcated avoided cost rates when the QF is not exceeding its original AC capacity is inconsistent with PURPA's requirements." *Id*. Furthermore, SACE agrees with the Public Staff that "material modification" is undefined and that the term should be defined further with stakeholder input for the purposes of avoided cost contracts. SACE agrees with NCSEA that material modification is more appropriately addressed in the interconnection proceeding and believes that to the extent material modification is used in avoided cost contracts that Duke's definition is overly broad. *Id*.

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

Duke witness Snider testified that the proposed changes to the PPA and Terms and Conditions are meant to clarify that operational QFs should not be allowed to modify their generating facility in order to increase generation and that to allow that would be "unjust and unreasonable and would result in significant customer overpayment relative to the incremental generation value being put to the grid." Tr. vol. 2, 87. Witness Snider stated that the modifications are necessary to protect customers from overpayment at rates that exceed the utility's current avoided cost and that power being delivered today from QFs date as far back as the 2010 avoided cost proceeding, Docket No. E-100, Sub 127. *Id*. In quantifying the potential impacts to customers, witness Snider stated that Duke is committed to purchasing the full contracted-for output from over 3,600 MW of currently or to-be installed QF generating facilities, "all of which are subject to rate schedules approved in Docket No. E-100, Sub 140 or earlier vintages." *Id*. at 88.

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

In response to the scenarios presented in the Commission's June 14, 2019 Order, witness Snider testified that a "committed" QF may not integrate battery storage without first obtaining Duke's consent, and, in all three scenarios, should enter into a new or modified PPA at the most recent avoided cost rates. Tr. vol. 2, 162-63. He further testified that "[a]llowing QF investors to integrate battery storage systems or any other technology that materially alters a QF's energy output or shifts power production under stale, legacy avoided cost rates would result in increased payments to QFs that exceed current avoided costs, in direct contravention of PURPA and HB 589's standard offer rate requirements." *Id*. at 166.

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

DENC witness Billingsley testified that DENC has not made any changes to the Schedule 19 tariffs or PPAs to specifically address the addition of battery storage. Tr. vol. 5, 58. DENC's position regarding all three scenarios presented in the Commission's June 14, 2019 Order is that a QF that seeks to add storage to a proposed or existing facility that has established a LEO or entered into a PPA would be required to establish a new LEO or execute a new PPA at current avoided cost rates. *Id*. Witness Billingsley testified that a QF that seeks to expand its maximum capacity or energy production, or to shift its hours of production under existing rates and terms would burden the Company and its customers with newly obligated overpayments at stale avoided cost rates in contravention of PURPA's requirement that utilities not pay more than their avoided cost for QF output. *Id*. at 59. The addition of battery storage would exacerbate the overpayment burden that the utility already faces, and "contradicts the requirement of PURPA that purchases at avoided cost rates be fair to both QFs and the utility (and its customers)." *Id*.

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

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

Public Staff witness Metz testified that the complementary function of energy storage, when paired with intermittent generation, can reduce needed system reserves by improving predictability of energy output, alleviate other challenges to the electrical grid, and increase the overall dependable capacity. Therefore, witness Metz stated that it is the Public Staff's position that "energy storage coupled with solar generation has the potential to provide benefits to ratepayers and should be appropriately encouraged and fairly treated." Tr. vol. 6, 349. He further testified that the challenge to the Commission is how to allow battery storage development with both future and existing solar QF generation and provide its benefits in a way that is fair to ratepayers. *Id*. at 330. He stated that he agrees with the Utilities that a "QF proposing to integrate battery storage should: (a) not be allowed to do so without the utility's consent; and (b) be required to enter into a new or modified power purchase agreement (PPA) at the Companies' then-current avoided cost rates." *Id*. at 331. Witness Metz stated that paying for additional energy and capacity at old, higher avoided cost rates that no longer reflect the actual avoided costs of the utility would be unfair to ratepayers, as they would "no longer be indifferent between energy supplied by a QF and energy generated by the utility." *Id*. at 333. However, witness Metz did not agree with the Utilities that a QF that adds storage or increases output should lose its eligibility for the rates it established for its original facility output (contract capacity and energy). *Id*. at 332. Rather, any "additional energy" put to the electrical grid from an already existing QF, whether commercially operational or studied as part of the facility's original interconnection request, should be compensated at the most current avoided cost rates and schedules. *Id*. at 349.

Witness Metz testified that it is possible for a QF to produce "additional energy" without adding battery storage by deciding to "re-panel" or "over-panel" to increase its DC capacity, which does not necessarily increase nameplate capacity due to inverter settings and other utility equipment limitations. These modifications, however, can result in faster ramp rates and increased "clipped" energy. *Id*. at 334-35. Witness Metz stated that under the proposed definition of Material Alteration, over-paneling and re-paneling would likely not be considered a Material Alteration so long as Existing Capacity is not increased. In response to questions by the Commission, witness Metz stated that it was possible to add energy storage without increasing the overall output of the facility, but there would have to be validation of certain equipment and contractual terms and conditions developed to ensure the Facility's output is not increased. *Id*. at 433.

With regard to adding storage and separately compensating the additional energy output of the facility, witness Metz testified that there are multiple possibilities to measure the output of co-located batteries, but that it would likely require further restrictions of commercial terms and conditions and may prove uneconomical. Witness Metz stated that in addition to engineering and technical challenges, impacts on the interconnection queue as well as the applicable contract terms and conditions would have to be further considered. *Id*. at 344. For example, if an existing facility sought to add battery storage and took the position that the storage could be separately measured, a methodology would have to be created to develop a baseline of current output for comparison purposes and incorporated into the commercial terms and conditions. *Id*. at 345. Witness Metz proposed a focused stakeholder discussion with an accelerated timeline to explore and develop a deployable energy storage solution for existing QFs and to identify specific challenges that prevent the commercial viability of adding energy storage to existing facilities. *Id*. at 351.

Ecoplexus witness Wallace testified that Ecoplexus agrees with the approach recommended by the Public Staff in its Initial Comments to separately meter any additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its current PPA. Tr. vol. 5, 347. He stated that there are multiple methods to measure the energy output of a battery system, including: (1) "transferring that data directly from the Energy Management System provided by the battery storage provider through network communications onsite;" and (2) "add[ing] a DC meter to the storage output so that energy output could be compensated at the current avoided cost rates and separated from the pre-existing PPA." *Id*. In the first option, the battery management system (BMS) collects information in real time and delivers it to the Energy Storage System (ESS), which processes and analyzes the data. BMS and ESS integrators provide a cloud-based system for monitoring, sharing, and displaying data. *Id*. at 347-48. In the second option, a DC meter could be added for each storage block in addition to the AC revenue meter installed at the point of interconnection, which will remain in place. *Id*. at 349. While witness Wallace stated that there "are no ANSI or IEEE standards in place for DC-meters," there are companies "that can meet [the] ANSI C12.1 accuracy specification." *Id*. Witness Wallace testified that if DC energy can be measured with revenue grade accuracy, a "simple ratio can be calculated and used at the [utility's] AC meter to decipher energy from the array as opposed to energy from the storage system to ensure the proper rate is assigned." *Id*. at 350. Lastly, he noted two outstanding issues that would need to be discussed and considered collaboratively: (1) a metering and communications standard, and (2) commercial PPA terms, and suggested a stakeholder process with a formal proposal to be submitted to the Commission within 150 days. *Id*. at 351.

NCSEA witness Norris testified that energy storage will play an increasingly significant role in enabling "a more affordable, reliable, and sustainable electricity system." Tr. vol. 6, 124. He stated that NCSEA and Cypress Creek believe that "it is incumbent upon the Commission to make decisive regulatory interventions to remove barriers to market entry for energy storage," and that it is of substantial importance in this State for committed QFs because more utility-scale solar is installed in North Carolina than any other state except California. *Id*. at 125. Witness Norris testified that "there is nothing in the standard offer terms and conditions that prohibits a QF from making equipment changes that change the schedule of the output," and "there is nothing in the standard offer QF PPA that prohibits or requires the Utility's consent for equipment changes." *Id*. at 150. He stated that "it is the view of NCSEA that committed generators are fully entitled to add storage under the terms and conditions of the standard offer PPA." *Id*. However, NCSEA offered to accept the alternative arrangement proposed by the Public Staff that output from the storage equipment would be compensated at the most recently determined avoided cost rate. *Id*. at 151. However, the avoided cost rate sought by NCSEA is the ten-year avoided cost rate. Under NCSEA's approach, the modified PPA would also maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor. This would properly value the capacity and will allow the QF to attract financing. A five-year avoided cost rate would "undercut or fully eliminate the capacity value of the storage equipment and make it wholly unfinanceable." *Id*. at 147.

Witness Norris testified that the Utilities' position that any committed generator that adds storage must terminate its existing PPA or LEO and seek an entirely new PPA would "wholly obstruct the addition of storage resources." *Id*. at 151. He stated that ratepayers could benefit from the addition of storage by "including bulk energy time shifting, peak capacity deferral, interconnection efficiency, [and] reduced solar curtailment" among other benefits. *Id*. at 152. Witness Norris also testified that the addition of battery storage could smooth the production curve in a way that could obviate the need for the integration services charge. *Id*. at 177.

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

In his testimony SACE witness Glick recommended that the Commission reject Duke's proposed changes to the Terms and Conditions, require Duke to honor existing contracts with QFs that integrate battery storage, and develop a modified rate design proposal for existing QFs that seek to integrate battery storage. *Id*. at 287-88. Witness Glick stated that as long as the QF does not increase its AC capacity, then "the utility has no reasonable basis to regulate the operation of individual components on the operator side of the meter." *Id*. at 274.

In joint supplemental rebuttal testimony, Duke witnesses Snider, Johnson, and Wheeler reiterated Duke's position that a committed QF proposing to integrate energy storage should not be able to do so without the utility's consent and should enter into a new PPA at current avoided cost rates. Tr. vol. 2, 176. Duke witness Snider testified that Duke is not opposed to entering a new PPA or negotiating a modified PPA if an existing QF proposes adding storage. *Id*. Witness Snider disagreed with NCSEA that the addition of storage to operating QFs will inherently create benefits for consumers. *Id*. at 181-82. Witness Snider stated that under the compromise position, even if "all the complex federal and state regulatory issues, contract law issues, and technical interconnection and metering issues" are resolved, customers will at best only be indifferent to adding storage because "it would be procured from an uncontrolled must-take QF generator being dispatched to maximize revenue and being paid at the utility's full avoided cost value rather than at competitively bid prices." *Id*. at 183.

Witness Snider further testified that if the Commission accepts the compromise, the QF owner seeking to add storage should be required to offer additional consideration that benefits customers in exchange for Duke agreeing to modify the existing commitment to purchase. *Id*. at 184-85. With regard to NCSEA's position that the Utilities should offer a standard offer avoided cost rate for additional output from a storage facility of ten years, witness Snider stated that this is a deviation from the express requirements of House Bill 589. *Id*.

Duke witness Wheeler stated that he has several concerns with Ecoplexus' proposal to measure energy storage output on the DC side of the power inverter and point of interconnection with the Duke system. *Id*. at 147-48. First, it is Duke's business practice to install metering exclusively on the utility's side of the point of interconnection; if it is installed on the QF side, the QF would have the opportunity to change the operation of the equipment without the utility's knowledge or control. Second, as witness Wallace admits, no ANSI standards currently exist to judge the accuracy of the meter data logger proposed in witness Wallace's testimony. Tr. vol. 2, 147-49.

Duke witness Johnson testified that he disagrees with NCSEA's assertion that energy shifting is currently allowed under Duke's avoided cost tariffs. *Id*. at 202-04. He stated that a unilateral change such as adding storage to a committed facility without obtaining Duke's consent would be an event of default. *Id*. at 204.

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

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

Discussion and Conclusions

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

With regard to the first issue, the Commission shares the concerns raised by the intervenors and the Public Staff regarding the term "Material Alteration." The Commission agrees with the Public Staff that QFs often complete maintenance on their facilities that could increase the energy or capacity such as replacing existing solar panels with newer panels, or re-paneling, without first obtaining the consent of the utility, and that this type of maintenance should not trigger a default of the existing PPA. The Commission concludes that Duke has adequately addressed these concerns with the defined term "Material Alteration" which expressly allows replacement of "like-kind" equipment and provides that material alterations will be evaluated by DEC and DEP in a "commercially reasonable manner."

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

For existing PPAs, material changes to the capacity of the QF should be authorized by the utility. However, as stated above the evaluation of any material alteration should be treated in a commercially reasonable manner. The Commission agrees that regular maintenance and repair of a facility after a storm, or similar instances that occur on a normal basis, should be treated within the normal course of operations and should not be considered a change that would allow the utility to void the existing PPA. For the reasons articulated by the Public Staff, the Commission finds that this modification to the Terms and Conditions is reasonable. Therefore, the Commission will approve the use of these revised Terms and Conditions.

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

The Commission finds persuasive NCSEA's argument that removing barriers to energy storage is particularly important in North Carolina because the amount of utility-scale solar that is already installed surpasses that of any other state except California. The Commission also notes the testimony of NCSEA's witnesses that energy storage is now a cost-competitive option, that there is likely to be a substantial deployment of storage before the next avoided cost biennial proceeding, and that energy storage will play a significant role in enabling a more affordable, reliable, and sustainable electricity system. NCSEA's witnesses further testified that NCSEA is willing to accept the "compromise" suggested by the Public Staff to explore separately metering battery storage and compensating additional output at the then-current avoided cost rate. NCSEA states though, that this may not be an economically viable alternative at this time and that the Commission would need to ensure that those QFs received the ten-year avoided cost rate for the additional output. The Commission determines that it is premature to resolve this issue at this time. Instead, for reasons discussed further below, the Commission will seek more detailed discussion on this issue through the stakeholder process required by this Order.

The Commission disagrees, however, with SACE that a QF should be allowed to add energy storage and be compensated at prior avoided cost rates for the additional energy added to the system not contemplated in the original PPA. As stated above the addition of energy storage to an existing QF is a material change to the terms of the prior contract and requires the utility's consent. Allowing a QF to modify its facility to substantially increase energy output and be compensated at prior avoided cost rates would result in significant overpayment beyond the current avoided cost, which would be unfair to ratepayers.

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

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

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

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

II. Commercial
   (a) Report on what existing commercial terms and conditions are preventive barriers for implementation.
   (b) Propose solutions to remove or mitigate preventive barriers.
   (c) Report on how to accomplish billing and payment for separately metered systems.

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

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

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

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

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

IT IS, THEREFORE, ORDERED as follows:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

24. That Duke shall include in its initial filings in the next biennial avoided cost proceeding an evaluation of whether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide;

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

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

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

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

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

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

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

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

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

ISSUED BY ORDER OF THE COMMISSION.

This the 15th day of April, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Joann R. Snyder

Joann R. Snyder, Deputy Clerk

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	DOCKET NO. 17-035-61 ORDER

ISSUED: October 30, 2020

SYNOPSIS

We approve an export credit rate for customer generation of 5.969 cents/kWh in summer rates and 5.639 cents/kWh in winter rates. These rates represent an avoided energy component of 2.439 cents/kWh in summer rates (June through September) and 2.109 cents/kWh in winter rates (October through May), plus total avoided generation, transmission, and distribution capacity costs of 3.53 cents/kWh.

Though some statutes describe jurisdiction to regulate the business of public utilities in broad terms,[1] our regulatory purview "does not encompass any and all considerations of interest to the public."[2] Our primary responsibility is to set rates based on the utility's cost of service. Accordingly, we have accepted and adopted every component of the export credit rate for which any party provided substantial evidence of a quantifiable impact on the utility's cost of service. We decline certain parties' invitation to incorporate components unrelated to utility ratemaking. While we recognize the importance of environmental considerations, carbon policy, economic

[1] Utah Code Ann. § 54-4-1.
[2] *Ellis-Hall Consultants, LLC v. Public Service Commission of Utah*, 2014 UT 52, ¶ 22. The quoted text pertains to the Court's conclusion that our statutory mandate to set avoided cost rates under the Public Utility Regulatory Practices Act that are in "the public interest" does not permit us to consider all considerations of interest to the public. While this matter concerns our authority in a different statutory context, we find the Court's reasoning persuasive and anticipate the Court would apply similar constraints on our regulatory purview with respect to setting an export credit rate. *See infra* at n.8.

development, and public health, these matters fall within the regulatory ambit of other government agencies. We will not appropriate those agencies' authority or pretend to their essential expertise by adopting a boundless view of our own in the context of utility ratemaking.

We have approved annual updates to the export credit rate, and have invited comments on the timing, procedure, and substance of those updates. We anticipate issues like market prices and updates to capacity contribution values will play a role in the updates, and we also recognize the opportunity to update the export credit rate in the event that carbon or environmental requirements allow the utility to avoid quantifiable costs through customer generation.

The highest and best use of customer generation is for the customer to avoid the purchase of electricity. For that use, customers avoid the full retail rate of electricity, a rate that includes variable and fixed costs. That highest and best use should incentivize customers to size their systems to take full advantage of the benefits of avoiding electricity purchases. Additionally, the export credit rate we order will provide meaningful compensation to those customers for their excess generation.

We decline to adopt the utility's proposed application fee, and direct the utility to apply to Schedule 137 the tiered application fee currently in place for Schedule 136. We decline to approve a time of use element in the export credit rate or interval netting of excess generation and accordingly, we also decline to adopt the utility's proposed metering fee. The value of a customer's monthly excess generation will be netted against the energy portion of the customer's monthly bill.

For the time being, we are retaining the annual expiration of accrued credits. We look forward to future evaluation of annual expiration based on data from customers who are compensated through the export credit rate.

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1. Background

This docket commenced on December 1, 2017 with an application filed by Rocky Mountain Power (RMP). The application followed a September 29, 2017 order ("2017 Order") by the Public Service Commission of Utah (PSC) approving a settlement stipulation in a separate but related docket.[3] The current docket was separated into two phases, the first of which concluded with a PSC order issued on July 10, 2018. This order addresses the docket's second phase, during which testimony and evidence were presented by RMP, the Division of Public Utilities (DPU), the Office of Consumer Services (OCS), Utah Clean Energy (UCE), Vivint Solar, Inc. ("Vivint"), Vote Solar (VS), Utah Solar Energy Association ("Utah SEA"), and Salt Lake City Corporation ("SLC").

2. Rate Elements Advocated by Parties

In Phase II we are considering a proposed rate structure for customer generation (CG) that includes an export credit rate (ECR) for excess customer-generated electricity as well as other rate structure details including fees and operational elements.

RMP proposed an ECR consisting of avoided energy costs with differentials based on summer/winter generation and peak/off-peak generation. RMP proposed adjustments for line

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[3] *Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program*, Docket No. 14-035-114.

losses and integration costs, net billing of a customer's excess generation against usage, annual updates to the ECR, and one-time fees for CG customers: a $150 application fee and a $160 metering fee. The DPU and OCS generally supported that structure proposed by RMP with some variations.

The remaining parties, to varying degrees, advocated for additional components to increase the ECR such as avoided capacity costs and ancillary, community, and environmental benefits. Those parties generally opposed RMP's proposed fees and annual expiration of credits, supported netting of excess generation on an hourly or greater basis, and supported various scenarios for locking in the ECR for individual customers on a long-term basis. Some parties supported a return to a "kWh for kWh" credit structure for CG, or for any new rates to be implemented gradually over time.

The details and nuances of these positions were presented in written testimony and discussed at the hearing. We will not attempt to summarize those further here, but we discuss them in this order as necessary to make our findings, conclusions, and decisions.

3. Findings of Fact, Conclusions of Law, and Decisions

a. We are implementing a CG rate structure ("Schedule 137"), including an ECR, that meets the requirements of Utah Code Title 54, Chapter 15, Net Metering of Electricity ("NM Statute"). Accordingly, it is not necessary at this time to conclude whether or not compliance with the NM Statute is mandatory in connection with Schedule 137.

RMP's net metering program was implemented and regulated by the PSC under the NM Statute. The NM Statute permits RMP to discontinue the net metering program after customer generation reaches a specified cumulative generating capacity, and permits the PSC to adjust that specified cumulative generating capacity.[4] Our 2017 Order approved a cap for the net metering program and a grandfathering period for customers whose interconnection applications were approved prior to that cap. Our 2017 Order also approved a transition program ("Schedule 136") for customers who submit an interconnection application prior to the earlier of the date a specified customer generation capacity is reached, or the date this order is issued.

This order establishes the parameters for Schedule 137 to govern electricity generated by customers who submit an interconnection application on or after its effective date. Schedule 137 operates independent of both the grandfathered and transition customers. The stipulation we approved in our 2017 Order appears to be premised on establishing Schedule 136 and ultimately Schedule 137 without the NM Statute governing those Schedules, but the stipulation does not explicitly state that legal outcome. In our 2017 Order, we did not make any conclusion of law regarding the applicability of the NM Statute to Schedule 136.

Similarly, it is unnecessary at this time to conclude whether Schedule 137 operates pursuant to, or independent of, the NM Statute. Regardless of whether the NM Statute's requirements apply to customers who take service under Schedule 137, we conclude our approval of Schedule 137, including an ECR, complies with those requirements.

Specifically, in this proceeding we have evaluated whether "costs that [RMP] or other customers will incur" from CG operating under Schedule 137 "will exceed the benefits" of that CG, or vice-versa.[5] We are approving a structure within Schedule 137 "in light of [those] costs

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[4] Utah Code Ann. § 54-15-103(2) and (3).
[5] Utah Code Ann. § 54-15-105.1(1).

and benefits."[6] Regardless of the specific legal applicability of the NM Statute to Schedule 137, the NM Statute represents the most salient state policy to guide our consideration of a just and reasonable CG rate structure and we conclude our findings herein satisfy the statute's requirements.[7]

All parties have advocated various rate components and operational elements that impact the ECR and other aspects of Schedule 137 and have provided evidence and testimony regarding the costs and benefits attributable to the individual rate components and operational elements. In this proceeding we have evaluated all costs and benefits advocated by all parties.

Our evaluation requires us to consider both the evidence supporting each cost and benefit advocated by a party, and the relevance of each cost and benefit. With respect to relevance, we conclude that for purposes of establishing Schedule 137, we should evaluate the costs and benefits that accrue to RMP and its customers in their capacity as ratepayers of RMP. Accordingly, we conclude that Schedule 137 should be based on costs and benefits that have a direct and quantifiable impact on RMP's cost of service. We conclude that costs and benefits that do not impact RMP's cost of service in a direct and quantifiable way are not relevant to the rate structure we are approving in this order.[8] We evaluate the costs, benefits, and Schedule 137 rate

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[6] Utah Code Ann. § 54-15-105.1(2).

[7] Pursuant to both our 2017 Order and the settlement stipulation we approved in the 2017 Order, both grandfathered and transition customers are continuing under the CG compensation structure established in the settlement stipulation without our having completed the statutory evaluation of the costs and benefits of the grandfathered and transition rate structures. No party has advocated for the discontinuation of the grandfathered and transition rate structures.

[8] More than thirty years ago, the Utah Supreme Court articulated our primary responsibilities to regulate utilities like RMP to ensure reliable service at a reasonable, non-discriminatory cost. *Garkane Power Ass'n v. Public Service Comm'n*, 681 P.2d 1196, 1207 (1984). If we were to base the ECR on costs and benefits that do not impact RMP's cost of service, we would be

elements advocated by the parties to this docket pursuant to those conclusions. If a cost, benefit, or rate structure component advocated by a party meets this relevance standard, we move forward to an evaluation of evidence addressing it.

b. We find that it is just and reasonable to update the ECR annually, without providing long-term price guarantees to Schedule 137 customers.

We find that annually updating the ECR is just and reasonable. Energy and capacity prices can change each year; no party argued otherwise. Some parties argued for individual Schedule 137 customers to lock in their ECR for a long-term period at the time of interconnection. Those parties supported that position with arguments about the need for potential CG customers to calculate the ultimate return on their CG investment, but we conclude those policy arguments are not relevant to RMP's cost of service. Additionally, a CG customer who wants to lock in a long-term value for the customer's generation could choose to sell their power to RMP under the Public Utility Regulatory Policies Act (PURPA). Schedule 37 is RMP's process for purchasing power from small generators, and there is no minimum capacity

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assuming authority that has not been legislatively delegated to us. For example, environmental regulation in Utah generally rests with the Department of Environmental Quality. Absent more specific statutory direction, we would be appropriating that agency's authority if we attempted to establish an ECR to promote or compensate environmental attributes in the absence of a direct and quantifiable impact on RMP's cost of service. While statutes such as Utah Code Ann. § 54-4-1 employ broad jurisdictional language, we conclude that it would be inappropriate to exercise that jurisdiction out of context from the more specific boundaries and contours outlining our authority, and the authority of other state agencies in Utah, established by both statute and case law. This conclusion is also supported by recent legislation in 2019 implementing a similar standard in a different context, the Community Renewable Energy Act. That Act codifies as state policy the premise that when we consider rates for participants under the Community Renewable Energy Act, we "shall take into account any quantifiable benefits to the qualified utility, and the qualified utility's customers, including participating customers in their capacity as ratepayers of the qualified utility, excluding costs or benefits that do not directly affect the qualified utility's costs of service." Utah Code Ann. § 54-17-904(4)(c).

requirement under that schedule. A CG customer who desires a long-term locked in price could choose Schedule 37 as long as the customer is also willing to accept the accompanying long-term obligations and requirements imposed by the Federal Energy Regulatory Commission.

We decline to approve a long-term price guarantee for Schedule 137 customers without accompanying long-term contractual and generation obligations. We find that annual updates to the ECR will keep that rate most accurate in context of changing market conditions. These updates will differ significantly from general rate cases, which evaluate total utility revenue requirements, cost of capital, and rate design. ECR annual updates will instead focus on the narrow issues related to the values represented in the ECR and other elements of Schedule 137. These updates will not directly impact the rates an RMP customer pays for electricity service from RMP, but instead will only impact the compensation Schedule 137 participants receive for their excess electricity. We invite any interested person to file comments on the potential timing, procedure, and scope of these annual updates on or before February 8, 2021, and to file reply comments on or before March 22, 2021.

c. Calculating the avoided energy component of the ECR with average locational marginal price data from the Western Energy Imbalance Market (EIM) operated by the California Independent System Operator, is a reasonable and transparent method.

No party alleged that avoided energy is not a relevant component of the ECR or that it does not impact RMP's cost of service. We conclude that avoided energy is relevant and should be the initial component of the ECR.

RMP proposed a method for calculating CG avoided energy using a single year, 2021 projection through the proprietary modeling software RMP uses for other purposes. VS proposed a method using market prices at three eastern energy hubs utilized by RMP based on the top 10% of load hours according to RMP's official forward price curve. Vivint originally proposed calculating the avoided energy component of the ECR with average locational marginal price data from the EIM. All three of these parties provided testimony and evidence in support of their proposed method, although in surrebuttal testimony Vivint updated its position to support the method originally proposed by VS. Other parties also expressed their preferences for one of those methods, and some of those preferences evolved to some degree during the various stages of testimony.

With annual updates to the ECR, we find that the general method that was originally proposed by Vivint, with the modifications to that method presented on surrebuttal by RMP, is the most reasonable. It does not require use of any proprietary software, and EIM price data is publicly available and transparent. It is also a more accurate method of calculating short-term compensation than using a forward price curve. A forward price curve is valuable in contexts such as resource planning and establishing prices for long-term fixed contracts with obligations from both the utility and generator. But as OCS witness Philip Hayet succinctly stated, "forecasts are not error free."[9] Recent EIM prices, on the other hand, reflect actual market prices within a specified time frame. Customers receiving an ECR updated annually using recent EIM prices will be more reasonably compensated based on the prices RMP in fact paid for energy during the most recently comparable time period.

[9] Rebuttal Testimony of Philip Hayet on behalf of the OCS, July 15, 2020, 20:443.

VS criticized RMP's load research study, its proposed method for calculating avoided energy, and the DPU for its reliance on that load research study. Because we are not adopting the method for calculating avoided energy that RMP originally presented in its application, and because the other components of the ECR we are adopting in this order also do not rely on RMP's load research study, it is not necessary for us to make any findings with respect to that study.[10]

RMP recommended that the EIM prices originally proposed by Vivint should be adjusted, arguing that Vivint incorrectly removed adders (generally negative for Utah prices) relating to greenhouse gas costs and transmission congestion. We find that these adjustments proposed by RMP are reasonable because the transmission congestion and greenhouse gas adders generally result in higher EIM prices in California, and the EIM prices we use to calculate the ECR should reflect prices paid by Utah customers through the EIM. For these reasons, we find the EIM-calculated avoided energy cost presented by RMP in its surrebuttal testimony, with the line losses adjustment we have described below, is a just and reasonable basis for the avoided energy component of the ECR.

i. We find that using a summer and winter ECR is reasonable, but we find that it is premature to include peak and off-peak pricing or to approve RMP's proposed metering fee.

No party contested RMP's proposed differential ECR rate for summer and winter, and we approve and adopt that ECR component with summer pricing from June through September, and

[10] RMP's proposed method of calculating avoided energy costs based on EIM pricing uses Schedule 136 customer census data, and we find RMP's use of that data to be reasonable and supported by substantial evidence.

winter pricing from October through May. However, we decline at this time to adopt a peak and off-peak component into the ECR. We have not yet adopted and approved mandatory time of use rates for RMP's residential[11] customers. We recognize that the ECR is not the same as a rate for customer purchases of utility service, and that nothing inherently prevents us from incorporating peak and off-peak pricing in the ECR without doing so in other customer rates. We also recognize RMP's assertion that peak and off-peak ECR pricing more accurately reflects the individual characteristics of Schedule 137 customers.

Nevertheless, peak and off-peak pricing comes with a cost, as represented in RMP's proposed metering fee. And the delta between the peak and off-peak ECR pricing proposed by RMP is relatively modest. Based on the record in this docket, we are unable to find that the benefits of peak and off-peak ECR pricing justify the additional metering cost. Therefore, we decline to approve both the peak and off-peak component of the ECR, and RMP's proposed metering fee. We recognize that even without a peak and off-peak ECR, metering costs are not necessarily zero. However, RMP testified that without a peak and off-peak ECR, and without interval netting which we are also declining to impose in this order, Schedule 137 metering needs would be equivalent to the metering needs that existed under Schedule 135, which did not include any metering fee beyond the metering component included in the customer charge of the monthly bill that RMP residential customers paid then and now. Peak and off-peak ECR compensation could be re-evaluated in the future if advanced metering deployment changes.

[11] We have approved time of use rates for large general service customers, but different policy considerations apply to those customers than those that apply to Schedule 137.

ii. We conclude that line losses are a relevant component of the ECR, and we find that line losses should include secondary line transformer losses.

All parties agreed that line losses represent an appropriate component of the ECR. We find that line losses reflect an impact on cost-of-service, and conclude that the issue is relevant to the ECR.

Vivint's original avoided energy proposal included an avoided line loss component embedded into the avoided energy rate. We find that based on the record in this docket, the EIM prices used by Vivint do not reflect the full value of all appropriate line losses.

The remaining primary difference between parties on this issue involves whether or not secondary line transformer losses should be included in the ECR. We find that the record supports the inclusion of secondary line transformer losses. Specifically, we find inadequate data in the record to support RMP's assertion that exported energy must be transformed before flowing to another customer. We find it intuitively likely for some exported energy to flow to another customer on the same secondary line. Accordingly, in the absence of more specific data identifying the frequency with which exported energy does and does not flow to a customer on the same secondary line (data that we recognize may be elusive), we find that the avoided line loss value proposed by VS, with the adjustment OCS recommended to apply the line losses to a one-year estimate of avoided energy costs rather than a 20-year levelized calculation, is both just and reasonable. We find the OCS adjustment is necessary and reasonable in context of our decision to update the ECR annually.

iii. We conclude that integration costs are a relevant ECR component and we find substantial evidence to support an adjustment to the ECR to reflect these costs.

RMP proposed that the ECR should be adjusted downward to reflect integration costs necessary to hold flexible resources to accommodate fluctuations in the system's load and resource balance. RMP argues this cost is necessary because CG is not under RMP's control. While some parties disputed RMP's evidence, no party alleged that RMP's proposed integration costs, if established by evidence, are not a component of cost-of-service, and accordingly we conclude this is a relevant ECR component for which we should evaluate the adequacy of the evidence.

We find that RMP's flexible reserve study provides substantial evidence of the necessary reserve requirements attributable to the aggregate variations from resources (including solar) that do not follow dispatch signals. This study therefore captured the benefits based on the aggregate variation of the diversity that exists among that category of resources. Though the flexible reserve study included only utility scale solar resources, we find that utility scale solar is a reasonable proxy for estimating integration costs for CG solar. RMP's calculation of a percent variability value for CG exports based on aggregate Schedule 136 exports provides evidence for our finding that CG integration costs are likely higher, but at least equal to, the integration costs for utility scale solar identified in the flexible reserve study. We expect the integration cost component of the ECR should be adjusted in future annual updates to reflect new resources that are in operation.

iv. We approve the avoided energy component of the ECR as 2.439 cents/kWh in summer rates, and 2.109 cents/kWh in winter rates.

For the reasons we have discussed, we approve the avoided energy component of the ECR as 2.439 cents/kWh in summer rates, and 2.109 cents/kWh in winter rates. We calculate that amount starting with the proposed avoided energy rates based on EIM pricing that RMP presented in its surrebuttal testimony. We have adjusted those rates to exclude the peak and off-peak differential, and adjusted them upward to reflect the calculations by the OCS to include secondary line losses.[12]

d. We conclude that avoided capacity costs are a relevant component of the ECR, and we approve a total avoided capacity cost (including avoided generation, transmission, and distribution capacity) for the ECR of 3.53 cents/kWh.

We conclude that avoided capacity costs, if quantified and calculated correctly, reflect a reduction to RMP's cost-of-service that result from CG. Accordingly, we conclude that avoided capacity costs are relevant ECR components for which we should evaluate the sufficiency of the evidence.

Most objections from parties to avoided capacity costs generally focus on the non-firm nature of CG, and the lack of control RMP has over those resources. We find, though, that aggregate CG output is an output on which RMP has chosen to rely in its integrated resource planning (IRP) process. CG does not provide firm capacity, but the record includes substantial

[12] The OCS proposed a 0.043 cents/kWh adjustment to the avoided energy cost RMP proposed in rebuttal testimony. The avoided energy cost RMP proposed in surrebuttal testimony included an amount for secondary line losses. When we reduce the OCS adjustment to account for RMP's proposed secondary line loss increment on surrebuttal and average that amount weighted between summer and winter rates, we calculate the OCS adjustment to be 0.0323 cents/kWh in summer rates, and 0.0279 cents/kWh in winter rates.

evidence that aggregate CG output reduces load sufficient to impact RMP's need to invest in future capacity.

i. We approve the capacity contribution value proposed by VS and apply it to each avoided capacity cost.

An initial difference in position, primarily between RMP and VS, applies to each component of a potential avoided capacity cost. VS advocates for a capacity contribution value significantly higher than the one presented by RMP in its surrebuttal testimony.[13] The two methods are calculated differently, but one significant difference is that the capacity contribution values advocated by VS include only resources currently operating, while RMP's proposed capacity contribution values include planned future resources. We find that difference to be most pertinent in deciding which capacity contribution factor to apply to avoided capacity costs.

We have approved capacity contribution values for use in calculating the rates to be paid to qualifying facilities under PURPA. However, PURPA rates include long-term contracts with levelized pricing. In that context, future resources planned in the IRP are an intuitive component of capacity contribution values. Additionally, PURPA rates often deal with energy and capacity separately.

The ECR we are approving, on the other hand, will be updated annually and will integrate energy and capacity components into one payment to CG customers. The annual updates provide us the opportunity to adjust capacity contribution values as new resources are added to the system. We find and conclude that any avoided capacity costs we include in the

[13] While RMP's position is that avoided capacity costs should not be part of the ECR, on surrebuttal RMP presented an alternate capacity contribution value to apply to avoided capacity costs.

ECR will better reflect the current impact of Schedule 137 on RMP's cost of service if they are calculated with an avoided capacity contribution value that reflects only currently operational resources. Accordingly, we approve the capacity contribution values proposed by VS.

ii. We apply an annual carrying charge of 7.82% to all of the proposed avoided capacity costs.

VS and Vivint were the only parties who provided methodologies to calculate generation, transmission, and distribution avoided capacity costs. Both of those parties applied a carrying charge of 9.39% based on a study filed in 2018 by PacifiCorp with the California Public Utilities Commission. We find that number does not represent the current cost of equity and debt for RMP in Utah. We find that the number proposed by RMP witness Daniel J. MacNeil in his rebuttal testimony, 7.82%,[14] more accurately reflects RMP's current cost of equity and debt in Utah, and that we should apply that number to the generation, transmission, and distribution avoided capacity costs.

iii. We approve the generation, transmission, and distribution avoided capacity costs proposed by VS, as adjusted to one-year calculations and using the appropriate carrying charge. This results in an addition of 3.53 cents/kWh to the ECR.

VS and Vivint were the only parties who provided methodologies for calculating generation, transmission, and distribution avoided capacity costs. The criticism of those costs generally focused on the non-firm nature of CG and the lack of control of CG output by RMP.

[14] Rebuttal Testimony of Daniel J. MacNeil, July 15, 2020, 39-40:830-836.

For the reasons we described previously, we find those criticisms do not warrant rejection of these avoided costs.[15]

We find that substantial evidence exists in the record to support the three avoided capacity costs proposed by VS. The only alternative methods were proposed by Vivint, a party that ultimately supported the VS methods. Having rejected the criticisms of avoided capacity costs generally, we find that the best evidence before us of the value of those avoided costs was provided by VS.

Adjusted to one-year calculations and for what we have found to be the more appropriate carrying charge, we approve an avoided generation capacity cost of 2.31 cents/kWh, an avoided transmission capacity cost of 0.91 cents/kWh, and an avoided distribution capacity cost of 0.31 cents/kWh.

e. We conclude that avoided fuel price hedging is a relevant potential ECR component that could impact RMP's cost of service, but we find that the evidence in this docket is insufficient to include that value in the ECR.

Fuel price hedging costs are a component of RMP's cost of service. Therefore, if CG were found to reduce those costs, that would be an appropriate component of the ECR. The record and evidence in this docket, though, are insufficient to include that component. The only

[15] While RMP and the OCS expressed some conceptual support for an avoided generation capacity cost, they rejected outright any avoided capacity cost for transmission or distribution. However, the arguments against all three types of avoided capacity costs were premised on the same concept that we have found not to be a basis to reject these costs: the non-firm nature of CG and the lack of control of CG output by RMP. While there was some anecdotal discussion of additional wear and tear CG could cause to the distribution system, the record evidence is insufficient to find that the avoided distribution capacity should be adjusted in any quantifiable amount. And finally, we cannot accept the OCS recommendation to reduce avoided generation capacity by 25% or 50% without additional evidence of the source of those two proposed percentages.

evidence in support of a quantified fuel hedging price savings to RMP as a result of CG is a 2011 published study of utilities in the Northwestern United States. The data is dated and is not specific to PacifiCorp's current hedging program or to the RMP territory in Utah. In particular, there was no evidence in the record of how CG would impact RMP's energy balancing account, or the process currently in place to evaluate fuel price hedging in the context of that balancing account. Accordingly, we decline to include an avoided fuel price hedging component in the ECR.

f. We conclude that all other proposed components of the ECR do not impact RMP's cost of service, and therefore we decline to approve them.

Various parties advocate for the following values to be included in the ECR (or given a "placeholder" for future consideration): avoided carbon compliance, ancillary benefits, community benefits, grid support services, reliability and resilience, health benefits from reduced air pollution, benefits from reduced carbon emissions, social benefits of reduced carbon emissions, avoided fossil fuel life cycle benefits, and local economic benefits. We conclude that none of these proposed ECR components have been demonstrated to impact RMP's cost of service, and that they are therefore not relevant to our establishment of an ECR.

We recognize that many of these proposed ECR components have societal value, and in some cases parties have quantified that value. But without an impact on cost of service, we decline to appropriate jurisdiction that properly belongs to other agencies who have more direct authority over and expertise related to these areas of policy. We do not set policy for the state of Utah on carbon, environmental regulations, social policy, or economic development.

We recognize that some of those issues may impact RMP's cost of service in the future. Some parties have advocated for a "placeholder" zero value, but we find that unnecessary considering annual updates to the ECR. For example, if a carbon cost is imposed on RMP in the future, then the ECR can be adjusted to reflect the extent to which CG avoids that cost. If the costs of a current or future environmental regulation can be shown to be avoided by CG, then the ECR can be adjusted to reflect that avoided cost.

g. We approve netting a customer's ECR value earned against energy costs incurred on the customer's monthly bill.

We have declined to conclude in this order whether the NM Statute applies to Schedule 137. However, if it does, Utah Code Ann. § 54-15-104(1) provides support for netting excess generation on the CG customer's monthly bill.

Several parties have advocated for netting an individual's generation on an hourly basis. We discussed previously in this order that we have rejected RMP's proposed metering fee because we did not find the benefits of the peak and off-peak rates to justify that cost. Therefore, there is no guarantee that all Schedule 137 customers will have meters capable of hourly netting.

But more importantly, hourly netting (or any netting interval) simply does not have a basis or justification in a cost of service setting. Most of the testimony on the issue focused on what would be more convenient or understandable to customers. While we find netting a customer's ECR values against energy charges on the customer's monthly bill to be simple and intuitive, we consider it unnecessary to consider whether some other netting interval might be more understandable, even though that seems unlikely. Cost of service principles dictate that Schedule 137 customers should receive the ECR for each kWh they actually export to the grid.

Netting the values of a customer's ECRs earned against the customer's energy charges on the monthly bill accomplishes that objective.

h. Some parties have advocated for the elimination of the annual expiration of accrued credits for excess customer-generated electricity. We find and conclude that the appropriate response to that request is: not yet.

We have declined to conclude in this order whether the NM Statute applies to Schedule 137. However, if it does, then this issue is settled. Annual expiration is codified in Utah Code Ann. § 54-15-104(3)(a)(ii).

Moving from a "kWh for kWh" net metering regime to one where Schedule 137 customers will be compensated for the value of their excess generation raises the legitimate policy issue of whether annual expiration still remains appropriate. Some parties discussed annual expiration as providing an important disincentive for a customer to over-size a CG system. The ECR should now accomplish that incentive because the highest and best use of CG, and the use that brings the greatest benefit to CG participants, is the energy they consume and thereby avoid purchasing from RMP.

Nevertheless, we are mindful that if we were to eliminate annual expiration of accrued credits at this time, we would do so without any experience with how the ECR will influence the size of future CG systems. Given how challenging it would be to walk back from such a change, we consider it more reasonable to defer a decision on discontinuing annual expiration of credits until the effects of the ECR on system size can be evaluated empirically. For now, accrued credits will expire coincident with the regularly scheduled meter reading for the month of March (or October for irrigation customers).

We have not yet established the timing, procedure, and scope of annual updates to the ECR. However, we fully plan and expect that the first annual update will include an evaluation of whether annual expiration of accrued credits should be eliminated.

i. We decline to approve RMP's proposed application fee, and we direct RMP to utilize the tiered application fee currently in place for Schedule 136.

We previously approved the current, tiered application fee in Schedule 136 as a just and reasonable fee. RMP has proposed establishing a flat application fee of $150 for Schedule 137. While RMP has provided substantial evidence that the proposed $150 fee reflects the actual aggregate costs of processing applications, RMP has not provided sufficient evidence that the proposed $150 fee reflects the cost of service for individual applicants. In other words, we previously approved the tiered application fee for Schedule 136 on the premise that it costs RMP more to process the applications of some customers than it does to process others. There is simply insufficient evidence in the record to establish that is no longer the case. Accordingly, we will apply to Schedule 137 the existing application fee regime for Schedule 136. Like other issues in this order, the application fee could be revisited in future dockets.

j. We decline to return to a "kWh for kWh" netting regime for Schedule 137.

While some parties have advocated for a return to the "kWh for kWh" netting regime that existed under Schedule 135, we conclude that the stipulation we approved in our 2017 order contemplated moving from that regime to one based on an ECR as a financial value, not as a traded kWh. We recognize the stipulation did not preclude a value identical or similar to the average retail rate for electricity, but the findings and conclusions we have made in this order lead to a lower ECR. Accordingly, we find and conclude that to provide Schedule 137 participants an ECR in excess of what we are approving in this order would constitute a subsidy to ECR participants from other RMP customers, would not reflect the utility's cost of service, and therefore would be neither just nor reasonable.

ORDER

1. We approve an ECR of 5.969 cents/kWh in summer rates (June through September) and 5.639 cents/kWh in winter rates (October through May), with no time of use differential.
2. Schedule 137 customers' excess generation will be netted monthly in connection with billing for RMP-supplied energy.
3. Accrued bill credits will expire annually coincident to the regularly-scheduled meter reading in the month of March (or October for irrigation customers).
4. We decline to approve RMP's proposed metering fee and application fee, but we approve application to Schedule 137 of the tiered application fee currently in place for Schedule 136.
5. RMP shall file revised tariff sheets to implement this order.
6. We invite any interested person to file comments on the potential timing, procedure, and scope of annual updates to Schedule 137 on or before February 8, 2021, and to file reply comments on or before March 22, 2021.
7. In accordance with the stipulation we approved in our 2017 Order, the transitional program ends today, the date this order is issued. RMP shall file tariff sheets that reflect this date appropriately in both Schedule 136 and 137.

DATED at Salt Lake City, Utah, October 30, 2020.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#316191

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this written Order by filing a written request with the PSC within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC does not grant a request for review or rehearing within 30 days after the filing of the request, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on October 30, 2020, a true and correct copy of the foregoing was delivered upon the following as indicated below:

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____
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- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities	DOCKET NO. 17-035-T07
Rocky Mountain Power's 2017 Avoided Cost Input Changes Quarterly Compliance Filing	DOCKET NO. 17-035-37 ORDER

ISSUED: January 23, 2018

SHORT TITLE

Updates and Revisions to Avoided Cost Pricing Methodologies for QF Resources

SYNOPSIS

The Public Service Commission (PSC) reaffirms its prior decision regarding the Proxy/PDDRR avoided cost pricing methodology and approves PacifiCorp's interpretation of the method for Schedule 38. The PSC also: 1) approves PacifiCorp's proposal concerning retention of Renewable Energy Credits (REC or RECs) associated with Qualifying Facility (QF) output; 2) approves application of the Proxy/PDDRR methodology to Schedule 37 QFs; 3) determines that proposed Wyoming wind and transmission facilities are deferrable until a final PSC determination is made regarding these resources or PacifiCorp independently determines it will no longer pursue these projects; 4) denies PacifiCorp's proposed treatment of Production Tax Credits in the calculation of avoided cost prices; and 5) declines at this time to subject Schedule 37 projects to the Schedule 38 queue.

TABLE OF CONTENTS

APPEARANCES

Yvonne R. Hogle, Esq. Rocky Mountain Power	For	Rocky Mountain Power
Justin C. Jetter, Esq. Utah Office of the Attorney General	"	Division of Public Utilities
Steven Snarr, Esq. Utah Office of the Attorney General	"	Office of Consumer Services
Sophie Hayes, Esq. Utah Clean Energy	"	Utah Clean Energy
Irion Sanger, Esq. Renewable Energy Coalition	"	Renewable Energy Coalition

PROCEDURAL HISTORY

On May 30, 2017, PacifiCorp, dba Rocky Mountain Power (PacifiCorp) filed with the Public Service Commission of Utah (PSC) proposed revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities (Schedule 37), in Docket No. 17-035-T07 (Application). Schedule 37 applies to Utah-located cogeneration qualifying facilities (QFs) with a design capacity of 1,000 kilowatts or less and small power production QFs with a design capacity of 3,000 kilowatts or less.[1]

On June 21, 2017, PacifiCorp, filed its 2017 Quarter 1 Avoided Cost Input Changes Quarterly Compliance Filing (Compliance Filing) in Docket No. 17-035-37. PacifiCorp's Compliance Filing identifies four routine and two non-routine updates to its calculation of avoided cost prices for Electric Service Schedule No. 38 (Schedule 38) QFs.[2] The Compliance filing was made pursuant to the PSC's June 9, 2015 Order Approving Settlement Agreement on Schedule 38 Procedures in Docket No. 14-035-140.[3]

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[1] PacifiCorp represents it filed the Application in compliance with the PSC's order in Docket No. 08-035-78 requiring PacifiCorp to update Schedule 37 annually, and the PSC's order in Docket No. 12-035-T10 directing PacifiCorp to file the update within 30 days of filing its Integrated Resource Plan (IRP) or IRP Update, or by April 30 of each year, whichever occurs first. *See In the Matter of the Consideration of Changes to Rocky Mountain Power's Schedule No. 135 - Net Metering Service*, (Report and Order Directing Tariff Modifications, issued February 12, 2009), Docket No. 08-035-78. *See also In the Matter of Rocky Mountain Power's Proposed Rate Changes to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities,* (Clarification and Procedural Order, issued November 28, 2012), Docket No. 12-035-T10.

[2] Schedule 38 applies to owners of existing or proposed QFs with a design capacity greater than 1,000 kW for a Cogeneration Facility or greater than 3,000 kW for a Small Power Production facility who desire to make sales to PacifiCorp, and to QFs who are not able to obtain pricing under Schedule 37 because the Schedule 37 cap has been reached.

[3] *See In the Matter of the Review of Electric Service Schedule No. 38, Qualifying Facilities Procedures, and Other Related Procedural Issues* (Order Approving Settlement Agreement on Schedule 38 Procedures, issued June 9, 2015, Attachment: Settlement Agreement, Settlement Terms 19-23), Docket No. 14-035-140.

On July 20, 2017, Utah Clean Energy (UCE) filed a motion to suspend the Phase II schedule in Docket No. 17-035-T07 and to consolidate it with the schedule in Docket No. 17-035-37 (UCE's Motion) because the issues in both dockets are materially similar.[4] The PSC issued a notice of filing and request to make objections to UCE's Motion known at the July 26, 2017 scheduling conference in Docket No. 17-035-37. All parties present at the scheduling conference supported UCE's Motion. Accordingly, on July 27, 2017, the PSC granted UCE's Motion and issued an Order Consolidating Dockets and Suspending the Phase II Schedule in Docket 17-035-T07, and Scheduling Order (Scheduling Order) consolidating Docket Nos. 17-035-T07 and 17-035-37.

Pursuant to the Scheduling Order, on August 17, 2017, PacifiCorp filed direct testimony. The Division of Public Utilities (DPU), the Office of Consumer Services (OCS), UCE, and the Renewable Energy Coalition (Coalition) filed direct testimony on October 3, 2017. PacifiCorp, the DPU, the OCS, and UCE filed rebuttal testimony on October 31, 2017. PacifiCorp, the DPU, UCE, and the Coalition filed surrebuttal testimony on November 21, 2017. The PSC held a hearing on December 4, 2017 at which PacifiCorp, the DPU, the OCS, UCE, and the Coalition presented testimony.

PACIFICORP'S FILINGS

Docket No. 17-035-T07: PacifiCorp's Application proposes to change the current Schedule 37 avoided cost pricing methodology to be consistent with the methodology used for

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[4] On June 12, 2007, the PSC issued a Scheduling Order and Order Suspending Tariff in Docket No. 17-035-T07. This order initially divided the 17-035-T07 docket into two phases with Phase I addressing the current Schedule 37 methodology and Phase II addressing the proposed changes to the Schedule 37 methodology.

determining avoided cost prices under Schedule 38. Specifically, PacifiCorp proposes to calculate Schedule 37 rates specific to each resource type using the Partial Displacement Differential Revenue Requirement (PDDRR) methodology approved by the PSC for determining non-standard avoided costs under Schedule 38. Using the Schedule 38 methodology results in the following changes:

- Renewable resources displace the next deferrable "like" renewable resource identified in PacifiCorp's 2017 Integrated Resource Plan (IRP) preferred portfolio,[5] after accounting for the queue of potential QFs. For non-renewable resources, or if no "like" renewables remain in the 2017 IRP preferred portfolio through the expected term, the next deferrable major thermal resource is displaced, again after accounting for the queue of potential QFs.

- Avoided energy costs are calculated using the expected output of a 10 MW resource of each type and are net of the value of displaced resources from the 2017 IRP preferred portfolio.

The Application also proposes that during the portion of a QF's contract in which it receives a capacity payment based on the costs of a renewable resource, PacifiCorp will be entitled to the renewable energy credits (RECs) associated with the QF's output. Beyond the renewable resource-based capacity payment, no additional compensation will be paid for these RECs. When a QF's capacity payment is not based on the costs of a renewable resource, the QF will continue to be entitled to the RECs associated with its output, as is currently the case today.

The Application also identifies and provides support for changes to several avoided cost model inputs including updated market prices reflecting PacifiCorp's March 31, 2017 Official Forward Price Curve (1703 OFPC), as well as updated wind and solar integration costs and

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[5] *See PacifiCorp's 2017 Integrated Resource Plan* (IRP Volumes 1 and 2 filed on April 4, 2017), Docket No. 17-035-16.

intermittent QF resource capacity contribution values consistent with PacifiCorp's 2017 IRP. The Application includes proposed revisions to P.S.C.U No. 50 (Tariff) Sheet Nos. 37.2, 37.4, 37.5, 37.6, and 37.7, reflecting PacifiCorp's proposal and minor revisions for clarity and consistency suggested by the DPU in Docket No. 16-035-T06.[6]

Docket No. 17-035-37: PacifiCorp's Compliance Filing identifies four routine and two non-routine updates used in its calculation of avoided cost prices for Schedule 38. In its routine updates, PacifiCorp proposes to: 1) update PacifiCorp's Generation and Regulation Initiative Decision Tool (GRID) to incorporate the preferred portfolio, capacity contribution, and integration costs from 2017 IRP; 2) implement PacifiCorp's 1703 OFPC; 3) incorporate the incremental demand side management (DSM) selections from the 2017 IRP preferred portfolio into load forecast dated October 4, 2016; and 4) update the QF queue to reflect current signed and potential QFs.

Regarding PacifiCorp's two non-routine updates, first (and identical to its Schedule 37 proposal), PacifiCorp proposes that during the portion of a QF's contract in which it receives an avoided capacity payment based on deferral of a like renewable resource, PacifiCorp would own the RECs associated with that QF's output. A QF would then receive no additional compensation for RECs beyond the capacity payment associated with the proxy resource being deferred. During any portion of a QF's term when its avoided capacity costs are not based on the costs of a renewable resource, the QF will continue to be entitled to the RECs associated with its output. Second, PacifiCorp proposes to calculate avoided cost pricing beyond the end of the IRP

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[6] *See In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities* (DPU Comments filed on May 24, 2016), Docket No. 16-035-T06.

preferred portfolio resource expansion planning period by escalating the final year values at inflation. PacifiCorp claims this change is necessary because: 1) given the current planning cycle, it is possible that a QF's contract term could extend beyond the end of the 2017 IRP study term which ends in 2036; and 2) the GRID model cannot produce accurate avoided costs when resources required to meet the load and planning reserve margin are not identified and included in the model.

DISCUSSION, FINDINGS AND CONCLUSIONS

I. UNDISPUTED ISSUES

A. Parties' Positions

At the conclusion of the December 4 hearing, no party opposed PacifiCorp's following updates for the Schedule 38 PDDRR Method: GRID updates to incorporate capacity contribution and integration costs from the 2017 IRP; use of PacifiCorp's 1703 OFPC; incorporation of the incremental DSM selections from the 2017 IRP preferred portfolio into the load forecast dated October 4, 2016; and updates to the QF queue for Schedule 38 to reflect current signed and potential QFs. Further, no party opposed PacifiCorp's non-routine post-IRP resource expansion plan pricing assumption update.

Regarding PacifiCorp's proposed non-routine post-IRP resource expansion plan pricing update, the DPU acknowledges that a QF initiating contractual negotiations with PacifiCorp prior to the end of the current IRP cycle could receive a contract term extending beyond the end of the 2017 IRP study term and agrees with PacifiCorp's assessment that the GRID model lacks the capability to produce accurate avoided costs beyond the end of this period. The DPU, therefore, supports PacifiCorp's proposal to determine avoided cost prices beyond the IRP resource expansion planning period by inflating the final year's value at the IRP's forecasted inflation rate. No party opposes the DPU's position.

B. Findings and Conclusions

Since no party challenges the routine updates identified above, we approve these updates pursuant to our order in Docket No. 14-035-140.

Based on PacifiCorp's assessment that the GRID model lacks the capability to produce accurate avoided costs beyond the end of the 2017 IRP study period, as supported by the DPU, we find PacifiCorp's proposal for post-IRP expansion plan pricing to be reasonable, and we approve it.

II. DISPUTED ISSUES

A. Compliance Filing Non-Routine Update - REC Ownership

1. Parties' Positions

As noted above, PacifiCorp proposes to retain the RECs associated with QF output during that period where a QF receives a capacity payment for deferring or avoiding a renewable resource of the same type. PacifiCorp cites the PSC's October 4, 2013 Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification in Docket No. 12-035-100 (October 2013 Order) to justify this change. In the October 2013 Order, the PSC determined the issue of REC ownership "may be more appropriately addressed and vetted by the [PSC] when a renewable QF is actually poised to defer a cost-effective renewable resource included in the IRP Action Plan."[7] PacifiCorp claims it is proposing this change because the 2017 IRP preferred portfolio now contains cost-effective renewable resources.

Both the DPU and the OCS agree PacifiCorp's REC ownership proposal is reasonable and should be adopted for both Schedule 37 and 38 QFs. The DPU maintains the proposal is consistent with the Public Utility Regulatory Policies Act of 1978 (PURPA) indifference standard. Likewise, the OCS maintains the proposed REC allocation approach is necessary to meet PURPA customer indifference standards. According to the OCS, the renewable resources identified in PacifiCorp's IRP account for RECs. Further, the OCS states that if a QF defers a renewable resource that would produce RECs for the benefit of customers, PacifiCorp should likewise retain the QF-generated RECs to maintain this benefit to customers.

Alternatively, the Coalition recommends that if a QF is paid a renewable rate (discussed below) it should transfer its RECs to PacifiCorp during the years in which the QF is deferring a renewable resource acquisition. Conversely, when the renewable QF is paid a non-renewable rate based on the costs of market purchases and a gas plant, the QF should retain the RECs associated with its output in all years.

2. Findings and Conclusions

In our October 2013 Order, we determined the value of RECs PacifiCorp assumes for either building or acquiring an IRP renewable resource acts as an offset to the IRP's renewable resource capital costs.[8] With the exception of the conditions identified in the Coalition's

[7] *In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts* (Order Granting in Part and Denying in Part Rocky Mountain Power's Petition for Review and Clarification, issued October 4, 2013, p. 7), Docket No. 12-035-100.

[8] *See id*.

proposal, no party opposes the concept that when a renewable QF defers or avoids a renewable resource, ownership of the RECs associated with that QF's output should be retained by PacifiCorp for the benefit of PacifiCorp's ratepayers. Further, no party disputes PacifiCorp's assertion that its IRP analysis now assumes that PacifiCorp retains title to the RECs associated with the output of renewable QF resources when a QF defers or avoids a renewable resource and that avoided cost pricing based on IRP resource costs accounts for the disposition of these RECs, better ensuring ratepayer indifference between the QF resource and the respective IRP preferred portfolio resource.

We find that when a QF defers or avoids a renewable resource, the ratepayers who pay for the QF contract are entitled to the benefits of the RECs PacifiCorp would have received from the deferred or avoided resource. When a QF's avoided capacity costs are not based on the costs of a renewable resource, the QF is entitled to the RECs associated with its output. Therefore, based on PacifiCorp's testimony, and the unopposed testimony of the DPU that PacifiCorp's proposal is consistent with the PURPA ratepayer indifference standard, we approve this Schedule 38 non-routine update and its applicability to Schedule 37.

B. Interpretation of the Proxy/PDDRR Methodology

1. Parties' Positions

Regarding its interpretation of the current Proxy/PDDRR methodology approved by the PSC in Docket No. 12-035-100, PacifiCorp proposes that when the IRP preferred portfolio includes renewable resources of the same type as a QF project, forecasted avoided capacity costs should be based on the assumed fixed costs of the next deferrable renewable resource of that like type.[9] Alternatively, if the IRP preferred portfolio does not include a renewable resource of the same type as a QF, avoided capacity costs should be based on the capital costs of the next deferrable thermal resource in the IRP preferred portfolio.

According to PacifiCorp, a QF must defer IRP resources based on equivalent capacity contributions to maintain a consistent load and resource balance sufficient to meet the assumed IRP system planning reserve margin. PacifiCorp asserts that limiting deferral to QFs of the same type ensures "reasonable alignment between the operating characteristics of a QF and the preferred portfolio resources it is assumed to defer, which in turn helps ensure that the least-cost, least-risk outcomes achieved by the preferred portfolio are maintained."[10] In addition, PacifiCorp claims this approach is necessary to ensure that avoided cost prices more accurately reflect the impacts and timing of federal production tax credit (PTC) benefits unique to the real-levelized annual cost of each different IRP renewable resource.

PacifiCorp notes that the 2017 IRP preferred portfolio now includes renewable resources (wind, solar, and geothermal) in addition to thermal resources, and testifies that these resources are included in the preferred portfolio because they support an optimized balance of cost and risk for the portfolio as a whole. PacifiCorp claims that limiting deferral of renewable resources to QFs of the same type helps maintain this optimized balance, thus ensuring the customer indifference standard is met.

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[9] According to PacifiCorp, IRP renewable resources that are of the same type as a renewable QF project means the QF's deferral capabilities are reflective of its operational characteristics, not the specific technology of the resource identified in the preferred portfolio. (*See* Direct Testimony of Daniel J. MacNeil, filed August 17, 2017, p. 8, lines 161-170), Docket Nos. 17-035-37 and 17-035-T07.

[10] *Id.* at 12, lines 239-242.

The DPU supports as reasonable PacifiCorp's interpretation of the approved Proxy/PDDRR method, testifying this approach preserves the customer indifference standard. The DPU asserts that since the operating characteristics of the QF and the preferred portfolio resource it defers are the same, the capacity provided by the QF should be equivalent to the capacity it replaces from the IRP preferred portfolio. DPU claims PacifiCorp's proposed approach will yield more accurate avoided cost prices for each resource type since specific GRID runs will be performed for each resource type based on the specific characteristics of the proposed QF and proxy resource.

Both UCE and the Coalition express concern with PacifiCorp's interpretation of the approved Proxy/PDDRR approach. Both parties oppose PaciCorp's proposal to limit a QF's deferral of an IRP preferred portfolio resource to only those renewable resources of the same type as the QF. According to UCE, PacifiCorp's approach will result in "technology-specific sufficiency and deficiency periods, resulting in anomalous avoided cost results."[11] UCE claims that by limiting renewable QFs to deferring resources of similar types, the QF may be denied access to prices reflecting PacifiCorp's true avoided costs, arguing that "PURPA calls for compensating QFs for a utility's actual incremental avoided energy and capacity costs, not just those not associated with a subset of comparable resources that happen to show up in an IRP portfolio."[12]

UCE also questions PacifiCorp's claim that costs and value of different renewable resources cannot be accurately compared. According to UCE, such a claim "implies that the

[11] Surrebuttal Testimony of Ken Dragoon, lines 180-181, filed November 21, 2017.
[12] December 4, 2017 Hearing Transcript at 126, lines 2-7.

differences between renewable resources is somehow greater and more difficult to assess than the differences between renewable resources and thermal resources."[13] UCE claims such an argument is unsupported in PacifiCorp's testimony and is counter to PURPA policy.

UCE suggests avoided costs for differing kinds of renewable QFs can be determined by basing the deferral of IRP preferred portfolio renewable resources on energy values instead of the QF's relative capacity contribution. UCE states that its suggested approach is straightforward and can be conducted using PacifiCorp's existing models and methods.

UCE challenges DPU's claim that allowing renewable QFs to defer only renewable resources with similar characteristics preserves the customer indifference standard. UCE argues this approach potentially prohibits QFs from receiving avoided cost rates that are consistent with the customer indifference standard.

UCE recommends the PSC reject PacifiCorp's proposed implementation of Schedule 38 avoided cost pricing. UCE recommends the PSC either: 1) use the IRP preferred portfolio resource costs to establish an avoided cost floor; or 2) approve the Coalition's recommendations to allow renewable QFs to choose either a renewable or a non-renewable avoided cost rate. In addition, UCE suggests the PSC require "further, more thorough evaluation of methods for setting renewable avoided cost prices based on the deferral of renewable resources of all types."[14]

The Coalition argues PacifiCorp's proposed like-for-like deferral restrictions are unreasonable and prevent a renewable QF from being fairly compensated simply because the QF

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[13] *Supra* n.11 at 6-7, lines 113-115.
[14] *Supra* n.12 at 130, lines 10-13.

is different from a resource type than that PacifiCorp deems deferrable at an earlier date in the IRP planning horizon. The Coalition claims that “[i]mplicit in [PacifiCorp’s] advocacy for these restrictions is the notion that [PacifiCorp] is somehow unable to partially or wholly defer a wind plant when a renewable QF using a different technology timely comes online.”[15] The Coalition contends such a premise is highly implausible.

When considering adding new resources in its IRP, the Coalition claims that “[PacifiCorp] must consider the impact of long-term QF contracts on the need for Company-owned capacity after taking account of the capacity characteristics of the QF resources.”[16] The Coalition argues this evaluation must be performed irrespective of the QF resource type, claiming it unreasonable to assume that a new renewable QF contract of one resource type would have no influence on the future need for a PacifiCorp-owned resource of another technology type.

The Coalition argues that any renewable QF seeking avoided cost pricing under either Schedule 37 or Schedule 38 should be able to have its avoided cost pricing determined based on displacement of the next renewable resource irrespective of type, with appropriate adjustments for capacity equivalence.

PacifiCorp claims that both UCE and the Coalition fail to provide evidence their proposed capacity equivalence methodologies produce more accurate avoided costs than under the current methodology and argues their proposals are inconsistent with the approved avoided cost methodology.

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[15] *Supra* n.12 at 145, lines 16-20.
[16] *Id.* at 145, lines 21-25; at 146, line 1.

PacifiCorp also asserts UCE's proposed avoided cost methodology does not account for the variations in operational characteristics between different types of renewable resources and, without supporting calculations, is difficult to evaluate. PacifiCorp maintains it is therefore impossible to judge whether avoided costs determined under either of the proposed alternate approaches would be just, reasonable, and consistent with the customer indifference standard.

2. Findings and Conclusions

In our August 16, 2013 Order on Phase II Issues (August 2013 Order) in Docket No. 12-035-100, we determined that for renewable QF resources seeking indicative pricing under Schedule 38, when PacifiCorp's planned resources include cost-effective renewable resources, "like" resource costs are reasonable to use as the proxy for purposes of avoided cost calculations of QF capacity payments determined within the Proxy/PDDRR method.[17] In this same order, we also determined that when a like cost-effective renewable resource is not included in PacifiCorp's planned resources, the capital cost of the next deferrable thermal resource will serve as the proxy for the Schedule 38 QF capacity payment.[18] Based on PacifiCorp's testimony, we reaffirm these determinations and agree since the 2017 IRP preferred portfolio now includes renewable resources, full implementation of this methodology is warranted.

We note PacifiCorp's testimony that the renewable resources appearing in the IRP preferred portfolio are components of the least-cost, least-risk portfolio of resources needed to meet system load over time. We also find compelling PacifiCorp's assertion the avoided cost

[17] *See In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts* (Order on Phase II Issues, issued August 16, 2013, p. 20), Docket No. 12-035-100.
[18] *See id*.

calculation should consider the operational and risk characteristics that are essential factors within the IRP's portfolio optimization process in determining whether one resource is preferable to another. At hearing, PacifiCorp testified that "Our best estimate of the capacity that the utility will actually avoid is by looking at the preferred portfolio, the information it contains, [and] the information it doesn't contain. . . ."[19] We agree this approach helps ensure avoided costs reflect the cost and risk characteristics of the proxy resource in the IRP preferred portfolio a QF is assumed to displace.

In considering the testimony of UCE and the Coalition, we find their proposed alternatives to be conceptual in nature and therefore we are unable to evaluate them for implementation. We agree with PacifiCorp's testimony that PacifiCorp's proposed implementation of the Proxy/PDDRR method regarding the deferral of renewable resources appearing in the IRP preferred portfolio is reasonable and consistent with our August 2013 Order. We adopt that position as our conclusion. Therefore, we approve this method for the determination of both Schedule 37 and 38 QF avoided cost pricing.

C. Compliance Filing – Routine Update - Incorporation of the 2017 IRP Preferred Portfolio -- Deferability of Wyoming Wind and Transmission Resources

1. Parties' Positions

PacifiCorp maintains the following resources from the 2017 IRP preferred portfolio are currently considered deferrable:

Thermal:
- 2029: Utah North simple cycle combustion turbine (SCCT) (200 MW)
- 2030: Willamette Valley combined cycle combustion turbine (CCCT) (436 MW)

[19] *Supra* n.12 at 32, lines 10-13.

- 2033: Dave Johnston SCCT (200 MW)
- 2033: Dave Johnston CCCT (477 MW)

Wind:
- 2031: Dave Johnston wind (85 MW)
- 2036: Goshen wind (774 MW)

Solar:
- 2028-2034: Yakima fixed tilt solar (240 MW)
- 2031-2036: Utah South single tracking solar (800 MW)

Geothermal:
- 2029: West geothermal (30 MW)

Absent from this list is PacifiCorp's 2021 proposed acquisition of 1,100 MW of Wyoming wind resources also identified in the 2017 IRP preferred portfolio. PacifiCorp claims the proposed Wyoming wind and associated Aeolus-to-Bridger/Anticline transmission resources are not deferrable. According to PacifiCorp, the Wyoming wind resources are eligible for the full value of PTCs and these resources, along with the new transmission associated with this project, provide all-in economic benefits to PacifiCorp customers in all jurisdictions. Further, PacifiCorp claims QF projects that do not interconnect with or use PacifiCorp's Wyoming transmission system to deliver energy and capacity in this timeframe would not partially displace or defer any of the 1,100 MW of new wind associated with the project.

According to PacifiCorp, if the Wyoming wind resource were deferred to a later date it would not qualify for PTC benefits if deferred after December 31, 2020. Without these benefits, PacifiCorp contends the Wyoming wind resource would not be part of its least-cost, least-risk plan to reliably meet system load. In addition, PacifiCorp asserts the proposed transmission line that enables interconnection of these resources to PacifiCorp's system cannot be reduced in size, arguing the transmission line and the new wind resources are mutually dependent upon one another.

In general, PacifiCorp contends partial displacement is reasonable when:

> "capacity additions can be delayed or scaled down as a result of a QF resource addition. The addition of a Utah wind QF project would not defer the new wind and transmission planned to come online by the end of 2020 in the Company's 2017 IRP preferred portfolio. Given the net benefits these projects provide to the Company's retail customers, it will pursue these projects even if new QF projects were added to the system in Utah."[20]

The Coalition contends the 2021 Wyoming wind resource should be the appropriate proxy that is partially displaceable or deferrable for the purpose of determining avoided capacity and energy costs for all renewable QFs seeking avoided cost pricing under either Schedule 38 or Schedule 37. The Coalition asserts the Wyoming wind project's associated transmission should likewise be considered in the calculation of avoided costs, arguing that the 2021 Wyoming wind resources cannot be wheeled to load without new transmission and would be avoided if the proxy (wind) resource were avoided.

According to the Coalition, PacifiCorp has not sufficiently explained its assertion that this resource cannot be partially displaced or deferred by QF resources outside of Wyoming. The Coalition asserts that while small amounts of capacity provided from QFs taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions, the aggregate capability of such purchases may permit the deferral or avoidance of a capacity addition. The Coalition argues if PacifiCorp's assumptions regarding deferral of the Wyoming

[20] *Supra* n.9 at 33, lines 682-688.

resource were accepted, Utah QFs would never be paid any capacity because no single Utah QF could displace a Wyoming power plant.

The Coalition recommends PacifiCorp's proposed 2021 Wyoming wind resource be considered the proxy resource for all QFs seeking avoided cost pricing, "unless and until [PacifiCorp] declares that it's not going to pursue this project, regardless of whether such a declaration results from a [PSC] decision, or for any other reason."[21] At hearing, the Coalition also clarified that this project be considered as the next deferrable resource unless and until PacifiCorp determines it will no longer pursue the project. The Coalition argues the PSC "should also consider whether a QF should also be credited with the equivalent of avoided transmission costs, given the linkage that exists between the 2021 Wyoming wind resource and the related transmission capability."[22]

If the PSC concludes the 2021 Wyoming wind resource is deferrable, the DPU agrees with the Coalition that QFs should be provided avoided transmission costs. However, if the PSC concludes the opposite, there should be no avoided transmission cost associated with the Wyoming projects. At hearing, the DPU testified it does not oppose including the proposed 2021 Wyoming wind resource in the Proxy/PDDRR methodology for calculating avoided cost prices.

The OCS agrees with the Coalition's recommendation that if the PSC allows the 2021 Wyoming wind resource to be included in the determination of avoided costs, the resource should be removed from the avoided cost calculation if PacifiCorp decides not to pursue the projects. If the resource remained within the avoided cost calculation, but were not to be pursued,

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[21] *Supra* n.12 at 146, lines 21-25; at 147, lines 1-2.
[22] *Id.* at 147, lines 2-6.

the OCS contends avoided cost prices would be overvalued and the ratepayer indifference standard would not be upheld.

At hearing, PacifiCorp testified Utah QFs do not displace or defer the proposed Wyoming wind resources because they do not interconnect with or use PacifiCorp's Wyoming transmission system. Even if this resource is considered deferrable, PacifiCorp argues the Aeolus to Bridger/Anticline transmission upgrade is not deferrable because it cannot be incrementally adjusted to a smaller size. PacifiCorp states the transmission upgrades, which enable interconnection of the 2021 Wyoming wind resources, provide additional benefits beyond the connection of the proposed wind project to PacifiCorp's system. First, the transmission additions provide incremental transfer capability for other resources such as PacifiCorp's existing wind resources and the Dave Johnston, and Wyodak coal plants. This additional transfer capability creates additional customer benefits by allowing these low-cost resources to displace higher-cost resources elsewhere on PacifiCorp's system. Second, the transmission upgrades will result in reduced line losses and reduced transmission system derates. PacifiCorp maintains, therefore, if transmission costs are included in avoided costs, the lost transmission benefits described above should also be considered.

2. Findings and Conclusions

At hearing, PacifiCorp testified it is pursuing the proposed 2021 Wyoming wind and transmission project because it, like all deferrable renewable IRP resources, represents a least-cost, least-risk resource within the IRP preferred portfolio. PacifiCorp also testified once it completes its Request for Proposals (RFP) process and selects a resource, that resource will no longer be deferrable. Until such time, PacifiCorp acknowledges it is possible other resources, including a QF, may defer a resource being considered in the RFP process.

No party disputes PacifiCorp's assertion that the Proxy/PDDRR method assumes a QF can partially displace its next planned resource to the extent of that QF's aggregate capacity value, even if the size of that resource cannot be modified. In addition, and as noted above, we reaffirm our August 2013 Order determination that when the IRP preferred portfolio includes renewable resources, a renewable QF of a "like" type is capable of partially displacing or deferring that resource.

To ensure consistency with the approved Proxy/PDDRR methodology, when PacifiCorp seeks approval of a renewable resource under the approved RFP process that appears as part of the IRP Preferred Portfolio, we find a renewable QF with similar operational characteristics is capable of partially deferring or displacing that resource until a final PSC determination is made concerning the resource. At this time, therefore, we determine PacifiCorp's proposed 2021 Wyoming wind and transmission resources to be deferrable by potential wind QFs for the purposes of determining avoided cost prices until the PSC issues a final determination on these resources or if PacifiCorp independently determines it will no longer pursue these resources.

We agree with PacifiCorp that there are potential benefits associated with the transmission upgrades enabling interconnection to the 2021 Wyoming wind resources, including incremental transfer capability to other PacifiCorp resources, reduced line losses, and reduced transmission system derates. Therefore, we order lost transmission benefits should be considered in the determination of avoided costs to the extent the 2021 Wyoming wind resources are deferred.

D. Application of Proxy/PDDRR Method to Schedule 37 QFs – Consistency with Schedule 38

1. Parties' Positions

With the inclusion of cost-effective renewable solar resources in the 2017 IRP preferred portfolio, PacifiCorp proposes that Schedule 37 rates specific to each resource type be calculated using the Proxy/PDDRR methodology approved by the PSC for determining non-standard Schedule 38 avoided cost prices. As with PacifiCorp's proposed changes to Schedule 38, renewable resources would partially displace the next deferrable "like" renewable resource identified in the 2017 IRP preferred portfolio, adjusting for differences in relative capacity contribution between the QF resource and the corresponding IRP renewable resource, and after accounting for the queue of potential QFs. For non-renewable QF resources, or if no "like" renewables remain in the 2017 IRP preferred portfolio through the expected term, the QF would partially displace the next deferrable major thermal resource, again based on the QF's capacity contribution and after accounting for the queue of potential QFs.

As noted above, PacifiCorp's proposed Schedule 37 avoided cost calculations account for the queue of potential QF resources, similar to the Schedule 38 methodology. PacifiCorp notes it is likely to acquire additional resources during the effective period of the Schedule 37 rates, either through QF resources or through RFP-based acquisitions. As a result, PacifiCorp claims avoided cost calculations must account for the impact of these potential resource additions to prevent Schedule 37 prices from being overstated.

As it relates to Schedule 37, PacifiCorp argues the Proxy/PDDRR methodology better captures the specific operational characteristics of different QF resource types than the current

Schedule 37 methodology. PacifiCorp claims adopting the Proxy/PDDRR methodology to determine avoided cost pricing for Schedule 37 QFs is more consistent with the customer indifference standard.

The DPU supports PacifiCorp's proposal to use the Proxy/PDDRR approach with a like proxy resource to calculate Schedule 37 avoided cost prices. The DPU agrees this approach is appropriate now that the current IRP preferred portfolio contains cost-effective renewable resources.

UCE recommends no changes to Schedule 37, except for an unspecified adjustment to Schedule 37 rates to account for avoided line losses for Schedule 37 QFs not connected to the transmission system. UCE argues PacifiCorp's proposal to apply the Schedule 38 pricing method to Schedule 37 is inappropriate and that doing so would result in artificially low prices for small QFs. UCE contends the Proxy/PDDRR methodology is more complex and more difficult to review. UCE argues there is no need for such a complicated process, since the annual sum of the capacity under Schedule 37 QFs is capped at 25 MW, a cumulative amount that is less than many single Schedule 38 QFs.

The Coalition claims PacifiCorp has not demonstrated its proposal to adopt the Proxy/PDDRR methodology for Schedule 37 would result in more accurate avoided cost rates for small QFs. The Coalition recommends the PSC direct PacifiCorp to continue to use the current GRID/Proxy methodology for setting small Schedule 37 QF rates, with a capacity equivalence adjustment that allows renewable resources of all types to be deferred rather than adopt the Proxy/PDDRR methodology used for Schedule 38 QF rates. Like UCE, the Coalition argues the PDDRR methodology is complex and is not transparent, and claims interested stakeholders must obtain expensive experts to evaluate the PDDRR configuration to determine if PacifiCorp's avoided cost price updates are accurate.

The Coalition recommends if the PSC adopts the Proxy/PDDRR method for calculating Schedule 37 avoided costs, the "like-for-like" restriction should be removed, as this would result in a more reasonable and equitable treatment of PacifiCorp's avoided costs.

According to PacifiCorp, UCE and the Coalition provide no evidence the current Schedule 37 GRID/Proxy methodology produces a more accurate forecast of avoided costs than the Schedule 38 Proxy/PDDRR method. PacifiCorp asserts the current Schedule 37 GRID/Proxy method is less accurate than the current Schedule 38 method because it calculates a single monthly avoided cost based on the generation of a baseload resource and thus does not accurately reflect the generation profiles of wind and solar resources. In addition, during the period when PacifiCorp is resource deficient, the current Schedule 37 method calculates avoided costs based on the fixed and variable costs of a thermal proxy. Because of this, the current method fails to account for the benefits associated with PacifiCorp's ability to dispatch the thermal resource up or down in response to resource needs and market prices.

2. Findings and Conclusions

With the 2017 IRP preferred portfolio containing a number of different renewable resources, and in consideration of our rationale for affirming the current Proxy/PDDRR approach used for Schedule 38 QFs, we agree a change in Schedule 37 is needed to align the methodologies for determining avoided cost prices for both small and large QFs. No party has provided evidence sufficient for us to conclude different methodologies for determining Schedule 37 and Schedule 38 avoided cost prices should be maintained considering the current

IRP preferred portfolio. Additionally, PacifiCorp testifies the current Schedule 37 GRID/Proxy method is less accurate than the Proxy/PDDRR method. We therefore approve PacifiCorp's proposal that Schedule 37 rates specific to each resource type be determined using the Proxy/PDDRR methodology.

E. Schedule 37 Queue

1. Parties' Positions

Similar to Schedule 38, PacifiCorp proposes Schedule 37 avoided cost calculations account for the queue of potential QF resources. PacifiCorp asserts an accurate forecast of avoided costs must account for the impact of QF resources in the QF queue. PacifiCorp notes it is likely to acquire additional resources during the effective period of the Schedule 37 rates, either through QF resources or through RFP-based acquisitions. As a result, PacifiCorp claims avoided cost calculations must account for the impact of these potential resource additions to prevent Schedule 37 prices from being overstated.

In its initial May 2017 filing in Docket No. 17-035-T07, PacifiCorp's Schedule 37 avoided cost calculations were based on the assumption Schedule 37 QFs are placed at the end of the QF queue that included the capacity of all signed and potential QF contracts. In response to party concerns, PacifiCorp's August filing proposes Schedule 37 rates based on a queue that only includes higher-queued resources from the May filing that had not dropped out of the queue or had been moved to the end of the queue. PacifiCorp claims this represents a point in the middle of the queue and will more accurately represent PacifiCorp's avoided costs between now and the next Schedule 37 tariff update.

The DPU contends since QFs with signed contracts and those actively negotiating a PPA are included in the GRID model as inputs when calculating avoided costs, their impact on the starting dates of the IRP resource deficiency period should not be ignored. The DPU, therefore, supports making changes to Schedule 37 to account for the pricing queue, but does not necessarily support moving potential Schedule 37 QFs to the end of the queue. The DPU recommends, in the interest of gradualism, Schedule 37 QFs assume a position at the midpoint of the queue. The DPU recommends potential adjustments from this midpoint position be evaluated in future years.

The OCS also believes including Schedule 37 QFs in the QF queue is appropriate. However, the OCS contends placing Schedule 37 QFs at the end of the queue may be extreme and would likely not produce the most reasonable results. At hearing, the OCS testified it supports the DPU's midpoint recommendation, expressing concern that if pricing is based on a number of QFs that ultimately leave the queue, Schedule 37 avoided cost prices will not be appropriate.

UCE argues there is no justification for making smaller, simpler projects eligible for published, standard rates subordinate to a queue of projects that must undergo complicated, often lengthy contract negotiations. According to UCE, PacifiCorp's placement of Schedule 37 QFs at the end of the queue implies all large QFs in the queue will get built ahead of them. UCE contends this assumption is unreasonable, arguing PacifiCorp's proposal may actually harm ratepayers by preventing lower cost resources from being built. At hearing, UCE testified its primary position is that if Schedule 37 QFs are included in the queue, the annual 25 MW cap for Schedule 37 QFs should be eliminated.

The Coalition states by assuming every single request for pricing will result in corresponding power sales, PacifiCorp artificially lowers its avoided cost rates. The Coalition believes a more reasonable queue position for Schedule 37 QFs should be based on the historic percentage of QFs constructed relative to the entire queue, or based on certain completion milestones that show a proposed project is likely to be constructed, such as a potential QF's completion of the interconnection study process or executed QF contracts.

2. Findings and Conclusions

No intervening party agrees with PacifiCorp's initial placement of Schedule 37 QFs at the end position in the queue, expressing concern about how such placement would impact Schedule 37 QF avoided cost pricing. At hearing, PacifiCorp agreed using the entire QF queue is inappropriate for setting Schedule 37 rates.

While including Schedule 37 QFs in the queue appears to be reasonable to account for the conditions PacifiCorp expects to occur during the term of the Schedule 37 tariff and for how resources should be displaced within the Proxy/PDDRR methodology, no party has provided a sufficiently detailed proposal to determine where the Schedule 37 QFs should be placed in the queue. We view PacifiCorp's proposal as a one-time adjustment that, in essence, places Schedule 37 QFs at the end of the queue going forward. In addition, we conclude the DPU's placement of Schedule 37 QFs at the queue's midpoint lacks sufficient basis. Similarly, the Coalition's recommendation to establish queue position based on the historic percentage of QFs constructed relative to the entire queue or upon QF completion milestones provides no specific recommendation upon which a historical percentage of QFs completed or completion milestones should be based. Nor does it demonstrate how such a recommendation would be implemented within avoided cost rates.

Due to the lack of sufficient evidence or a clearly defined process concerning the placement of Schedule 37 QFs in the queue when calculating Schedule 37 pricing, we decline to adopt any of the parties' proposals at this time. We encourage parties to explore this issue in future proceedings.[23] Schedule 37 projects will not, at this time, be priced subject to a pricing queue.

F. Avoided Cost Price Floor

1. Parties' Positions

UCE recommends when proxy renewable resources appear in the IRP preferred portfolio, any renewable QF resource should receive a capacity payment during the period when PacifiCorp is resource deficient. Under UCE's proposal, avoided costs would be calculated based on the Proxy/PDDRR methodology, using the next deferrable IRP thermal resource to establish the capacity payment. UCE then recommends establishing an avoided cost price "floor" based on the levelized cost of a proxy IRP preferred portfolio renewable resource during the years in which the renewable resource appears. This avoided cost price floor would then be applied to a renewable QF, with adjustments made for relevant differences between the QF resource and the IRP resource.

PacifiCorp testifies UCE's renewable price floor proposal would produce inaccurate avoided costs by ignoring geographic and operational differences between renewable resources

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[23] As parties continue to explore this issue, another option to consider might be determining Schedule 37 avoided cost prices based on a pricing queue that accounts for executed QF contracts only.

and by failing to account for the aggregate effects of QFs on PacifiCorp's portfolio and system. PacifiCorp claims it is possible a thermal resource and a renewable resource of a type comparable to the QF may simultaneously appear in the IRP preferred portfolio in the year of resource deficiency. Under UCE's proposal in such a situation, PacifiCorp maintains the QF could be paid higher avoided costs based on the deferred thermal resource rather than the IRP resource more comparable to the QF resource type. PacifiCorp contends customers should not "pay more as a result of 'adjustments' to a mismatched resource than they would have paid for [a] more closely matched resource."[24] Further, PacifiCorp argues "to the extent the IRP evaluated resource options that are of the same type and location as a QF," the absence of such resource options in the IRP preferred portfolio is evidence such resource costs are in excess of avoided costs.[25] PacifiCorp maintains UCE has not provided any supporting documentation or calculations in support of its proposal sufficient to determine whether ratepayer indifference is maintained.

2. Findings and Conclusions

We agree each renewable resource appearing in the IRP preferred portfolio provides benefits unique to that resource and that these benefits were considered in the process that led to the resource's selection and inclusion in the preferred portfolio. UCE's proposed avoided cost price floor lacks sufficient detail to allow us to determine that the avoided cost payments a QF receives would accurately reflect the costs and characteristics of a corresponding cost-effective IRP resource. Since a determination cannot be made on whether such an approach would lead to

[24] Rebuttal Testimony of Daniel J. MacNeil, at 18, lines 375-376, filed October 31, 2017.
[25] *Id.* at 4, lines 80-84.

just and reasonable avoided cost rates, we decline to adopt UCE's avoided cost price floor proposal.

G. Renewable Avoided Cost Rates

1. Parties' Positions

The Coalition argues that regardless of whether the current Grid/Proxy approach or a Proxy/PDDRR methodology is used, all renewable QFs under Schedules 37 and 38 should have the option of being compensated on either a renewable avoided cost rate or a non-renewable avoided cost rate when PacifiCorp is planning to acquire new renewable resources. The Coalition argues renewable rates are justified because renewable QFs help utilities meet their load requirements, meet renewable portfolio standard (RPS) requirements, and maintain a diverse portfolio of resources. The Coalition also asserts renewable avoided cost rates are justified since renewable QFs help PacifiCorp defer or avoid planned acquisition of renewable resources.

Accordingly, the Coalition suggests renewable rates be based on the costs of PacifiCorp's next planned renewable resource acquisition. If the QF is paid a renewable rate, the Coalition recommends it should be required to transfer its RECs to PacifiCorp during the period the QF is deferring PacifiCorp's planned acquisition of a renewable resource. When the renewable QF is paid a non-renewable rate based on the costs of market purchases and a gas plant, the QF would retain the RECs associated with their output.

UCE agrees with the Coalition that the PSC should allow QFs to choose between renewable and non-renewable avoided cost rates. Allowing QFs to choose between a renewable and a non-renewable rate is likely a more "durable" solution than an avoided cost price floor, according to UCE. This would be the case, especially if the QF gives up its RECs in exchange for the renewable avoided cost rates.

PacifiCorp claims the Coalition’s recommendation to allow Utah QFs to choose between renewable and non-renewable avoided cost rate options should not be adopted because it is not consistent with PURPA regulations and FERC precedent. PacifiCorp states it has no obligation under PURPA to pay more for renewable resources in Utah than the costs it would otherwise incur, noting it has no RPS or any other obligation to procure renewable resources in Utah. PacifiCorp contends there is no basis for paying different prices for renewable and non-renewable resources, because system operations and dispatch would be the same for a given project regardless of renewable energy credit ownership.

The DPU recommends the PSC reject the Coalition’s renewable avoided cost rate proposal, arguing this approach is contrary to the ratepayer indifference standard and may lead to gaming in the calculation of avoided costs.

The Coalition counters a separate renewable rate is not inconsistent with PURPA's customer indifference standard and argues an RPS obligation is not required to justify a separate renewable avoided cost rate. The Coalition asserts if the PSC declines to adopt a separate renewable rate, it must include cost-effective renewable resource acquisition in PacifiCorp's avoided cost pricing to ensure the customer indifference standard is met.

2. Findings and Conclusions

We find the Coalition’s recommendations on this issue to be conceptual in nature and lack sufficient detail for evaluation and implementation within either Schedule 37 or Schedule 38. In addition to concerns raised by PacifiCorp and the DPU regarding potential ratepayer indifference impacts associated with differential avoided cost rates, PacifiCorp states there are significant differences between PacifiCorp's renewable rates and standard Schedule 37 rates in other jurisdictions. Absent a detailed proposal for evaluation by parties, we decline to adopt a renewable avoided cost option for either the Schedule 37 or Schedule 38 avoided cost methodologies.

H. Avoided Line Losses

1. Parties' Positions

UCE claims since Schedule 37 projects are able to deliver electricity to load without using the transmission system, they avoid associated line losses. UCE therefore recommends small QFs not interconnected to the transmission system should be credited for avoiding transmission line losses. UCE, however, does not specify how a line loss adjustment should be calculated.

DPU agrees with UCE's assertion, claiming if a small QF is built within the distribution system, presumably it is not using the transmission system and there will be no transmission loss associated with delivery of its output to load. The DPU agrees avoided cost rates for these QFs should reflect an appropriate credit associated with avoided line losses.

PacifiCorp argues that simply because a QF is connected to the distribution system does not ensure line losses will be avoided. PacifiCorp claims the addition of a QF may result in a surplus of resources that would need to be exported to another load area, potentially creating more losses than would have otherwise occurred had the same resource been interconnected to the transmission system directly. PacifiCorp suggests this issue would be better addressed in the forthcoming Export Credit Proceeding in Docket No. 17-035-61.

The DPU claims it is unaware of any instance where the addition of a new resource resulted in a resource surplus requiring export to another area thereby causing increased line losses. Unless PacifiCorp provides evidence for this assertion, the DPU maintains its support of UCE's line loss proposal.

At hearing, PacifiCorp testified it did not know the number of Schedule 37 projects connected directly to PacifiCorp's distribution system. In addition, UCE testified it did not know the number of Schedule 37 projects connected to the transmission system.

2. Findings and Conclusions

The record before us is insufficient for us to conclude UCE's proposal is reasonable and should be implemented for Schedule 37. We direct PacifiCorp to evaluate this issue prior to the next Schedule 37 filing and encourage parties to explore this issue further in the current Export Credit proceeding in Docket No. 17-035-61.

I. Removal of PTCs from the Levelized Avoided Cost Calculation

1. Parties' Positions

Under the current Proxy/PDDRR methodology, tax credits are spread over the life of the asset. Because the PTC benefits associated with the 2021 Wyoming wind resources will be received in the first ten years of operation, PacifiCorp now proposes to reflect these benefits over a ten-year period. PacifiCorp maintains this method reflects the actual timing of tax credit benefits.

The Coalition asserts this is an ad-hoc adjustment that removes the PTCs from the real levelization price stream, while at the same time maintaining the real levelization for the fixed capital cost of the resource. The Coalition contends this change is not consistent with the IRP and is likewise inconsistent with PacifiCorp's current real levelization pricing approach for calculating avoided cost pricing in Utah.

The Coalition claims PacifiCorp models PTCs and capital costs in the IRP using a thirty-year real levelization approach "to make projects of disparate life expectancies comparable."[26] The Coalition argues PacifiCorp's proposal to measure PTC values only over the first ten years of the project has the effect of "fully loading these costs into the first ten years rather than spreading them out over the life of the deferred asset using the real levelization technique."[27] The Coalition argues since the contract life of a standard QF contract is considerably shorter than the life expectancy of the deferred plant, the capacity cost assumed by ratepayers over the first fifteen years of the life of a PacifiCorp-owned asset is greater than the capacity cost of a fifteen-year QF contract that is based on the avoided cost of that same PacifiCorp-owned asset.[28]

The Coalition argues if real levelization is to continue to be used for avoided capacity cost pricing, then it should likewise continue to be used for avoided PTC valuation, consistent with the IRP. The Coalition argues 10-year levelization for avoided PTC valuation unfairly disadvantages a QF and should be rejected.

2. Findings and Conclusions

No party disputes the Coalition's testimony that the capacity payment a QF receives is calculated on a real levelized basis. Furthermore, the total resource costs for supply-side resource options represent real levelized values that are inputs for PacifiCorp's IRP modeling in

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[26] Surrebuttal Testimony of Neal Townsend at 4, line 88, filed November 21, 2017.
[27] *Id.* at 5, lines 91-93.
[28] *See* Direct Testimony of Neal Townsend at 24, lines 527-531, filed October 3, 2017.

determining the preferred portfolio.[29] These costs include PTC values for wind resources.[30] At hearing, PacifiCorp testified: "[T]o the extent we want to acquire resources…we use the same models that we use in the IRP."[31]

Since the Proxy/PDDRR methodology draws upon the optimized IRP preferred portfolio, established on the basis of levelized input values, we find such values should be consistently applied in the determination of avoided cost prices. No party rebuts the Coalition's argument that if real levelization is to be used for avoided capacity cost pricing, then it should likewise be used for avoided PTC valuation, consistent with the IRP. We therefore reject PacifiCorp's proposed removal of PTCs from the calculation of real levelized avoided cost prices.

ORDER

Pursuant to our discussion, findings and conclusions, we:

1. approve undisputed routine and non-routine updates used in the calculation of avoided cost pricing;
2. approve PacifiCorp's proposal for REC ownership for Schedule 37 and 38 QFs;
3. approve PacifiCorp's interpretation and application of the Proxy/PDDRR Method;
4. direct PacifiCorp to include its proposed 2021 Wyoming wind and transmission resources as deferrable resources in the determination of avoided cost prices for wind QFs until the PSC issues a final determination on these resources or unless PacifiCorp determines it will no longer pursue these resources.

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[29] *See* PacifiCorp's 2017 IRP, p. 101.
[30] *See* PacifiCorp's 2017 IRP, Table 6.2, p. 111.
[31] *Supra* n.12 at 31, lines 23-25; at 32, line 1.

5. direct PacifiCorp to include lost transmission benefits in the determination of avoided costs to the extent the 2021 Wyoming wind resources are deferred.
6. approve PacifiCorp's proposal to calculate avoided cost pricing for QFs under Schedule 37 using the Proxy/PDDRR method consistent with Schedule 38 with certain exceptions;
7. decline to adopt a change in the queue position used in the calculation of Schedule 37 pricing;
8. decline to adopt proposals regarding an avoided cost floor or renewable avoided cost rates;
9. decline to include avoided line losses in Schedule 37 pricing and direct PacifiCorp to study this issue and present information on the extent to which Schedule 37 QFs connected at the distribution level avoid line losses, in its 2018 Schedule 37 pricing update;
10. deny PacifiCorp's proposal pertaining to the treatment of PTC values in the calculation of avoided costs; and
11. direct PacifiCorp to file updated Electric Service Schedule Nos. 37 and 38 consistent with this order, within 30 days.

DATED at Salt Lake City, Utah, January 23, 2018.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Jordan A. White, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#299311

CERTIFICATE OF SERVICE

I CERTIFY that on January 23, 2018, a true and correct copy of the foregoing was delivered upon the following as indicated below:

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____
Administrative Assistant

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-184-E – ORDER NO. 2019-847

DECEMBER 9, 2019

IN RE:	)
South Carolina Energy Freedom Act	)
(H.3659) Proceeding to Establish	)
Dominion Energy South Carolina,	)
Incorporated's Standard Offer, Avoided	)
Cost Methodologies, Form Contract	)
Power Purchase Agreements,	)
Commitment to Sell Forms, and Any	)
Other Terms or Conditions Necessary	)
(Includes Small Power Producers as	)
Defined in 16 United States Code 796, as	)
Amended) - S.C. Code Ann. Section 58-	)
41-20(A)	)

ORDER

ON AVOIDED COSTS AND RELATED ISSUES

TABLE OF CONTENTS

INTRODUCTION

This matter comes before the Public Service Commission of South Carolina ("Commission") pursuant to the requirements of S.C. Code Ann. § 58-41-20 as contained in 2019 Act No. 62 ("Act No. 62"), which was enacted into law by the South Carolina General Assembly and became effective on May 16, 2019. Specifically, Act No. 62 directed the Commission to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20(A).

In compliance with Act No. 62, on May 30, 2019, the Commission established the above-captioned docket for the purpose of establishing Dominion Energy South Carolina, Inc.'s ("DESC" or the "Company") standard offer, avoided cost methodologies, form contract power purchase agreements ("PPAs"), commitment to sell forms, and any other terms or conditions necessary to implement the requirements of S.C. Code Ann. § 58-41-20.

THE INTERRELATION BETWEEN RATEPAYER IMPACTS AND THE COST OF RENEWABLE ENERGY

This Order is of significant public importance and rests upon a foundational understanding of the interrelation between three entities in the electric sector: the utility, renewable developers, and the ratepayer. Specifically, critical in the interpretation of this Order is the allocation of costs of energy between these three entities.

The utility, generally, sells electricity to the ratepayer for a fixed – or known - price per unit of power. The utility can only sell electricity at rates approved by the Public Service Commission, which are established in litigated cases. The utility's rates are set at a level that gives the utility an opportunity to earn a return on its assets if it operates its company efficiently. A part of the utility's cost of service that is accounted for in the price of electricity that the ratepayer is to be charged is the cost of fuel and purchased power. Utilities are allowed to charge for the price of fuel used to generate power but are not allowed to make a profit on the fuel costs. Treated similarly to fuel costs, the utility is able to purchase power from another source – like a renewable generator – to sell to the ratepayers, but again is not allowed to make a profit on what it spends to purchase that power. This provides the utility an opportunity to earn profit from its own assets, but not overcharge ratepayers for fuel being consumed or power purchased from another source.

In the case of a renewable generator selling power to the utility, there are several financial events happening. At the highest level, shareholders or investors from an energy company must invest money in building a facility, during which process the energy company agrees to sell – and the utility agrees to buy – the electricity generated by the facility. The utility, having purchased the power as it is being generated, will sell the power to ratepayers. The price of that power, as reflected in the ratepayers' bills, will be dependent on the price at which the utility agreed to purchase the electricity generated by the facility.

At issue is the minimum price at which the utility – and therefore also the ratepayer – must pay for electricity generated by newly built (predominantly solar) facilities. There are provisions requiring the utility to purchase power at its avoided cost rate, which is basically the cost the utility would have if it generated the next unit of power rather than purchased it. At an accurate avoided cost rate, the ratepayer would be receiving electricity at exactly the same rate as if the utility generated it. In other words, with an accurate avoided cost rate, the consumer does not pay more for electricity even though the power was purchased rather than generated by the utility.

This is the balance at issue in this case. If the avoided cost rate is higher than the utility's true avoided cost, developers would be more willing to build facilities, but ratepayers would pay a higher price. If the avoided cost rate is lower than the utility's true avoided cost, then developers would be less willing to build facilities. To the extent that they do not build new facilities, ratepayers would continue to buy electricity generated by the utility and existing renewable facilities. If the avoided cost is correctly determined, however, the ratepayers are protected, and the economic facilities will be built.

Not all renewable generators are large scale, however. Ratepayers that install rooftop solar, for example, are customer-generators that participate in a Net Energy Metering program. Those ratepayers benefit from reasonable and accurate rates that fully represent the value and costs of their generation to the system. Accuracy in this rate is also important to keep ratepayers that are not participating in rooftop solar from subsidizing those that are. In the current case, the accurate valuation of Net Energy Metered resources – rooftop solar – actually increased by about 12%. In other words, rooftop solar owners are going to be paid more for the energy they generate. This provides additional benefit directly to ratepayers that have installed solar.

There is always a risk, even using the best available information to project avoided cost and set avoided cost rates, that the actual costs will change over time. This leads to the possibility of ratepayers paying an inaccurate rate for the power from renewable generators. If the cost of generation decreases over time, for example, the ratepayer will be overpaying for electricity. Overpayment in that situation occurs because the ratepayer must continue to buy the power from the generator at the higher price that was in effect when the renewable developer agreed to sell the power. This overpayment risk is reduced when avoided costs are lower than historical average. The avoided cost rates set by the Commission in this Order are priced very favorably to ratepayers compared to the historical experience; therefore, the risk of overpayment by the ratepayer is less likely.

This Order establishes an avoided cost rate that is accurate, which provides both the maximum protection for ratepayers and the opportunity for economic renewable generators to participate in the market.

I. NOTICE AND INTERVENTIONS

By letter dated July 18, 2019, the Clerk's Office of the Commission instructed the Company to publish, by July 29, 2019, a Notice of Filing and Hearing and Prefile Deadlines ("Notice") in newspapers of general circulation in the area affected by the issues presented in this proceeding. Among other things, the Notice[1] informed customers and the public of the nature of the proceeding and advised all interested parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On August 5, 2019, the Company filed with the Commission affidavits demonstrating that the Notice was duly published in accordance with the instructions set forth in the Clerk's Office July 18, 2019 letter.

Timely Petitions to Intervene were received from Johnson Development Associates, Inc. ("JDA"); the South Carolina Solar Business Alliance, Inc. ("SCSBA"); the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy (collectively, "CCL/SACE"); Walmart, Inc. ("Walmart"); the South Carolina Energy Users Committee ("SCEUC"); and Ecoplexus, Inc. ("Ecoplexus"). DESC did not oppose the Petitions to Intervene and no other parties sought to intervene in this proceeding. The South Carolina Office of Regulatory Staff ("ORS") also is a party of record pursuant to S.C. Code Ann. § 58-4-10(B).

[1] *See* Notice of Filing and Hearing and Prefile Testimony Deadlines dated July 18, 2019.

II. PREHEARING MATTERS

On June 14, 2019, the Commission held an Advisory Committee Meeting to discuss Act No. 62 and related procedural and scheduling issues. On July 17, 2019, the Commission held a hearing to consider oral arguments regarding procedural scheduling issues in this matter including, among other things, whether to consolidate the issues in this matter with those of Docket Nos. 2019-185-E and 2019-186-E pertaining to Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. In Order No. 2019-524, the Commission concluded that judicial economy would not be served in consolidating these three dockets[2] and established prefiled testimony deadlines and hearing dates for the individual dockets.[3] The Commission concluded that the proposed schedule would best effectuate the statutory requirements of Act No. 62 and would afford all parties the opportunity to litigate their positions on the matters before the Commission.

On August 12 and 19, 2019, the Commission held two Special Commission Business Meetings, during which the Commission received presentations from and conducted public interviews of prospective third-party consultants and experts who sought to be employed to perform the duties of a qualified independent third party as set forth in S.C. Code Ann. § 58-41-20(I). The Commission also permitted the parties of record to submit proposed written questions concerning each of the proposed candidates. *See* Order No. 2019-557, dated August 7, 2019. By way of Order No. 2019-585, dated August 21, 2019, the Commission also permitted the parties of record to submit comments on the public interviews of the prospective third-party consultants by

[2] On May 23, 2019, the Commission staff also opened a generic docket, Docket No. 2019-176-E, to establish each electrical utility's standard offer, avoided cost methodologies, form contract PPAs, commitment to sell forms, and any other terms and conditions necessary to implement S.C. Code Ann. § 58-41-20. By way of Order No. 2019-524, the Commission closed Docket No. 2019-176-E.

[3] *See also* Notice of Filing and Hearing and Prefile Testimony Deadlines dated July 18, 2019.

August 23, 2019. On August 28, 2019, the Commission issued Order No. 2019-621, in which it selected John Dalton of Power Advisory, LLC to serve as the qualified independent third party in Docket No. 2019-184-E.

On August 23, 2019, and in accordance with the Notice issued by the Commission Staff on July 18, 2019, DESC prefiled the direct testimony and exhibits of its witnesses.[4] On September 23, 2019,[5] the other parties of record likewise prefiled the responsive direct testimony and exhibits of their witnesses. On October 7, 2019, the Company prefiled the rebuttal testimony and exhibits of its witnesses and, on October 11, 2019, the other parties of record prefiled surrebuttal testimony and exhibits of their witnesses.[6]

On September 13, 2019, the Hearing Officer in this matter issued a directive permitting any party to this docket to file a prehearing brief by September 23, 2019, and a responsive brief by September 30, 2019. *See* Order No. 2019-103-H. Subsequently, the Hearing Officer revised the prehearing briefing schedule to allow the parties until September 30, 2019 to file a prehearing brief and until October 8, 2019 to file a responsive brief. *See* Order No. 2019-108-H. On September 30, 2019, DESC, ORS, and CCL/SACE each filed a prehearing brief and SCSBA and JDA filed a joint prehearing brief. Walmart and SCEUC also separately filed letters in lieu of a prehearing brief. On October 8, 2019, DESC and CCL/SACE each filed a responsive prehearing brief and SCSBA and JDA jointly filed a letter in lieu of a responsive prehearing brief.

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[4] On September 20, 2019, the Company filed amended versions of the direct testimony of Witnesses James W. Neely, John E. Folsom, Jr., and Allen W. Rooks to correct certain inadvertent errors that were contained in the versions of testimony filed on August 23, 2019.

[5] On September 17, 2019, the Hearing Officer issued a directive, Order No. 2019-106-H, granting ORS's request for an extension until September 23, 2019, for the other parties of record to prefile responsive direct testimony of their witnesses. Likewise, DESC's time to prefile rebuttal testimony and exhibits was extended to Monday, October 7, 2019.

[6] On October 12, 2019, SCSBA filed amended versions of the surrebuttal testimony of Witnesses Burgess and Levitas.

III. HEARING

In order to hear testimony, receive documentary evidence, and consider the merits of this case, the Commission convened a hearing on this matter on October 14-15, 2019, with the Honorable Comer H. "Randy" Randall presiding. DESC was represented by K. Chad Burgess, Esquire; Matthew W. Gissendanner, Esquire; Belton T. Zeigler, Esquire; and Mitchell Willoughby, Esquire. JDA and SCSBA were jointly represented by Weston Adams, III, Esquire, and Jeremy C. Hodges, Esquire. JDA also was represented by James H. Goldin, Esquire, and SCSBA also was represented by Benjamin L. Snowden, Esquire. Richard L. Whitt, Esquire, jointly represented SCSBA and Ecoplexus. CCL/SACE was represented by Stinson Woodward Ferguson, Esquire; J. Blanding Holman, IV, Esquire; and Lauren Joy Bowen, Esquire. Scott Elliott, Esquire, represented SCEUC. ORS was represented by Jeffrey M. Nelson, Esquire; Nanette S. Edwards, Esquire; and Jenny R. Pittman, Esquire. In this Order, DESC, JDA, SCSBA, Ecoplexus, CCL/SACE, SCEUC, and ORS are collectively referred to as the "Parties" or sometimes individually as a "Party."

DESC presented the direct testimony of John H. Raftery and the direct testimonies and exhibits of Dr. Joseph M. Lynch, James W. Neely, Eric H. Bell, Dr. Matthew W. Tanner, Daniel F. Kassis,[7] and Allen W. Rooks. SCSBA presented the responsive direct testimonies of Hamilton Davis and Jon Downey and the responsive direct testimonies and exhibits of Steven J. Levitas and Ed Burgess. JDA presented the responsive direct testimony of Rebecca Chilton. CCL/SACE presented the responsive direct testimony and exhibits of Derek P. Stenclik. ORS presented the

[7] At the hearing, Mr. Kassis testified that he had read Mr. Folsom's pre-filed direct testimony and exhibits and was adopting the pre-filed direct testimony and exhibits of Mr. Folsom.

responsive direct testimony of Robert A. Lawyer and the responsive direct testimony and exhibits of Brian Horii.[8]

In response to the issues raised in the responsive direct testimony presented by the other parties, DESC presented the rebuttal testimony of Witnesses Lynch, Tanner, Bell, Neely, Raftery, and Hanzlik. DESC also presented the rebuttal testimony and exhibits of Witnesses Kassis and Rooks.

SCSBA presented the surrebuttal testimony of Witnesses Levitas, Burgess, and Davis. JDA presented the surrebuttal testimony of Witness Chilton. CCL/SACE presented the surrebuttal testimony of Witness Stenclik. ORS presented the surrebuttal testimony of Witnesses Horii and Lawyer.

IV. STATUTORY STANDARDS AND REQUIRED FINDINGS OF FACT[9]

A. Background of Act No. 62 and PURPA

The Commission recognizes that Act No. 62 has made significant changes to the procedures related to avoided costs and utility purchases of power under PURPA and the issues to be considered by the Commission in this docket. However, a fundamental question posed to the Commission has remained unchanged: whether or not the avoided costs paid to qualifying facilities ("QFs") by electric utilities and the related agreements between such entities are reasonable, appropriate, and in compliance with applicable laws. In fact, in enacting Act No. 62, the General

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[8] Without objection, the Commission permitted the parties to utilize panels for the presentation of witnesses. DESC Witnesses Kassis and Raftery were presented in the first panel for the Company; DESC Witnesses Hanzlik and Bell were presented in the second panel; and DESC Witnesses Neely, Tanner, and Lynch were presented in the third panel. DESC Witness Rooks separately presented his testimony. SCSBA Witness Levitas and JDA Witness Chilton were presented in the next panel. SCSBA Witnesses Downey, Davis, and Burgess were presented in the next panel. CCL/SACE Witness Stenclik and ORS Witness Lawyer separately presented their testimonies. Without objection, ORS Witness Horii also separately presented his testimony via video teleconferencing.

[9] To the extent the following findings of fact are conclusions of law, they are adopted as such.

Assembly made clear that any decisions by this Commission must "be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and [FERC's] implementing regulations and orders, and nondiscriminatory." S.C. Code Ann. § 58-41-20(A). These requirements are echoed in the testimony of SCSBA witness Mr. Davis who recognized that the Commission's "decisions on avoided cost issues must be 'consistent with PURPA and [FERC's] implementing regulations and orders,' and that any power purchase agreements or other terms and conditions for [QFs] are commercially reasonable and consistent with PURPA and FERC's implementing regulations and orders." Tr. Vol. 2, pp. 544.6-544.7.

The General Assembly, through Act No. 62, encouraged the development of renewable energy resources, such as solar generation, in a manner that is fair and balanced to all customers of all programs related to renewable energy and energy storage. It also made clear that revenue recovery, cost allocation, and rate design of utilities should be just and reasonable, and it established procedures to ensure that QFs are properly compensated for the energy they produce, as is required by PURPA, while at the same time mandating that costs not be shifted onto utility customers in an effort to subsidize such programs. *See* S.C. Code Ann. § 58-41-05 (renewable energy issues must be addressed "in a fair and balanced manner, considering the costs and benefits to all customers" and must ensure that "the revenue recovery, cost allocation, and rate design of utilities that [the Commission] regulates are just and reasonable"); S.C. Code Ann. § 58-41-20(A) (the Commission "shall strive to reduce the risk placed on the using and consuming public"). In this regard, Act No. 62 is designed to ensure that the Company determines its costs and sets its rates at just and reasonable levels to comply with the legislative requirements and to implement the programs required by the Act, while also preventing the shifting of costs to customers.

With respect to avoided costs, the Commission also recognizes that Act No. 62 requires the establishment of methodologies for each electric utility that accurately determines the costs the utility avoids as a result of purchases it makes from QFs under PURPA. *See* S.C. Code Ann. § 58-41-20(B)(3). PURPA specifically provides that "[n]o … rule … [regarding the sale and purchase of QF power] shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy." 16 U.S.C.A. § 824a-3(b). PURPA's implementing regulations also expressly provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2).

The goal of Act No. 62 is to ensure that QFs are properly paid for the electricity they produce in accordance with the costs avoided by utilities while also making sure that excess costs are not shifted to or borne by utility customers. To meet this goal, purchases from QFs are to be revenue neutral to the ratepayers, which is what is required by both PURPA and Act No. 62.

For these reasons, the Commission concludes that it is important to calculate a utility's avoided costs correctly so that customers will not be impacted by, and will be economically indifferent to, purchases of QF power as opposed to paying for DESC's cost to construct and operate additions to utility power plant or to purchase power. Likewise, ensuring that avoided costs are correctly calculated will allow QFs, such as solar generators, to secure a non-discriminatory rate to which they are entitled.

Among other things, Act No. 62 requires the Commission to establish "each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement" the requirements of S.C. Code Ann. § 58-41-20.

1. Avoided Cost Methodology

As defined by both PURPA regulations and Act No. 62, "avoided costs" are "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from [QFs], such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6); S.C. Code Ann. § 58-41-10(2). FERC further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel and some operating and maintenance expenses.[10] Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). The Commission also has recognized in Order No. 81-214, dated March 20, 1981, Docket No. 80-251-E, and in subsequent decisions that electric utilities are entitled to recover from customers their avoided costs paid to QFs under PURPA.

Importantly, PURPA does not require electric utilities to pay QFs more than their avoided costs. PURPA and its implementing regulations expressly provide that "[n]othing … requires any electric utility to pay more than the avoided costs for purchases" from QFs. 18 C.F.R. § 292.304(a)(2). It is intended to equalize the rates charged for utility power resource additions and utility purchases of QF power so as to make certain that customers do not pay more for electricity under either option.

[10] The Commission also has recognized that energy costs include certain environmental costs which are subject to recovery in fuel rates pursuant to S.C. Code Ann. § 58-27-865.

S.C. Code Ann. § 58-41-20(A) provides that "[a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility … and shall strive to reduce the risk placed on the using and consuming public." Thus, if a utility's avoided costs are calculated reasonably to reflect the utility's avoided costs, customers would not be impacted by purchases of QF power and would be economically indifferent to whether the power in question was supplied by the QF purchase or by other means. Under both PURPA and Act No. 62, utilities are only required to pay QFs the utility's avoided costs. To do otherwise would be in conflict with the requirements set forth in S.C. Code Ann. § 58-41-20(A) because it would require customers to subsidize these privately held QF projects – which is a result not contemplated by either PURPA or Act No. 62.

In considering the avoided cost methodologies to be approved in this proceeding, S.C. Code Ann. § 58-41-20(B) requires the Commission to "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:

> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs; … and
>
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."

2. Standard Offer

A standard offer (the "Standard Offer") is defined by S.C. Code Ann. § 58-41-10(15) to mean "the avoided cost rates, power purchase agreement,[11] and terms and conditions approved by the commission and applicable to purchases of energy and capacity by electrical utilities … from small power producers up to two megawatts AC in size." Stated differently, a Standard Offer is a PPA that contains an avoided cost rate paid to eligible QFs that are 2 MW in size or smaller. Additionally, the Standard Offer contract sets the terms and conditions and allows any qualifying small power producer, as defined by S.C. Code Ann. § 58-41-10(14), to contract with the utility to supply electricity at established rates without the need to negotiate individual contracts. The Standard Offer therefore establishes set prices, terms, and conditions, and is not negotiated by DESC or the eligible QF. It is intended to address the concern that the costs of negotiating and administering individually-negotiated contracts could render smaller projects non-viable. In this manner, Act No. 62 expands the requirements of PURPA, which only requires that utilities have in place standard rates for QFs up to 100 kW-AC, by increasing the upper limit on the required offer of standardized rates, terms, and conditions contained in PURPA from 100 kW-AC to 2 MW-AC in size. An increase in the availability of Standard Offer contracts accentuates the importance of ensuring that their pricing, terms, and conditions do not prejudice the interests of the QF, the customers, nor the utility.

[11] "'Power purchase agreement' ["PPA"] means an agreement between an electrical utility and a small power producer for the purchase and sale of energy, capacity, and ancillary services from the small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-10(9).

Form Contract PPA

A form contract PPA is similar to a Standard Offer, except that, pursuant to S.C. Code Ann. § 58-41-20(A), it is for use for qualifying small power production facilities that are not eligible for the Standard Offer, i.e., QF facilities that are greater than 2 MW and up to 80 MW in size. The statute also requires that these PPAs contain provisions for force majeure, indemnification, choice of venue, confidentiality provisions, and other such terms. However, the PPA is not determinative of the price or duration of the contract. These issues are to be separately negotiated by the Company and the applicable QF and "may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-20(B)(3). As proposed by DESC, the terms and conditions for the Standard Offer and the form PPA are similar since the potential impacts to the Company's system and its customers from projects 2 MW or less in size can be comparable to those that exceed 2 MW.

3. Commitment to Sell Form

Act No. 62 also mandates that QFs "have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility." S.C. Code Ann. § 58-41-20(D). This standard notice of commitment to sell form ("NOC Form") is required to provide the QF a reasonable period of time from its submittal of the form to execute a PPA, but shall not require a QF, "as a condition of preserving the pricing and terms and conditions established by its submittal of an executed [NOC Form] to the electrical utility, … to execute a [PPA] prior to receipt of a final interconnection agreement from the electrical utility." *Id.*

B. Issues Related to Bifurcation of Docket No. 2019-2-E

In addition to the issues required to be addressed in this proceeding under S.C. Code Ann. § 58-41-20, it also is appropriate and necessary for the Commission to address certain issues that previously were presented for consideration in the Company's 2019 fuel cost proceeding, Docket No. 2019-2-E, but ultimately bifurcated from the decisions reached in that matter. Specifically, prior to the enactment of Act No. 62, DESC's avoided costs and underlying methodologies were approved in the Company's annual fuel cost proceeding as provided by S.C. Code Ann. § 58-27-865. As part of the Company's 2019 fuel cost proceeding, DESC proposed to include the updated avoided costs, variable integration costs, and updates to the Net Energy Metering ("NEM") values in its fuel costs effective with the first billing cycle of May 2019. However, the Commission determined that these issues should be bifurcated from consideration in Docket No. 2019-2-E and would be addressed in a later, appropriate hearing. Order No. 2019-229 at 1; Order No. 2019-43-H at 1. The Commission also determined that DESC's then-current avoided cost rates and NEM values were to remain the same as those in effect at the time the issues were bifurcated and that, after the Commission held a hearing to consider updates to these rates, these rates and values would be subject to a "true up." Order No. 2019-43-H at 1. Accordingly, these issues are appropriate for consideration in the above-captioned docket.

V. EVIDENCE OF RECORD AND RESULTING FINDINGS OF FACT[12]

A. Report of Power Advisory, LLC

Prior to reaching the central determinations in this case, the Commission must address the "Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62" which was submitted by Power Advisory, LLC on November 4, 2019 (the "Power Advisory Report"). As noted above, the Commission retained Power Advisory to serve as "a qualified independent third party" in these proceedings, as such is contemplated by S.C. Code Ann. § 58-41-20(I). Under that statute, the Commission is authorized to engage such a third party, whose responsibility it is "to submit a report that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs." § 58-41-20(I). The Commission may then use any conclusions based on the evidence in the record and included in the third-party's report "along with all other evidence submitted during the proceeding to inform its ultimate decision setting the avoided costs for each utility." *Id.* The Power Advisory Report is attached as Order Exhibit 1 and is explicitly incorporated into this order.

After the Power Advisory Report was submitted, on November 8, 2019, DESC timely submitted its Comments in Response to the Power Advisory, LLC Report, and at the same time filed a Motion to Strike Final Report of Power Advisory, LLC. Both in its Comments and Motion, DESC essentially sought to eliminate Power Advisory, LLC's Final Report from the Commission's consideration in the decision or decisions made in Docket No. 2019-184-E. The reasoning given by DESC to exclude such information is that Power Advisory, LLC did not

[12] As to all factual matters, they reflect the Commission's decision that the preponderance of the evidence as presented in this hearing, and after weighing the probative value and credibility of the testimony of each witness, supports the conclusion reached. To the extent the following findings of fact are conclusions of law, they are adopted as such.

perform completely independent analyses in the proceeding, and instead, relied upon the information provided by the parties. DESC's Motion and Comments both ignore the plain language of Act No. 62; specifically, Section 58-41-20(I), which instructs the qualified independent third party "to submit a report that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs for purposes of proceedings conducted pursuant to this section." Section 58-41-20(I) further states that "any conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding to inform its ultimate decision setting the avoided costs for each electrical utility." To strike the complete Power Advisory Report would be to disregard the plain language requirement under Section 58-41-2(I) and is impermissible.

Moreover, it is evident that some parties support both the selection of Power Advisory, LLC and the content of the report. Johnson Development Associates, for example, filed a letter in response to the Power Advisory Report stating:

> JDA does believe that the report was thorough, well-reasoned, and completed in compliance with the intent of the Energy Freedom Act" and "JDA believes the Commission used this expert as the tool that Act No. 62 of 2019 envisioned it become. JDA wishes to express its appreciation to the work of Power Advisory. The expert brought confidence to the parties to the proceedings through the transparency, expertise, and impartiality of the expert as evidenced by the Report.

Similarly, the South Carolina Solar Business Alliance, Incorporated filed a letter in response to the Power Advisory Report stating:

> The SCSBA does… believe that the report was completed impartially and the expert was diligent in the discharge of their duties. We believe the Report complies with the requirements of the Energy Freedom Act. SCSBA would like to thank Power Advisory for their diligent and thorough work, especially given the short timeframe for this docket. Transparency, fairness, the state's policy of

encouraging renewable energy, and ratepayer protection have all been assisted by the work of Power Advisory.

Summary of Conclusions Made by Power Advisory and Adopted by this Commission:

Transparency:

Transparency, for purposes of these proceedings, is a two-fold concept. The willing and timely responses to requests for production is one part of transparency; further, the utility's report is to be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed. Power Advisory reported that Dominion responded to all requests for production. However, there was concern that the underlying assumptions, data, and results did not have documentation presented that would allow for accessible analysis. While Dominion adequately responded to requests for production, as expected, Power Advisory recommended that Dominion be required to present substantially more information about the underlying assumptions and data, such that the parties to such future proceedings may more meaningfully evaluate and analyze the methodologies and models employed by the utility. In this regard the Commission's decision is to adopt the recommendations in the Power Advisory Report in respect to the Company's future avoided cost filings.

Methodology; Integration Charges for Solar:

The methodology used by Dominion in this case is designed to reasonably reflect the utility's actual cost – and avoided cost- of power production, pursuant to S.C. Code Section 58-41-20(B)(3). Dominion proposed Variable Integration Charges and Embedded Integration Charges – both of which the Company said were designed to reflect the additional cost of connecting solar power generation to the Company's system. Specifically, the "VIC" was to be applied to existing generators and the "EIC" was to be applied to the future generators via an embedded reduction in the avoided cost rate available to those generators. We accept Power Advisory's recommendations to apply an interim value of $2.29/MWh to both the VIC and EIC, and order that we initiate an integration study in accordance with South Carolina Annotated Section 58-37-60 in Dominion's balancing area. Once the integration study process set out in Section 58-37-60 is completed, we shall initiate a proceeding as allowed under S.C. Code Section 58-41-20(A) for the purpose of addressing Dominion's avoided costs, armed with the publicly reviewed evaluation of solar integration in Dominion's balancing area.

Avoided Capacity:

In Power Advisory's consideration of Avoided Capacity, it agreed with the ORS's determination that the Company's proposed avoided capacity is calculated using several inputs or assumptions that are inaccurate, namely, the reserve margin, excessive and inconsistent use of low cost capacity purchases, an overly long combustion turbine life, and a mismatch between the avoided cost resource change and the assumed size of a CT unit. However, Dominion Witness Lynch also performed an Effective Load Carrying Capability, or ELCC, analysis that resulted in, among other things, a 4% capacity value for solar. This Commission has rejected the Company's preferred Avoided Capacity value of zero. Instead, it has accepted the recommendation of Power Advisory and adopted the 4% capacity value, which is derived by the ELCC analysis performed by Dr. Lynch, and uses an industry standard methodology according to Power Advisory. The Commission has found that the Avoided Cost rates recommended by Power Advisory are just, reasonable, and reasonably reflective of the utility's cost of generation. This Commission further agrees with Power Advisory's recommendation that the avoided capacity rates proposed by ORS Witness Horii be approved, with one correction. The capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. This contracted capacity is currently 1,048 MW, which implies a capacity value of 4%.

Avoided Energy Cost:

Power Advisory's recommendations modify several inputs to the calculation of avoided energy cost, such as the amount of operating reserves, and are discussed more fully in this Order. The Commission has found the avoided energy cost, calculated with the incorporation of the recommendations of Power Advisory and ORS witness Mr. Horii to be fair, just, and reasonable.

Other Contract Terms:

Power Advisory's analysis addressed numerous additional contract terms. These terms and the Commission's findings on these issues are fully discussed in this Order.

B. Avoided Cost Methodologies

1. Difference in Revenue Requirements Methodology

In brief: the Commission considers whether the avoided cost methodology proposed by DESC is appropriate.

DESC proposes in this proceeding to use a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and the capacity component of its avoided costs. Tr. at 308.7-308.8. The DRR methodology is one of the generally accepted methods for calculating PURPA avoided energy costs, is used throughout the United States, and has been previously approved by the Commission in Order Nos. 2016-297 and 2018-322(A). Tr. at 695.25. This approach involves calculating the revenue requirements between a base case and a change case. Tr. at 308.8. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed PPAs. *Id.* The change case is the same as the base case except that a zero-cost purchase transaction is modeled after assuming the addition of an incremental amount of QF energy to its system. *Id.* The Company's change case also reflects an increase in the amount of operating reserves maintained by DESC to address the variable nature of solar energy. *Id.* For the avoided energy cost determination, the Company uses a computer program called PROSYM, which models the commitment and dispatch of generating units to serve load hour by hour, makes two runs and estimates the production costs and benefits that result from the purchase transaction. *Id.* The base and change cases are identical except for the zero-cost purchase transaction and, in the change case for solar, the increased operating reserves. *Id.* The avoided energy cost is the difference between the base case costs and the change case costs. *Id.*

For avoided capacity costs, DESC calculates the difference in revenue requirement between the base case and the change case. Tr. at 308.11. Using the resource plan in its latest integrated resource plan ("IRP") or an updated resource plan, if appropriate, DESC calculates the incremental capital investment-related revenue required to support the existing resource plan. *Id.* For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of adding incremental QF capacity. Tr. at 308.11 – 308.12. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. Tr. at 308.12.

Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR methodology, no other party objected to the use of the DRR methodology or proposed an alternative methodology to calculate DESC's avoided costs. The Commission therefore finds that it is appropriate to use the DRR methodology to calculate the Company's avoided costs.

2. Incremental Change Amount

In brief: the Commission considers whether the change case of 100 MW from the base case is appropriate.

As part of the DRR methodology, DESC proposes to calculate its avoided energy and capacity costs based upon an assumed incremental addition of 100 MW of QF energy. Tr. at 308.8. ORS, however, proposes to calculate the avoided costs based upon an assumed addition of 93 MW of QF energy based upon the capacity of combustion turbine ("CT") units that DESC projects to add for new capacity in its IRP. Tr. at 695.39. ORS also suggests that it is appropriate to use a 93 MW change because of the "lumpiness," or limited flexibility of sizing of CT plants. *Id.* Power Advisory agrees with ORS and recommends using the 93 MW addition, rather than 100 MW as proposed by DESC. No other party of record proposed that a different capacity addition should be used in connection with the DRR methodology.

The Commission rejects DESC's proposal and instead adopts Power Advisory's and ORS' proposal, therefore finding that it is appropriate for DESC to use a 93 MW change in energy in connection with its DRR methodology. Primarily, PURPA specifically provides that a utility may use a change of up to 100 MW to calculate avoided energy costs, 18 C.F.R. § 292.302(b)(1). Clearly, then, a 93 MW increase is permissible under PURPA, and more accurately reflects actual potential incremental changes in DESC's generation fleet. Act No. 62 specifies that the Commission's decisions in this proceeding shall be consistent with PURPA and FERC's implementing regulations and orders. S.C. Code Ann. § 58-41-20(A). In addition, the Commission finds that ORS's concerns about the "lumpiness" of a 100 MW noteworthy. The record reflects that the only way to avoid any such "lumpiness" would be to add additional resources that exactly equal the amount needed to meet the reserve margin requirement each year, which would be unreasonable and inappropriate for planning purposes. However, to the extent that a more accurate estimate can be established without causing undue burden, such accuracy should be sought. The Commission therefore finds that the use of a 93 MW change in QF capacity is reasonable, appropriate, and consistent with Act No. 62, PURPA, and FERC's implementing regulations and orders.

3. Avoided Energy Costs – Time Periods

In brief: the Commission considers whether the time periods used to price avoided energy are appropriate. This includes evaluation of short- and long-term periods, as well as the four pricing periods used by DESC to value avoided energy cost.

Using the DRR methodology, DESC proposes to calculate its avoided energy costs over two time periods. Tr. at 308.8 – 308.9. The short-run avoided energy costs[13], which are reflected in Rate PR-1 and which apply to small QFs of not more than 100 kilowatts ("kW"), are calculated for a 12-month period. Tr. at 308.8. For solar QFs that have production capacity up to 2 megawatts ("MW") and that are subject to Rate PR-Standard Offer, and for solar QFs that have production capacity greater than 2 MW and that will sell the energy generated pursuant to an executed PPA, DESC calculates the long-run avoided energy costs for a 10-year period. Tr. at 308.8 – 308.9; 308.11. The Company then divides these ten-year periods into two groups of five years. *Id.* For non-solar QFs subject to Rate PR-1 or Rate PR-Standard Offer, DESC then accumulates the avoided energy costs into four time-of-use periods reflecting the amounts non-solar QFs would be paid based on how much energy they produce in each of the four time-of-use periods. Tr. at 308.11; 308.18.

[13] Short-run and long-run avoided energy costs are also discussed at pp. 44 – 45.

Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR methodology, only SCSBA addressed any issues with respect to the time periods used by DESC to calculate avoided energy costs. Specifically, SCSBA Witness Burgess expressed a concern that DESC's selection of the four pricing periods was potentially biased against solar QFs on the basis that DESC's proposed avoided energy costs are higher during the winter "Off Peak Season" months and lower during the summer "Peak Season" months when solar resources are more abundant. Tr. at 523.25. As DESC Witness Neely testified, however, the four time-of-use rates are not applicable to solar QFs, but only to non-solar QFs. Tr. at 308.11. Although Witness Burgess testified in surrebuttal that the four time-of-use rates were included in certain modeling information produced by DESC in discovery, Tr. at 527.8, SCSBA failed to demonstrate how this information evidenced bias by DESC in proposing rates for non-solar QFs.

Power Advisory, the qualified independent third-party consultant, concludes that the pricing periods should be chosen to reflect discernable pricing patterns and underlying differences in avoided costs throughout the day. The use of broad pricing periods increases the risk that these periods are composed of times when there are consistent underlying differences in avoided costs, which would be better reflected in more narrow pricing periods. The independent consultant recommends that DESC provide support for the pricing periods that it employs in its next avoided cost filing. We agree. While the record did not sufficiently evidence that the DESC pricing periods were actually biased or inappropriate, the risk of – at a minimum – inaccuracies due to the broad pricing periods is significant. Accordingly, additional justification for pricing periods should be presented in future filings.

4. Avoided Energy Costs – Operating Reserves

In brief: the Commission considers whether additional operating reserves are required to account for the intermittency and variability of solar generation. This question contemplated whether additional decrement to the value of solar-generated avoided energy is warranted.

In calculating its avoided energy costs for solar QFs, DESC determined that additional reserves equal to 35% of the installed solar capacity are needed to cover most of the one-hour solar intermittency. Tr. at 308.23. The Company therefore modeled its avoided cost calculations with additional reserves equal to 35% of the installed solar capacity, during solar generating hours, but noted that, as more solar is added to the system, these percentages may change and new operating reserve requirements will be reflected in future avoided cost calculations. Tr. at 308.10.

DESC employed Navigant Consulting, Inc. ("Navigant") and Company Witness Tanner who conducted a "Cost of Variable Integration Study" ("Navigant Study"). Tr. at 290.3; Hr'g Ex. 5, MWT-2. Witness Tanner testified that the scope and purpose of the study was to estimate the impacts that solar installations will have on DESC's system operations. Tr. at 290.5. He stated that it also establishes the resulting incremental integration costs for projects that are already under contract and have a Variable Integration Clause in their PPA and describes how the additional reserve requirements for DESC that are caused by solar will result in additional fuel costs. Tr. at 290.5 – 290.6.

Specifically, Witness Tanner stated that the Navigant Study evaluated the variable integration costs for two different scenarios of solar generation installed on the system. Tr. at 290.6. The study also describes how the additional reserve requirements for DESC that are caused by solar can be incorporated into the avoided cost methodology in the future. Id. Finally, the study describes the requirements that solar projects must meet in order to avoid the need for DESC to implement additional reserve requirements. Id.

The initial analysis focused on establishing a benchmark for Navigant's PROMOD® production cost model that reflected DESC's actual system operating experience and the Company's own internal planning. Tr. at 290.7. Navigant then conducted a solar uncertainty analysis, which estimated the forecast error for hourly generation from solar, by comparing solar forecasts with actual solar generation from the United States National Renewable Energy Lab's ("NREL") solar integration dataset. Id. Using this information, Navigant calculated the probability of how much less than expected solar facilities actually generate, which varies depending on the forecasted level of solar generation. Tr. at 290.12 – 290.13.

Witness Tanner testified that the analysis also considered the challenges the Company would experience if additional reserves are not added to the system. The Study provides examples and analyses of time periods when DESC operators would experience insufficient amounts of resources that would be needed to maintain system reliability and demonstrates that DESC needs to maintain additional reserves to safely and reliably operate its electric system in light of the variability in solar generation. Tr. at 290.7. Witness Tanner also testified that the study took into account the impact of geographic diversity of renewable resources and recognized that solar generation is not located in a single area, but in different places throughout a system. Tr. at 290.15 – 290.16. This geographic diversity means that there is variability in how weather will affect the generation output of dispersed solar installations at any given time. Id. The Study further allowed the model to change the operation of the Fairfield Pumped Storage System ("Fairfield") to minimize overall system cost while meeting the requirements for solar integration. Tr. at 290.20.

Witness Tanner also stated that the Study evaluated alternative approaches to providing the necessary reserves including an analysis of the potential and cost to add new resources to the system as an alternative mitigation option. This involved estimating the Company's cost to maintain additional reserves necessary to integrate the variable energy generated by solar facilities. Specifically, Witness Tanner stated that the amount of 1-hour battery storage that can be added for the additional system costs of approximately $73.2 million is approximately 95 MW assuming future improvements in technology and cost declines through 2025. Tr. at 290.21. The amount of CT gas capacity that can be added is approximately 110 MW. Id. However, Witness Tanner stated that neither of these capacities is sufficient to provide the reserves needed to integrate the solar generation. Tr. at 290.22. Witness Tanner testified that the Study also considered the ability of solar projects to provide sufficient flexibility so that DESC does not have to add reserves. Tr. at 290.22. He further stated that, while detailed conditions would need to be defined in the future for solar projects willing to offer such flexibility, certain operating conditions would allow for DESC to avoid the need to increase reserve requirements in order to plan for potential drops in solar generation. Id. These conditions would include 1) giving DESC some ability to control the dispatch of the generation from the project; 2) being able to replace enough of the nameplate capacity of the project when called upon to make up for generation lower than forecasted; and 3) being able to maintain the replaced generation for sufficient time to avoid reliability challenges. Id.

Carrying additional operating reserves for QF solar intermittency is a widely accepted practice and was not disputed by the intervening parties. In fact, ORS Witness Horii testified that it is reasonable for the Company to require additional operating reserves to address the possibility that renewable generation output will be lower than forecasted and that increasing operating reserves is one method for addressing the uncontrolled variation in solar output. Tr. at 695.11. He also testified DESC derived the 35% value from 2018 solar data by looking at the observed drops in solar output over a 1-hour period and determining that the 35% value would be required to cover 96% of the 1-hour drops in solar output. Tr. at 695.28. However, Witness Horii stated that, if solar output was analyzed over a shorter period of time such as a 15-minute period, the amount of solar drops would be less and the need for additional reserves would be less. *Id.* He also stated that, if there is a drop in expected solar output in subsequent 15-minute periods, the operator could call upon other off-line resources to stand by to inject power to restore the desired operating reserve level. Tr. at 697.2. On this basis, ORS recommended that avoided energy costs should be calculated assuming additional reserves of only between 13% and 18%. Tr. at 697.2 – 697.3.

Independent consultant Power Advisory states that modeling by the utility's external consultant, Navigant, as well as those later done by DESC for its embedded avoided cost analysis, maintained high reserve levels even when solar generation was modeled to be low. It is likely that this contributed to over-estimation of the cost of maintaining additional reserves, because many of the hours when reserve levels are low (and the cost of maintaining additional reserve levels is therefore likely to be high) occur in the early morning when there is little or no solar generation. In Power Advisory's opinion, DESC has not provided convincing evidence that holding constant levels of additional reserves, either in all hours (Witness Tanner's VIC analysis)[14] or in all solar generating hours (DESC's embedded avoided cost analysis), does not significantly overstate solar integration costs.

In consideration of the testimony of ORS witness Mr. Horii and upon the recommendation of Power Advisory, we find that the reserve requirements recommended by the Company to be excessive and adopt the recommendation of Mr. Horii.

[14] See Variable Integration Charge ("VIC") discussion at pp. 52 - 56, below.

5. Avoided Capacity Costs – Impact of Solar on Capacity Needs

In brief: the Commission considers whether and to what extent solar generation contributes value to the capacity needs of DESC's electric system.

A primary issue in this proceeding is what impact energy supplied by solar QFs has on DESC's future capacity needs. In analyzing this issue, DESC Witness Lynch conducted an updated analysis of the study performed as part of the Company's 2018 fuel proceeding, Docket No. 2018-2-E. This analysis, which is presented in a study titled "The Capacity Benefit of Solar QFs 2018 Study ("Solar Capacity Benefit Study"), alleges that solar power cannot help serve DESC's winter peaking needs. Tr. at 276.3; Hr'g Ex. 4, JML-1. According to DESC, this is because, in the winter, the Company's system typically peaks early in the morning before sunrise.

DESC Witness Lynch also testified that, in the context of determining the Company's avoided costs, "capacity value" means capacity costs that would be avoided as a direct result of a change in the resource plan caused by a solar purchase. Tr. at 276.11. The main driver of the Company's need for additional capacity is its peak demand needs. In this context, Witness Lynch testified that DESC conducted a "Peak Demand Forecast" study, which used customer and energy sales forecasts and customer load characteristics to forecast the Company's seasonal peak demands. Tr. 276-12 – 276.13; Hr'g Ex. 4, JML-2. As a result of this study, DESC expects its winter peak demand to be higher than its summer peak demand over the 15-year planning horizon under normal weather conditions. Tr. at 276.13.

DESC Witness Lynch also considered the Effective Load Carrying Capacity ("ELCC") methodology to establish the firm capacity value of solar, even though he asserts that the ELCC value is an application of the Loss of Load Expectation ("LOLE") technique which is not appropriate for DESC. Tr. 276.9. This methodology demonstrates that the addition of 500 MW of solar represents 185 MW of firm capacity, or about 37% of nameplate capacity. Tr. at 276.10. When another 500 MW of solar is added to the system, however, the incremental value of solar decreases to only 59 MW of firm capacity. *Id.* Additionally, Dr. Lynch testified that the ELCC value of an increment of 100 MW of solar above the 1,048 MW of solar under a signed PPA to DESC, is only 3 or 4 MW, i.e., 3 or 4%. Thus, he states the 244 MW or 24% of nameplate capacity does not reflect an increment of QF capacity which would be methodologically appropriate but rather reflects the total 1,000 MW of solar nameplate capacity currently under a signed PPA.

DESC also updated its "2018 Reserve Margin Study" and provided more analysis to establish the winter and summer peak demand risk related to extreme weather. Tr. at 276.17. Specifically, Witness Lynch testified that the Company developed three separate equations to study DESC's reserve margin needs for both the summer and winter periods, taking into account the Company's Virginia and Carolina Reserve Sharing Group ("VACAR") requirements as well as its demand-side and supply-side risk reserve requirements. *Id.*; Hr'g Ex. 4, JML-3. As a result of that study, DESC determined that it requires a 14.3% reserve margin in the summer and a 20.2% reserve margin in the winter, which supports its continued use of a 14% minimum summer reserve margin and a 21% minimum winter reserve margin. Tr. at 276.18

Accordingly, DESC asserts that it will need capacity in the future in order to meet its forecasted winter peak load. DESC also concluded that, as more and more incremental solar is added to its system, each increment will affect fewer daily peaks than previous increments and that, eventually, adding more solar capacity will no longer affect the summer peak. Because DESC needs capacity in the winter, and solar does not provide capacity either on early winter mornings before sunrise when the system peaks or during non-peak hours on most non-summer days when the system peaks before sunrise or after sunset, DESC concluded that incremental solar will not allow DESC to avoid any future capacity costs. The Company therefore asserts that the capacity value of additional solar QF generation is zero. Tr. at 276.11.

SCSBA Witness Burgess questioned DESC's analysis of the capacity value of solar, even though he recognized that DESC has experienced its annual peak load hour during winter in recent years. Tr. at 523.48. Instead, Witness Burgess suggests that there may be some future years where summer peak exceeds winter peak. *Id.* He also suggests that it is inappropriate for DESC to plan for serving load on one peak hour of the year that has the highest probability of an outage and, instead, the Company should consider the other hours of the year that have smaller probabilities of an outage. *Id.* Therefore, Witness Burgess posits that it is more appropriate to "place a series of smaller bets on the second, third, and fourth ranked" possibilities so as to potentially reduce the overall risk of QF investments. *Id.* He also suggests that load growth and load shapes may shift over the next ten years. Tr. at 523.51. Like Witness Horii, discussed below, Witness Burgess further testified that DESC's ELCC analysis suggested solar has a capacity value of approximately 24% of nameplate capacity. Tr. at 523.56. He also stated that solar has a meaningful contribution to reducing the overall probability of an outage and, thus, has capacity value. Tr. at 523.57. On this basis, Witness Burgess suggested using DESC's ELCC value to determine capacity payments or to adjust the weightings to more accurately reflect DESC's summer peak load hours. Specifically, Witness Burgess suggested using a "Technology-neutral Seasonal Allocation Method" in which the resulting avoided costs are applied based on when QF production occurs and its coincidence with the seasonal peak periods, regardless of the underlying technology. Tr. at 523.59 – 523.61.

Witness Horii disagrees with DESC witness Lynch's assertion that incremental solar provides no capacity value in the winter season or that capacity need is driven solely by peak demand. DESC witness Neely states that "only half of the peak days would occur in the winter" evidencing that the Company understands that half of the peak days occur in the Summer months, thus supporting Mr. Horii's use of a summer capacity value. Tr. p. 319.11, l. 20. As Mr. Horii points out, DESC witness Lynch also performed a probabilistic analysis known as the Effective Load Carrying Capacity ("ELCC") method which demonstrates a solar capacity value equal to 24% of nameplate capacity.

In Rebuttal Testimony replying to witness Horii, DESC witness Lynch contends that his Convolution Formula is not overly simplistic but provides nothing in the way of new facts or evidence to support this claim. Tr. p. 283.2, l.6 to p. 283.3, l. 2. In Surrebuttal, Mr. Horii further defined his argument on this issue in stating that it is not the Convolution Formula itself that is simplistic, but rather the fact that the formula is not the driver of DESC's valuation. Tr. p. 695.10. As Mr. Horii explained to this Commission in his Surrebuttal, DESC's determination of reserve margins performs a simple addition of independent supply risk and demand risk, a simplistic approach which is used in driving its recommendations for avoided capacity costs. Id.

Another of the differences in the calculations of avoided capacity between Mr. Horii and Mr. Neely is Mr. Horii's recommendation that a 93MW change in generation should be used as opposed to the 100MW used by the Company. Tr. p. 695.39, ll. 7-14. While Mr. Horii's use of a 93MW change is based on his specific calculations, Mr. Neely only supports the Company's use of 100MW.

We find Mr. Horii's testimony on this issue to be compelling and supported by more focused and accurate formulas and considerations than those expressed by the Company's witnesses. Additionally, DESC maintains it is a winter peaking utility, yet DESC witnesses testified that the Company experiences almost as many, if not the same amount, of peaks in the summer as it does in the winter. Testimony in the record supports our finding here that the need for capacity is not a simple comparison of summer versus winter capacity need, but rather capacity needs over the whole year. See, Tr. p. 695.34, ll. 20-23.

Further, Power Advisory states that capacity value should therefore be estimated using the ELCC methodology. As raised by Dr. Lynch, DESC has over 1,000 MW of solar capacity under contract and therefore the capacity value of solar should be estimated assuming this capacity is already in place. As noted, this provides a capacity value of 4% of installed capacity on the basis that 1,000 MW of solar have already executed a contract.

After considering the evidence of record on this issue, the Commission concludes that DESC's position that incremental energy supplied by solar QF facilities will not allow it to avoid any future capacity is not reasonable. The Commission adopts the view of the independent consultant, Power Advisory, which concludes that the ELCC analysis conducted by Dr. Lynch (but not preferred by him) is a reasonable method of estimating the capacity value of solar. As a result, solar will be afforded a 4% of installed capacity value at this time.

The Commission also finds that SCSBA's "Technology-neutral Seasonal Allocation Method" is inappropriate for use in this proceeding. By advocating for this methodology, SCSBA requests that the Commission approve a single QF rate that would be paid regardless of the nature of the underlying technology. However, the record reflects that stand-alone solar generation has a unique profile that is non-dispatchable and is not similar to other QF resources such as natural gas-fired generation. For this reason, the Commission finds that an accurate avoided cost for incremental, non-dispatchable stand-alone solar can only be captured using a solar-specific avoided cost calculation. In making this finding, the Commission also recognizes that Act No. 62 provides "[a]voided cost methodologies approved by the commission may account for differences in costs avoided based on the … resource type of a small power producer's qualifying small power production facility." S.C. Code Ann. § 58-41-20(B)(3).

In short, the Commission finds that there is substantial evidence, as adopted by independent consultant Power Advisory, demonstrating that incremental solar QF energy will, at this time, have an effect equal to about 4% of its nameplate capacity for solar generators on its need for future capacity.

6. Operational Issues Related to Solar

In brief: the Commission considers whether additional costs incurred by the need for more generation assets and/or different (less efficient) generator operation, incident to the previously proposed additional required reserves, would be reasonably required to account for the intermittency and variability of solar generation.

DESC has demonstrated that the integration of solar energy presents unique operational challenges for a large-scale utility tasked with generating electricity to meet customer demand across its service area, even during a given day. More particularly, DESC Witness Bell explained that, because photovoltaic ("PV") solar panels convert light directly into electricity, the amount of sunlight on the panels dictates the electrical output of each facility. Tr. at 167.3. Uncontrollable factors, including time of day and local weather conditions, influence the amount of energy that can be produced. *Id.* This means that PV solar produces electricity independently of customers' demand for energy. *Id.* This is unlike dispatchable generation, such as those from natural gas-fired generating facilities, that can be controlled and adjusted to produce more or less energy as is needed to meet demand. *Id.*

Witness Bell explained that, in general, PV solar facilities begin producing energy just after sunrise, with their output increasing for the next several hours in the day, depending on cloud cover. *Id.* DESC's data shows output averages of about 74% of rated capacity by around 11 a.m.

Id. However, in addition to the more predictable ramps at the beginning and end of the day, unpredictable minute-to-minute variability occurs throughout the day depending on weather conditions. *Id.*

Witness Bell explained that when unplanned drops and increases occur in solar generation—which his demonstrative charts showed could reflect changes to the order of hundreds of megawatts within a day—DESC must ramp up or ramp down its dispatchable generators in order to cover the fluctuations and meet customer demand. Tr. at 167.12. DESC says it must maintain sufficient generation capability in reserve in order to compensate for the intermittent variability of solar and to meet this demand. In other words, it is arguing that the integration of solar generation onto its grid requires additional back-stop reserves – achieved through new generation assets and/or different generation operations (less efficient, increased spinning reserves) - due to its inherent variability. DESC is in effect saying that the avoided cost value of solar generation must be discounted to reflect the additional reserves the company must maintain when solar is relied upon for system power. In addition to being variable moment to moment, Witness Bell explained that solar generation can also vary widely from the solar generation forecasts provided by solar operators and Company forecasters, which creates an additional need for reserves. *Id.* In recent years, DESC has experienced a significant increase in PV generator connections and expects an even greater increase in the near future. Tr. at 167.10-167.11.[15] Ultimately, DESC anticipates that solar generation will exceed its ability to provide adequate

[15] Witness Bell testified that, as of August 2019, DESC had a total of 511 MW of solar generation in commercial operation on its system, and that by the end of 2020, the Company expects to have a total of 1,152 MW of solar facilities interconnected with its system, which represents about one quarter of the Company's current peak demand. *Id.*

reserves unless DESC maintains more hourly operating reserves or adds more quick-start resources to its system. *Id.*

Witness Bell explained that DESC is subject to requirements established by NERC and the SERC Reliability Corporation. Tr. at 167.14. As noted, the Company is also a signatory to VACAR through which it is required to maintain reserve generation capability at all times in the event of a contingency—that is, a reserve call from a neighboring utility, a sudden loss of generation such as when a dispatchable generating facility is unable to generate electricity, or unexpected and higher demand on DESC's system. *Id.* Thus, when the territorial load exceeds forecast, or non-dispatchable solar generation is not producing the expected level of electric generation, DESC must ensure that other generation is producing power to meet load, while making additional generation supply available to maintain the reserve requirement. *Id.* Under these circumstances, DESC must have generators available or online that are capable of quickly and reliably producing electricity so that any sudden shortfall can be met. *Id.*

Witness Bell explained that contingency reserves must be supplied on demand within fifteen minutes. Contingency reserves include both "spinning" and "non-spinning" reserve requirements. Tr. at 167.15. Spinning reserves are those provided by generators that are already online but not operating at full capacity and therefore can immediately generate additional electricity to serve the load. *Id.* Non-spinning reserves may be supplied by both online and offline generators that can be fully loaded within fifteen minutes. *Id.* Witness Bell explained that the generators with the fastest response capability are quick-start internal combustion turbines ("ICTs"), some hydropower facilities, and pumped storage generators ("Pumped Storage"). *Id.*

Witness Bell explained that the only way to increase reserves from ICTs and Saluda Hydro is to construct additional units. *Id.* DESC's reserves from quick starts and Saluda Hydro, he explained, have been fully utilized for years, and no additional reserve value can be gained from those existing units. *Id.* While he explained that Pumped Storage does supply both spinning and non-spinning reserves, Witness Bell further explained that the optimal use of Pumped Storage is dictated by economic factors. *Id.* Creating additional reserves by holding back Pumped Storage adds fuel costs in most circumstances because the output from higher-cost generating units must be increased to replace the power. Tr. at 167.15-167.16. Witness Bell explained that DESC can increase its reserves by operating more coal and gas-fired baseload units; however, doing so may require DESC to operate its natural gas or coal-fired generating facilities under low load conditions or at an output level that is less efficient, i.e. more costly, than the optimal level for which they were designed. Tr. at 167.16. Thus, Witness Bell explained, there is a cost to operating the generating units that provide these higher reserve levels, and those costs increase as more reserves are required. *Id.*

As it concerns DESC's reserve requirements to address these issues with the variability of solar, CCL/SACE Witness Stenclik testified that the Navigant Study (discussed *infra*) improperly assumed high reserve requirements for DESC. Tr. at 629.5. More specifically, he testified that the study does not accurately capture DESC's operating practices because DESC does not currently require operating reserves for existing solar generation. *Id.* He also testified that the Navigant Study failed to account for aggregation benefits that naturally reduce the relative forecasting errors and resource variability as the solar generation fleet grows. *Id.* Witness Stenclik also testified that the analysis used an excessive 4-hour ahead forecast, overstating the forecast error that may impact actual operations. *Id.*

Responding to the criticisms of Witness Stenclik, Witness Bell testified that DESC's actual operating practice requires additional reserves equaling 40% of actual or forecast solar output to account for solar intermittency. Tr. at 176.7. This is in addition to contingency reserves, which are a different form of reserves altogether. The 40% flexible reserve allows the system to respond to solar intermittency that exceeds 15 minutes and still maintain the operating reserves necessary to respond to the largest thermal unit in operation at that time tripping offline. Tr. at 176.7-176.8. Witness Bell testified that solar intermittency is different from a thermal unit dropping offline, which happens in a single event, and the effects of which in terms of loss of generation can be calculated precisely. Rather, the loss of solar generation often occurs as a decline in generation that stretches over multiple 15-minute intervals and can evolve over several hours. Tr. at 176.8-176.9.

Also, because the probability is significant of a coincidence of a thermal unit's forced outage and a large, unplanned drop in solar generation persisting for hours, Mr. Bell testified that prudent operators must consider and plan for both contingencies happening at the same time, and must also keep in mind the ramp-up time for the next available unit—if the next available unit takes 3-4 hours to ramp up to supply load, then the operator must make system adjustments sufficiently ahead of time to allow that unit to reach generation capacity. Tr. at 176.9. It is for these reasons, Witness Bell stated, that reserves for solar intermittency must be in addition to the existing contingency reserve requirement, and additional reserves of less than 40% would expose DESC's customers to unacceptable risks. Tr. at 176.9-176.10.

Witness Stenclik also expressed concern that the Navigant Study imposed additional fixed solar reserve requirements for each hour of the year rather than being a function of hourly forecasted solar generation. Tr. at 629.5. Witness Bell responded that DESC uses hourly forecasted solar production, as well as actual solar production, to plan and maintain reserves on an hourly basis for real-time system operations, which limits the additional reserves for solar and the associated cost to daylight hours. Tr. at 176.10.

In third-party consultant Power Advisory's view, neither DESC's nor Navigant's analyses of solar intermittency provide good bases for estimating the quantity of additional reserves that will be required, likely resulting in significant overestimation of the amount of additional reserves required and the associated costs. DESC's analysis is based on changes in solar generation from one-time interval to another, rather than on differences between forecast and actual solar generation for the same interval. Since the purpose of reserves is to address unexpected changes in supply and demand, DESC's analysis is simply not relevant.

Power Advisory reports that Navigant's analysis was based on a comparison between forecast and actual solar generation, but their exclusive reliance on four-hour-ahead forecasts is overly simplistic and fails to conform with best practice. Recognizing that there is a cost associated with a greater forecast error and that this forecast error can be reduced if the forecast is made closer to real-time, as acknowledged by Dr. Tanner, Power Advisory believes that using a four-hour-ahead forecast is overly conservative and contributes to a need for higher reserves than would be required under an appropriate application of best practices.

Power Advisory recommends to the Commission that this issue be evaluated in greater detail during the independent study recommended in Act 62 to evaluate the integration of renewable energy and emerging energy technologies into the electric grid. It does not believe that DESC's or Navigant's analyses of solar intermittency provide appropriate bases for determining additional requirements for flexible reserves.

In Power Advisory's view, none of the three standards used by DESC to determine the additional reserves attributable to solar generation (35% of nameplate capacity for the avoided cost calculations, up to 32% of installed capacity for the VIC calculations, and DESC System Control's 40% of forecast generation) have been adequately justified as a reasonable balance between costs and risks. Power Advisory recognizes that this is not a simple or straight forward analysis but believe that greater analytical rigor is required than DESC has employed to ensure a reasonable trade-off between reserve costs and risks.

The Commission agrees with the Power Advisory assessment of DESC's position. There is an inadequate basis to determine an accurate level of additional reserves needed for integration of solar at this time, and adoption of DESC's position would carry a large risk of overestimating any reserves that may be justified with solar integration.

7. Resource Plan

In brief: the Commission considers whether DESC's approach to resource planning is reasonable, and whether the particular resource planning model used in this case is founded on appropriate input assumptions and data.

In analyzing its resource needs, which inform the amount of capital expenditure that may be deferred or eliminated by including additional QF generation, the Company also performed a resource study to assess the cost of generation that could meet DESC's resource plan needs. Tr. at 308.4; Hr'g Ex. 6, JWN-1. Specifically, the Company used 19 resource plans evaluated under 4 different sets of assumptions for a total of 76 different scenarios. Tr. at 308.3. The four sets of assumptions included 1) Base Gas Prices with Zero CO2 Costs, 2) High Gas Prices with $15/ton CO2 costs, 3) High Gas Prices with Zero CO_2 Costs, and 4) Base Gas Prices with $15/ton CO_2 Costs. Tr. at 308.6. In each case, generation was added over a 30-year horizon, then modeled using DESC's hourly dispatched model. Hr'g Ex. 6, JWN-1. The Company then extrapolated costs for another 10 years and compared the scenarios using each scenario's 40-year levelized present value. *Id.* DESC determined that base gas prices is the most likely gas scenario with zero

CO_2 costs. Tr. at 308.6. Based on this assumption, DESC determined that the addition of two 540 MW combined cycle gas generation plants in the winters of 2029 and 2040 would result in the lowest cost resource plan. Hr'g Ex. 6, JWN-1. On this basis, DESC calculated its avoided energy costs using this resource plan because it is the lowest-cost resource plan identified. To calculate avoided capacity costs of QFs that would potentially displace peaking resources, however, DESC determined that it would be more appropriate to use a plan that is populated with peaking resources. Tr. at 319.25. Accordingly, DESC proposed to use an ICT to calculate avoided capacity costs.

SCSBA Witness Burgess testified that the use of a new ICT peaking facility was incorrect and biased against QFs, however. Tr. 523.41. Instead, he suggested that there has been a growing trend towards more flexible, aero-derivative types of peaking facilities, which might be more efficient, but also more expensive in terms of upfront capital costs. Tr. at 523.42. Witness Burgess also recommended a capital cost assumption that represented the midpoint between the capital costs of the two types of peaking facilities. Tr. at 523.44. In response, Witness Neely testified that the capital cost of peaking resources used by DESC accurately reflects the cost of procuring and installing a 100 MW aero-derivative simple cycle generating unit with a net capacity of 93 MW on DESC's system. Tr. at 319.26. He further testified that this choice of peaking resource is appropriate because it is the lowest-cost peaking resource plan identified and that SCSBA Witness Burgess' suggestion would require a more expensive plan. *Id.*

Witness Burgess also criticized DESC's estimates of the cost of capacity purchases from other neighboring utilities in years 2022 through 2028. Tr. at 523.40 – 523.41. He posited that the cost estimates used by the Company for these purchases is relatively low, does not accurately reflect market value, and therefore artificially depresses the avoided capacity cost in the change case. Tr. at 523.45. In response, Mr. Neely testified that the purchased capacity component reflects a 3-month winter purchase or winter demand response resource. Tr. at 319.27. However, he noted that Witness Burgess inappropriately compared this cost to an annual cost for capacity from PJM and that, if SCSBA's suggestion was properly applied, it would result in a lower avoided cost of capacity cost, not a higher one. Tr. at 319.27 – 319.28.

The Commission finds that the type of resource planning proposed by DESC to calculate avoided costs are reasonable, but that the actual scenarios employed by DESC included inputs that were not representative of best practice. But for the Company being required to purchase electricity generated by QFs, it would be reasonable and appropriate for DESC to plan for its resource needs based on adding capacity that would meet its needs and at the lowest reasonable cost that is commercially feasible and adequate. For example, the use of ICT units is appropriate, but the cost associated with the units – as a function of unit life - is not. Both the expansion plan set forth in the Company's 2019 IRP and the use of an ICT to calculate capacity costs are reasonable to consider when calculating avoided costs, but the IRP and a single type of turbine need not be considered exclusively in this or future proceedings.

8. Proposed Avoided Costs and Methodology

In brief: the Commission considers whether the methodology previously discussed is appropriately applied to the calculation of avoided costs in DESC's PR-1 and PR-Standard Offer rates.

In connection with this proceeding, DESC proposes to use the DRR methodology to calculate avoided energy costs over two time periods: "short-run" avoided energy costs, which are for the 12-month period of May 2019 through April 2020, and "long-run" avoided energy costs, which are for the 10-year period of 2020 through 2029. Tr. 308.8 – 308.9. Long-run avoided energy costs are then divided into two groups of five years each: 2020-2024 and 2025-2029. Tr. at 308.9. DESC also proposes to calculate avoided capacity costs using a 10-year period. *Id.* Witness

Neely testified that the 10-year period for long-run avoided energy and capacity costs was appropriate because using projected costs beyond the 10-year period required by Act No. 62 would be speculative and could increase the costs paid by DESC's customers. Tr. at 308.13.

Again, Witness Neely testified that to calculate avoided energy costs for QF facilities under Rate PR-Standard Offer, DESC uses PROSYM to estimate the change in production costs that result from serving the loads in the base case and the change case. Tr. at 308.11. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. *Id.* The avoided costs are then accumulated into four time-of-use periods. *Id.* The change case for solar QFs is derived from the base case by subtracting a 100 MW power purchase modeled after a solar profile. *Id.*

For avoided capacity costs under Rate PR-Standard Offer, DESC takes a similar approach. *Id.* Witness Neely testified that using the resource plan in its latest IRP or an updated resource plan if appropriate, DESC calculates the incremental capital investment related revenue required to support the existing resource plan. *Id.* For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW facility. Tr. at 308.11 – 308.12. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. Tr. at 308.12. Witness Neely testified that this method is reasonable because it identifies adjustments to the utility's expansion plan that are attributable to purchases from QFs and accurately reflects the capacity cost benefits that would result from the QF purchase. *Id.*

Witness Neely stated that, because incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost as discussed more fully above, the avoided cost for solar QFs subject to Rate PR-Standard Offer is zero. *Id.* For non-solar QFs that qualify for the Standard Offer Rate, Witness Neely testified that the avoided capacity cost is $73.46/MWh, but this value only applies for a limited period of time. *Id.* These avoided capacity rates will be paid during the months of December, January and February for energy generated from 6 a.m. to 9 a.m. *Id.* In order to qualify for this credit, the Seller's generation should be fully dispatchable during all of the identified capacity credit hours. *Id.*

Witness Neely therefore testified regarding what he believes are the avoided costs that should be approved for Rate PR-Standard Offer.

Witness Neely also testified that Rate PR-1 and PR-Standard Offer would not be applicable to QFs greater than 2 MW. Tr. at 308.15. Instead, Witness Neely stated that the Company would negotiate separate contracts for these projects and would calculate the avoided costs for these projects using the same methodology outlined above, but with unit-specific data and the other requirements described in the Company's proposed Rate PR-Avoided Cost Methodology. *Id.*

Regarding QFs in the future that seek to interconnect both solar generation and storage, DESC has not proposed a tariff for these types of projects in this docket. Rather, by settlement agreement previously approved with modifications by the Commission in Order No. 2018-804, the Company agreed to file rate schedules for solar with storage on or before December 31, 2019. The Company represented that it was prepared to meet that deadline.

For Rate PR-1, Witness Neely testified that the Company uses the same methodology to estimate avoided energy costs for solar QFs as it did for solar QFs for Rate PR-Standard Offer, except that the short-run avoided energy costs are estimated for the period May 2019 through April 2020. Tr. at 308.18. He also explained that losses for Rate PR-1 are calculated at the primary distribution level. *Id.* For non-solar QFs, Witness Neely testified that DESC uses PROSYM to estimate the change in production costs that result from serving the base case and the change case.

Id. The avoided energy costs then are accumulated into four time-of-use periods, and non-solar QFs would be paid based on how much energy they produce in each of these periods. *Id.* For avoided capacity costs, Witness Neely testified that DESC calculates the incremental capital investment related revenue required to support the existing resource plan and considers the impact of a QF purchase from a 100 MW facility on the resource plan. Tr. at 308.19. The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan. *Id.*

Based on this methodology, Witness Neely testified that the avoided capacity cost component for solar QFs under Rate PR-1 is zero because these facilities do not affect the resource plan. *Id.* For non-solar QFs that qualify for the PR-1 Rate, the avoided capacity cost is $0.07346/kWh, which will be paid during the months of December, January, and February for energy generated from 6 a.m. to 9 a.m. *Id.* Witness Neely also stated that the capacity payment is available only to generators capable of providing power in all of the identified hours. *Id.*

On behalf of SCSBA, Witness Burgess suggested that, rather than adopting DESC's proposed avoided costs, the Commission instead should approve avoided cost rates that are on the higher end of a "zone of reasonableness." Tr. at 523.11. He suggests that this method would marginally increase customer costs, but that such costs would be transparent, stable, and tied to a QF's performance. Tr. at 523.12. However, Witness Burgess provided no evidence, much less substantial evidence, demonstrating the bounds of this purported "zone of reasonableness" or what avoided costs values would be appropriate for adoption by this Commission using such a criterion. In this regard, the Commission finds that setting avoided costs on this basis would require the Commission to engage in speculation instead of establishing just and reasonable avoided costs as directed by the General Assembly in Act No. 62. In addition, and as acknowledged by Witness

Burgess, such an exercise would "increase customer costs," even if only marginally. The Commission finds that taking such action would shift the risk of solar developments onto DESC's customers and arbitrarily increase their rates, both of which would directly violate the requirements of PURPA and Act No. 62.

Witness Burgess also questioned DESC's proposal to use a different rate methodology for solar and solar with storage, stating that a resource-specific approach raises significant concern about the ability of separate rates to properly represent the full suite of QF technological possibilities. Tr. at 523.19. Instead, Witness Burgess suggested that a single QF avoided cost value be determined for projects up to 2 MW that reflects the value to DESC's system regardless of the fact that the underlying record reflects solar and solar with storage are different resources with different generation profiles. Tr. at 523.20. In order to determine the most accurate avoided cost for each technology, including the amounts of energy and capacity each technology allows DESC to avoid, it therefore is appropriate to consider these technologies separately. Every project that currently comprises the 1,048 MW of solar to be interconnected with DESC's system consists of non-dispatchable, variable solar generation. Tr. at 319.20.

Power Advisory asserts that a technology neutral approach is more flexible and reflects actual value for customers in specific hours. It further asserts that the approach suggested by Burgess modeled on the non-solar QF contract is reasonable, though it may be necessary to develop a larger number of groupings to reflect value from generators with highly correlated profiles, such as solar.

Power Advisory's recommendation to use a technology neutral approach with a subset of groupings for generations with shared characteristics – like solar – appears to be a distinction without a difference. Whether the Commission adopts a technology neutral rate with modifications in a subset for solar, or whether we adopt a technology-specific rate from the outset; either case means having rates that reflect the generation characteristics of solar in a rate. Given that the result is the same, it serves to further transparency in DESC's rate structure to have easily identified rates that are applicable to, essentially, the exclusive technology being installed and interconnected onto DESC's system.

The Commission therefore finds that it is appropriate to calculate the solar avoided cost based on non-dispatchable solar. The Commission further recognizes that the Company's proposed Form PPA allows utilities to calculate a resource-specific avoided cost value for other QF facilities such as flexible solar. For these reasons, the Commission finds that calculating a single QF avoided cost value as Witness Burgess suggests, would not only be inappropriate but also would result in customers having to bear excessive costs, which is directly contrary to the requirements of PURPA and Act No. 62.

In response to the testimony of DESC regarding the calculation of avoided costs, however, ORS disagrees with certain inputs and assumptions that DESC employed in developing their avoided capacity cost estimates. ORS's concerns and corrections are discussed in detail in ORS witness Horii's direct testimony. Mr. Horii notes that DESC understates the avoided capacity cost estimates due to the following incorrect assumptions: 1) an incorrect reserve margin, 2) excessive and inconsistent use of low cost capacity purchases, 3) an overly long combustion turbine ("CT") life, and 4) a mismatch between the avoided cost resource change and the assumed size of a CT unit. Tr. p. 695.33, l. 20 to p. 695.34, l. 5.

Witness Horii also disagrees with DESC witness Lynch's assertion that incremental solar provides no capacity value in the winter season or that capacity need is driven solely by peak demand. DESC witness Neely states that "only half of the peak days would occur in the winter" evidencing that the Company understands that half of the peak days occur in the Summer months, thus supporting Mr. Horii's use of a summer capacity value. Tr. p. 319.11, l. 20. As Mr. Horii points out, DESC witness Lynch also performed a probabilistic analysis known as the Effective Load Carrying Capacity ("ELCC") method which demonstrates a solar capacity value equal to 24% of nameplate capacity.

In Rebuttal Testimony replying to witness Horii, DESC witness Lynch contends that his Convolution Formula is not overly simplistic but provides nothing in the way of new facts or evidence to support this claim. Tr. p. 283.2, l. 6 to p. 283.3, l. 2. In Surrebuttal, Mr. Horii further defined his argument on this issue in stating that it is not the Convolution Formula itself that is simplistic, but rather the fact that the formula is not the driver of DESC's valuation. Tr. p. 695.10. As Mr. Horii explained to this Commission in his Surrebuttal, DESC's determination of reserve margins performs a simple addition of independent supply risk and demand risk, a simplistic approach which is used in driving its recommendations for avoided capacity costs. *Id*.

Another of the differences in the calculations of avoided capacity between Mr. Horii and Mr. Neely is Mr. Horii's recommendation that a 93MW change in generation should be used as opposed to the 100MW used by the Company. Tr. p. 695.39, ll. 7-14. While Mr. Horii's use of a 93MW change is based on his specific calculations, Mr. Neely only supports the Company's use of 100MW.

We find Mr. Horii's testimony on this issue to be compelling and supported by more focused and accurate formulas and considerations than those expressed by the Company's witnesses. Additionally, DESC maintains it is a winter peaking utility, yet DESC witnesses testified that the Company experiences almost as many, if not the same amount, of peaks in the summer as it does in the winter. Testimony in the record supports our finding here that the need for capacity is not a simple comparison of summer versus winter capacity need, but rather capacity needs over the whole year. *See*, Tr. p. 695.34, ll. 20-23.

Based on the above referenced testimony, the Commission hereby approves the following avoided energy and capacity rates as meeting the requirements of S.C. Code Ann. § 58-41-20(A):

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
May 2019 – April 2020	0.03075	0.02566	0.03330	0.03363

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
May 2019 – April 2020	0.03114

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
2020-2024	0.03280	0.02797	0.03301	0.03073
2025-2029	0.03879	0.03166	0.04191	0.03519

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
2020-2024	0.02112
2025-2029	0.02375

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December thru February, 6:00 a.m. to 9:00 a.m.	0.24725

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December thru February, 6:00 a.m. to 9:00 a.m.	0.24725

AVOIDED CAPACITY COSTS
Solar QFs

As discussed on pages 21 – 22, and pages 34 - 36, this Commission agrees with Power Advisory's recommendation that the avoided capacity rates proposed by ORS Witness Horii in Direct Evidence be approved, with one correction. The capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. This contracted capacity is currently 1,048 MW, which implies a capacity value of 4%.

9. Variable Integration Costs

In brief: the Commission must consider what integration charge would accurately represent the true cost of integrating – or connecting – new solar generation onto DSC's electrical system.

According to ORS witness Horii, the overall concepts of the methodology used in DESC's Navigant Study are reasonable as integrating renewable generation does create additional costs for utilities. However, he also finds that the Navigant Study performed for the Company is overly risk adverse. Tr. p. 695.10, ll. 21-23. Mr. Horii testified that E3 has observed that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. The cost impact can include higher start-up costs, fuel costs, and operating and maintenance costs resulting from resources operating at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs can also increase for additional generation plant required to provide additional flexible capacity.

ORS witness Horii testified that he considers the Company's analysis to be an acceptable approach to estimating solar integration costs, however, he does make the following observations:

1) The assumptions used by Navigant unreasonably increase the risks of uncertain variable generation to the Company which inflates the resulting variable integration costs. He therefore proposes a more balanced approach which results in a reasonable value for the VIC;

2) The Company failed to conduct an analysis that balances risks and costs in determining the additional amount of operating reserves that would need to be carried due the existence of variable solar resources on the system;

3) The Company is unreasonably risk averse in its determination of the amount of additional operating reserves due to potential solar forecast error; and

4) The Navigant Study overstates operating reserves needed by holding reserve levels constant over each day, rather than allowing operating reserves to reflect how any solar forecast risk would not be at DESC's high estimated levels over the entire day.

Tr. p, 695.8 to p. 695.11.

According to ORS witness Horii, integration costs should be reduced by modifying the Company's methodology in determining the solar forecast uncertainty and applying his calculated 36.2% reduction of forecast uncertainty. Tr. p. 695.21, ll. 4-5. He also recommended to the

Commission that DESC be required to conduct a new VIC study, and involve the solar community in that process to allow for an effective and cooperative interchange of ideas. Tr. p. 690, ll. 15-19.

SBA witness Burgess testified that should the Commission approve an integration charge in this case, that it should: 1) be adequately capped, 2) reflect the drivers of the integration costs, 3) based on real-world data, and not projections, and 4) have the ability to be mitigated through appropriate dispatch of solar, storage or other QF technology. Tr. p. 523.90

Forecast uncertainty drives the amount of additional reserves that Navigant has modeled for DESC. Since the forecast uncertainty that needs to be accounted for according to witness Horii is 36.2% less than modeled, the amount of additional reserves for solar should also be 36.2% less than estimated. To convert that reserve change to a cost impact, he referred to Navigant's estimates of integration costs by reserve level. That figure shows that the integration costs can be estimated as a simple linear relationship to additional reserve levels. Because of this linear relationship, the 36.2% reduction in forecast uncertainty results in a 36.2% reduction in integration costs. As a result, witness Horii believes the Company's proposed VIC of $4.14/MWh should be reduced by 36.2% to $2.29/MWh. Tr. p. 695.19. Additionally, witness Horii reviewed the distribution of solar forecast error to determine the percentage of time that forecast error could exceed his recommended level. As provided in his testimony, witness Horii determined that there was a less than 1% chance that solar forecast error would exceed his recommended reduction to DESC's Integration Study estimate by 36.2%. Tr. p. 695.21, l. 10-16.

Power Advisory issues a very strong opinion on the solar integration charges:

In Power Advisory's opinion, DESC's proposed values for the solar VIC, and solar integration costs embedded in its proposed avoided costs, are insufficiently supported by the evidence.

The data and analysis on which solar intermittency risks are estimated are inappropriate, being based either on actual changes in solar output over time (rather than on a comparison of forecast and actual output for the same time period) or on a four-hour-ahead forecast that is inconsistent with the timeframe under which reserves would be dispatched (which may be four hours some of the time, but will often be much shorter).

It is unclear whether the risk thresholds implicitly used in the estimates of solar integration costs are appropriate, because they have not been justified either by a loss of load probability calculation or by a comparison of the costs that would be incurred if reserves were insufficient vs. the costs of maintaining additional reserves.

The modelling of additional required reserves for both the VIC and avoided costs is significantly different from DESC's actual practices for establishing reserves. DESC's actual practice is to base reserve levels on forecast solar generation, which means no increase in reserve levels at night and small increases in the early morning when solar generation is low. In contrast, both sets of simulations increase required reserves based on installed capacity (not forecast generation) in many hours beyond what is reasonably necessary, including nighttime hours (Navigant only) and hours with low solar generation (both). DESC asserts that this has no impact on the modeling results, but has not provided convincing evidence to support this claim. In Power Advisory's estimate, the modeling results are likely to include at least some hours with little or no solar generation but with significant additional costs attributed to solar generation.

There has been inadequate consideration of alternative ways of providing additional reserves, such as combustion turbines or batteries, which might be cost-effective when multiple revenue streams are considered in addition to those from providing reserves; demand response targeted at solar integration; and reserve sharing with neighboring utilities at least toward the end of the study period.

Moreover, Power Advisory ultimately recommended as an interim step until such time as the integration study has been completed and the results implemented, adjusting DESC's solar rates – including PR-1, Avoided Cost and DER rates – to remove DESC's proposed integration costs and replace them with an integration cost of $2.29/MWh for all periods under consideration.

We believe ORS witness Horii's position, supported by Power Advisory, is a reasonable balance of risk and costs, especially given his other concerns over the Navigant costs being biased upward. We find these recommendations to be just and reasonable to customers, consistent with PURPA and FERC regulations and orders, non-discriminatory to QFs, and serve to reduce the risk placed on the using and consuming public.

C. Form Contracts

In brief: the Commission considers numerous terms and conditions that are to be incorporated into contracts between solar developers and DESC.

1. Standard Offer

As stated previously, Act No. 62 requires electric utilities to establish Standard Offer contracts in order to implement the requirements of S.C. Code Ann. § 58-41-20(A). As defined by S.C. Code Ann. § 58-41-10(15), a "standard offer" consists of "the avoided cost rates, power purchase agreement, and terms and conditions approved by the Commission and applicable to purchases of energy and capacity by electrical utilities … from small power producers up to 2 MW in size." In this regard, Company Witness Kassis testified that PURPA requires utilities to have in place standard rates for QFs up to100 kw-AC, and Act No. 62 increases this threshold to require standardized rates, terms, and conditions for QFs up to 2 MW-AC in size. Tr. Vol. 1, p. 59.17. In order to satisfy the requirements of Act No. 62 in this regard, DESC proposed a Standard Offer for the Commission's consideration. Witness Kassis testified that the proposed Standard Offer is very similar to the Form PPA proposed by the Company in that both are largely based upon the form PPA that DESC previously has used for similar utility-scaled projects. Tr. Vol. 1, p. 59.18. He also stated that it is important to include similar terms and protections for DESC's customers. *Id.*

Witness Kassis did, however, identify certain terms and conditions in the Standard Offer that differed from the previous PPA contracts used by the Company and from the Form PPA proposed by the Company in this proceeding. For example, Witness Kassis testified that the VIC clause was removed from the Standard Offer because the avoided cost methodology proposed by the Commission in this proceeding for future QF projects will directly incorporate the integration costs associated with non-variable, solar QF energy. *Id.* He also testified that the proposed Standard Offer does not contain a "seller buy down" provision as does its proposed Form PPA because it is not necessary given the other customer protections included in the Standard Offer. Tr. Vol. 1, p. 59.19. He also stated that DESC does not anticipate the need to file the Standard Offer contracts with the Commission in that it will not disclose confidential or market sensitive information. *Id.* Accordingly, DESC's proposed Standard Offer includes the mutual acknowledgement of the QF and DESC that the Standard Offer will be filed with the Commission in unredacted form. *Id.*

Witness Kassis also expressed concern that QF developers may attempt to take advantage of the Standard Offer and flood DESC with projects no larger than 2 MW-AC and that the total aggregate MW-AC of power purchased by DESC under the Standard Offer could be very significant. *Id.* He also stated that a developer could attempt to split a project into multiple smaller projects to take advantage of the Standard Offer. Tr. Vol. 1, p. 59.20. In order to address this concern, DESC proposes that the Standard Offer not be made available to a QF owned by a seller or an affiliate or partner of a seller, who sells power to DESC from another QF, using a renewable energy resource within one mile of each other, unless the aggregate capacity of the QFs is equal to or less than 2 MW-AC. *Id.* Witness Kassis testified that such a limitation would be similar to PURPA's "one-mile rule." *Id.*

As an initial matter, the Commission recognizes that certain parties disputed DESC's proposed avoided cost rates, which are reflected in the Standard Offer as proposed by the Company. The Commission has previously addressed herein the issues pertaining to avoided costs and determined that **the avoided costs set forth in DESC's proposed Standard Offer are unreasonable and inappropriate.** Accordingly, the Commission incorporates herein by reference those same findings.

With respect to the terms and conditions of the Standard Offer, ORS Witness Horii testified that the Standard Offer generally is commercially reasonable and conforms to industry standards. Tr. Vol. 2, p. 695.47. However, he identified a concern with the lack of clarity in section 6.1(a) of the Standard Offer as proposed by DESC. *Id.* Specifically, he expressed concern about what would constitute an acceptable "expected range of certainty" regarding forecasted energy production, or what a QF with no historical operating experience would provide in this regard. Tr. Vol. 2, p. 695.48. In response, Company Witness Kassis agreed with ORS's recommendations and removed the identified sentence from both the Standard Offer and the Form PPA. Tr. Vol. 1, p. 66.5, l. 21 – p. 66.6, l. 4. DESC also corrected certain errors in the Standard Offer and Form PPA that were identified by ORS. Tr. Vol. 1, p. 66.6. The Commission finds that these changes are reasonable and should be incorporated into the Standard Offer as proposed by ORS and agreed to by DESC.

On behalf of SCSBA, Witness Levitas made several references to a standard of "commercial reasonableness" which he suggested required striking a balance between promoting QF development and protecting ratepayer interests. Specifically, he stated that contract terms which make it difficult to finance QF development do not strike that balance. Tr. Vol. 2, p. 451.8. In this regard, Witness Levitas proposed to include a definition of "commercial reasonableness" in the Standard Offer and the Form PPA. *Id.* Company Witness Kassis testified, however, that SCSBA's proposed definition solely refers to what may constitute reasonableness in the mind of the "promisor" without any reference to the perspective or unique obligations that may be placed upon the counterparty under the agreement who is affected by the promisor's efforts. Tr. Vol. 1, p. 66.15. He further stated that the proposed definition contains vague language that would be incredibly difficult, if not impossible, to follow. Tr. Vol. 1, p. 66.16. After considering these issues, the Commission finds that Witness Levitas' proposed language regarding commercial reasonableness is inappropriate for inclusion in the Standard Offer and the Form PPA. Specifically, the Commission finds that attempting to define the term "commercial reasonableness" in this context likely would exacerbate disputes between QFs and DESC over the meaning of the language.

Witness Levitas also objected to language in the Standard Offer that would provide relief for liquidated damages only for interconnecting utility delays pertaining to the construction of required interconnection facilities that do not include network upgrades. Tr. Vol. 2, p. 451.13. DESC agreed with this concern and revised its Standard Offer and Form PPA by modifying the definition of "Excusable Delay" and adding a definition of "Network Upgrades."

Tr. Vol. 1, p. 66.19. Witness Levitas also questioned the inclusion of language that would allow DESC to approve the Seller's engineering, procurement, and construction contracts and operation and maintenance contracts. Tr. Vol. 2, p. 451.19. Although Company Witness Kassis testified that DESC included these provisions to mitigate adverse operating conditions, he stated that the Company is willing to strike the provisions of Section 4.1(b) and has done so in its revised Form PPA and Standard Offer. Tr. Vol. 1, p. 66.24, l. 17 – p. 66.25, l. 2. The Commission finds that these changes are reasonable and should be incorporated into the Standard Offer as proposed by SCSBA and agreed to by DESC.

Liquidated Damages and Extension Payments

Further, regarding liquidated damages and extension payments, DESC originally proposed liquidated damages for failure to achieve commercial operation in the amount of $55,000/MW. In its revised filing, DESC has reduced that amount to $41,000/MW. However, it is this Commission's belief that the DESC proposal on liquidated damages, even as revised, bears no reasonable relationship to actual damages that DESC would suffer in the event that a contracted Facility fails to be placed in service, and, further, would result in extremely high liquidated damages. Company Witness Kassis acknowledges that liquidated damages must bear some relationship to actual damages, stating that "Liquidated damages in this context are generally estimated as a proxy amount to compensate the utility for any costs or losses it incurs in obtaining replacement capacity and energy due to a QF's non-performance." Tr. Vol. 1, p. 66.18. With respect to energy purchases, to the extent that DESC would enter into long-term contracts in the absence of QF supply, it would be easy enough for it to do so upon early termination of a QF contract and recover its actual damages. We agree with SCSBA witness Levitas that any damages are likely to be largely administrative in nature. Tr. Vol. 2, p. 453.6.

It is instructive to compare DESC's proposed liquidated damages with those proposed by Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), as discussed by the surrebuttal testimony of SCSBA Witness Levitas. *Id.* DEC and DEP have recently proposed a methodology under which liquidated damages are based on expected annual capacity payments up to 15 MW and a $10,000 per MW payment over 15 MW. This methodology results in dramatically lower liquidated damages that those proposed by DESC, even with their proposed reduction. We hold that this methodology for determination of liquidated damages bears a closer relationship to actual damages than does the DESC proposal. Accordingly, we approve a determination of liquidated damages based on expected annual capacity payments up to 15 MW and a $10,000 per MW payment over 15 MW, as proposed by SCSBA witness Levitas and as recommended by Power Advisory.

Guaranteed Energy Production

With regard to Guaranteed Energy Production, we explicitly reject DESC's provision for termination if the Facility fails to deliver 85% of the Guaranteed Energy Production in any two consecutive Contract years and hold that this provision shall be eliminated from PPAs. The Independent Consultant's ("Power Advisory's") Report discusses this matter in detail at 60-61. In DESC's Standard Offer and Form PPA, the Seller estimates the expected annual output of Net Energy for each year of the contract term ("Contract Quantity"). The Guaranteed Energy Production is eighty-five percent (85%) of the Contract Quantity. A Shortfall occurs if the Facility fails to deliver the Guaranteed Energy Production in any particular Contract Year. If there is a Shortfall, the Seller is subject to Performance Liquidated Damages which must be paid within 30 days of receipt of an invoice. The Buyer can terminate the PPA if the Facility fails to deliver eighty-five percent (85%) of the Guaranteed Energy Production in any two consecutive Contract Years.

In his direct testimony, Mr. Levitas asserts that DESC's proposal is not commercially reasonable, though SBA acknowledges that this contract provision varies widely in the industry. SBA recommends that DESC should adopt the Duke shortfall amounts (i.e., 70%) and DESC should adopt Duke's approach which is calculated based on a rolling two-year average. Tr. Vol. 2, p. 451.16.

In his rebuttal testimony Mr. Kassis states that the Guaranteed Energy Production provision is "purely a commercial matter to address risk arising from a QF's failure to perform in accordance with the contract." Tr. Vol. 1, p. 66.20. He goes on to state that the Standard Offer and Form PPA stipulates "that the QF will operate at and maintain an expected performance of 95 percent", and thus DESC has provided additional flexibility by defining Shortfalls at or below 85 percent. Further, the Seller is in the best position to address such shortfall. Mr. Kassis further says that the termination provision is reasonable because the "QF can, in large measure, control the variables affecting its ability to meet this requirement." Tr. Vol. 1, p. 66.21. The effect of termination would be that the parties would enter into a new PURPA PPA at new avoided cost rates. Duke's PPAs do not contain this termination provision. SBA suggests that liquidated damages ("LDs") should be the Buyer's sole remedy in the event of a Shortfall. Tr. Vol. 2, p. 453.7. During direct witness examination by Mr. Adams, when discussing termination due to a shortfall, Mr. Levitas stated that "termination would, in fact, serve no purpose because under PURPA, the QF would be entitled to enter into a new PPA." Tr. Vol. 2, p. 447.

Power Advisory states that, on an annual basis, solar output is very predictable. While Power Advisory is concerned about consistency between DESC and Duke terms and conditions given that facilities will be located within the same state, Power Advisory does not recommend a lowest common denominator approach to establishing terms and conditions. Power Advisory states that In the San Diego Gas & Electric Company's Standard Offer PPA in California, the Guaranteed Energy Production (GEP) is equal to 70% of the average Contract Quantity over a 2-year period for wind and 85% for all other technologies. In the case that this GEP is not met, the seller pays liquidated damages, but the contract is not terminated. In the Avista Corporation's Standard Offer PPA contract in Washington State, on a monthly basis, if the monthly production is less than 90% of the month's Net Output Estimate for the corresponding month, then a Shortfall Energy Price applies for the Shortfall Energy which is the lower of the Market Energy Price and the Avoided Cost Rate. The contract is not terminated. In the Puget Sound Energy Standard Offer PPA contract in Washington State, the Seller is responsible for providing at least the Annual REC Quantity specified in the REC Contract, which is executed in conjunction with the PPA. If the facility does not generate enough RECs in a given year then they need to source the shortfall from a third party. The contract is not terminated.

To summarize, Power Advisory has not found precedent in other contracts to include contract termination in the event of a shortfall. While following the termination the QF can enter into another PURPA PPA, this would potentially be at a lower rate. Power Advisory's research indicates that providing a termination right for a PPA where pricing is based on avoided costs and thereby reflects the buyer's cost of generating or purchasing the power is outside the norm. Therefore, Power Advisory states that such a provision disproportionately increases project risks relative to the harm that would be realized by customers and believes that the termination if the Facility fails to deliver 85% of the Guaranteed Energy Production in any two consecutive Contract

Years right should be eliminated. We agree and hold that the provision proposed by DESC shall be eliminated from PPAs.

The Commission finds that DESC's proposed Standard Offer form, with the modifications discussed above, is reasonable and appropriate, satisfy the requirements of Act No. 62, and therefore are hereby approved.

2. Contract Power Purchase Agreements

Act No. 62 also requires the Commission to approve a form contract PPA reflecting "an agreement between an electrical utility and a small power producer for the purchase and sale of energy, capacity, and ancillary services from the small power producer's qualifying small power production facility." S.C. Code Ann. §§ 58-41-10(9), -20(A). In proposing a Form PPA for the Commission's consideration in this proceeding, Company Witness Kassis testified that DESC believes that keeping its Form PPA largely consistent with the existing form makes sense from a business perspective because many in the renewable energy industry have either (i) executed a contract very similar to the Form PPA or (ii) become familiar with at least some iteration of this general form of PPA over the last several years. Tr. Vol. 1, p. 59.11. He also testified this concept makes sense from a regulatory perspective because these executed PPAs have all been filed with and accepted by the Commission. *Id.*

However, Witness Kassis did testify that the Company had made several modifications to tailor the Form PPA to the requirements of Act No. 62. For example, he stated that the Form PPA is no longer specific to any one type of renewable fuel source, but it is designed to accommodate any eligible renewable source, subject to some additional project-specific details. Tr. Vol. 1, p. 59.12. He also testified that DESC added a section regarding Development Period Credit Support, which is a form of security posted by the QF to secure its obligations prior to commercial operation, is common in commercial agreements, and provides security to utility customers. *Id.* The Form PPA also includes a provision regarding Excusable Delays, which generally represent delays in the ability of a QF to begin delivery of power to DESC due to (i) Force Majeure, (ii) a delay caused by DESC, or (ii) delays in the completion of the Interconnection Facilities unless such delay was directly or indirectly caused by the QF. *Id.* He testified that, if these limits are exceeded, the QF would have to pay to extend the deadline in order to maintain a viable PPA, and that these limits properly reflect the risk assumed by the QF and are appropriate with a longer 24-month development period. *Id.* Witness Kassis also testified that the Form PPA limits curtailments to Emergency Conditions and events of Force Majeure. Tr. Vol. 1, p. 59.13.

Regarding Renewable Energy Certificates ("RECs"), Witness Kassis testified that the existing PPA typically provided for a right of first offer, but that the negotiation of RECs is outside the scope of PURPA. *Id.* Witness Kassis therefore testified that RECs are not addressed in the Form PPA but will be handled on a case-by-case basis. *Id.* As stated previously, Witness Kassis stated that the Form PPA also does not include a VIC clause because variable integration costs will be addressed in the proposed avoided cost methodology for future PPAs. Tr. Vol. 1, p. 59.14. Witness Kassis further testified that future Form PPAs will be filed in redacted form to protect certain market sensitive information including, but not limited to, avoided cost rates specific to the PPA. *Id.* Accordingly, the Form PPA was revised to reflect the protection of confidential or market sensitive information. *Id.* Finally, Witness Kassis testified that S.C. Code Ann. § 58-41-20(A) requires PPAs to address choice of venue and, therefore, the Form PPA specifies that venue shall be Columbia, South Carolina for any state or federal disputes that may arise. Tr. Vol. 1, p. 59.15.

As for criticisms of the Form PPA raised by other parties, the Commission first recognizes that certain of these challenges also pertain to provisions of the Form PPA that are similar or identical to provisions in DESC's proposed Standard Offer. In this regard, the Commission incorporates herein by reference those same findings as they may apply to the Form PPA.[16]

With respect to the terms and conditions of the proposed Form PPA, ORS Witness Horii testified that the Form PPA contains terms and conditions consistent with PURPA and FERC implementation guidelines and satisfies the requirement of Act No. 62 that the Form PPA have a 10-year term option. Tr. Vol. 2, p. 695.45.

The General Assembly has mandated that electric utilities must initially offer to purchase power from QFs pursuant to fixed price PURPA PPAs with commercially reasonable terms and a duration of ten years. Act 62 also provides that the Commission "may . . . approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." S.C. Code. Ann. § 58-41-20(F)(1). In her testimony, Johnson Development Witness Chilton agreed that a decrement to the 10-year avoided cost rate is required in order for the Commission to adopt a fixed price contract for a term longer than 10 years. In her prefiled surrebuttal testimony, she left open the possibility to later offer testimony regarding various methods of complying with the Act 62 requirements for longer term contracts. However, that testimony was never offered. She did not identify any specific proposal that Johnson Development supported to comply with the statutory requirements for the Commission to consider

[16] To the extent that issues pertaining to the Form PPA also relate to similar provisions in the Standard Offer, the Commission makes these same findings with respect to the Standard Offer.

a longer-term fixed price PPA. Therefore, Commission approval of a fixed price power purchase agreement with a duration longer than 10 years is not supported by the evidence in this record; only a 10-year contract term is. Because any determination by the Commission to approve contracts with a duration of longer than ten years must be predicated on specific proposals from intervenors that comply with S.C. Code Ann. § 58-41-20(F)(1) and are entered into the evidentiary record during the course of this proceeding, we decline to approve the post-hearing proposals from Johnson Development and SCSBA at this time. Such proposals, and others, may appropriately be addressed in the record of the next avoided cost proceeding such that all parties may have their due process rights protected.

Energy Storage

Regarding Energy Storage, Mr. Levitas' direct testimony pointed out that the DESC PPA is silent on Energy Storage, despite requirements from Act 62. He noted that Energy Storage would typically only be considered for facilities greater than 2 MW, therefore absence of language leaves it up to PPA negotiation without Commission oversight. Tr. Vol. 2, p. 451.17 – 451.18.

Mr. Kassis states in rebuttal testimony that per the Settlement Agreement filed in Docket No. 2017-370-E on November 30, 2018, DESC agreed to file with the Commission for its approval either "proposed avoided cost rates for energy and capacity that provide accurate pricing for storage as a separate resource; or proposed technology-neutral avoided cost rates for energy and capacity that provide accurate pricing for dispatchable renewable generating facilities such as solar + storage (e.g., hourly pricing)." Tr. Vol. 1, p. 66.23. Mr. Kassis goes on to quote Section 14 of Act 62 which states, "[t]he provisions of Section 58-41-20 shall not be interpreted to supersede the conditions of any settlement entered into by an electrical utility and filed with the commission prior to the adoption of this act." *Id.* Therefore, as explained by Mr. Kassis, DESC plans to meet its obligation under the Settlement by making a filing with the Commission on or before December 31, 2019, and that Act 62 requires that each utility's avoided cost methodology account for Energy Storage, but it does not expressly address, much less mandate, terms and conditions. *Id.*

During direct witness examination by Mr. Adams, when discussing termination due to a Shortfall, Mr. Levitas stated:

> Dominion has not proposed contractual terms for the inclusion of Energy Storage devices. As you know, they're required to propose a solar-plus storage rate, but as things stand, developers will have no idea how to qualify for that rate. And, again in contrast, Duke has proposed an Energy Storage protocol in its Large QF PPA and has now agreed to incorporate the same protocol in its Standard Offer PPA.

Tr. Vol. 2, p. 447.

Power Advisory believes that it would have been desirable for DESC to outline the provisions for Energy Storage as part of this proceeding. However, given that Act 62 is not intended to "supersede the conditions of any settlement entered into by an electrical utility and filed with the commission", Power Advisory does not find a reason for DESC to be required to provide terms and conditions related to Energy Storage at this time. More importantly, according to Power Advisory, imposing associated terms and conditions would deprive the parties from the opportunity to negotiate provisions of these terms and conditions. This Commission agrees with and adopts the reasoning of Power Advisory. Under Act 62, the parties have an opportunity to negotiate these important terms and conditions, and we believe, and so hold, that the parties shall have this opportunity. Under the prior settlement agreement, DESC is required to make a filing by December 31, 2019 regarding Energy Storage contract terms.

As discussed above, Witness Levitas also suggested a number of changes to the Form PPA for the purported purpose of reflecting "commercial reasonableness." For example, he suggested that the environmental risks for certain hazardous projects found near the QF projects should be shifted to DESC and its customers. Tr. Vol. 2, p. 451.22. The Commission finds this suggestion unreasonable, however. In these situations, the QF controls site selection, not DESC, and it would be inappropriate to shift these risks onto DESC and its customers when QFs are in the best position to mitigate or evaluate such risks. Tr. Vol. 1, p. 66.27. Witness Levitas also suggested that DESC should approve a surety bond form as an exhibit to the Form PPA and Standard Offer. Tr. Vol. 2, p. 451.22. DESC agreed to this recommendation and the Commission finds that this recommendation of SCSBA, as agreed to by the Company, should be approved. Witness Levitas further criticized the language in Section 5.1(e) of the Form PPA alleging that this provision, which allows DESC to curtail energy under Emergency Conditions, was too vague. Tr. Vol. 2, p. 451.22, l. 21 – p. 451.23, l. 3. However, the Commission finds that Witness Levitas' suggestion relates only to directives of DESC Transmission pursuant to applicable agreements for generator and interconnection and transmission service. Tr. Vol. 1, p. 66.28. Accordingly, the Commission finds that this section focuses on directives pursuant to applicable terms within an executed interconnection agreement rather than curtailment pursuant to the provisions of the Standard Offer or the Form PPA. The Commission therefore declines to adopt SCSBA's proposed language in this regard.

Witness Levitas also suggested edits to Section 5.2(e) and (f) regarding the Seller's indemnification of the Buyer for Environmental Liability and personal energy and property damage. Tr. Vol. pp. 451.22 – 451.23. Again, the Commission finds that these suggestions improperly attempt to allocate risk between the QF and DESC and that the QF is best suited to recognize and mitigate these types of risk. However, DESC agreed to add language that would provide that the Buyer shall indemnify the Seller against losses resulting from gross negligence or intentional misconduct of its officers. Tr. Vol. 1, pp. 66.28 – 66.29. The Commission finds that this language is reasonable and should be included in the Form PPA and Standard Offer as suggested by SCSBA and agreed to by DESC Witness Levitas further stated that language regarding termination of the Form PPA if a milestone is not achieved should not be permitted if the failure to meet a milestone does not affect the Seller's ability to achieve the Completion Date. Tr. Vol., p. 451.23. Witness Kassis stated, however that this language aligns with FERC precedent on similar issues. Tr. Vol. 1, p. 66.29. The Commission finds that Witness Levitas' suggestion should not be adopted. The Form PPA provides QFs with the possibility to extend the 30-day cure period if it gives advance notice to DESC and fulfills certain other conditions. *Id.* The Commission therefore finds that giving QFs an additional extension option with no advance notice is unreasonable.

Regarding Force Majeure, Witness Levitas states that there is no extension of force majeure relief where the problem cannot be corrected in the defined time period but could be remedied with an extension. Tr. Vol. 2, p. 451.23. The Commission finds, however, that an amendment to the Form PPA to address this concern is not necessary because termination under this provision does not arise until the Force Majeure has existed for at least 8 months, which is a sufficient period of time. Even so, DESC revised this provision to include a 6-month period of Force Majeure that may be extended to 9 months under certain conditions. *Id.* The Commission finds that the language proposed by DESC addresses Witness Levitas' concerns and strikes an appropriate balance on this issue and, therefore, approves the revision. Witness Levitas also recommended the deletion of Section 11.6 which acknowledges that damages provided for in the event of a default are reasonable damages. Tr. Vol. 2, p. 451.23. After considering this issue, the Commission finds that the identified language would ensure the enforceability of the agreement and does not find it necessary to delete the section as suggested.

Regarding Section 12.2 of the PPA, Witness Levitas states that the language should be revised to require the Indemnified Party to pay for its own counsel if it chooses to be separately represented. Tr. Vol. 1, p. 451.23. Witness Kassis testified, however, that this would result in an unbalanced risk allocation. Tr. Vol. 1, p. 66.31. The Commission agrees with Witness Levitas and finds that it would be appropriate to sever the obligation to pay for expenses related to the claims because the Indemnified Party may seek to use separate counsel. Witness Levitas also questioned Section 15.1 and its requirement that the Buyer must give prior written consent for the Seller to pledge the agreement or associated revenues to a Financing Party. Tr. Vol. 2, p. 451.24. Witness Kassis testified, however, that this suggestion would eliminate DESC's ability to mitigate potential risk exposure related to pledges, encumbrances, and collateral assignments. Tr. Vol. 1, p. 66.32. The Commission finds that DESC's concerns are reasonable and finds that this provision is appropriately modified to provide transparency regarding direct and upstream owners of QFs, particularly in the instance of a foreclosure. In resolution, the Seller must provide written notification to the Buyer prior to pledging, encumbering, or assigning revenues to a Financing Party.

Witness Levitas further asserts that Section 15.13 and its requirement that the Seller must repair the Facility within 8 months if damaged by weather or other unusual events is unreasonable. Tr. Vol. 2, p. 451.24. However, the Commission finds that this section is appropriate because it mitigates DESC's risk exposure inherent in its resource planning. Tr. Vol. 1, pp. 66.32 – 66.33. Regarding Section 15.14 of the Form PPA, Witness Levitas suggests that current and prospective investors and prospective purchasers should be added to the list of parties with whom confidential information can be shared and that the Agreement should not be confidential. Tr. Vol. 2, p. 451.24. Witness Kassis stated that DESC was willing to add prospective investors and purchasers of the facility provided that the QF provides the names of these parties prior to sharing the information. Tr. Vol. 1, p. 66.33. The Commission finds that this revision, as agreed to by DESC, is reasonable and allows the Company to be aware of the potential for abuse.

Regarding Section 15.16, Witness Levitas states that it is unreasonable to require a Seller to coordinate with the Buyer when making public announcements about the construction of the facility and to obtain the Buyer's approval of any publicity materials. Tr. Vol. 2, p. 451.24. The Commission disagrees and finds that it is reasonable for QFs to coordinate with DESC on public announcements Tr. Vol. 1, pp. 66.33 – 66.34. Finally, Witness Levitas suggests the inclusion of a termination right by the QF in the event "interconnection facilities and network upgrades required for the facility to be interconnected . . . exceeds $75,000 per MW or project nameplate capacity." Tr. Vol., p. 451.25. Witness Kassis stated that DESC's current business practice is to work with QFs individually to develop a similar arrangement apart from these agreements on a case-by-case basis. Tr. Vol. 1, p. 66.34. Even so, Witness Kassis stated that the recommended amount was in the range DESC has used previously and therefore agreed to this recommendation in the Form PPA and Standard Offer. *Id.* The Commission finds that this provision, as suggested by SCSBA and agreed to by DESC is reasonable.

The Commission finds that DESC's proposed Form PPA, with the modifications discussed above, are reasonable and appropriate, satisfy the requirements of Act No. 62, and therefore are hereby approved.

3. Commitment to Sell Forms

Act No. 62 also requires DESC to propose a commitment to sell form. Specifically, S.C. Code Ann. § 58-41-20(D) provides that "[a] small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility." In this regard, Company Witness Kassis stated that this provision is comparable to PURPA's legally enforceable obligation ("LEO") requirement that guards against the possibility of utilities refusing to enter into PPAs with QFs, thereby not providing them with access to the marketplace. Tr. Vol., pp. 59.21 – 59.22. He stated that, in contrast, a QF can submit the NOC Form without ever attempting to negotiate any PPA with DESC. *Id.* However, he stated that, common to both the LEO concept and the NOC Form is that the QF must make a substantial commitment to sell the electrical output of its facility to the utility in order to establish this non-contractual, yet binding, commitment. Tr. Vol. 1, p. 59.22.

In satisfaction of this requirement, DESC proposed a NOC Form, which Witness Kassis stated draws largely upon LEO concepts in place in other states, as well as DESC's institutional knowledge accumulated from experience in this arena. *Id.* He testified that the NOC Form is built around the foundational principle that the QF must make a substantial commitment to delivering the electrical output of its facility before it can establish the type of non-contractual, yet binding, relationship contemplated by the NOC Form. Tr. Vol 1, p. 59.23. He also stated that the NOC Form touches upon issues such as site control, delivery periods, and delivery deadlines as these provisions evidence substantial commitment and are important to prevent a developer from gaming the system by locking-in rates for a speculative project, which would be detrimental to ratepayers and the solar industry as a whole. *Id.*

On behalf of ORS, Witness Horii stated that the Company's proposed NOC form generally complied with PURPA and FERC implementation guidelines. Tr. Vol. 2, p. 695.45. However, he stated that there is a lack of clarity in clause 8(iii) governing automatic terminations of the NOC Form. Tr. Vol. 2, p. 695.46. Specifically, he stated that it is unclear which entity (the QF or

DESC) is responsible for installing additional facilities to establish adequate interconnection facilities, and whether the QF is eligible for any payments or damages due to delays. *Id.* In response, Witness Kassis testified that DESC revised the NOC Form to expressly state that no damages will be imposed on either party as a result of DESC having insufficient interconnection facilities. Tr. Vol. 1, p. 66.5. The Commission finds that these changes are reasonable and should be incorporated into the NOC Form as proposed by ORS and agreed to by DESC.

Seller Termination Payment

Regarding the proposal for a Seller Termination Payment under certain circumstances, we would note that Power Advisory's Report contains an extensive discussion on the subject on pages 63-67. Per DESC's proposed Standard Offer and Form PPA, if Buyer terminates the agreement due to an event of default on or after the Commercial Operation (with some prescribed exceptions), the Seller will be required to pay a Termination Payment according to a formula which results in a price floor on damages. *See* Power Advisory Report at 64. According to Power Advisory, the floor increases the Termination Payment to a level that is likely to be greater than cost of the replacement energy, (DESC Folsom Amended Exhibit JEF-1 to Direct Testimony, Section 11.4.)

In his direct testimony, Mr. Levitas argues that this provision is not commercially reasonable and should be deleted. He states that since payments under the contract are based on avoided costs and DESC is not assigning a capacity value, there should be little harm to the Buyer for termination. Mr. Levitas goes on to point out that "Witness Folsom emphasizes how bad PURPA PPAs are for ratepayers in which case they should welcome any that go away." Tr. Vol. 2, p. 451.20. Further, Mr. Levitas asserts that the floor on damages established is completely unreasonable. If Net Energy Rate is $32/MWh and market price for renewable energy is $34/MWh, damages would be set to $16/MWh, even though the actual incremental cost of procuring replacement renewable energy would $2/MWh. Further, Levitas testifies that there is no reason to base the cost of procuring replacement energy on renewable energy, as DESC is not buying RECs and contract price is based on avoided energy. *Id.* Overall, Mr. Levitas states opposition to post-COD damages, but if they are included, Shortfall LDs payable should be clearly waived. SBA recommends that the Termination Payment reflect the Duke approach such that DESC is made whole for any overpayment to the Seller relative to applicable avoided cost rates. Tr. Vol. 2, p. 451.21.

In his rebuttal testimony, Mr. Kassis emphasized that the approach to the measurement of damage was reasonable, stating:

"DESC accounts for these generating assets in its resource plan and relies on these plants performing pursuant to the contract. Moreover, Mr. Levitas fails to take into account that when a QF terminates after COD, DESC incurs damages in the form of lost opportunities, e.g., self-build, RFP, or other competitive solicitation or procurement options." Tr. Vol. 1, p. 66.25.

During direct witness examination by Mr. Adams, when discussing the termination payment, Mr. Levitas stated that:

> Dominion proposes a totally unreasonable 50 percent floor on such damages that could potentially result in a massive and unjustified windfall to the Company. I explain this in detail in both my direct and surrebuttal testimony. And I would also note that there is no comparable floor on Dominion's damages to the QF should they be in breach of the agreement resulting in termination.

Tr. Vol. 2, p. 448.

During examination by Vice Chairman Williams, when asked about DESC's termination payment, Mr. Levitas stated that DESC's proposal is "unprecedented in my experience and, I mean, if I had to say, maybe the single most unreasonable thing in the whole document." Tr. Vol. 2, p. 495.

Power Advisory states that the proposed Termination Payment does not appear to be consistent with any actual damages or consequences experienced by DESC as a result of contract termination. As discussed below, it is common that the termination fee may include compensation to the buyer for any over payment, lost value (i.e., difference between the contract and market price) or legal fees associated with termination. Some jurisdictions may include cost of replacement energy over a period of time (i.e., 24 months), while others leave the determination of termination payments up to commercially reasonable negotiations. Power Advisory Report at 65.

Power Advisory presents some examples of how other jurisdictions treat termination payments resulting from Seller default as follows:

• Duke Energy Carolinas, LLC (North Carolina) - The termination fee equals the amount of (a) the minimum monthly charges which would have been payable during the unexpired term of the Agreement plus (b) the Early Termination Charge. The Early Termination Fee is the total Energy and/or Capacity credits received in excess of the sum of what would have been received under the Variable Rate for Energy and/or Capacity Credits applicable at the initial term of the contract period and as updated every two years, plus interest. *Duke Energy Carolinas, LLC. Terms and Conditions for the Purchase of Electric Power. Effective March 1, 2016. NCUC Docket No. E-100 Sub 140.*

• Pacific Power & Light Company (Oregon) - The termination fee is the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for the Average Annual Generation that Seller was otherwise obligated to provide at the Mechanical Availability Guarantee for a period of twenty-four (24) months from the date of termination, plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, plus the estimated administrative cost to the utility to acquire replacement power. *Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016.*

• San Diego Gas & Electric Company (California)- If either Party exercises a termination right after the Commercial Operation Date, the non-defaulting Party shall calculate a settlement amount ("Settlement Amount") equal to the amount of the non-defaulting Party's aggregate Losses and Costs less any Gains, determined as of the Early Termination Date. (Note, the terms Gains, Losses and Costs, are defined terms, however open to commercially reasonable interpretation.) *Renewable Market Adjusting Tariff Power Purchase Agreement, approved by California Public Utilities Commission in Decision 13-05-034 effective May 23, 2013.*

• Avista Corporation (Washington) - In the event of default or early termination due to failure to perform, Avista can retain the contract security. *Avista Corporation, Washington, Standard form of Power Purchase Agreement for Qualifying Facilities with Capacity of 5 MW or less, Rev 08/2019.*

Accordingly, Power Advisory recommends that DESC remove the floor on damages and amend the formula to reflect the cost of replacement energy at the then-current costs of replacement energy, as shown in the Power Advisory Report at 67.

We agree with witness Levitas that the floor on damages should be removed, in that there is no comparable floor proposed should DESC be in a breach of the agreement, resulting in termination. Further, the formula as proposed by Power Advisory and as stated above should be adopted to reflect the cost of replacement energy at the then-current costs of replacement energy, which is consistent with procedures cited by Power Energy in other jurisdictions. Collection of replacement energy costs at then-current costs is a fair contract provision, should a QF terminate its contract. The formula appears to include all appropriate factors for calculation of these costs.

Proposed Limitation of PPA Eligibility Following Termination

With regard to the proposal to limit eligibility for fixed pricing under certain circumstances, Witness Levitas testified that it is not commercially reasonable for a QF who submits an executed NOC Form but fails to execute a PPA in a timely fashion to not be eligible for fixed pricing for a period of two years. Tr. Vol. 2, p. 451.27. However, Company Witness Kassis stated that the purpose of this provision was to reduce the potential for gaming the system by QFs. Tr. Vol. 1, p. 66.36. Specifically, he stated that a QF must make a binding commitment to sell its output to the utility at a defined price to establish a LEO and that the NOC Form provision is intended to deter QFs from establishing a LEO and then refusing to perform if they can lock in a LEO at a later date at higher avoided cost rates. *Id.*

Even so, DESC's proposal in its Notice of Commitment Form to limit the QF's ability to pursue fixed pricing for two years appears to this Commission to be inconsistent with PURPA and is not commercially reasonable. It also does not compensate the utility for the QF's failure to perform. *See* Tr. Vol. 2, p. 451.27. Witness Levitas testified that a QF who fails to perform under a LEO should be liable for the same damages it would face for failing to perform under a PPA (i.e. those contained in the Standard Offer). The liquidated damages for a QF's failure to achieve timely COD should be set at $5,000 per MW AC nameplate capacity up to 20 MW, and at $2,000 per MW above 20 MW. So, a Standard Offer QF (with a maximum capacity of 2 MW) would be subject to maximum damages of $10,000. Tr. Vol. 2, p. 451.28. We hold that this formula fairly compensates the utility for the QF's failure to perform.

Day In-Service Deadline

DESC's proposed NOC form states that the seller must deliver power within 365 days of submitting the NOC form. In Mr. Levitas' direct testimony, he states that the NOC form establishes a commitment to enter into a PPA within 30 days, which would have sufficient requirements with respect to in-service deadlines. If the in-service deadline is to remain, it should only be applicable when there are sufficient network resources for interconnection at the time of the deadline. Tr. Vol. 2, p. 451.30.

In his direct testimony, Mr. Folsom asserts that QF's cannot be viewed as having to make a substantial commitment if the project is more than a year from actual power delivery. He also references similar precedents established in other jurisdictions; for example, Idaho has a requirement to deliver power within 365 of establishing a LEO. More stringent requirements in other jurisdictions have also been upheld, for example, Texas has a 90-day delivery window. Tr. Vol. 1, p. 59.24.

In his surrebuttal testimony, Mr. Levitas stated that SBA is "prepared to accept DESC's proposed requirement that Seller commence delivery within 365 days of its Notice of Commitment to Sell, provided that such obligation is subject to the same Excusable Delays as the in-service deadline under DESC's proposed PPAs." Tr. Vol. 2, p. 453.13.

Power Advisory believes that Mr. Levitas' proposal has merit and is reasonable. It is logical to align PPA terms with LEO requirements, and that the NOC form acknowledges Excusable Delays that would impact the in-service deadline, according to Power Advisory. This Commission agrees with the reasoning of Power Advisory. It is clearly logical to align PPA terms with LEO requirements. It is also clearly logical that the NOC form acknowledges Excusable

Delays that would impact the in-service deadline. This is a reasonable proposal and is hereby adopted.

Eligibility Pre-Conditions

In addition to other pre-conditions (i.e., commitment, site control, fee), DESC's proposed NOC form states the QF is required to have secured all land-use approvals and environmental permits that would be required to have the facility in service within 365 days. Further, the Seller is required to have an executed System Impact Study Agreement. In his direct testimony, Mr. Levitas states that environmental permits and land use approvals are expensive and time consuming and that it is unreasonable to incur such expenses without securing a price for the project. Tr. Vol. 2, p. 451.29. Levitas further states that this is not a requirement of the PPA, and there is no logic for having more onerous requirements in LEO. Tr. Vol. 2, p. 451.29, l. 22 – p. 451.30, l. 1. Further, Levitas asserts that the Seller should only be required to execute a System Impact Study Agreement if one has been tendered to it by the DESC. Tr. Vol. 2, p. 451.29.

Mr. Folsom, in his direct testimony, emphasized that the "NOC Form is purely a creature of the Act". Tr. Vol. 1, p. 59.21. QFs can submit a NOC without attempting to negotiate with DESC. Tr. Vol. 1, p. 59.21, l. 20 – 59.22, l. 1. In DESC's view, QFs must make substantial commitments to sell output in order to establish a LEO. Tr. Vol. 1, p. 59.22. States have discretion with respect to LEOs and the proposal reflects DESC institutional knowledge and experience (e.g., need to reduce speculative projects). *Id.* Mr. Folsom also cites precedent from other jurisdictions implementing "control-and-approval" concepts in the LEO framework. Tr. Vol. 1, p. 59.25.

In his rebuttal testimony, Mr. Kassis states:

> Reform NOPR, the FERC specifically permits states to require a QF to make a showing that it has "satisfied or, is in the process of undertaking, at least some" enumerated items in the Reform NOPR, such as obtaining site control, filing an

> interconnection application, securing permitting, and certain other "reasonable criteria to allow the QF to demonstrate its commercial viability and financial commitment."

Tr. Vol. 1, p. 66.37. Mr. Kassis also notes that Mr. Horii finds these provisions reasonable. *Id.*

During direct witness examination by Mr. Adams, Mr. Levitas emphasized that requiring permits prior to securing pricing certainty would be unreasonable and stated that it is "not a reasonable requirement without the QF knowing what its project economics are." Tr. Vol. 2, p. 449. Mr. Levitas goes on to state:

"I also don't believe it's consistent with PURPA to require that a seller at either established interconnection service or signed a system impact study agreement as a condition of LEO formation because this improperly places control over LEO formation in the hands of the utility." Tr. Vol. 2, pp. 449-450.

Power Advisory recommends that since SBA has agreed to the 365-day in-service date requirement, QFs be allowed to secure permits after formation of a LEO. This makes it consistent with the PPAs which do not require permits be obtained before execution. Power Advisory also asserts that the requirement is unnecessarily onerous on the QF. In fact, Power Advisory states that DESC is making it more onerous to form a LEO than to enter into a PPA. The QF already has to meet the requirement of being in-service within 365 days or risk termination and liquidated damages. Power Advisory further asserts that this requirement alone will result in QFs with viable projects moving forward with LEO formation. Power Advisory Report at 70.

We agree with Power Advisory that it is indeed unnecessarily onerous on the QF to require that permits be secured prior to formation of a LEO. PPAs clearly do not contain this requirement, which supports the argument that DESC would make it more onerous to form a LEO than to enter into a PPA if permits had to be obtained prior to LEO formation. We also agree that viable projects with LEO formation will already move forward with the existence of the requirement of being in service within 365 days or risking termination and liquidated damages. Therefore, we reject DESC's proposed eligibility preconditions as described above during the permitting process.

Based upon the application of these findings and the agreed upon revisions to the NOC Form, the Commission therefore finds that the NOC Form is reasonable and satisfies the requirements of Act No. 62. Specifically, the NOC Form appropriately provides small power producers a reasonable period of time from its submittal of the NOC Form to execute a PPA. Further, the NOC Form does not require, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, that a small power producer execute a PPA prior to receipt of a final interconnection agreement from the electrical utility. Accordingly, the Commission finds that the NOC Form, as modified in accordance with the discussions herein above, should be approved.

D. Other Terms and Conditions

Pursuant to Act No. 62, the Commission is authorized to approve other terms and conditions as may be required to implement the requirements of S.C. Code Ann. § 58-41-20. No party identified or proposed any other term or condition related to this matter, other than those previously discussed herein. The Commission therefore finds that no other terms and conditions currently are required with respect to the implementation of S.C. Code Ann. § 58-41-20. In making this finding, however, the Commission does not intend to preclude or prevent the parties of record or other interested persons from requesting in future proceedings under S.C. Code Ann. § 58-41-20 the approval of other terms and conditions as may be necessary.

E. Updates to NEM Methodology

In brief: the Commission considers what the appropriate valuation is for net energy metering customer-generators. Such consideration includes both the characteristics to be valued and the calculation of those values.

As discussed previously, the Commission determined in Docket No. 2019-2-E that issues related to avoided costs, variable integration costs, and the NEM methodology should be bifurcated from consideration in Docket No. 2019-2-E and would be addressed in a later, appropriate hearing. Order No. 2019-229 at 1; Order No. 2019-43-H at 1. The Commission also determined that DESC's then-current avoided cost rates and NEM values were to remain the same as those in effect at the time the issues were bifurcated and that, after the Commission held a hearing to consider updates to these rates, these rates and values would be subject to a "true up." Order No. 2019-43-H at 1. DESC therefore asserts that it is appropriate to consider these issues in the current proceeding and proposes to update the NEM values in connection with this docket.

Company Witness Neely testified that, in Order No. 2015-194, issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

Net Energy Metering Methodology
1. +/- Avoided Energy
2. +/-Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided CO_2 Emission Cost
8. +/- Fuel Hedge
9. +/-Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

= Total Value of NEM Distributed Energy Resources

Tr. at 308.21.

Company Witness Neely also testified that the Company updated these components of value by calculating both the current value and the value over the IRP planning horizon. Witness Neely further provided information on DESC's evaluation of these components and its estimate of the associated values.

ORS Witness Horii was the only other witness to address the NEM Distributed Energy Resources values. Specifically, Witness Horii recommended that the Commission approve alternative NEM values based upon his analyses of and recommendations regarding avoided energy and capacity costs and utility integration and interconnection costs, which have been addressed and discussed by the Commission above. Tr. at 695.43. For the same reasons discussed previously, the Commission finds that Witness Horii's recommendations are appropriate for use in calculating the NEM Distributed Energy Resources values as follows:

Total Value of NEM Distributed Energy Resources[17]

Current Period ($/kWh)	10-Year Levelized ($/kWh)	Components
$0.03022	**$0.02111**	Avoided Energy Costs
TBD	**TBD**	Avoided Capacity Costs
$0.00000	$0.00000	Ancillary Services
$0.00000	$0.00000	T&D Capacity
$0.00003	$0.00003	Avoided Criteria Pollutants
$0.00000	$0.00000	Avoided CO2 Emission Cost
$0.00000	$0.00000	Fuel Hedge
$0.00000	$0.00000	Utility Integration & Interconnection Costs
$0.00000	$0.00000	Utility Administration Costs
$0.00089	$0.00105	Environmental Costs
$0.03114	$0.02598	Subtotal
$0.00235	$0.00189	Line Losses @ 0.9245
TBD	**TBD**	**Total Value of DER**

[17] The Avoided Capacity Costs will be determined after the Company calculates the Avoided Capacity factor as Ordered on page 97.

Based on the evidence of record and the Commission's findings set forth previously herein, the Commission therefore finds that Witness Horii properly evaluated the components of value for NEM Distributed Energy Resource. The Commission therefore finds that ORS's proposed NEM Distributed Energy Resource values are appropriate and reasonable, are in accordance with the NEM methodology approved by the Commission in Order No. 2015-194, and are hereby approved.

These reasonable and accurate rates fully represent the value and costs of their generation to the system. Accuracy in this rate is also important to keep ratepayers that are not participating in rooftop solar from subsidizing those that are. In the current case, the accurate valuation of Net Energy Metered resources – rooftop solar – actually increased by 12%.

F. Bifurcation of Issues from 2019-2-E

Company Witness Rooks testified that, as part of the 2019-2-E fuel cost proceeding, DESC proposed to include the updated avoided costs, variable integration costs, and updates to the NEM values in its fuel costs effective with the first billing cycle of May 2019. Tr. at 432.10. As stated previously, in Order No. 2019-43-H, the Commission determined that these issues should be bifurcated from DESC's fuel cost proceeding held in April 2019. Based upon the Commission's ruling in Order No. 2019-43-H, Witness Rooks testified that DESC proposes to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding, and then separately account for the difference as an incremental cost adjustment. *Id.* Witness Rooks explained that the Company proposes an effective date for the rate changes as of the first billing cycle of May 2019. *Id.* He further testified that the Company also proposes to adjust its fuel costs as part of its 2020-2-E annual fuel cost review proceeding to account for these incremental costs and that the "true up" will be reflected as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020. *Id.*; tr. at 729.6.

As to variable integration costs, Witness Rooks testified that the Company proposes to true up these costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the Commission issues its order in this proceeding. Tr. at 432.10. He further stated that DESC proposes to deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs. *Id.* Witness Rooks testified that the result of this proposal would be to reduce base fuel purchased power expense for DESC electric customers. *Id.*

ORS Witness Lawyer testified that DESC's proposed implementation of the "true-up" was reasonable. Tr. at 729.6. No other party of record opposed the Company's proposal in this regard.

The Commission finds that DESC's proposal to "true up" of the avoided cost and NEM methodology costs is reasonable and appropriate. The Commission finds that, by adjusting the Company's fuel costs in this manner, customers will not experience any immediate rate impact, and these amounts will be appropriately accounted for and "trued up" as contemplated by the Commission in Order No. 2019-43-H. The Commission therefore approves DESC's proposal and authorizes the Company to account for and recover these incremental costs through an adjustment to the fuel rates to be considered in connection with Docket No. 2020-2-E. The Commission further approves DESC's proposal that this adjustment go into effect with the first billing cycle of May 2020. Regarding the "true up" of variable integration costs, the Commission also finds that the Company's proposal is a reasonable method to reimburse DESC for these costs pursuant to the contractual agreements between the Company and QFs.

G. DESC's Proposed Rate Schedules

In brief: the Commission considers approval of the form of rate schedules to reflect the findings in this Order, including PR-1, PR-Standard Offer, discontinuance of PR-2, and other terms.

DESC Witness Rooks sponsored the Company's proposed rate schedules and riders in this proceeding. Witness Rooks first sponsored DESC's proposed updates to Rate PR-1 to reflect the Company's proposed avoided costs for QFs that have power production capacity less than or equal to 100 kW. Tr. at 432.4. The Company's Rate PR-1 sets forth separate avoided energy and capacity costs for both solar and non-solar qualifying small power producers. *Id.* Witness Rooks also sponsored the Company's proposed updates to its NEM Rider to reflect the current components of values for NEM Distributed Energy Resources as discussed by Witness Neely and addressed by the Commission above. Tr. at 432.4 – 432.5. Next, Witness Rooks sponsored a new rate schedule, identified as Rate PR-Avoided Cost Methodology, which sets forth the Company's proposed methodology to be used in computing the avoided energy and capacity costs associated with PPAs as provided under the provisions of S.C. Code Ann. § 58-41-20 and PURPA. Tr. 432.5. Witness Rooks also sponsored the new Rate PR-Standard Offer rate schedule. Tr. at 432.6. This rate schedule incorporates DESC's proposed Standard Offer PPA, which is more fully described by Company Witness Kassis and includes the Standard Offer avoided cost rates described and calculated by Company Witness Neely. *Id.* Witness Rooks further sponsored the Company's Rate PR-Form PPA rate schedule, which includes DESC's proposed Form PPA as more fully discussed by Company Witness Kassis. Tr. at 432.6 – 432.7.

Finally, Witness Rooks testified that, as part of this proceeding, DESC is seeking to withdraw and terminate its Rate PR-2. Tr. at 432.7. Witness Rooks testified that Rate PR-2 was intended to set forth the Company's long-run avoided costs for PPAs with a term greater than one year and was available for QFs greater than 100 kW and up to 80 MW. *Id.* As discussed by Company Witnesses Raftery and Folsom, Act No. 62 now requires DESC to make available a Standard Offer contract for QFs up to 2 MW and for QFs greater than 2 MW, DESC is required to make available the Form PPA. Tr. at 432.8. Because of these new statutory requirements, Witness Rooks stated that there is no longer a need for a standard rate schedule setting forth the avoided costs for QFs greater than 100 kW and up to 80 MW in size. *Id.* He also stated that, because Rate PR-2 has been stayed since the issuance of Order No. 2019-274 in Docket No. 2019-2-E, the date of the withdrawal and termination of Rate PR-2 should be made effective as of the last billing cycle of April 2019. Tr. at 432.9.

As a general matter, several witnesses presented by the other parties of record proposed alternative avoided costs and methodologies through their testimony in this proceeding. These proposals would require changes to the rate schedules sponsored by Company Witness Rooks. Based upon the stated findings of the Commission above, however, the Commission finds that DESC's proposed avoided costs and methodologies are inappropriate and should be modified to be compliant with the adoption of provisions in this order. DESC should make changes to the rate schedules necessary to be compliant with changes, modifications, and provisions of contained throughout this Order.

ORS Witness Lawyer made one recommendation with respect to the "Limiting Provisions" section of the Company's proposed Rate PR-1 rate schedule and suggested that DESC should add language to clarify the effects of an executed legally enforceable obligation in this section. Tr. at 729.7. Company Witness Kassis testified, however, that Witness Lawyer appeared to be referencing the submittal of an executed NOC form to DESC by a QF and, in that case, the QF must execute the Form PPA within a reasonable period of time from such submission. Tr. at 66.7.

Subsequently, the Form PPA would govern the relationship between the QF and DESC and Witness Kassis therefore testified that it is not necessary to replicate the same level of detail in the NOC Form. *Id.* The Commission finds that the change proposed by ORS to Rate PR-1 is reasonable and should be adopted.

Witness Lawyer also recommended a change to DESC's proposed Rate PR-Avoided Cost Methodology. Specifically, he suggested that the Commission should require the language in Section C to include the following provision: "Any updates to the factors or analysis must be approved by the Public Service Commission of South Carolina." Tr. at 729.7 – 729.8. In this regard, Witness Lawyer stated the intention was to make clear that DESC's avoided cost methodology may not be updated without prior Commission approval pursuant to S.C. Code Ann. § 58-41-20(A) of Act 62. Tr. at 729.8. In response, Witness Rooks testified that DESC did not oppose the addition of this language to the extent that the language is intended to clarify that any changes to the methodology itself would require Commission approval. However, he testified the Company would oppose this language if the intention of the language was to require DESC to come before the Commission each and every time it negotiates a PPA with a QF in order to receive approval for the underlying data used in the methodology to calculate avoided costs for each specific project. Tr. at 437.2 – 437.3. At the hearing in this matter, ORS Witness Lawyer agreed ORS's recommendation only pertained to changes to the methodology itself and not to the underlying data used in the methodology. Tr. at 733.

After reviewing the evidence of record and based upon the findings previously addressed herein, the Commission finds that Section C of Rate PR-Avoided Cost Methodology should be modified as proposed by ORS. The Commission further finds that this language shall not be interpreted to require DESC to come before the Commission each and every time it negotiates a

PPA with a QF in order to receive approval for the underlying data used in the methodology to calculate avoided costs for each specific project. Rather, this language shall be interpreted to mean that DESC must receive Commission approval before making any changes to the underlying methodology itself. The Commission has made extensive modifications to the rate schedules proposed by the Company. The rates resulting from Commission modification as reflected in this Order are reasonable and appropriate, satisfy the requirements of S.C. Code Ann. § 58-41-20, are hereby approved, and shall be made effective with the first billing cycle of the month following the date of this Order. The Commission also finds that, in light of the requirements of Act No. 62, the Company's Rate PR-2 is no longer necessary or required. The Commission therefore approves the withdrawal and termination of Rate PR-2 effective as of the last billing cycle of April 2019.

H. Transparency of DESC's Proposals

In brief: the Commission considers the positions of other parties on the transparency of DESC's filings in this case.

Act No. 62 also provides that "[e]ach electric utility's avoided cost filing must be reasonably transparent [so that the utility's] underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." S.C. Code Ann. § 58-41-20(J). On behalf of ORS, Witness Horii testified that the Company's filings in this matter were reasonably transparent for his independent review and analysis. Tr. at 695.6. He also testified that DESC provided data responses and supporting information to its filings that allowed ORS to conduct its analysis, assess the reasonableness of the Company's proposals, and develop recommendations regarding the implementation of Act 62. *Id.* In addition, Witness Horii stated that he was able to recommend changes to the Company's assumptions and flow his changes through the Company's models to update the avoided energy and capacity rates for all QFs and the VIC for solar QFs. *Id.*

SCSBA Witness Burgess testified, however, that he did not believe the filings had been reasonably transparent and that he could not independently verify the reasonableness of DESC's proposed rates based on the information provided. Tr. at 523.22. Specifically, he referenced a meaningful lack of transparency regarding DESC's rationale for selection of peak hours and peak seasons, as well as hourly avoided cost data and marginal cost data for the base and change case in the DRR analysis. *Id.* In response, DESC Witness Neely stated that, through his direct testimony, Witness Burgess was able to accurately describe the methodology used by the Company and, therefore, appeared to understand and be aware of the methodology employed as well as its individual components and the underlying data. Tr. at 319.21.

Similarly, Power Advisory reported that, while DESC did produce discovery documents in a timely fashion, it felt that DESC's proposal was not as transparent as would have been appropriate to facilitate third-party analysis of underlying assumptions and inputs into the DESC models and methodologies.

Even though Witness Burgess and Power Advisory stated that DESC only provided an insufficiently high-level explanation of its methodologies in its direct testimony, the Commission finds that the record does reflect that DESC complied with discovery requests. Through his direct testimony, Witness Burgess, as well as the other parties, were able to present alternative avoided cost values and methodologies using the information provided by DESC. In addition, the Commission notes that there were no outstanding motions to compel as of the date of the hearing. Although SCSBA did file a motion to compel, it ultimately elected to withdraw the motion and did not seek to have the Commission intervene into the discovery process. The record therefore reflects that parties determined that responses to their discovery demands were sufficient to further inform them about DESC's filing and to allow them to conduct their analyses. Accordingly, the Commission finds that the Company has satisfied the requirements of S.C. Code Ann. § 58-41-20(J) and that its avoided cost filing has been reasonably transparent.

However, DESC is instructed to file substantially more information about the underlying assumptions and data, such that the parties to such future proceedings – those involving avoided cost calculations or methodologies - may more meaningfully evaluate and analyze the methodologies and models employed by the utility.

VI. CONCLUSIONS OF LAW[18]

In entering its order in this proceeding, the Commission makes the following conclusions of law based upon the filings, testimony, and exhibits that were received into evidence at the hearing in this proceeding and based on the entire record of these proceedings:

1. The Commission has jurisdiction over this matter pursuant to Act No. 62 and S.C. Code Ann. § 58-41-20.

2. DESC is lawfully before the Commission pursuant to S.C. Code Ann. § 58-41-20 seeking approval of its calculations of avoided costs, its proposed avoided cost methodology, and its proposed Standard Offer, Form PPA, and NOC Form.

3. Act No. 62 requires the Commission to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The

[18] To the extent the following conclusions of law are findings of fact, they are so adopted.

Commission also is required to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of Act No. 62.

4. The DRR methodology used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer as described in the testimonies of Company Witnesses Lynch, Neely, and Bell are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and have the ability to reduce the risk placed on the using and consuming public.

5. The avoided energy and capacity costs for DESC's Rate PR-1 and Rate PR-Standard Offer established by the terms of this Order are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

6. With the modifications approved by the Commission herein, DESC's proposed Rate PR-1 and Rate PR-Standard Offer, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are lawful, just and reasonable.

7. With the modifications approved by the Commission herein, DESC's Rate PR-Avoided Cost Methodology, is reasonable and prudent; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is just and reasonable; is

nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

8. With the modifications approved by the Commission herein, DESC's proposed Form PPA, as reflected in Rate PR-Form PPA, is just and reasonable; is commercially reasonable; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

9. With the modifications approved by the Commission herein, DESC's proposed NOC Form is just and reasonable; provides small power producers a reasonable period of time from its submittal of the form to execute a PPA; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

10. The updated components of value for NEM Distributed Energy Resources established in this Order are reasonable and prudent, comply with the NEM methodology approved by the Commission in Order No. 2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to DESC's system, and satisfy the requirements of S.C. Code Ann. § 58-40-10, et seq. (2015).

11. DESC's proposed revisions, as modified and amended herein, to its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities tariff sheet, including the rates, terms, and conditions, are lawful, just and reasonable.

12. DESC's method of accounting for avoided costs and incremental costs for NEM were reasonable and prudent, were consistent with the methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10 *et seq.* (2015).

13. Pursuant to Order No. 2019-43-H, DESC should be permitted to 1) to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding as of the first billing cycle of May 2019, 2) separately account for the difference as an incremental cost adjustment in its 2020-2-E annual fuel cost proceeding to account for these incremental costs, and 3) reflect this "true up" as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020.

14. Pursuant to Order No. 2019-43-H, the Company should be permitted to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

15. It is reasonable and appropriate for Rate PR-2 to be withdrawn and terminated effective as of the last billing cycle of April 2019.

VII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

1. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

2. The avoided energy and capacity costs for DESC's proposed Rate PR-1 listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's

implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
May 2019 – April 2020	0.03075	0.02566	0.03330	0.03363

PR-1 RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
May 2019 – April 2020	0.03114

PR-1 RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December thru February, 6:00 a.m. to 9:00 a.m.	0.24725

AVOIDED CAPACITY COSTS
Solar QFs

As discussed on pages 21 - 22 and 34 - 36, this Commission agrees with Power Advisory's recommendation that the avoided capacity rates proposed by ORS Witness Horii in Direct Evidence be approved, with one correction. The PR-1 capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. This contracted capacity is currently 1,048 MW, which implies a capacity value of 4%.

The Company will recalculate the PR-1 capacity rate to reflect these assumptions and include with tariffs sheets filed with the Commission.

3. The avoided energy and capacity costs for DESC's proposed Rate PR-Standard Offer listed in the table below are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours ($/kWh)	Peak Season Off-Peak Hours ($/kWh)	Off-Peak Season Peak Hours ($/kWh)	Off-Peak Season Off-Peak Hours ($/kWh)
2020-2024	0.03280	0.02797	0.03301	0.03073
2025-2029	0.03879	0.03166	0.04191	0.03519

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/kWh)

Time Period	Year Round ($/kWh)
2020-2024	0.02112
2025-2029	0.02375

STANDARD OFFER RATE: AVOIDED CAPACITY COST
Non-Solar QFs ($/kWh)

Time Period	($/kWh)
December thru February, 6:00 a.m. to 9:00 a.m.	0.24725

RATE PR-STANDARD OFFER AVOIDED CAPACITY COSTS
Solar QFs

As discussed on page 21 - 22 and 34 - 36, this Commission agrees with Power Advisory's recommendation that the avoided capacity rates proposed by ORS Witness Horii in Direct

Evidence be approved, with one correction. The Standard Offer capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. This contracted capacity is currently 1,048 MW, which implies a capacity value of about 4%. The Company will recalculate the Standard Offer capacity rate to reflect these assumptions and include with tariffs sheets filed with the Commission.

As approved with modifications by the Commission in Order No. 2018-804, the Company will file rate schedules for solar with storage on or before December 31, 2019.

3. As modified by the Commission in this Order, Rate PR-1, Rate PR-Standard Offer, Rate PR-Avoided Cost Methodology, Rate PR-Form PPA, and the NOC Form, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this order.

4. DESC's method of calculation for avoided and incremental costs for NEM were reasonable and prudent, were consistent with the methodology approved in Commission Order No. 2015-194, and complied with S.C. Code Ann. § 58-40-10, *et seq.*

The updated components of value for NEM Distributed Energy Resources listed in the table below comply with the NEM methodology approved by the Commission in Order No. 2015-194, properly evaluate and/or quantify all categories of potential costs or benefits to DESC's system and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq.*

Total Value of NEM Distributed Energy Resources[19]

Current Period ($/kWh)	**10-Year Levelized ($/kWh)**	**Components**
$0.03022	**$0.02111**	Avoided Energy Costs
TBD	**TBD**	Avoided Capacity Costs
$0.00000	$0.00000	Ancillary Services
$0.00000	$0.00000	T&D Capacity
$0.00003	$0.00003	Avoided Criteria Pollutants
$0.00000	$0.00000	Avoided CO_2 Emission Cost
$0.00000	$0.00000	Fuel Hedge
$0.00000	$0.00000	Utility Integration & Interconnection Costs
$0.00000	$0.00000	Utility Administration Costs
$0.00089	$0.00105	Environmental Costs
$0.03114	$0.02598	Subtotal
$0.00235	$0.00189	Line Losses @ 0.9245
TBD	**TBD**	**Total Value of DER**

5. DESC shall revise its "Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities" tariff sheet, to be consistent with this Order, including the rates, terms, and conditions. A tariff compliant with such modifications shall be lawful, just and reasonable and is hereby approved for use on, during, and after the first billing cycle of the month following this Order.

6. DESC is authorized to 1) to calculate the difference between the updated avoided costs and the NEM methodology costs proposed in the 2019-2-E proceeding and their updated values in this proceeding as of the first billing cycle of May 2019, 2) separately account for the difference as an incremental cost adjustment in its 2020-2-E annual fuel cost proceeding to account

[19] The Avoided Capacity Costs will be determined after the Company calculates the Avoided Capacity factor as Ordered on page 97.

for these incremental costs, and 3) reflect this "true up" as an adjustment to fuel rates that will go into effect with the first billing cycle of May 2020.

7. DESC is authorized to 1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and 2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement in order to reimburse the Company for any such variable integration costs.

8. Rate PR-2 is withdrawn and terminated effective as of the last billing cycle of April 2019.

9. Within ten (10) days of receipt of this Order, DESC shall file with the Commission and serve copies on the Parties the tariff sheets and rate schedules approved by this Order, which are as follows:

a. Rate PR-1;
b. Rider to Retail Rates – Net Energy Metering for Renewable Energy Facilities;
c. Rate PR-Avoided Cost Methodology;
d. Rate PR-Standard Offer;
e. Rate PR-Form PPA
f. NOC Form compliant with the terms of this Order

The avoided cost and other rates reflected in any such tariff sheets shall be consistent with the components and factors set forth herein. The revised tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov/). An additional copy should be sent via e-mail to etariff@psc.sc.gov to be included in the Commission's ETariff system (https://etariff.psc.sc.gov). DESC shall provide a reconciliation of each tariff rate change approved as a result of this order to each tariff rate revision filed in the ETariff system. Such reconciliation shall include an explanation of any differences and be submitted separately from the Company's ETariff filing. Each tariff sheet shall contain a reference to this Order and its effective date at the bottom of each page.

11. This Order is intended to initiate an integration study in accordance with South Carolina Annotated Section 58-37-60 in Dominion's balancing area.

10. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Comer H Randall

Comer H. "Randy" Randall, Chairman

ATTEST:

Jocelyn Boyd

Jocelyn Boyd, Chief Clerk/Executive Director

Commissioner Thomas J. Ervin, CONCURRING:

There is a myth being circulated that the PSC's directive adopting the General Assembly's ten-year contract term for Power Purchase Agreements (PPAs) for solar qualified facilities (QFs) is "doomsday for renewable energy in South Carolina". That is not what a solar industry representative told the press after the House unanimously adopted a ten-year contract for South Carolina. The Chairman of the South Carolina Solar Business Alliance, who worked closely on Act 62, stated that the ten-year term for standard offer PPAs was a legislative "compromise" that he called "reasonable" and a term that "would not" affect the solar developers' ability to get financing. (https://www.utilitydive.com/news/south-carolina-compromises-on-purpa-contracts-eliciting-duke-support-for-p/553895/; accessed December 9, 2019) The fact is that a ten-year contract term better protects both ratepayers and small QF solar developers by ensuring that avoided cost rates reflect the actual costs of generating electricity. The General Assembly considered these arguments and unanimously adopted a ten-year contract. They got it right. While the act allows the small solar developers to prove a case for a longer contract term, the Solar Business Alliance failed to make their case. But they will have another opportunity to do so in future dockets since the Commission must re-examine avoided costs PURPA contract length and terms every other year.

Fifteen- or twenty-year contracts would require the Commission to calculate rates based on assumptions about the future costs of electricity and fuels like natural gas. The longer the contract term, the less accurate these predictions become. Thus, longer term contracts create a greater risk that consumers will wind up paying solar QFs inflated rates that are higher than the actual costs that utilities pay for power.

Several Southeastern states have recently taken steps to protect ratepayers from the risks associated with excessively long fixed rate contracts. In 2017, the North Carolina legislature reduced contract lengths from fifteen years to ten years for QF solar developers. North Carolina ratepayers were being hit by substantial overpayments to solar providers in excess of $2.02 Billion because avoided cost rates set years ago missed the mark on projecting natural gas prices which dropped dramatically over the term of the contract. North Carolina customers are now left to pick up this $2.02 Billion bill for those overpayments. These unintended consequences should sound familiar to us. Remember the Base Load Review Act debacle which left SCE&G and Santee Cooper customers with a $9 Billion hole in the ground? While we all want cleaner and greener renewable energy to succeed, it doesn't make sense to put our South Carolina ratepayers at unnecessary risk of overpaying for renewable energy.

For some perspective, Florida's Commission has adopted two-year terms for standard offer contracts. Alabama has one-year contracts which are renewable annually. Georgia, Mississippi and Louisiana have no contract lengths but allow QF solar developers to negotiate terms with their monopoly utilities.

Another myth is that the PSC's new avoided costs rates are "the most unfavorable renewable energy rates in the Southeast". Not true. On December 1, 2019, the Tennessee Valley Authority (TVA) set avoided costs rates that are lower than the rates set by the PSC in this docket. The TVA also reduced their standard fixed rate contract from ten years down to five years.

The cost to produce electricity has dropped dramatically in recent years due to lower natural gas prices. New natural gas production techniques like hydraulic fracking have resulted in an abundance of natural gas at historically low prices. The Commission is obligated under federal law to enforce the requirements of the Public Utilities Regulatory Policy Act (PURPA) to ensure that customers pay no more for power from independent solar producers than they would otherwise pay for power generated by the utility or purchased on the open market.

It should be noted that North Carolina passed a Competitive Energy Solutions Act in 2017 which created an alternative to PURPA-based implementation by offering solar providers an opportunity to participate in a competitive bidding process for renewable energy. This legislation created an opportunity for solar developers to participate in a market driven process as opposed to the "must take" solar track mandated by Congress using PURPA contracts. Competitive bidding guarantees that ratepayers are getting the lowest price for solar while eliminating the overpayment concerns that result in higher utility rates for customers. This is something our General Assembly considered in Act 62, and this Commission has now established a docket regarding exploration of a South Carolina competitive procurement program as allowed by South Carolina Code Section 58-41-20(E)(2). Until then, South Carolina's solar QFs have been allowed to participate in the North Carolina process.

Small solar QFs have made an important contribution to historic renewable development since Congress passed PURPA decades ago but they represent a much smaller part of overall renewable development today. Larger solar projects and rooftop solar will continue to lead our state and region toward the environmental goals of reducing our dependence on fossil fuels while providing safe and reliable electricity for our residential, industrial, agriculture and small business sectors.

For these reasons, I concur with the majority opinion.

Thomas J. Ervin, Commissioner

Commissioner Justin T. Williams, DISSENTING:

I respectfully dissent.

The South Carolina Energy Freedom Act (the "Act" or "Act 62") considerably reforms South Carolina's implementation of PURPA. It authorizes the Commission to create avenues and opportunities for small power producers to diversify South Carolina's energy portfolio. However, through this Order, the Commission approves a fixed price power purchase agreement duration which makes it uneconomical to finance PURPA projects in South Carolina. That is incongruent to Act 62. I believe the Commission is empowered to approve a term of at least 15 years, as advocated for by our consultant and several parties.

Act 62 authorizes the Commission to approve fixed price power purchase agreements with "commercially reasonable terms and a duration of ten years." S.C. Code Ann. § 58-41-20(F)(1). However, ten years is the floor. The Commission may approve a duration of longer than ten years with "additional terms, conditions, and/or rate structures as proposed by intervening parties." *Id.* The Act continues, ***directing*** the Commission to support contracts with terms longer than ten years as a means of promoting renewable energy. *See* S.C. Code Ann. § 58-41-20(F)(1) (the Commission may also determine "any other necessary terms and conditions deemed to be in the best interest of the ratepayers."); S.C. Code Ann. § 58-41-20(F)(2) (the Commission is "expressly directed to consider the potential benefits of terms with a longer duration to promote the state's policy of encouraging renewable energy.").

Similarly, the Power Advisory Report and witness testimony provide support for terms longer than 10 years. As JDA Witness Chilton describes, QFs must "be able to obtain regularly-available, market-rate financing for the cost of developing, building, and operating their projects." (Tr. Vol. 2, p. 462.4, l. 17-18.) SBA Witness Levitas further explains that "FERC requires PURPA

PPAs to be of sufficient length to give QFs a reasonable opportunity to attract capital to finance their projects." JDA Witness Chilton recommends PPAs with tenors of at least 15 years and up to 20 years as this would facilitate the opportunity to obtain financing for a majority of QFs in South Carolina. (Tr. Vol. 2, p. 462.10, ll. 8 – 18.) Power Advisory notes, "without higher contract length, the solar industry would be unable to finance PURPA projects in South Carolina because they would be uneconomical." *Power Advisory Report*, p. 51. Particularly, as articulated by SBA Witness Levitas, "given Dominion's aggressively low proposed avoided cost rates . . . longer tenor will be needed than would be the case with a higher avoided cost rate." (Tr. Vol. 2, p. 451.9).

Act 62 requires the Commission to encourage renewable energy. In my opinion, our consultant's report and witness testimony confirm that a fixed price PPA duration of 10 years is incongruent with supporting renewable energy. Therefore, the Commission should approve a contract term of at least 15 years.

Justin T. Williams, Vice Chairman

November 4, 2019

Submitted by:

John Dalton,
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Order Exhibit 1
Docket No. 2019-184-E
Order No. 2019-847
December 9, 2019

Executive Summary

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[1]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. The main areas of review and analysis are solar integration charges; avoided costs; and appropriate PPA terms and conditions. Each is reviewed below.

Solar Integration Charges

Solar integration costs are central to two aspects of DESC's filing: (1) as their proposed Variable Integration Charge (VIC) for solar generation, and (2) embedded in their proposed avoided cost rates for solar generation. The proposed VIC is an estimate of the cost of maintaining additional reserves due to increased solar capacity. The resulting VIC estimate is $4.14/MWh; this is the amount that DESC is proposing to charge to approximately 700 MW of solar projects with signed Power Purchase Agreements containing a clause requiring them to pay variable integration charges.

DESC's calculation of its avoided costs of solar generation included the assumption that it will need to maintain higher levels of reserves than it would without solar generation reserves. The effect of this assumption is to decrease its projected avoided costs for solar generation by approximately $7/MWh, or almost 30%, in 2020-2024, and $10/MWh, or 40%, in 2025-2029.

Areas of investigation with respect to DESC's solar integration charges included the following:

- Analysis of Solar Intermittency
- Risk Threshold

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[1] Act 62. Section 58-41-20. (A)

- Constant Reserve Levels
- Alternative Mitigation Options

In Power Advisory's opinion, DESC's proposed values for the VIC, and solar integration costs embedded in its proposed avoided costs, are not adequately supported by the evidence and recommend that lower solar integration costs be employed. In addition, as provided for in Act 62, we recommend that the Commission initiate a study with an independent consultant to assess DESC's solar integration costs.

Avoided Costs

DESC discussed the risk of overpayment and said that the 10-year term mitigates against that risk relative to longer PPA lengths. Other parties asserted that locking in current low avoided costs with long term contracts would be in ratepayer's best interest because natural gas prices are low and forecast to increase significantly.

Parties identified factors that would result in avoided costs increasing or decreasing in the future, benefiting or harming ratepayers given the long-term contracts with QFs at a fixed price based on current avoided costs. A critical determinant of future avoided costs was identified as natural gas prices, with intervenors noting that the Energy Information Administration forecasts gas prices to triple in 30 years. Another possible driver of higher avoided costs cited was a potential carbon tax.

Avoided Energy Costs

DESC projected avoided energy costs for both solar and non-solar QFs using a simulation model of their system. Our review of DESC's avoided energy costs focused on the following areas:

- Transparency, where we felt that DESC's filing was deficient
- Technology Neutral Approach, where we believe that DESC's approach is potentially discriminatory against certain project configurations
- Selection of Pricing Periods, where we recommend that in future avoid cost filings DESC provide support for its pricing periods

Avoided Capacity Costs

Our review of DESC's avoided capacity cost estimates focussed on the following areas:

- Capacity Value Methodology, where we recommend that capacity value should be estimated using the ELCC methodology

- DESC Capacity Cost Methodology, where we recommend that capacity value should be determined based on the avoided cost of a combustion turbine not consider the projected cost of market purchases

- DESC Capacity Cost Assumptions, where we recommend that the change in capacity between the base case and the change case be aligned with the size of the combustion turbine that DESC adds for additional capacity (93 MW) rather than 100 MW differential between the base and change case, and a 20-year asset life be assumed

PPA and NOC Terms and Conditions

Power Advisory discussed the concept of commercial reasonableness as it relates to the Power Purchase Agreements and Notice of Commitment to Sell Forms. We also discussed the implications of a 10-year contract term identified in Act 62.

In the course of this proceeding, the two sides (namely DESC and SBA) came to agreement on many matters which Power Advisory found to be fair and reasonable. The matters that were unresolved were as follows:

DESC's PPA Terms and Conditions

- Liquidated Damages and Extension Payments
- Guaranteed Energy Production
- Energy Storage
- Termination Payment

Notice of Commitment to Sell Form

- Limiting PPA eligibility following
- 365-day in-service deadline
- Eligibility pre-conditions

For each of these issues, Power Advisory provided a summary of the positions of both sides and provided its independent opinion based on the evidence provided.

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1. INTRODUCTION

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). PURPA was originally enacted by the US Congress in 1978.[2] There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power (see discussion in Chapter 3). These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62. QFs include small power producers that utilize renewable energy to generate electricity and range are 80 MW or smaller as well as cogeneration facilities.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[3]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. Standard offers are employed to recognize that small projects are less able than large projects to bear the costs associated with negotiating a PPA and ascertaining the terms and conditions under which the local electric utility would be willing to purchase power.

Act 62 applies to all utilities that are regulated by the Commission, except that electric utilities serving less than 100,000 customers are exempt from the renewable energy programs outlined in Chapter 41 of the Act. As such, the Act applies to Dominion Energy South Carolina, Inc. (DESC); and Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), collectively the "Companies". Pursuant to Act 62 the Commission opened three dockets for the three utilities to

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[2] On September 19, 2019, FERC issued a Notice of Proposed Rulemaking on Qualifying Facility Rates and Requirements and Implementation Issues Under PURPA (NOPR), which proposes to scale back some of the requirements of PURPA. FERC characterizes the intent of the NOPR to "rebalance the benefits and obligations of the Commission's PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated in 1980." (para 4.) Power Advisory notes that the Commission's actions in these dockets are in response to Act 62, but that Section 58-41-10 (B) does specify that "implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that: …power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."

This is only a notice of proposed rulemaking, which should not be interpreted as the promulgation of final regulations.

[3] Act 62. Section 58-41-20. (A)

which the Act applies, for DESC Docket No. 2019-184-E, DEC Docket No. 2019-185-E, and DEP Docket No. 2019-186-E.

With respect to implementing the Act, the Commission is directed:

> "to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The commission also is directed to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of this act."[4]

The Act requires Commission decisions to reflect a careful balancing of interests:

> "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[5]

Further guidance regarding how the interests of QFs will be protected and balanced with customers' interests flows from the direction to:

> "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:
>
> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
>
> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
>
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited

[4] Act 62. Section 58-41-05.

[5] Act 62. Section 58-41-20. (A)

to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[6]

Act 62 also authorizes the commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under this section, including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions under this section."[7] Power Advisory LLC (Power Advisory) was engaged by the Commission on September 3rd to serve as the independent third-party consultant in the three dockets filed pursuant to Act 62. This is Power Advisory's report to the Commission outlining our findings from the review of the materials filed by the parties and the hearings before the Commission regarding DESC in Docket No. 2019-184-E.

1.1 Relevant Experience of Power Advisory

Power Advisory is a management consulting firm focused on the North American electricity sector. The lead consultant on this project and Power Advisory President, John Dalton, has over thirty years of experience as a senior electricity market analyst and policy consultant. John has testified in over 25 proceedings before state and provincial regulatory commissions; advised jurisdictions on the design of renewable energy procurement frameworks including standard offer programs; and has extensive experience overseeing and reviewing quantitative analyses including avoided cost estimates, electricity price forecasts, generation technology cost estimates and production cost modeling.

Recent Power Advisory consulting assignments related to the mandate of South Carolina Act 62 include drafting and review of Power Purchase Agreements for renewable energy resources including variable output resources such as solar; assessing renewable technology costs; evaluating the requirements to integrate variable output renewable energy resources and reviewing utility avoided costs. Power Advisory has overseen the development, reviewed the implementation, and advised on changes to renewable energy procurement programs in Alberta, British Columbia, Massachusetts, New York, Nova Scotia, Ontario, Rhode Island and Vermont. For some of these projects, Power Advisory was responsible for drafting the Power Purchase Agreement. While serving as the Nova Scotia Renewable Energy Administrator, Power Advisory drafted the PPA which was accepted by the Utility and Review Board. Relevant to the consideration of variable energy integration charges, Power Advisory prepared a report for the Government of Canada on the integration of variable output renewable energy sources focusing on the importance of essential reliability services. Power Advisory team members have a long history of running and overseeing the specification of production cost models (and reviewing the results of these models) such as DESC used to develop their avoided cost estimates.

[6] Act 62. Section 58-41-20. (B)

[7] Act 62. Section 58-41-20. (H)

1.2 Power Advisory Review and Participation in Proceeding

As indicated, Power Advisory was engaged by the Commission on September 3, 2019. Hearings in this proceeding began on October 14th after the parties submitted Direct, Rebuttal and Surrebuttal Testimony. Power Advisory issued interrogatories and requests for production of documents to DESC, reviewed the interrogatory responses and documents provided by the parties as well as reviewed the Direct, Rebuttal and Surrebuttal Testimony and monitored the hearings. Given the schedule in this proceeding which requires a Commission decision by November 16th, we were requested by the Commission to issue a final report on or before November 4th to provide the parties an opportunity to comment on the report.

Act 62 specifies that "the qualified independent third party's duty will be to the commission. Any conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility."[8] We have sought to follow this direction and ensure that our conclusions are based on the evidence in the record. The fact that the schedule for this proceeding was compressed and issues with the transparency of DESC's filing limited our ability to reach conclusions in a number of areas. Where necessary and appropriate, we rely on our expertise in the electricity sector to evaluate and analyze the findings and information presented by the parties.

1.3 Contents of the Report

Our report consists of four chapters, the first of which is this Introduction. Chapter 2 reviews DESC's estimates of solar integration costs, including the Variable Integration Charge estimated by DESC and the solar integration costs embedded in the avoided costs projected for solar QFs.[9] Although DESC used different methodologies for the VIC and for its avoided costs, the issues brought up in these proceedings are sufficiently related that we are addressing them together. This chapter discusses DESC's estimates of solar integration charges, the methodologies that were used to develop these estimates, various parties' criticisms of these methodologies, and the resulting charges.

The next chapter, Chapter 3, addresses other aspects of the rates based on avoided costs (i.e., all rates except the VIC). It is organized along the primary areas of focus of Act 62, and includes our review of the definition of avoided costs, a discussion of potential risks from avoided cost-based rates, a review of the avoided cost methodology proposed and the resulting avoided cost

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[8] Act 62. Section 58-41-20. (I)

[9] We elect to review the solar integration costs before reviewing total avoided costs because an important element of DESC's avoided cost analysis are its assumptions regarding the modeling of these integration costs. Therefore, understanding our assessment of the solar integration cost modeling assists in understanding our assessment of DESC's avoided cost analysis.

estimates, and responses to major issues regarding these avoided cost estimates identified by parties to this proceeding. Finally, Chapter 4 reviews various terms and conditions that are disputed by the parties pertaining to the proposed PPAs and NOC forms.

Act 62 provides that "The independent third party shall also include in the report a statement assessing the level of cooperation received from the utility during the development of the report and whether there were any material information requests that were not adequately fulfilled by the electrical utility."[10] Power Advisory notes that DESC cooperated as would be expected. However, there are fundamental issues with respect to the transparency of their avoided cost filing and analysis, which causes Power Advisory to temper our assessment of the level of cooperation provided. At times this cooperation was as explicitly required, but not in spirit. Our assessment of the transparency of their avoided cost filing is provided in Chapter 3.

[10] Act 62. Section 58-41-20. (H)

2. SOLAR INTEGRATION CHARGES

2.1 Importance of Solar Integration Charges

Solar integration costs are central to two aspects of DESC's filing: as their proposed Variable Integration Charge (VIC) for solar generation, and embedded in their proposed avoided cost rates for solar generation. The proposed VIC is simply an estimate of the cost of maintaining additional reserves due to increased solar capacity. The resulting VIC estimate is $4.14/MWh; this is the amount that DESC is proposing to charge to approximately 700 MW of solar projects with signed Power Purchase Agreements containing a clause requiring them to pay variable integration charges.[11]

DESC's calculation of its avoided costs of solar generation included the assumption that it will need to maintain higher levels of reserves than it would without solar generation reserves. The effect of this assumption is to decrease its projected avoided costs for solar generation by approximately $7/MWh, or almost 30%, in 2020-2024, and $10/MWh, or 40%, in 2025-2029, as shown in Figure 1.

Figure 1. DESC's Proposed Avoided Costs with and without Additional Reserves [12]

($/MWh)	2020-2024	2025-2029
DESC's Estimate of Avoided Costs	$16.76	$15.66
Avoided Costs Without Additional Reserves	$23.46	$26.08
Difference	$6.70 *29%*	$10.42 *40%*

DESC's estimates of solar integration costs – both the VIC, and as a factor embedded in their avoided cost rates for solar QFs – are based on the cost of maintaining additional reserves in response to the intermittency of solar generation. The reserves used to develop these estimates are specifically reserves that are available within a few minutes. Dr. Tanner defines reserves as follows:

> "Operating Reserves" means the capability of the electric system to quickly increase generation either by turning on quick-start electric generating units or ramping up the generating output of units that are currently online but not operating at full capacity.

[11] DESC Bell Direct, p. 19 line 19 to p. 20 line 14.

[12] DESC Responses to Power Advisory First Interrogatories, #1-7, p.8.

> Available operating reserves are calculated in terms of how much additional generation is available in a given period of time. Operating reserves are needed by an electric system in order to respond to unexpected drops in generation or unexpected increases in load.

DESC maintains three types of such reserves: regulating reserves to respond to fluctuations in frequency and Area Control Error, contingency reserves required under a reserve-sharing agreement with the "VACAR" group of neighboring utilities, and "flexible" reserves "to meet the challenge of solar intermittency and other un-forecasted variations in demand and supply above VACAR contingency reserve requirements".[13] DESC maintains approximately 200 MW of contingency reserves to respond to generator outages, and 40 MW of flexible reserves "for intra-hour load variation" (i.e., before considering solar intermittency).[14] The increase in reserve requirements which is the basis for DESC's estimates of solar integration costs means an increase in flexible reserves.

With respect to the consideration of solar integration costs in its avoided cost methodology, DESC noted that "The most appropriate method of addressing issues created by solar intermittency is to model the system with higher operating reserves. The increase in operating reserves is now part of the model and is reflected in our estimated avoided energy costs."[15] Without these additional reserves, system costs in the change case would be lower, and the resulting estimates of solar avoided costs would be higher.

The VIC estimate was developed by Navigant Consulting, Inc. ("Navigant") rather than DESC itself, but it used a similar approach: "the cost of holding additional reserves is calculated by comparing the PROMOD production costs with and without holding additional reserves required to meet solar uncertainty."[16] Although many of the details are different (modeling software used, hourly profile of the additional reserves modeled, etc.), the general approach is similar, as are most of Power Advisory's concerns.

Both DESC and Navigant modeled the system operating with set amounts of installed capacity, changing slightly over time and different between the base case and change cases, but otherwise fixed. In addition, Navigant briefly analyzed the possibility of adding new capacity, either quick-start gas CTs or energy storage, as possible alternatives to meeting the need for additional reserves, but concluded that "additional resources are not currently feasible for reducing integration costs in any of the solar penetration scenarios".[17]

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[13] DESC Bell Rebuttal, p. 5, lines 5-6.

[14] DESC Bell Rebuttal, p. 4 line 19 to p. 5 line 4.

[15] DESC Neely Direct, p. 10.

[16] DESC Tanner Direct, Exhibit MWT-2, p. 29.

[17] DESC Tanner Direct, Exhibit MWT-2, p. 31. As discussed below, Power Advisory believes that Navigant's analysis of alternative mitigation measures is inadequate.

Participants in this proceeding identified a number of issues with both methodologies. Power Advisory considers the most significant of these issues to be the following:

- Inappropriate choice of data to analyze solar intermittency
- Lack of support for the risk threshold used to determine additional reserve requirements
- Inappropriate modeling of the additional reserve requirements
- Inadequate consideration of alternative sources of reserve capacity.

2.2 Analysis of Solar Intermittency

The additional reserves for solar used by DESC in its estimation of avoided costs (35% of nameplate capacity[18]) and by Navigant in its estimation of the VIC (up to 32% of installed capacity[19]) are based on their analysis of data on solar intermittency. DESC's testimony emphasized that the cost of solar integration is due to its unpredictability: the potential difference between forecast and actual generation. Mr. Bell stated:

> "By comparison, solar generation is a product of uncontrollable factors such as available sunlight and cloud cover, and a solar facility's output is not necessarily responsive to system needs. Because of this variability in generation, DESC must make operational adjustments to follow the energy generated by solar facilities and to maintain sufficient reserve generation capability in order to meet system reliability requirements. In addition to being variable moment to moment, solar generation varies widely from the solar generation forecasts provided by solar operators, which also creates a need for reserves."[20]

DESC's VIC and avoided costs estimates are based on the cost of additional reserves, which are a function of variation between forecast and actual output. The additional reserves should therefore be based on differences between forecast and actual generation – more specifically on differences between the best available forecast, on a timeframe appropriate to setting reserve levels, and actual generation.

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[18] DESC Neely Direct Testimony, p. 10, lines 18-20.

[19] DESC Tanner Direct Testimony, Exhibit MWT-2, p. 17 Table 6 and p. 26 Table 12. Navigant's calculation of the VIC is based on differences between the Initial Solar and the All Solar cases. Table 12 shows a difference of 230 MW in Maximum Additional Reserves Needed in all years (except slightly less in 2020). Table 6 shows a difference of 708 MW in Maximum DESC Solar Capacity in all years. 230 is 32.5% of 708. Navigant adjusts the modelling results to use lower required reserves on some days: either the same amount as in the Initial Solar case, or an intermediate amount.

[20] DESC Bell Direct, p. 12, lines 7-15.

When asked by ORS "Provide the justification of solar capacity additional reserves. Specifically, detail on the analysis done to arrive at the 35% value (page 10/27 of James W. Neely's Direct Testimony)", DESC's reply was:

> "Using 2018 aggregated 15-minute solar generation DESC identified the 15-minute, 1-hour, 2-hour and 4-hour reductions in solar generation ("drops"). In the months of January, February, March, April, October, November, and December, DESC looked at drops before 4pm. In the months of May, June, July, August and September, DESC looked at drops before 6pm. 80 MW is sufficient to cover 96% of the 1-hour drops and is 35% of the maximum capacity analyzed. To cover 100% of the 1-hour drops would require reserves of 101.5 MW or 45% of the capacity analyzed."[21]

When asked "Why did the Company pick the one-hour time frame -- a one-hour time frame to operate the reserves when drops occur in varying lengths?" Mr. Neely replied, "in our opinion, the one-hour reserves is appropriate for balancing the risk versus cost."[22]

However, as Brian Horii of ORS correctly notes in his Surrebuttal Testimony of October 11, "the Company provides no data to support that the drop is the difference between *__expected__* [emphasis in the original] and actual output. Rather, the Company's response indicates the drop is simply the reduction in solar generation." [23] Many "drops" between one hour and the next (including those before 4 pm in winter/6 pm in summer) are entirely predictable, and to the extent that they are predictable, do not necessitate additional reserves.

Navigant's standard (up to 32% of installed capacity) is somewhat more transparent: "For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that need to be held to ensure that the reserve requirements are met."[24] Navigant states that "The forecast uncertainty is developed from the National Renewable Energy Lab's (NREL) Solar Integration Dataset. This is a public dataset that provides both forecasted and real-time solar generation at a large number of sites across the LLS."[25] Navigant calculated "forecast error" by comparing NREL's "actual" generation for 5-minute intervals to NREL's 4-hour-ahead forecast; forecast errors for the 5-minute intervals were then averaged over 15 minute intervals.[26]

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[21] DESC Responses to ORS AIR #2-6, p. 6.

[22] Hearing Vol. 1, p. 400, lines 3-5 and 14-16 (DESC Neely)

[23] ORS Brian Horii Surrebuttal, p. 3, lines 18-21.

[24] DESC Tanner Direct, Exhibit MWT-2, p. 25. As discussed below, there is some confusion about whether Navigant's reserve levels were based on the absolute maximum, or on the largest 1% of drops.

[25] DESC Tanner Direct, Exhibit MWT-2, p. 21.

[26] DESC Tanner Direct, Exhibit MWT-2, p. 21.

Several witnesses questioned the use of a 4-hour-ahead forecast to make decisions about requirements for flexible reserves, which by definition are able to respond within a few minutes. Mr. Horii states:

> "... the 4-hour period is inconsistent with the intended purpose of operating reserves. Operating reserves are carried to address short-term changes in demand or generation. Changes over four (4) hours can be addressed with options that are less costly, such as generation unit rescheduling and the starting of off-line resources."[27]

As Mr. Stenclik notes:

> "the least reserves are required, and the lowest costs will be incurred, if the most accurate, and therefore shortest term forecast, is used…The 4-hour window does not represent state-of-the-art forecasting capability, commercial service offerings, or technical constraints of the DESC fossil generation, but rather the available data in the NREL datasets. In actual operations, the utility can implement a rolling solar forecast that is routinely updated at day-ahead, 4-hour ahead, 2-hour ahead, and real-time intervals. This will allow for rolling decisions that occur throughout the day, rather than at static pre-determined intervals."[28]

When asked by South Carolina Conservation League and Southern Alliance for Clean Energy "Please explain why it is appropriate to base reserve requirements on the 4-hour solar forecast error when the CC plants can start in 2 hours and CT plants start faster", Dr. Tanner responded:

> "The 4-hour forecast is an appropriate estimate for the forecast error because, although some of the CCs can start in 2 hours, there would need to be some lead time between receiving the forecast and discovering that it is less than the expected solar generation. This assumption is that DESC would not be able to know whether the forecast was wrong for at least two hours after receiving the four-hour ahead forecast. This analysis is conservative in that many of the ST plants on the system and a few of the CCs need longer than 2-4 hours to start."[29]

Mr. Stenclik asserts that:

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[27] ORS Horii Surrebuttal, p. 3, lines 13-16.

[28] SACE/CCL Stenclik Direct, Exhibit B, p. 9.

[29] Dr. Tanner's statement was made during a different proceeding before the Public Service Commission (2019-2-E) and is quoted in Mr. Stenclik's Direct Testimony. DESC confirmed, in its Response to South Carolina Conservation League and Southern Alliance for Clean Energy First Data Request 1-13, that its response remains the same in the current proceeding.

"This response misrepresents the objective of operating reserves. Variable integration reserves are designed to protect against the possibility that the solar forecast is so wrong that there won't be enough reserves to cover any drop in actual solar generation. The operator does not need to determine if the current forecast is accurate; the reserves are being held precisely in case the forecast is wrong. If there is time to determine if the forecast is correct, then there is no need for forecast-error reserves. With a 2-hour ahead forecast there is no need to wait and determine if the solar forecast is accurate. The reserve requirement is based on the forecast amount and already incorporates the risk that the forecast is wrong. If the 2-hour ahead forecast estimates a solar generation level that indicates the need for an additional CC to be operating to supply reserves, the CC can begin to be started immediately." [30]

As noted above, DESC based the estimate of solar integration costs which it used in its own avoided cost calculations on "drops" over a one-hour period, not a four-hour period.

In order to assess the impact of a one-hour-ahead forecast instead of a four-hour-ahead forecast, Power Advisory attempted to replicate the "actual" data used by Navigant based on four NREL sites.[31] This data was used to develop a one-hour ahead forecast for each 15-minute interval based only on extrapolating from earlier data – i.e., without the benefit of a weather forecast, NREL's own 4-hour-ahead forecast, or any information other than solar generation in previous intervals.[32] Even using this simplistic forecast, the "drop" between forecast and actual generation was less than 16.8% of installed capacity in 99% of intervals (i.e., in all but 166 of the 16,573 intervals with non-zero solar generation). If additional data were available – for example, weather forecasts showing that cloud banks were likely to arrive within an hour – it is likely that a one-hour-ahead forecast could be significantly more accurate than this simplistic construct. Power Advisory is not suggesting that 99% is the appropriate risk threshold, or that that drops expressed as a percentage of solar capacity are the appropriate basis for reserve requirements. The intent is only to illustrate

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[30] SACE/CCL Stenclik Direct, Exhibit B, p. 10.

[31] Power Advisory selected four of the NREL datafiles: "Actual_32.55_-80.85_2006_UPV_128MW_5_Min.csv", "Actual_32.95_-80.35_2006_UPV_16MW_5_Min.csv", "Actual_33.65_-81.75_2006_UPV_32MW_5_Min.csv" and "Actual_34.05_-80.85_2006_DPV_35MW_5_Min.csv". These sites were selected to be as close as possible to the "NREL Sites" shown in the attachment to DESC's response to Power Advisory's Interrogatory 13 "Please provide a map of DESC's service territory and indicate the location of these 8 solar sites and the four locations where NREL data was used." These may not be the specific sites used by Navigant, but Power Advisory's analysis of NREL's datafiles indicates that sites close to each other show very similar solar generation, adjusted for the assumed size of the facility. For each site, output was divided by the indicated nameplate capacity, and the results were averaged to give a single solar profile for 5-minute intervals. These 5-minute intervals were grouped into 15-minute intervals (four per hour). The analysis was done on these 15-minute intervals.

[32] The forecast was based on two factors: average solar generation in the period between 75 and 60 minutes before the forecast interval, and the change in generation between those two times of day in the previous week. For example, the forecast for 11:00 to 11:15 am on January 8 was a function of (a) generation between 9:45 and 10:00 on January 8, and (b) the ratio of generation between 11:00 and 11:15 on January 1, 2, 3, 4, 5, 6, and 7, and generation between 9:45 and 10:00 on those same seven days.

how using a different forecast period could have changed Navigant's results, even with no additional data.

Power Advisory Assessment

In Power Advisory's view, neither DESC's nor Navigant's analyses of solar intermittency provide good bases for estimating the quantity of additional reserves that will be required, likely resulting in significant overestimation of the amount of additional reserves required and the associated costs. DESC's analysis is based on changes in solar generation from one time interval to another, rather than on differences between forecast and actual solar generation for the same interval. Since the purpose of reserves is to address unexpected changes in supply and demand, DESC's analysis is simply not relevant.

Navigant's analysis was based on a comparison between forecast and actual solar generation, but their exclusive reliance on four-hour-ahead forecasts is overly simplistic and fails to conform with best practice. Recognizing that there is a cost associated with a greater forecast error and that this forecast error can be reduced if the forecast is made closer to real-time, as acknowledged by Dr. Tanner,[33] Power Advisory believes that using a four-hour-ahead forecast is overly conservative and contributes to a need for higher reserves than would be required under an appropriate application of best practices.

Power Advisory recommends to the Commission that this issue be evaluated in greater detail during the independent study recommended in Act 62 to evaluate the integration of renewable energy and emerging energy technologies into the electric grid.[34] We do not believe that DESC's or Navigant's analyses of solar intermittency provide appropriate bases for determining additional requirements for flexible reserves.

2.3 Risk Threshold

There is some confusion in DESC's testimony about the exact level of risk used by Navigant in determining required reserve levels. According to Navigant's report, their reserve levels were sufficient to cover all possible drops: "For each solar penetration scenario, the maximum expected drop in solar generation for each year was used to determine the extra operating reserves that

[33] DESC Response to Power Advisory First Set of Interrogatories, #16 (d), p.21.

[34] Act 62. Section 58-37-60. "Independent study to evaluate integration of emerging energy technologies. The commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest."

need to be held to ensure that the reserve requirements are met."[35] In his rebuttal testimony, Dr. Tanner described it somewhat differently:

> "Navigant's analysis did not use the absolute maximum in potential solar undergeneration to estimate the amount of reserves that need to be held. In order to avoid the most extreme events in the data set, the analysis used a threshold of rounding to 1%."[36]

Regardless of whether Navigant's specific risk threshold was 0% or 1%, no explicit basis for it was provided in their report. As Mr. Horii notes:

> "When evaluating the need for additional operating reserves for DESC, Navigant does not perform any balance of risk and cost in the Integration Study. Nor does the Integration Study seek to maintain a specific level of risk previously deemed reasonable. Instead, the Integration Study assumes that solar generation will drop from its forecast level to its minimum output level based on forecast error information from the NREL. This assumption essentially places an infinite value on the cost of unserved energy, and results in integration costs that are likely higher than what would have been estimated had an actual risk-based analysis been performed by DESC. The balancing of costs and risks is a fundamental principle of electricity resource planning."[37]

Dr. Tanner responded to this as follows (including the statement quoted above about Navigant's risk threshold):

> "Q. … Mr. Horii suggests that DESC failed to conduct an analysis that balances risks and costs to determine the amount of operating reserves needed as a result of variable solar resources. Do you agree?
>
> A. No. Navigant's analysis did not use the absolute maximum in potential solar undergeneration to estimate the amount of reserves that need to be held. In order to avoid the most extreme events in the data set, the analysis used a threshold of rounding to 1%. This threshold was chosen specifically to balance the risk reduction vs. the cost of holding the additional reserves needed to integrate the solar generation. This is very far from an analysis of what it would take to mitigate all risks. In electric system operations, 1% can be a very meaningful risk."[38]

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[35] DESC Tanner Direct, Exhibit MWT-2, p. 25.

[36] DESC Tanner Rebuttal, p. 3, lines 15-18. The word "round" and variations on it ("rounded", "rounding", etc.) do not appear in Dr. Tanner's Direct Testimony of which Navigant's report is an exhibit.

[37] ORS Horii Direct, p. 12, lines 13-21.

[38] DESC Tanner Rebuttal, p. 3, lines 9-21.

However, no evidence was provided to quantify that risk. Mr. Stenclik states:

> "Rather than a grid outage event and customer disruption, a shortfall could lead to a potential violation of NERC standards and a potential fine. This is an important distinction when evaluating the tradeoff between risks and costs associated with reserve requirements. If a grid blackout were feasible, there should be significantly less risk tolerance."[39]

Mr. Bell argues that:

> "It is not realistic to assume these drops will not coincide with a unit trip, unit forced outage, limited transmission interface, or unusually high loads. To the contrary, it is likely to only be a matter of time before such a coincidence occurs, and we are in a situation where solar variability results in a generation shortfall.
>
> To put this risk in perspective, consider that there is about a 32% probability (very significant) that at least one baseload or intermediate generating unit will be forced out during the year. With solar generating more than 50% of the hours in a year and cloud formations somewhere across the system almost every day interfering with solar output, there is a significant risk of an overlap of solar drops and base/intermediate generator outages."[40]

Whether such an overlap would be problematic would depend on the size of the drop. It is common practice for utilities to calculate the risk of two or more problems occurring simultaneously resulting in inadequate supply (this is called "Loss of Load Expectation" or "LOLE". DESC did not provide LOLE results or any other quantification of the probability that a generator outage would coincide with a large drop in solar generation below forecast levels resulting in either a loss of load, or in a violation of NERC standards.

A similar criticism applies to DESC's use of a 35% standard, the basis of which is that it covers 96% of drops. There is no analysis to support 96% coverage, rather than the maximum observed drop, or some lower metric, as the appropriate threshold that balances costs and risks.

As support for both DESC's and Navigant's additional reserves to cover solar intermittency, Mr. Bell points to DESC System Control's current operating practice:

> "DESC's actual operating practice requires additional reserves (40% of actual output) for solar intermittency. This is greater than but generally consistent with the 35% one-hour

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[39] SACE/CCL Stenclik Surrebuttal, p. 22, lines 5-9.

[40] DESC Bell Rebuttal, p. 4, lines 3-13.

> ahead value (35% of installed solar nameplate) used in the avoided cost studies and in line with the Navigant Study 4-hour drop probability table."[41]

However, DESC's testimony on their current operating practices did not refer to a specific risk threshold, or to any explicit comparison of the cost of insufficient reserve levels to the cost of maintaining additional reserves. When asked "when did you first implement that assumption or that rule of thumb?", Mr. Hanzlik responded "I think over time it's -- it's [evolved] into that number."[42] Mr. Stenclik states:

> "Mr. Bell's rebuttal states that current operating practices include reserves to cover 40% of solar output. This is the first time where this information is stated by DESC in this docket and it appears to be a very recent development. The very recent imposition of increased reserve requirements lends further support to the need for additional study and operational experience prior to imposing a VIC. Adding contractual costs based on reserve requirements that have not been thoroughly established and vetted is premature and would be adding a real cost based solely on a simulated or very newly imposed reserve requirement."[43]

Power Advisory Assessment

In Power Advisory's view, none of the three standards used by DESC to determine the additional reserves attributable to solar generation (35% of nameplate capacity for the avoided cost calculations, up to 32% of installed capacity for the VIC calculations, and DESC System Control's 40% of forecast generation) have been adequately justified as a reasonable balance between costs and risks. We recognize that this isn't a simple or straight forward analysis, but believe that greater analytical rigor is required than DESC has employed to ensure a reasonable trade-off between reserve costs and risks.

2.4 Constant Reserve Levels

A third problem with DESC's solar integration cost estimates is that they were not modelled in ways that are consistent either with DESC's current operating practices or with industry-wide best practices for estimating solar integration costs. As discussed above, DESC's current practice is to

[41] DESC Bell Rebuttal, p. 7, lines 12-16.

[42] Hearing Vol. 1, p. 237, lines 1-7 page 54, lines 18-24 (DESC Hanzlik). The transcript shows "involved" but the questioner's response on line 12 interprets Hanzlik's answer as "evolved."

[43] SACE/CCL Stenclik Surrebuttal, p.13 lines 4-11.

maintain additional reserves equivalent to 40% of their forecast of solar generation as it varies during the day.[44]

Unlike DESC's actual practice, the simulations used to estimate solar integration costs did not vary reserve levels in proportion to solar generation. Rather, DESC's simulations to estimate avoided costs kept reserve levels constant at 35% of nameplate capacity in all solar generating hours[45] (i.e., with no reserves at night). Mr. Horii states:

> "In my direct testimony, I express concern over holding the higher reserves "in the evening or early morning" (Horii Direct, p. 23). Those are times when system loads can be high and solar output low. Since the solar output expected in the evening or early morning hours would be lower than at midday, there would be much lower downward output risk during those hours than during the middle of the day. Therefore, a higher level of extra daytime operating reserves would potentially overestimate the costs that would actually be needed to maintain system reliability during those hours."[46]

Navigant's simulations to estimate the VIC went even further, maintaining constant levels of reserves in all hours of the day, including nighttime.[47] Navigant did make some post-modeling adjustments for day-to-day variations in reserve requirements:

> "... the analysis calculated integration costs for the All Solar Case using the following proportions of days in which these levels of reserves must be maintained:
>
> - All Solar level of reserves is needed 38% of the days
> - Intermediate level of reserves is needed 51% of the days

[44] Hearing Vol. 1, p. 214, lines 6-14.

[45] DESC Neely Direct, p. 10. "Solar generating hours" is not explicitly defined, but Mr. Stenclik estimates that it includes 4,000 to 4,200 (46-48%) of the 8760 hours in a year (Hearing Transcript, Day 2, p. 651, line 8; this seems reasonable. Mr. Bell, in his Rebuttal Testimony, states that "the additional reserve requirement [in the DESC Avoided Cost Methodology] is included as an hourly profile and is an accurate and required input in the avoided cost calculation" (p. 3, lines 7-9). However, there is no indication that this "profile" changes from hour to hour, other than being 35 MW during solar generating hours and zero in other hours.

[46] ORS Horii Surrebuttal, p. 11, lines 8-14.

[47] There are no direct statements in either Navigant's report or DESC's testimony that the same level of reserves was used in every hour, but there was also no mention of using different reserves amounts in different hours within the same case. Navigant discusses adjusting the modeling results to reflect different reserve requirements on different *days*, as discussed in the next footnote, but does not discuss any adjustment for different reserve requirements in different hours.

- Initial Solar level of reserves is needed 12% of the days"[48]

However, Navigant varied required reserve levels only between days, not hour-to-hour within the same day. Mr. Stenclik questions Navigant's approach:

> "Most troubling is that additional fixed solar reserve requirements were imposed 8,760 hours a year rather than being a function of the hourly forecasted solar generation, greatly overstating additional reserve costs."[49]

It is theoretically possible that the modeled cost of maintaining these extra reserves is low; Navigant states:

> "In most hours, especially overnight, DESC holds more than the minimum necessary reserves through their least-cost security constrained dispatch. This means that adding to the reserve requirement in the simulation does not materially influence the system operation in those hours."[50]

Dr. Tanner is more specific:

> "Thus, in the hours when the sun is not shining, the model shows that average reserves held on DESC's system are over 1,500 MW. By contrast, the planning model only required that 240 MW be held in the business-as-usual (i.e., non-solar) reserves case. This means that the additional reserves required for solar integration are not a binding constraint on the system in non-solar hours and thus do not materially impact the overall system operating costs or contribute to the calculation of the Variable Integration Charge ("VIC")."[51]

However, Dr. Tanner's conclusion (that the additional reserves required overnight "do not materially impact the overall system operating costs") does not logically follow from his statement that "average reserves held on DESC's system are over 1,500 MW" in non-solar generating hours. The estimate of VIC is not based on *average* reserves in all hours, but on the need to alter system

[48] DESC Tanner Direct, p. 18, lines 5-10. The All Solar Case required 230 more MW of reserves than the Initial Solar Case. The Intermediate level of reserves is described as "between the All Solar and BAU requirements" (Tanner Direct Testimony, Exhibit MWT-2, p. 26, Footnote 9) but is not specified; 115 MW, or half of the All Solar Case requirement, is a reasonable estimate. Navigant's estimate of the VIC is therefore based on maintaining, on average, approximately 145 MW of additional reserves, which is 20% of the 708-MW difference in solar between the Initial Solar Case and the All Solar Case.

[49] SACE/CCL Stenclik Direct, p. 8 lines 18-20.

[50] DESC Tanner Direct, Exhibit MWT-2, p. 28.

[51] DESC Tanner Rebuttal, p. 6, lines 2-8.

operation in selected hours. Dr. Tanner's statement could only be true if none of those selected hours occurred at night. However, Mr. Hanzlik states:

> "The typical winter load curve begins with a morning peak just prior to sunrise when there is no solar output. During these early morning hours, solar is not available and DESC's non-solar generators are near maximum generation output levels while reserves are at the lowest level for the day."[52]

Navigant increased reserve levels in all hours, including these early morning hours with low reserve levels, even though there was no solar generation in these hours. It seems highly unlikely that this didn't have a material impact on their estimates of system operating costs.

DESC's response to these criticisms has been to point to Navigant's use of different reserve levels on different days. For example, Mr. Bell states:

> "Accounting for the difference between PROMOD's limitations and actual costs incurred, Navigant has made a logical and appropriate adjustment to the variable integration cost ("VIC") calculation to adjust for the difference between constant reserves and lesser amounts needed on 62% of days modeled."[53]

But such statements do not address the basis of the criticism, which is not about variations in reserve requirements from day to day (for example between a cloudy day and a sunny day) but about variations in reserve requirements from hour to hour (for example, between noon and midnight). As Mr. Stenclik notes:

> "Finally, the blending method suggested by Dr. Tanner to account for this is not standard industry practice. Production cost modeling tools such as GE MAPS and PLEXOS have been used for many, if not most, of North America's largest variable renewable integration studies and are capable of simulating hourly reserve requirements. Hourly simulation of reserve requirements is a standard approach implemented in renewable integration studies and the Cost of Variable Integration Study should be no different."[54]

While the above criticisms apply only to Navigant's simulations, DESC's avoided cost simulations could also be overstating solar integration costs, even though they did not maintain additional reserves overnight. Mr. Horii states:

> "In my direct testimony, I express concern over holding the higher reserves "in the evening or early morning" (Horii Direct, p. 23). Those are times when system loads can be high and

[52] DESC Hanzlik Rebuttal, p. 12, lines 16-20.

[53] DESC Bell Rebuttal, p. 3, lines 3-6.

[54] SACE/CCL Stenclik Surrebuttal, p. 12, lines 10-16.

> solar output low. Since the solar output expected in the evening or early morning hours would be lower than at midday, there would be much lower downward output risk during those hours than during the middle of the day. Therefore, a higher level of extra daytime operating reserves would potentially overestimate the costs that would actually be needed to maintain system reliability during those hours."[55]

Power Advisory Assessment

Both DESC and Navigant maintained high reserve levels even when solar generation was modeled to be low. It is likely that this contributed to over-estimation of the cost of maintaining additional reserves, because many of the hours when reserve levels are low (and the cost of maintaining additional reserve levels is therefore likely to be high) occur in the early morning when there is little or no solar generation. In Power Advisory's opinion, DESC has not provided convincing evidence that holding constant levels of additional reserves, either in all hours (Tanner's VIC analysis) or in all solar generating hours (avoided cost analysis), does not significantly overstate solar integration costs.

2.5 Alternative Mitigation Options

As Navigant points out, there are two ways to maintain reserve requirements:

1. Operate the existing system differently so that there are more operating reserves.
2. Procure quick-start resources such as battery storage or CT gas units that will be able to provide reserves even when offline.[56]

Navigant considers three types of such resources: quick-start combustion turbines, lithium-ion batteries with one hour of storage, and lithium-ion batteries with two hours of storage. For each, Navigant estimates its capital costs (ranging from $700 to $1,000/kW), calculates the amount of each that could be purchased at the same cost incurred by carrying more reserves (ranging from 75 to 110 MW), compares those amounts to the additional reserve requirements (which Navigant assumes to be 230 MW for a tranche of approximately 700 MW of solar, as discussed above, and concludes that "None of these capacities would be sufficient to meet the additional reserve requirements of the solar generation."[57] Navigant states "It does not currently seem cost-effective for DESC to add resources solely to provide the needed reserves."[58]

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[55] ORS Horii Surrebuttal Testimony, p. 11, lines 8-14.

[56] DESC Tanner Direct, Exhibit MWT-2, p. 28.

[57] DESC Tanner Direct, Exhibit MWT-2, p. 30.

[58] DESC Tanner Direct, Exhibit MWT-2, p. vii.

Mr. Stenclik, among others, has several issues with this approach. The first is that

> "… the resources were evaluated "solely" to provide reserves. A battery storage asset, or other new technologies, can provide multiple benefits to the system and should be evaluated in a more holistic way. These services could include firm capacity benefits, energy or energy arbitrage benefits, transmission and distribution deferral, and environmental benefits. Evaluating only reserve provision limits the ability for the resources to be economic based on multiple value streams."[59]

Navigant itself acknowledges the validity of this in a footnote, stating "it may be cost-effective to add resources for other purposes such as energy or capacity that have the added benefit of adding reserves to the systems that would reduce overall operating costs."[60]

Mr. Stenclik's second concern is that:

> "the Variable Integration Study did not evaluate other potential technologies and operating strategies, including new demand response, combined cycle upgrades, and discounting of solar forecasts."[61]

Mr. Raftery took issue with an earlier version of Mr. Stenclik's statement about demand response, noting:

> "the Company has conducted an extensive investigation into the possibility of relying on additional demand response programs to reduce peak demand … The study determined that there are no new cost-effective programs that the Company can add that will assist to mitigate the winter peak."[62]

Mr. Stenclik's original statement was "DESC did not include existing demand response resources to the full extent possible … DESC did not evaluate the potential to reduce ratepayer costs … by implementing new demand response."[63] Although Mr. Stenclik wrote "DESC", that section of his testimony was about "the Cost of Variable Integration study DESC has presented in the Cost of Variable Integration analysis"[64] – i.e., Navigant's VIC study. Navigant's study does not mention demand response or the other resources that Mr. Stenclik lists. Moreover, the fact that demand

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[59] SACE/CCL Stenclik Surrebuttal, p. 13, lines 2-8.

[60] DESC Tanner Direct, Exhibit MWT-2, p. 30, footnote 13.

[61] SACE/CCL Stenclik Surrebuttal, p. 13, lines 18-20.

[62] DESC Raftery Rebuttal, p. 3, lines 17-19 and p. 4, lines 2-4.

[63] SACE/CCL Stenclik Direct, p. 9, lines 9-16.

[64] SACE/CCL Stenclik Direct, p. 8, lines 1-2.

response has not been found to be cost-effective for meeting winter peak demand does not mean that it would not be cost-effective for providing reserves. Mr. Stenclik states:

> "[Peaking] demand response is fundamentally different than demand response for operating reserves as it typically requires at least 4-hours of customer load interruption. Demand response for operating reserves can be much shorter, only required until the next unit is turned online. This type of demand response has been introduced commercially at other utilities for variable renewable integration. Evaluating a study across a 13-year horizon without including new demand response resources as a candidate option overstates the cost of providing reserves, especially in future years."[65]

Mr. Stenclik's third concern is that "DESC did not evaluate the potential to reduce ratepayer costs through participation in a larger balancing area."[66] Mr. Bell responded:

> "Assuming a coordinated approach to solar intermittency is workable, it will require the agreement of multiple utilities and will involve quantifying and sharing the resulting costs. The success or value of such an approach cannot be assumed at this time and is beyond the scope of the current proceeding."[67]

Mr. Stenclik acknowledges the complexities of reserve sharing, but he disagrees with basing the solar integration costs on the assumption that DESC is effectively an "island":

> "Reserve sharing and coordination is the economically responsible behavior for the ratepayer, regardless of the market structure. While this type of coordination will undoubtedly take time to develop, it is certainly reasonable during the 13-year study horizon evaluated.
>
> I will add that this coordination does not necessarily require a reserve sharing agreement. By simply increasing bilateral energy transactions with neighboring utilities, DESC can "free up" their own generation (allowing their generators to back down to lower loading levels) to provide reserves instead of energy. There is already a long history of these energy transactions and it is a regular part of DESC's operations. This mitigation could be introduced today."[68]

Power Advisory Assessment

In Power Advisory's opinion, Navigant and DESC did not adequately evaluate alternative means of ensuring adequate reserves. It is impossible to determine, based on the evidence submitted, whether combustion turbines or batteries would be cost-effective if other value streams were

[65] SACE/CCL Stenclik Surrebuttal, p. 22, lines 2-9.

[66] SACE/CCL Stenclik Direct, p. 9, lines 14-15.

[67] DESC Bell Rebuttal, p. 12, lines 19-22.

[68] SACE/CCL Stenclik Surrebuttal, p. 8, lines 11-20.

considered; if demand response targeted at providing flexible reserves appropriate for solar integration would be cost effective; or how likely it is that some kind of reserve sharing for solar integration will occur at some point over the period for which these rates would apply.

2.6 Integration Charge Conclusions

In Power Advisory's opinion, DESC's proposed values for the solar VIC, and solar integration costs embedded in its proposed avoided costs, are insufficiently supported by the evidence.

- The data and analysis on which solar intermittency risks are estimated are inappropriate, being based either on actual changes in solar output over time (rather than on a comparison of forecast and actual output for the same time period) or on a four-hour-ahead forecast that is inconsistent with the timeframe under which reserves would be dispatched (which may be four hours some of the time, but will often be much shorter).
- It is unclear whether the risk thresholds implicitly used in the estimates of solar integration costs are appropriate, because they have not been justified either by a loss of load probability calculation or by a comparison of the costs that would be incurred if reserves were insufficient vs. the costs of maintaining additional reserves.
- The modelling of additional required reserves for both the VIC and avoided costs is significantly different from DESC's actual practices for establishing reserves. DESC's actual practice is to base reserve levels on forecast solar generation, which means no increase in reserve levels at night and small increases in the early morning when solar generation is low. In contrast, both sets of simulations increase required reserves based on installed capacity (not forecast generation) in many hours beyond what is reasonably necessary, including nighttime hours (Navigant only) and hours with low solar generation (both). DESC asserts that this has no impact on the modeling results, but has not provided convincing evidence to support this claim. In Power Advisory's estimate, the modeling results are likely to include at least some hours with little or no solar generation but with significant additional costs attributed to solar generation.
- There has been inadequate consideration of alternative ways of providing additional reserves, such as combustion turbines or batteries which might be cost-effective when multiple revenue streams are considered in addition to those from providing reserves; demand response targeted at solar integration; and reserve sharing with neighboring utilities at least toward the end of the study period.

Mr. Stenclik states:

> "The independent renewables integration study authorized by recent South Carolina legislation would allow for a more transparent and accurate calculation of integration cost that includes stakeholders and additional technical experts."[69]

Given the lack of evidence to support DESC's estimates of solar integration costs, Power Advisory recommends that a cost study be undertaken as part of the independent study recommended in Act 62 to evaluate the integration of renewable energy and emerging energy technologies into the electric grid (as mentioned earlier).

Mr. Stenclik recommends that for now, no VIC should be charged:

> "The Commission must consider whether any integration charges are just and reasonable. Given the significant problems with the Dominion Cost of Variable Integration study approach and analysis, as outlined in my testimony and attached report, the Commission should not approve Dominion's proposed variable integration charge. The utility should revise its approach to address the problems identified and hold off on any integration charge until these concerns have been addressed and the utility has gained more operational experience, so that actual charges are not based solely on flawed simulations."[70]

Power Advisory does not support this recommendation. Power Advisory notes that a number of the parties in the DEC / DEP proceeding reached a settlement that accepted a solar integration charge of $1.10/MWh for DEC and $2.39/MWh for DEP. Based on this Power Advisory is reluctant to recommend that there be no solar integration charge.

Mr. Horii presents an alternative: temporarily use $2.29/MWh as an estimate of the cost of solar integration, using it both as the VIC and as the solar integration cost embedded in avoided cost-based rates:

> "For the value of solar integration, or "VIC," I find that the Navigant VIC study is overly risk averse in determining the need for additional operating reserves to account for the intermittency of solar generation. The Navigant study is overly risk adverse by focusing on just solar generation and not considering the totality of risk that involves all generation, transmission, and customer demand deviations. The Navigant study also overstated operating reserve needs by holding reserve levels constant over all hours when solar is operational. While I was not able to correct for the second problem, I was able to use Navigant's data to estimate VIC costs using a more reasonable level of additional operating reserves. By using my more reasonable level of additional operating reserves, the VIC drops from $4.14 per megawatt-hour to $2.29 per megawatt-hour, which is

[69] SACE/CCL Stenclik Surrebuttal, p. 22, lines 4-5.

[70] SACE/CCL Stenclik Direct, p. 10, lines 16-23.

> comparable to the solar integration cost proposed by Duke Energy Progress in Docket Number 2019-186-E.
>
> I, therefore, recommend in my surrebuttal testimony that avoided costs for solar QFs and solar-with-storage should start with Dominion's avoided energy cost for solar resources that exclude any additional operating reserves. My recommended VIC should then be subtracted from these avoided energy costs to arrive at avoided energy costs for solar that reflect a reasonable estimate of integration costs for solar." [71]

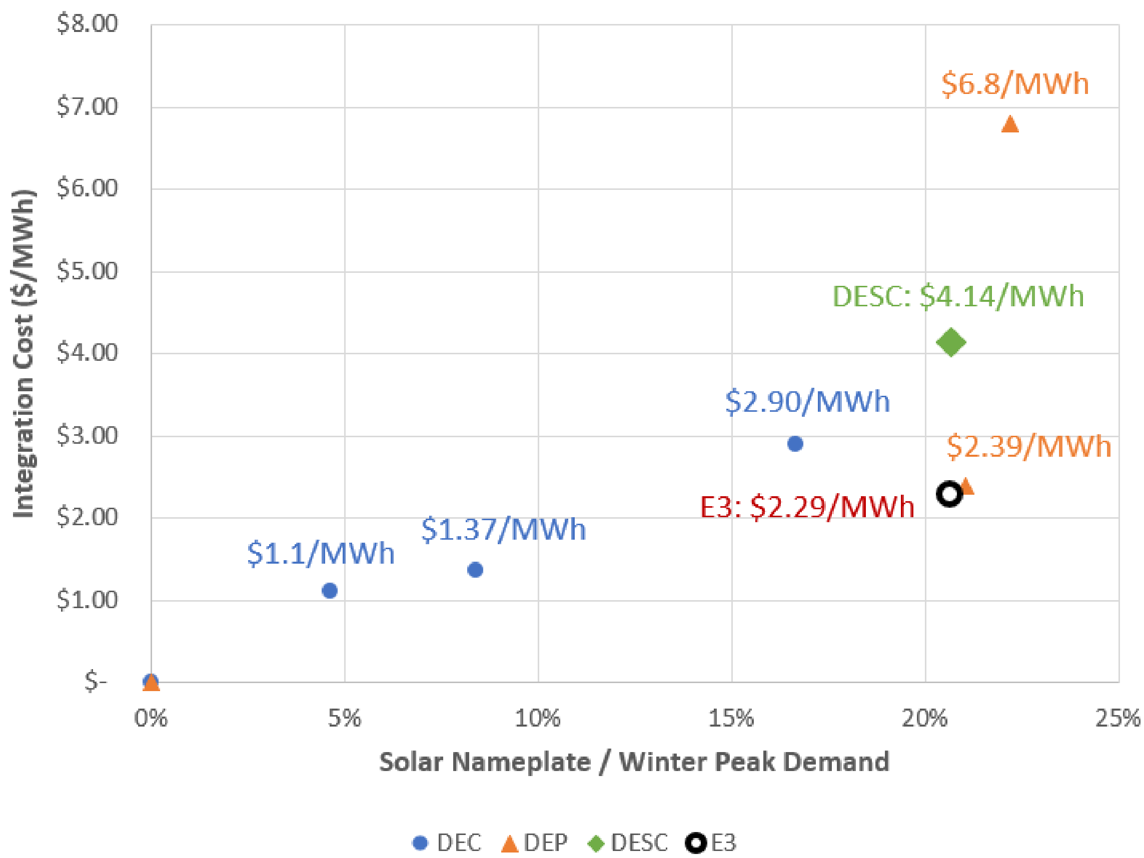
Power Advisory agrees with Mr. Horii's approach of developing a reasonable interim estimate of solar integration costs, using it as the VIC, and also using it to adjust the avoided cost-based rates – i.e., start with avoided costs that do not reflect solar integration costs, than subtract from them the same solar integration cost estimate used for the VIC. We do not support the specific calculations he used to arrive at $2.29/MWh, because it is based on Navigant's analysis, which is flawed in several ways, only one of which Mr. Horii attempts to correct. However, its magnitude is reasonable compared to the other solar integration costs proposed. Mr. Horii compared the E3 adjusted value and DESC proposal to the values for DEC and DEP in their respective dockets 2019-185-E and 2019-186-E (see Figure 2). Horii states that this figure:

> "…shows that my adjusted integration cost is very close to the value for DEP, and below the highest value for DEC. I believe the DEP result, however, is far more applicable to DESC than DEC. DEC has a higher percentage of coal and nuclear generation and lower percentage of natural gas generation than DESC and DEP. This would result in less flexibility for DEC and higher integration costs, all other things being equal. … The comparison to the DEC and DEP systems is useful because they are neighboring utilities subject to similar weather patterns. In addition, both DEC and DEP have seen significant, yet different solar penetration, which provides a useful comparison of estimated integration costs as a function of relative penetration levels."[72]

[71] Hearing Vol 2, p. 689 line 19 to p. 690 line 14 (ORS Horii).

[72] ORS Horii Direct, p. 19-20.

Figure 2. Renewable Integration Costs Proposed in South Carolina[73]



As an interim measure, until such time that the integration study has been completed and the results implemented, Power Advisory recommends using Horii's estimate ($2.29/MWh) as the VIC, and adjusting DESC's other solar rates (including PR-1, Avoided Cost and DER rates) to remove DESC's embedded integration costs and replace them with the same amount ($2.29/MWh) for all periods under consideration.

[73] Ibid.

3. STANDARD OFFER AND AVOIDED COST METHODOLOGIES

3.1 Defining Avoided Costs

Act 62 defines "avoided cost" as "…the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[74] DESC Witness Neely also notes this definition in his amended direct testimony.[75] The Act also directs that:

> "each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[76]

3.2 Avoided Cost Risks

DESC highlights the consumer risks posed by establishing avoided costs that ultimately prove to overstate actual incremental energy and capacity costs. To the extent that actual avoided costs are lower than projected avoided costs, ratepayers would be paying higher costs than if there were no QF contracts at these fixed prices. Conversely, if actual avoided costs are higher than projected, ratepayers would benefit from these fixed price QF contracts.

In support of this overpayment risk, DESC witness Kassis cites that FERC found from its 2016 PURPA technical conference that "allowing QFs to fix their avoided cost rates at the time a LEO is incurred has resulted in overpayments as energy prices have generally declined over the years, leaving the fixed energy portion of the QF rate well above the purchasing electric utility's actual avoided energy costs at the time of delivery."[77]

A shorter contract term is discussed as a primary way to mitigate some of the overpayment risk. That is the argument made by Kassis.[78] Notably, the proposed 10-year avoided cost determination consistent with Act 62 in this proceeding is significantly shorter than the historic PURPA contracts of 15 to 20 years that are offered as examples of overpayment. The time between LEO establishment, when avoided costs are fixed, and commercial operation also factor into the risk

[74] 16. U.S.C. Section 824a-3(b); (d).

[75] DESC Neely Direct Amended, p.3 lines 3-6.

[76] Act 62. Section 58-41-20 (B) (3)

[77] DESC Kassis Rebuttal p.12-13 (168 FERC ¶ 61,184, p.27).

[78] Hearing Vol 1, p.63 (DESC Kassis) and DESC Kassis Rebuttal, p.13.

of overpayment. The shorter the period, the lower the risk that the costs do not reflect the systems avoided costs. Furthermore, the avoided costs are to be updated every two years with the idea that no payment to a QF starts at a rate that is more than two years old. (DESC's proposed commercial terms and standard forms are discussed in Chapter 4).

SBA's Hamilton Davis argues that the risks to ratepayers that the Commission should consider "are not limited to inaccurate avoided energy rates and extend to utility development and ownership of other generating resources, against which SPPs provide a significant risk hedge."[79] SBA Witness Burgess offers the cancelled VC Summer nuclear Units 2 and 3 as an example of the risks of conventional generation and notes that payment to QFs is performance-based which protects customers from construction risks.[80] Together, the SBA witnesses acknowledge that there is a risk of overpayment, but assert that there are additional consumer risks posed by utility generation investment that should be weighed.

Power Advisory also notes that DESC's calculated avoided costs are substantially lower than the avoided cost rates that have historically been paid to solar QFs in South Carolina. With lower established avoided cost rates, the risk and potential magnitude of overpayment is reduced. Underlying factors, such as forecast fuel prices, in particular natural gas prices, may further mitigate the risk. The primary driver of the declining energy prices that have resulted in overpayments under PURPA contracts is low natural gas prices. While further declines in natural gas prices are possible, this is expected to be less of a factor in future years.

3.2.1 *Implications of QF Market Size*

The amount of long-term QF contracts is one driver of avoided cost risk. The larger the amount of long-term contracts, the greater the chance for over or underpayment and resulting impacts on ratepayers.

Over the past two years, the drop in avoided costs paid to solar QFs in South Carolina has been dramatic. DESC indicated that avoided cost rates paid to solar QFs calculated in this proceeding are 40-60% lower than prices from just one year ago in 2018 and the rates in 2017 were about 50% lower than those in 2018.[81] DESC Witness Neely said that no PPAs have been signed under the 2018 rates and he expects that no PPAs will be signed for the rates set out in this proceeding.[82]

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[79] SBA Davis Direct, p.7.

[80] SBA Burgess Direct, p.14-15.

[81] Hearing Vol. 1, p.335 lines 1-23 (DESC Neely).

[82] Hearing Vol. 1, p.338 lines 8-23 (DESC Neely).

3.3 Rate Impacts

There was disagreement over whether ratepayers would stand to benefit or lose from the avoided costs calculated in this proceeding that would be paid to QFs. JDA and SBA testified that currently, the avoided costs are historically low and will likely rise in the future, thereby benefiting ratepayers should DESC lock in contracts now with QFs. At the heart of this discussion was gas prices. JDA Witness Chilton indicated that the EIA expects gas prices to almost double over the next 15 years and to triple over the next 30 years, which would drive avoided costs higher.[83] She went on to say at the hearing: "long-term PPAs entered into with QFs, at currently relatively low avoided costs, would protect the ratepayers of South Carolina by giving them the benefit of a locked-in low price."[84] Similarly, Mr. Levitas said at the hearing, "I think there's every reason to believe that locking in rates now at these very low rates is going to be extremely good for ratepayers over a long period of time."[85] In response, DESC Witness Neely said forecasts are not certain and indicated that it is entirely possible that gas prices triple over the next 30 years or drop by 50% over the next 30 years.[86] However, DESC Witness Neely acknowledged that if the gas prices go up as the EIA predicts that it is in the ratepayers' interest to lock in for a longer term.[87]

SBA Witness Adams pointed to the risk of higher natural gas prices and the risk ratepayers face of paying for costs stemming from the utility abandoning a project, which it doesn't face with a QF:

> "The evidence will show that these longer-term PPAs actually protect customers. Risks – they protect customers from risks that natural gas prices are going to rise. All the risks that come with a utility's decision to build its own generation plant -- cost overruns, delays, possibility that the utility will invest billions in a project that's abandoned – all of those are not borne by the ratepayers from a QF development. QF contracts insulate ratepayers from all these risks."[88]

Mr. Levitas noted the possibility of a carbon tax on the horizon which would drive prices higher, stating: "I think you should assume that there is a very high likelihood… sometime over the life of the horizon that you're planning for here, that the carbon and greenhouse gas implications of

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[83] JDA Chilton Direct, p.8 lines 1-5.

[84] Hearing Vol. 2, p.483 lines 14-18 (JDA Chilton).

[85] Hearing Vol. 2, p.477 lines 6-9 (SBA Levitas).

[86] DESC Neely Rebuttal, p.16 lines 7-14.

[87] Hearing Vol. 1, p.366 line 24 (DESC Neely).

[88] Hearing Vol. 1, p.25 lines 7-18 (SBA Adams).

natural gas exploration and development and transport, in addition to the combustion impacts, will come under significant regulation."[89]

3.4 Avoided Energy Costs

DESC estimated avoided energy costs for both solar and non-solar QFs using a simulation model of their system. In general, the intervenors did not indicate an issue with the overall framework, but as discussed further below some did suggest certain assumptions were problematic and led to avoided cost estimates that were too low, particularly for solar generation.[90] Given the interest of many intervenors, avoided energy costs for non-solar facilities received relatively limited attention.

3.4.1 DESC Methodology and Results

DESC uses a Difference in Revenue Requirements ("DRR") methodology to calculate both the energy component and capacity component of its avoided costs. DESC Witness Mr. Neely notes that "This approach involves calculating the revenue requirements between a base case and a change case. The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed a power purchase agreement. The change case is the same as the base case except that a zero-cost purchase transaction modeled after the appropriate 100 MW energy profile is assumed."[91] The long-run avoided costs are calculated from 2020 to 2029 and are divided into two groups of five years: 2020-2024 and 2025-2029.

As discussed, DESC provided separate avoided cost estimates for a solar QF and a non-solar QF. The solar estimate was developed using a solar profile to reflect an hourly production shape from a 100 MW solar facility, whereas the non-solar estimate was developed using a 'flat' 100 MW 24 x 7 block of incremental energy.

DESC used PROSYM for its analysis. The base and change cases are identical except for the zero-cost purchase transaction in the non-solar case, and the zero-cost purchase plus incremental operating reserves in the solar generation case. The avoided energy cost is the difference between the base case costs and the change case costs for each. As discussed in Chapter 2 above, the solar avoided cost calculations were modeled with additional reserves equal to 35% of the installed

[89] Hearing Vol. 2, p.510 lines 10-16 (SBA Levitas).

[90] SBA Burgess Direct, p. 2 provides a summary of issues and ORS Horii Direct, p. 27.

[91] DESC Neely Direct, p. 7. Mr. Neely notes that this methodology was approved by the Commission in Orders No. 2016-297 and 2018-322(A).

solar capacity, during solar generating hours.[92] Issues with this aspect of DESC's methodology are discussed in that chapter.

DESC ran its model 10 times for each year and labeled these iterations of its model "seeds". This approach reflects uncertainty in certain assumptions such as generator availability due to forced outages and hourly demand patterns due to weather. It is an industry standard approach to reflect random elements in the system, though DESC did not make clear in the information provided what varied within each iteration. Each iteration of the model represents a possible outcome in terms of avoided costs and DESC estimated the avoided costs by averaging the 10 seeds. Again, this approach was not articulated but is apparent from the spreadsheets provided for modeling results.

DESC's results from this process are highlighted in Figure 3. The avoided energy costs for non-solar generation are grouped into 4 pricing periods within the standard offer, but are shown as an all-hour average in this figure for ease of comparison to solar avoided energy costs. The values in the figure are taken from modeling results files provided by DESC.

Figure 3. DESC's Proposed Avoided Costs [93]

	Avoided Costs - Non Solar ($/MWh)	Avoided Costs - Solar ($/MWh)
All Hours 2020-2024	$30.93	$16.76
All Hours 2025-2029	$36.46	$15.66

The intervenors largely accepted the overall methodology at a conceptual level, but indicated a number of specific concerns. Mr. Horii asserts that:[94]

- DESC overstated the amount of incremental operating reserves required to integrate 100 MW of solar.
- DESC used operating reserves rather than a potentially lower cost form of reserves to integrate solar.

[92] DESC Neely Direct, p. 10.

[93] DESC Response to ORS Utility Services Request #1-2 and #1-3. Data from files "Avoided Costs – Standard Offer.xls" and "Avoided Costs – Non-Solar.xls"

[94] ORS Horii Direct, p. 27

- DESC used flawed assumptions and produced inconsistent results in terms of the integration costs for solar that alternated from positive to negative integration costs annually.

Mr. Burgess argues that:[95]

- DESC assumptions and methodology were not transparent.
- DESC's selection of pricing periods is potentially biased against solar.
- DESC treated solar with storage inappropriately.[96]
- DESC's treatment of imports and exports raised concerns.

With respect to Mr. Horii's concern that DESC used flawed assumptions and produced inconsistent results, the concern was that the costs associated with higher reserves for integrating solar alternated from positive to negative. [97] Power Advisory has similar concerns as discussed below. DESC recognized an error in their results and addressed this concern, as stated in its rebuttal testimony and outlined in its hearing testimony.[98]

The issues that we believe warrant further discussion are outlined throughout the next sections of this chapter.

Power Advisory Assessment

The key issue in estimating avoided energy costs relates to integration costs and the solar avoided cost rates. DESC has assumed that it will need to carry 35% of installed solar capacity in incremental operating reserves, whereas a range of intervenors have indicated this results in is a large over statement of integration costs as discussed in Chapter 2. Notwithstanding this specific critique of DESC's approach, Power Advisory would expect very little impact on off-peak costs due to an increase of 100 MW of installed solar capacity. DESC results do not show this pattern.

Figure 4 and Figure 5 highlight this concern for two model iterations from results provided by DESC in 2027.[99] Seed 1 was selected as a model iteration that illustrates results that are difficult to reconcile with logical expectations. The graphs show the increase or decrease in system costs in $/MWh on the vertical axis, while hours of the day are on the horizontal axis. Note that the $/MWh costs in the graph are the change in total system costs, i.e. if hourly load was 5,000 MW at 4 am, a $4/MWh cost represents a $20,000 increase in energy costs in an hour with no solar

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[95] SBA Burgess Direct, p. 21-22

[96] Hearing Vol 1, p. 340 line 3 to p. 342 line 14 (DESC Neely). Neely states that the solar and storage rate has not been prepared but will be prepared by the end of 2019 as mandated.

[97] ORS Horii Direct, p.29-30.

[98] DESC Neely Rebuttal, pp. 6-7 and Hearing Testimony, October 14, 2019, pp.127-128 (Witness Neely).

[99] DESC Response to ORS Request #1-2, file "Avoided_Cost_seed1_Base.mrg" less "Avoided_Cost_seed1_Change.mrg". Winter is defined as November through March in the graphic, while Summer is defined as the remainder of the year for simplicity.

production. This graph is an hourly representation of the DRR methodology results as reflected by DESC's hourly data.

[redacted]

As illustrated, in winter months particularly, Seed 1 has very high over-night costs associated with 100 MW of incremental solar capacity, a time when there would be no solar output. While DESC did not provide hourly data for the iterations of the model without incremental operating reserves, the hourly results with the solar resources appear to show that additional solar generation results in very large overnight costs. This seed does not reflect a similarly large reduction in avoided energy costs in hours with solar production, especially during winter hours (defined as November through March within this analysis).

Power Advisory cannot reconcile this pattern of very high overnight costs when there should be no incremental ancillary services costs from solar generation (as there would be no solar output) against minimal on-peak avoided energy costs. [100] Notably, in this iteration of the DESC model,

[100] DESC Neely Direct, p. 10. States that reserves are added only during solar generating hours.

[redacted]

Seed 2 is another iteration of the model that shows above average avoided costs for solar generation but still shows significant incremental costs in hours with no expected solar generation. For example, in the winter months the model shows [redacted] Minor changes in avoided costs overnight are reasonable due to small changes in timing of storage decisions and unit commitment, but it is unclear what would trigger large incremental costs in hours when solar generation is not operating.

[redacted]

Comparison of the individual model runs within the files noted also raises concerns with the modeling for solar generation.[102] As noted, DESC performed 10 iterations of its models to determine the avoided cost via the DRR methodology. The results for the solar generation avoided cost estimates appear to demonstrate an extreme level of modeling uncertainty around the estimated solar avoided costs. For example, the model results indicate that when incremental

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[redacted]

[102] Power Advisory has reviewed similar data for the non-solar analysis and does not have concerns.

reserves are carried to integrate solar, in some iterations solar generation has avoided energy costs below [redacted]

[redacted]

This level of uncertainty calls into question the overall reliability of the results for solar generation. Given that the main fundamental supply and demand assumptions are identical between model seeds,[103] avoided energy costs from solar generation ranging from -$6/MWh to $30/MWh is concerning. At a minimum, these results should be examined in much greater detail than was possible given the timing and lack of supporting data provided by DESC. Power Advisory does not have similar concerns with the non-solar modeling.

Second, the fact that individual seeds vary so widely with constant assumptions raises the possibility that the results are highly sensitive to assumptions such as unit commitment and storage treatment, as well as other less obvious assumptions. Clarity around the impact of key drivers is necessary to properly evaluate the reasonability of the results. To the degree that the modeling results reflect such variability we would expect that the factors that contribute to this variability would be explained in an effort to demonstrate the reasonableness of these results.

[103] In Power Advisory's experience and with the information provided in the filing, albeit minimal in nature, the fundamental assumptions (supply mix, fuel costs, annual load and unit characteristics) are understood to be identical across model seeds and only random factors drive the difference.

Finally, the results suggest a fundamental concern that cannot be addressed with the data as provided. Very high overnight costs associated with solar generation are counterintuitive. Incremental operating reserve costs should not be the driver as there is no solar generation in these hours and DESC has indicated reserves were only added during solar production hours. Other factors such as differences in unit commitment are a possible explanation, but accepting this as the driver would require much more information than available.

3.4.2 Transparency

Mr. Burgess suggested that DESC did not meet the transparency requirement of Act 62, while Mr. Horii did not mention transparency concerns but did note that more time to do more detailed analysis would be helpful. [104] [105] As stated in the legislation, "Each electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[106] Mr. Burgess argues:

> "there are several aspects of DESC's avoided cost calculations and methodologies that are obscure and unexplained, both in Dominion's initial cost filings and in discovery responses. Dominion's filings are far less transparent than Duke's filings, which themselves were not models of clarity. As a result, there may be additional problems with methodologies and assumptions beyond the issues identified in my testimony below. Certainly it would be impossible to independently "verify" the reasonableness of Dominion's proposed rates based on the information that has been provided by the company. The issues on which there is a meaningful lack of transparency include (but are not limited to) the rationale for selection of peak hours and peak seasons as well as hourly avoided cost data and marginal cost data for the base and change case in DRR analysis."[107]

DESC disagreed with Mr. Burgess' assessment. Witness Neely states "I believe that Mr. Burgess' own testimony disproves his suggestion that DESC's avoided cost filings are not reasonably transparent. On page 21, line 17 through page 22, line 12 of his direct testimony, Mr. Burgess accurately describes the methodology used by the Company, which indicates that he understands and is aware of the methodology employed as well as its individual components and the underlying data. I would also state that DESC properly responded to all of SCSBA's requests for information."[108]

[104] SBA Burgess Direct, p.22.

[105] ORS Horii Direct, p.6.

[106] Section 58 41 10 (J)

[107] SBA Burgess Direct, p.21, lines 4-14.

[108] DESC Neely Surrebuttal, p.21, lines 4-10.

Mr. Burgess argued that a high-level understanding is not sufficient to meet the requirements of the Act. He states:

> "I was able to describe my understanding of DESC's approach in general terms, because DESC provided a high-level explanation of its methodologies in its direct testimony (as it has historically done in previous dockets setting avoided cost). But that is not sufficient for Act 62, which requires enough transparency 'so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission.' As described in my direct testimony, there are many instances in which Dominion did not provide access to adequate data and modeling details to verify the reasonableness of specific methodological choices or inputs and assumptions used by DESC, or its subsequent findings. Additionally, key portions of DESC's analysis on integration costs were provided only one day before intervenor direct testimony was due, thus severely limiting my to analyze the results or serve discovery in a timely manner."[109]

Power Advisory Assessment

In Power Advisory's view, the DESC avoided cost filing did not fully provide a sufficient level of transparency "so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[110] For example, DESC provided avoided cost data in response to interrogatories and didn't identify the data structure or format, requiring a secondary interrogatory, which consumed valuable time in any already compressed schedule.[111] Although transparency improved throughout the proceeding, significant portions of the data were provided in a form that required substantial effort to digest. We would expect that basic data to support the avoided cost estimates could be provided as part of the initial filing.

In addition, there remain significant questions as noted in this chapter that cannot be answered with the information provided. While hourly avoided costs data was provided, other data required to fully vet the drivers of the avoided cost patterns outlined in this chapter were not provided. Therefore, we don't believe that DESC satisfied the transparency standard outlined in Act 62.

3.4.3 Technology Neutral Approach

DESC has proposed two distinct rates: one for solar generation and one for non-solar generation. As stated during the Hearing, DESC believes that the unique production profile of solar generation justifies a rate specific to solar generation.[112] In contrast, a technology neutral approach could

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[109] SBA Burgess Surrebuttal, p.4-5.

[110] Act 62. Section 58-41-30. (J)

[111] DESC Response to SBA Request #2-1 and 2-2.

[112] Hearing Vol. 1, p. 315 lines 15-23 (DESC Neely).

define avoided cost values by time block and all resource types would be paid the same for energy produced in that time block.

Mr. Burgess suggests a technology neutral approach that values energy the same in a given time period regardless of the type of generator that supplied it. Mr. Burgess outlined that "This resource-specific approach raises significant concern about the ability of separate rates to properly represent the full suite of QF technological possibilities within the categories of "solar" and "solar-plus-storage." Singling out these resource categories and computing pre-determined avoided cost rates suggests that they each have rigid technological and performance specifications when in fact both "solar" and "solar-plus-storage" cannot be generalized as such."[113]

Mr. Burgess further states that a technology neutral approach could "be similar to the non-solar QF rate that DESC has proposed, but made available to all technologies. I believe such a "technology-neutral" rate would provide a better price signal to prospective solar and solar-plus-storage generators to target energy and capacity delivery during the times they benefit customers most."[114] Burgess also notes that this is the approach Duke has taken.

In the absence of a technology neutral approach, Burgess suggests an approach that provides a unique value to all possible configurations of solar and solar plus storage.[115]

DESC disagreed with both the proposal to develop a technology neutral rate, as well as with Burgess' alternative approach in the absence of a technology neutral approach. Specifically, Neely notes "Solar has a unique profile and therefore the true avoided cost of additional non-dispatchable solar can only be accurately captured using a solar specific avoided cost calculation. As well, the Form PPA tariff envisioned by Act No. 62 allows utilities to calculate resource specific avoided cost rates."[116]

Power Advisory Assessment

A technology neutral approach is more flexible and reflects actual value for customers in specific hours. The approach suggested by Burgess modeled on the non-solar QF contract is reasonable, though it may be necessary to develop a larger number of groupings to reflect value from generators with highly correlated profiles, such as solar. Power Advisory agrees with the concern that there are a large number of configurations that will result in materially different solar profiles

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[113] SBA Burgess Direct, p. 19-20.

[114] Ibid,, p. 20-21.

[115] Ibid., p. 21.

[116] DESC Neely Rebuttal, p. 20.

from new facilities, and as a result the DESC approach is potentially discriminatory because it is premised on a specific production shape that may not hold true for future facilities.

3.4.4 Selection of Pricing Periods

Burgess raises a concern that the grouping of hours is potentially biased against solar generation and that the data to support the groupings shown was not supported. [117] [118] Burgess also questions the result that avoided costs are higher during off-peak seasons, in contrast to typical expectations. This is supported with analysis of load shapes and load shapes net of solar generation. Burgess concludes by suggesting that hourly data on avoided costs and marginal costs should be provided.[119]

In Rebuttal Testimony, Neely indicates that Burgess' concerns are not valid as the selection of pricing periods applies only to non-solar generation. In his Surrebuttal Testimony, Burgess stated that data files provided by DESC do in fact group data into the four hourly pricing periods noted for solar generation.

Power Advisory Assessment

The pricing periods should be chosen to reflect discernable pricing patterns and underlying differences in avoided costs throughout the day. The use of broad pricing periods increases the risk that these periods are composed of times when there are consistent underlying differences in avoided costs, which would be better reflected in more narrow pricing periods. We recommend that DESC provide support for the pricing periods that it employs in its next avoided cost filing.

3.4.5 Avoided Energy Cost Conclusions and Recommendations

The data provided by DESC raises significant concerns with the modeling used to estimate avoided energy costs for solar generation. These concerns are driven in part by the approach of adding ancillary services to integrate solar generation, but it remains unclear why off-peak costs during hours with no solar generation are, in some cases, nearly as large (or even larger) than the on-peak avoided costs. The extreme range in the estimates across different iterations of the model is also problematic as the overall system assumptions are the same for each iteration of the model, and the range of outcomes is outside of what would be expected based on Power Advisory's experience.

Hourly data was only provided for the solar change case including incremental operating reserves. Based on the pattern of hourly avoided costs seen in the change case with incremental operating

[117] SBA Burgess Direct, p. 24

[118] SBA Burgess Direct, p. 24-28.

[119] Ibid., p. 27-28. Note that hourly avoided cost data was subsequently provided on a confidential basis.

reserves, it is important to understand the driver of overnight cost increases. With the data provided, it is not possible to determine if the ancillary services assumptions are driving the impact or whether other factors such as altered generation commitment patterns are driving the result. In either case, the results raise concerns with the approach both due to the pattern of hourly avoided costs and the extreme range of avoided costs across model iterations.

Given Power Advisory's view that the 35% of installed solar capacity reserve assumption is inappropriate (see Chapter 2 conclusions), Power Advisory recommends that the Commission undertake an independent renewables integration study, as authorized by Act 62. This will "allow for a more transparent and accurate calculation of integration cost that includes stakeholders and additional technical experts."[120] In addition, in subsequent avoided cost filings Power Advisory recommends that DESC be required to include avoided cost estimates as part of its initial filing and we would expect that it would provide evidence that highlights the key assumptions and where there are counterintuitive results (e.g., overnight negative avoided costs from solar) or extreme ranges in outcomes across model seeds that these be explained. In order to determine if the avoided cost estimates are reasonable, it is first necessary to understand what is driving the results outlined in this chapter.

Given our concerns with the avoided cost modeling and the relatively significant divergence in avoided costs from those projected for DEC and DEP, we are concerned that the avoided cost estimates presented by DESC are not reliable. [121] Given the lack of transparency with respect to the Company's avoided cost methodology and assumptions there aren't specific changes to the methodology and assumptions that we can recommend.

As an interim step and as noted in Chapter 2, until such time as the integration study has been completed and the results implemented, Power Advisory recommends adjusting DESC's solar rates – including PR-1, Avoided Cost and DER rates – to remove DESC's proposed integration costs and replace them with an integration cost of $2.29/MWh for all periods under consideration, based on a proposal by Mr. Horii.

3.5 Avoided Capacity Costs

There are two key areas debated on the value of capacity. First, there are methodological issues on the amount of capacity provided by solar resources. Second, several issues are related to the actual cost of capacity resources that would be avoided that impacts both solar and non-solar resources.

[120] SACE/CCL Stenclik Surrebuttal, p. 22, lines 4-5.

[121] Power Advisory acknowledges that caution should be exercised when comparing avoided cost estimates between two different companies and when doing so consideration needs to be given to differences in their resource mix and demand profile.

3.5.1 DESC Capacity Value Methodology

DESC and several intervenors disagree on the approach to determine the capacity value of solar resources. At issue is how much capacity solar QFs actually avoid. There are two basic approaches. The DESC approach assumes that DESC is a winter peaking system and the capacity value of a resource is a function of how much it generates during the peak winter hours. This is effectively a reserve margin approach that assumes if there is enough capacity to meet demand in the peak demand hour, there will be enough capacity in the rest of the year as well. The alternative approach is more probabilistic in nature and assesses how much an asset will be producing on an expected basis during 'critical' hours, where critical hours are influenced by both supply outages and high demand. This is known as the Effective Load Carrying Capacity (ELCC) approach.

DESC Witness Lynch provides an overview of the ELCC approach as applied by DESC. "There are basically three steps in calculating an ELCC value. The first step is to calculate the LOLH in the base case. The second step is to create a change case by combining the solar profile with the base system load profile to create an adjusted load profile net of the solar output and then recalculate an LOLH. The LOLH in the change case will be lower than in the base case indicating more reliability. In the third step, either the loads are increased, or the capacity is decreased in the change case until the LOLH matches the base case LOLH. The resulting adjustment in load or capacity is the ELCC value of the solar profile since it results in an equivalent LOLH value to the base case."[122]

A second approach employed by DESC is a reserve margin approach, which DESC asserts indicates that solar generation does not provide any capacity value for its system.[123] DESC argues that capacity needs are driven by winter peaks and solar does not provide any energy during these critical peak periods. DESC notes it has done significant work studying the capacity value of solar. In Mr. Lynch's Rebuttal testimony he stated "All three analyses represent thorough and detailed studies of the characteristics of solar generation and its impact on the Company's system load. All three support the same conclusion that solar does not avoid the Company's need for winter capacity, does not avoid any capacity costs, and therefore has a zero-capacity value. I do not consider this work overly simplistic; instead, it represents direct analysis of actual solar profiles and provides clear and irrefutable evidence that solar has a zero-capacity value on DESC's system."[124]

The essential finding Mr. Lynch relies on is that the combination of solar production timing and the timing of load peak hours do not align because the peak load hours are early morning in the winter. DESC suggests that unless a resource serves load in these peak hours, there is no capacity contribution because the company will still purchase capacity sufficient to meet its reserve margin

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[122] DESC Lynch Direct, p. 9.

[123] DESC Lynch Rebuttal, p. 2.

[124] DESC Lynch Rebuttal, p. 2.

target in the critical hours. On this basis, Mr. Lynch discounts entirely the value of the ELCC approach:

> "Unfortunately, it does not matter how good or bad the ELCC estimates are in summer. DESC needs capacity in the winter and solar does not provide capacity on early winter mornings before sunrise when the system peaks nor during peak hours on most non-summer days when the system peaks before sunrise or after sunset."[125]

ORS witness Horii suggests that the ELCC approach is the industry standard and more appropriately reflects capacity value of solar:

> "Therefore, I maintain the position that DESC's approach for avoided capacity cost is simplistic. This simplistic focus is reinforced by the Company's own rebuttal testimony that attacks the industry standard Effective Load Carrying Capacity ("ELCC") approach because the ELCC recognizes there is a value from solar capacity at times other than before sunrise (Lynch Rebuttal, pp. 4-5). While DESC's system may often peak before sunrise, the need for capacity also depends on the risk of generation or transmission outages, which can occur at other times of the day, therefore resulting in values for capacity at other times of the day."[126]

SBA Witness Burgess makes similar comments on the probabilistic nature of outage events. Mr. Burgess describes the DESC approach as "…somewhat akin to betting on a horse race. One strategy might be to put all your money on the front runner since that horse is more likely to win. However, another strategy might be to place a series of smaller bets on the second, third, and fourth ranked horses. Over the long-run the second strategy could have a similar or even greater payout. Diversifying one's "bets" in this way also serves to reduce the overall risk of the investment, as compared to a single large bet on the leading horse. Likewise, for resource planning, one could plan solely for the one peak hour of the year that has the highest probability of an outage (e.g. as DESC claims, this might correspond to January at 7 a.m.). However, this would ignore many other hours of the year that have smaller, but still meaningful probabilities of an outage. Covering these hours could have the same or even greater contribution to reliability from a probabilistic standpoint as addressing the single peak hours."[127]

Mr. Burgess expands on this point to suggest DESC's system has net summer peaks that are very close to the winter peaks and the relative importance of summer peaks versus winter peaks could easily change.[128] His evidence suggests the DESC approach overstates the degree to which only

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[125] DESC Lynch Direct, p. 11 lines 9-13.

[126] ORS Horii Surrebuttal, p. 10.

[127] SBA Burgess Direct, p. 47-48.

[128] SBA Burgess Direct, p. 50-52.

winter capacity has value on the system and therefore understates the capacity value of solar generation.

Mr. Burgess also provides evidence in support of using the ELCC approach, as it is a common approach, particularly in regions with large solar generation fleets.[129]

Based on the ELCC methodology, Mr. Horii suggests that solar should receive a capacity benefit of 11.8% of its nameplate capacity because there are already over 500 MW of solar operating in DESC territory. Given that solar adds progressively less capacity value as its installed base grows, Mr. Horii proposed that the ELCC value from 500 MW to 1,000 MW be used.[130] SBA Witness Burgess suggests solar could receive a capacity value of 24% based on the average capacity contribution of 1,000 MW of solar, as calculated by DESC under the ELCC approach.[131] DESC Witness Lynch states that because the company already has 1,048 MW of signed solar PPAs, even under the ELCC approach the appropriate value for solar capacity is 4%.[132]

Power Advisory Assessment

The ELCC methodology is industry standard and reflects a probabilistic approach to resource modeling. Power Advisory agrees with Mr. Horii and Mr. Burgess that solar provides capacity even in the event it does not generate during the system peak load hour because capacity shortfalls can occur in non-peak hours due to supply side issues. Reliability is a function of both supply and demand factors, and the approach outlined by Lynch does not reflect this. The fact that DESC has summer peak loads relatively similar to winter peak loads after the impact of demand response has been netted out, as outlined by Mr. Burgess, reinforces the approach that values capacity during all potential hours where there may be insufficient supply.[133]

Capacity value should therefore be estimated using the ELCC methodology. As raised by Mr. Lynch, DESC has over 1,000 MW of solar capacity under contract and therefore the capacity value of solar should be estimated assuming this capacity is already in place.[134] As noted, this provides a capacity value of 4% of installed capacity on the basis that 1,000 MW of solar have already executed a contract.

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[129] SBA Burgess Direct, p. 52.

[130] ORS Horii Direct, p. 37.

[131] SBA Burgess Direct, p. 59-60.

[132] DESC Lynch Rebuttal, p.11 line 12 to p. 12 line 8.

[133] SBA Burgess Surrebuttal, p. 11 paragraph 1-2.

[134] Ibid.

3.5.2 DESC Capacity Cost Methodology

The second key area of disagreement involves the approach used to estimate the actual value of capacity. In effect, DESC uses a methodology that intervenors suggest under-values capacity on a $/MWh or $/kW basis.

DESC states it has in effect two reserve margin targets for winter capacity. Its "base" reserve margin target is 14% and its peaking reserve margin target is 21%. Similarly, DESC as a base reserve margin target of 12% in the summer and a peaking reserve margin target of 14%.[135] DESC purchases capacity from lower cost resources such as market purchases or demand response to meet the "peaking" reserve margin requirements, whereas "base" requirements are meant with internal capacity such as generation development.

At issue is whether the avoided capacity cost should be estimated based on the cost of meeting peaking needs with a gas generator or with market purchases. The impact of this choice on avoided capacity cost is significant. Witness Horii estimates capacity costs more than three times higher for non-solar generation than DESC.[136]

> "The correction of the winter reserve margin and the consistent use of CTs to meet capacity needs has the largest impact. I also detected an error in the DESC model. The Company incorrectly used a 14% reserve margin in their model, which reduces the need for capacity, thereby reducing the value of QF capacity. A 21% reserve margin is DESC's stated reserve margin for evaluating the need for peak capacity (Lynch, p. 17), and also the reserve margin used for their resource planning, as shown on their Load and Resource Balance tables on pages 47-48 of their 2019 IRP."[137]

DESC disagrees with Mr. Horii and states that it uses a 14% reserve margin in estimating the capacity value of PURPA resources because it purchases low-cost and relatively short duration capacity to meet the 21% reserve margin. In effect, DESC uses a 14% reserve margin for base winter capacity needs and the incremental 7% margin is required for rare periods when cold weather increases peak demand above typical levels. This relatively rare capacity need is met by demand response (interruptible load) or market purchases, as an example.

As stated by DESC Witness Neely:

> "The low-cost capacity resources in the avoided capacity calculation were the same as those shown on pages 47 and 48 of the Company's 2019 IRP. These low-cost capacity resources could be purchased power or other types of low-cost resources such as interruptible load. These low-cost capacity resources were meant to provide needed

[135] DESC Neely Rebuttal, p. 9.

[136] ORS Horii Direct, p. 41.

[137] ORS Horii Direct, p. 40.

> peaking reserves for the top 10 to 20 days of highest capacity need each year. Because only half of the peak days would occur in the winter, it would be inappropriate to add a generating resource for the purpose of only covering generation needs for 5 to 10 winter peak days a year. Instead, the Company currently plans to only add generating resources to the resource plan when the winter reserve margin drops below the 14% level or the summer reserve margin drops below the 12% level. These costs accurately reflect DESC's forecasted costs and reflect an approach to system planning that minimizes costs to customers."[138]

Mr. Horii disagreed with this approach in his surrebuttal testimony and stated that the appropriate approach to meet even infrequent capacity needs remains a combustion turbine.[139] The rationale provided was that surplus capacity may not be available from other markets when needed, and savvy capacity providers would price short-term capacity at the avoided cost level of the buyer in any event. Finally, Mr. Horii notes that for consistency if the DESC approach is used, the value of selling excess capacity in summer months for DESC should be recognized.

As noted, the impact of this issue is large on two fronts. First, using a 14% reserve margin versus a 21% reserve margin requirement alters the timing of DESC's capacity needs. This directly impacts the avoided capacity cost estimates, since the lower requirement capacity is not needed as early in the forecast period. Second, the use of low-cost resources such as interruptible load and market-sourced capacity purchases represents a lower cost of capacity that is avoided in the change case.

Power Advisory Assessment

In Power Advisory's view, capacity requirements are not typically bifurcated as base and short-term as has been done by DESC. Rather, the capacity requirement is generally set and resources are procured to meet the overall capacity need. As a result, capacity value should be determined based on the avoided cost of a combustion turbine generator rather than market purchases. Combustion turbines are used as the proxy capacity resource in many markets because they represent the 'default' capacity resource. Power Advisory concurs with Mr. Horii.

3.5.3 DESC Capacity Cost Assumptions

Intervenors disagreed with a number of DESC assumptions that led to different estimates of capacity cost.

Mr. Horii raised a concern that DESC understates capacity cost with its choice of a 100 MW solar change case and a 93 MW peaking resources.

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[138] DESC Neely Rebuttal, p. 11.

[139] ORS Horii Surrebuttal, p. 8-9.

> "I use a 93 MW change in capacity between the base case and the change case because 93 MW is the capacity of the CT units that DESC adds for new capacity. Because of the lumpiness (limited flexibility of sizing) of CT plants, a 100 MW or a 93 MW change result in the same Change Case expansion plan. However, since the cost difference between the Change Case and the Base Case expansion plans are divided by the capacity change (100 MW or 93 MW), the choice of capacity change amounts will affect the final dollar per kW avoided capacity cost. Using the 100 MW change results in an avoided cost that is 7% lower than the avoided cost using the 93 MW change."[140]

DESC disagrees with this approach. DESC Witness Neely states:

> "PURPA specifically provides that a utility may use a capacity change of up to 100 MW to calculate avoided costs. Using a capacity change of 100 MW is consistent with the avoided energy costs and with the Company's prior calculations. Moreover, using a 93 MW capacity change as Mr. Horii suggests would not address his concern about the "lumpiness" in the calculation. The only way to avoid such "lumpiness" would be to add additional resources that exactly equal the amount needed to meet the reserve margin requirement each year, which is unreasonable."[141]

The choice of asset life also impacts the estimate of capacity value because it influences the cost estimate of new capacity that is displaced by the resource. DESC uses a 60-year asset life for combustion turbines based on its depreciation study.

> "It therefore is entirely appropriate and evidence based to use a 60-year economic life when considering the annual cost of a CT unit. To suggest using a shorter economic life is inconsistent with the actual useful life of these assets and the depreciation analysis reviewed and accepted by the Commission and results in DESC customers overpaying avoided capacity costs." [142]

ORS witness Horii provides evidence that using a 60-year asset life assumption, in isolation, leads to an understatement of the capacity cost.

> "While CT lives can be extended far beyond their original expected lives, such an extension would require expensive plant overhauls. DESC's avoided cost model did not include major overhaul costs. Had major overhaul costs been included, a 60-year economic life could have been used, however the resulting avoided capacity costs would likely be similar in

[140] ORS Horii Direct, p. 39.

[141] DESC Neely Rebuttal, p. 13.

[142] DESC Neely Rebuttal, p. 12.

magnitude to the estimates produced using a 20-year economic life without major overhaul costs."[143]

Power Advisory Assessment

Power Advisory agrees with Mr. Horii that the capacity between the base case and the change case should be aligned. DESC's use of a 100 MW solar change case and a 93 MW combustion turbine resource base case serves to understate avoided capacity costs by 7%.

Power Advisory also agrees that a 60-year asset life assumption is not reasonable for estimating avoided capacity costs. This ignores associated major maintenance fixed costs as noted by Horii, and is contrary to typical industry assumptions in assessing fixed costs of new capacity. As noted, 20 years is a reasonable economic life assumption and this assumption is used in many markets throughout the United States. Absent adjustment to reflect incremental fixed costs associated with a 60-year asset life, a 20 year asset life should be assumed in calculating capacity value.

3.5.4 Avoided Capacity Cost Conclusions and Recommendations

Power Advisory believes DESC's approach serves to understate avoided capacity costs. Power Advisory recommends that the avoided capacity rates proposed by ORS Witness Horii in Direct Evidence be approved, with one potential correction. [144] The capacity rate for solar should be adjusted to reflect an ELCC value for a 93 MW increment above the current existing and contracted solar capacity. Power Advisory's understanding is this is currently 1,048 MW, which implies a capacity value of about 4% as outlined above.

[143] ORS Horii Surrebuttal, p. 10.

[144] ORS Horii Direct, p. 41.

4. FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND OTHER RELATED TERMS AND CONDITIONS

4.1.1 Background on Commercially Reasonable Terms and Conditions

Act 62 specifies that the Commission should treat QFs on a fair and equal basis with utility-owned resource while protecting ratepayer interests. The relevant sections of the Act as it relates to this chapter of the report include the following (emphasis added):

- "Within such proceeding the commission shall approve one or more standard form power purchase agreements for use for qualifying small power production facilities not eligible for the standard offer. Such power purchase agreements shall contain provisions, including, but not limited to, **provisions for force majeure, indemnification, choice of venue, and confidentiality provisions** and other such terms, but shall not be determinative of price or length of the power purchase agreement. The commission may approve multiple form power purchase agreements to accommodate various generation technologies and other project specific characteristics."[145]
- "A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. **In no event**, however, **shall the small power producer**, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, **be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility**."[146]
- "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[147]

[145] Act 62. Section 58 41 10 (A)

[146] Act 62. Section 58 41-10. (D)

[147] Act 62. Section 58-41-20. (A)

- "In implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources by ensuring that power purchase agreements, including terms and conditions, are **commercially reasonable** and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."[148]

- "In establishing standard offer and form contract power purchase agreements, the commission shall consider whether such power purchase agreements should prohibit any of the following: (a) **termination of the power purchase agreement**, **collection of damages from small power producers**, or commencement of the term of a power purchase agreement prior to commercial operation, if delays in achieving commercial operation of the small power producer's facility are due to the electrical utility's interconnection delays"[149]

- "The commission is expressly directed to consider the potential benefits of terms with a longer duration [than 10 years] **to promote the state's policy of encouraging renewable energy**." [150]

In this chapter, we examine terms and conditions of the Standard Offer PPA, the Large QF PPA and the Notice of Commitment to Sell Form, and consider their commercial reasonableness.

As specified by Act 62 a critical standard for assessing the reasonableness of the terms and conditions is the degree to which they are commercially reasonable. In the most basic sense commercially reasonable means terms and conditions that are consistent with the concepts of good faith and fair dealing. For a PPA this requires a balancing of various principles and concepts including: (1) the terms and conditions should conform to industry norms and what is typical, with good comparables being other PURPA PPAs; (2) result in an appropriate alignment of risk, with risks best managed by those who have control over them; (3) the terms and conditions should not unduly impair the ability of the QF to secure financing. For example, if there is an unreasonable risk of termination of the PPA that cannot be adequately mitigated by the QF, or financial penalties that would imperil the ability to cover debt service, without a reasonable opportunity to remedy, or other significant risks related to the cash flows, the project would be in jeopardy of not securing financing; and (4) the terms and conditions should be reasonable from the perspective of

[148] Act 62. Section 58-41-20. (B) (2)

[149] Act 62. Section 58-41-20. (E) (3) (a)

[150] Act 62. Section 58-41-20. (F) (2)

ratepayers and reflect the objective in the Act to reduce the risk placed on the using and consuming public. [151]

In our comments below, we have attempted to strike a reasonable balance between treating QFs on a fair and reasonable basis and protecting ratepayer interests, while striving to reduce the risk placed on the using and consuming public.

4.1.2 Reasonableness of 10-year PPA Contract Length in South Carolina

As discussed, Act 62 represents a delicate balancing of the interests of the consuming public and the interests of QFs, while striving to reduce the risk placed on the using and consuming public. However, as various parties pointed out the Act was passed unanimously in the South Carolina House and Senate. Given the effort devoted to drafting this legislation it would appear that there was an expectation by legislators that the Act would engender a response beyond the filings by various electric utilities. Nonetheless, Act 62 by no means establishes securing financing or ensuring QF project development as a threshold. However, we expect that the Commission would be interested in understanding the implications of the proposed avoided costs on the resulting opportunities for QF development in South Carolina, recognizing that the Act provides:

> "Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost."[152]

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[151] Reflecting the balancing of these principles and the appropriate risk allocation, the QF is ultimately responsible for project construction and operation and the terms and conditions should provide proper incentives to ensure that these responsibilities are discharged in a manner the project provides the value that the utility has contracted for "the Scheduled Commercial Operation Date shall be no more than three years from the date the Effective Date."

PacificPower "Oregon Standard Power Purchase Agreement (New QF)", approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.

https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

[152] Act 62. 58-41-20 (F)(1)

Contract length was an important issue in this proceeding, with a number of intervenors arguing that contract lengths longer than 10-years were essential if QFs were to secure regularly-available market-rate financing, under the term employed by Johnson Development Associates, Inc. Witness Ms. Chilton. In her direct testimony, Ms. Chilton, representing JDA, emphasized that for QFs to attract commercially reasonable and market-rate financing both the initial term and PPA must be strong enough to attract capital.[153] She further states

> "The longer the contract term, accompanied by a reasonable avoided cost-based purchase price, the more mainstream capital will be available for QF development. PURPA and FERC regulations defer to Commissions to direct PPA terms. In South Carolina, Act 62 recommends a ten-year term as a starting point, but does not limit PPAs to ten years. Indeed, Act 62 expressly encourages this Commission to support longer-term contracts as a means of promoting renewable energy."[154]

Ms. Chilton recommends that

> "the Commission set the tenor of length of PPA contracts at a minimum of fifteen (15) years with appropriate conditions as set forth in SC Code Ann. § 58-41-20(F)(1) to facilitate the opportunity to obtain financing for a majority of QFs in South Carolina."[155]

In his rebuttal testimony, Mr. Kassis responds by stating:

> "Contrary to Ms. Chilton's assertion that PURPA requires pricing and initial term strong enough to attract financing, FERC is concerned with adhering to Congress' fundamental requirement that avoided cost rates may not exceed incremental costs. If an avoided cost rate is accurate but low, it may not be raised above incremental costs for any reason, even if the reason is to attract more favorable financing."[156]

In her surrebuttal, Ms. Chilton states that FERC expects that the calculation of avoided cost together with other PPA terms that are fair to QFs will result in "just and reasonable prices for consumers and the development of QFs."[157]

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[153] JDA Chilton Direct, p.6.

[154] JDA Chilton Direct, p.8.

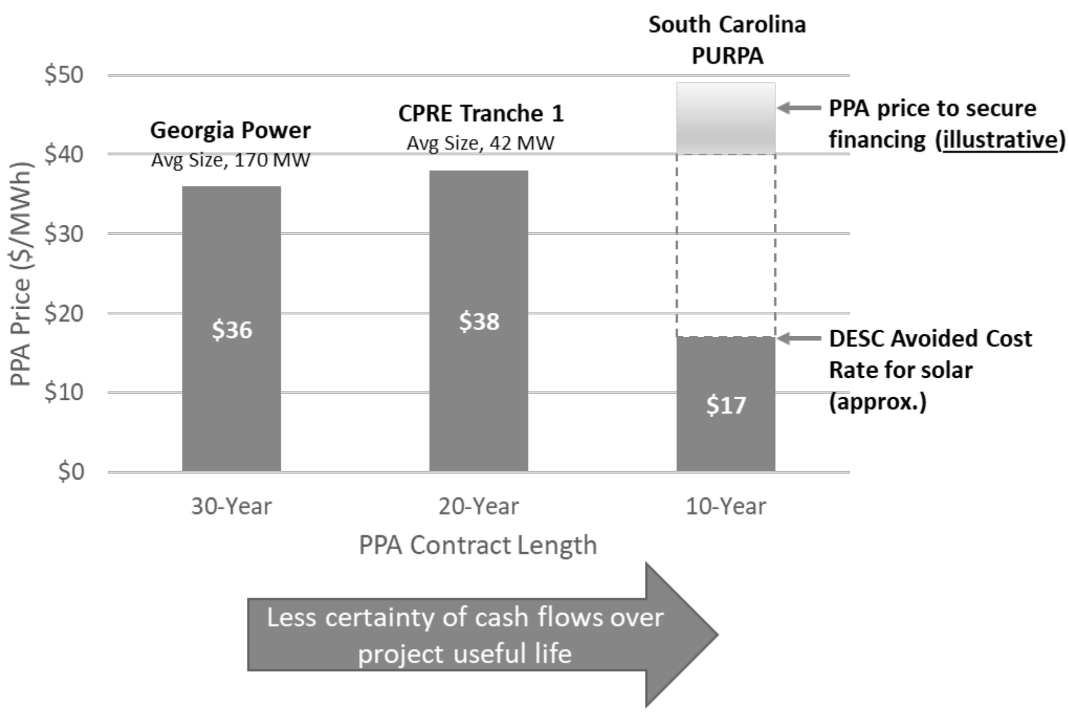
[155] JDA Chilton Direct, p.10.

[156] DESC Kassis Rebuttal, p.14

[157] JDA Chilton Surrebuttal, p.3.

At the heart of whether the 10-year term is sufficient or not to enable financing under reasonable terms is the contract price. As contract length shortens, the required PPA price to secure conventional financing increases owing to the riskiness of the cash flows in the post-PPA period. This relationship is illustrated in Figure 7. The figure contains PPA pricing for 30-year, 20-year and 10-year PPAs. In late 2017, through competitive bid, Georgia Power contracted for 510 MWs of solar in Georgia with an average price of $36/MWh for 30-year contracts.[158] Eighteen months later, in 2019, Duke contracted for 550 MWs of solar projects in North Carolina (CPRE Tranche 1) for an average price of $38/MWh for 20-year contracts. Owing to the increased riskiness of the cash flows in the post-PPA period, the $/MWh price for a 10-year PURPA contract in South Carolina would need to exceed the $38/MWh figure. The problem is that the currently proposed avoided cost rates for DESC are expected to be about well below these results. [159] Thus, without higher longer contract length, the solar industry would not be able to finance PURPA projects in South Carolina because they would not be economical. While the bar on the right shows a required PPA price to secure financing, Power Advisory has not calculated that price so the top part of the bar is illustrative only.

Figure 7. PPA Price ($/MWh) vs. Contract Length (Years)



[158] Georgia Power, "Georgia Power renewable growth to continue throughout 2018: 970 MW of solar capacity online today, 510 MW of new solar contracts recently awarded" March 13, 2018

https://southerncompany.mediaroom.com/2018-03-13-Georgia-Power-renewable-growth-to-continue-throughout-2018

[159] DESC Neely Direct, p. 14 lines 9-12.

It's also important to note two things that could drive required PPA prices in South Carolina even higher:

- The Investment Tax Credit (ITC) declines from 30% in 2019 to 26% in 2020, to 22% in 2021 to 10% in 2022, thus eroding solar economics over time (and drives required PPA prices higher)
- The comparable PPA rates for 30 year and 20 year PPAs have average project sizes of 170 MWs and 42 MWs, respectively. These sizes are much higher than the average South Carolina PURPA projects. Thus, project economics would be worse.

Two other investor concerns related to the 10-year contract length include the following:[160]

- It is hard to forecast the avoided cost of a given utility to understand what the pricing will be 10 years from now.
- There is regulatory risk in terms of whether there will still be a utility purchase obligation 10 years from now, or what the terms and conditions of the purchase obligation will be.

This is in contrast to an organized power market such as PJM, ISO-NE or ERCOT where there is a liquid market for electricity in the post-PPA term and far more confidence in the price forecasts. In addition, a hedge product can be used to put a floor under the electricity prices. As a result, shorter term PPAs are possible in these organized markets. By contrast, the risks in South Carolina in the post-PPA period are much harder to mitigate.

Intervenor Proposals for Terms and Conditions for Longer PPA Lengths

It is important to note that the Intervenors were planning to propose terms and conditions for longer PPA lengths, however, Power Advisory did not receive these prior to submission of this report.

4.1.2.1 Comparison with PURPA Contract Lengths in Other States

Power Advisory reviewed contract lengths in some of the most prominent PURPA states, where the market for PURPA projects has been the greatest over the past 10 years in megawatts. The average contract length of 15 states as shown in the figure is currently 14.1 years, down from 15.5 years when taking into account regulatory actions over the past few years. The current contract lengths ranged from 2 to 25 years, with a median of 15.

[160] Norton Rose Fulbright, Project Finance NewsWire, August 2019, p.2. https://www.projectfinance.law/newswire-archive/august-2019/

Figure 8. PURPA Contract Length by State Sorted Longest to Shortest [161]

State	Current Term (Years)	Date Effective	Increase/Decrease	Previous Term (Years)
Montana	25	Apr-19	Retained same	25
Vermont	25		Same	25
Oregon	20	Mar-16	Retained same	20
Wyoming	20	Jun-16	Retained same	20
New Mexico	20		Same	20
Michigan	20		Same	20
Utah	15	Jan-16	Decrease	20
Washington	12	Jun-19	Increase	5
Connecticut	12		Same	12
North Carolina	10	Oct-17	Decrease	15
South Carolina	10	May-19	Retained same	10
California	10		Same	10
Mississippi	5		Same	5
Georgia	5		Same	5
Idaho	2	Aug-15	Decrease	20
Average	**14.1**			**15.5**

The most significant change in contract length over the past few years occurred in Idaho, the third largest PURPA market over the last 10 years in megawatt additions, according to data from EIA.[162] In August 2015, at the request of the utility, the Idaho Public Service Commission reduced the PURPA contract length from 20 years to 2 years.[163] That made it the shortest PURPA PPA contract

[161] Power Advisory, based on various regulatory filings, Standard Offer PPAs and associated documents

[162] Data are from the US Energy Information Administration (EIA), EIA-860 database:
https://www.eia.gov/electricity/data/eia860/

[163] Idaho Public Utilities Commission, "Idaho commission reduces contract length for some PURPA projects to two years" Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-0, August 19, 2015.
https://puc.idaho.gov/press/150820_PURPAfinal_files.pdf

length in the US and remains that way to this day. Although the QF was eligible for continual renewal of its contract every two years at then-current avoided costs, this effectively turned the project into a merchant plant. Since this ruling, no new QF projects of greater than 1 MW have become operational in Idaho according to data from EIA. In the wake of this change, several other utilities have requested their regulator reduce contract lengths to shorter durations. Some of the results of those requests are as follows:

- In Utah, the utility requested a reduction from 20 to 2 years, but the Public Service Commission decided to reduce it more moderately, from 20 to 15 years[164]
- In Wyoming, PacifiCorp asked its regulator to reduce contract length from 20 years to 3 years but was denied[165]

On the flip side, in June 2019, Washington State increased its contract length from 5 years to 12-15 years.[166]

4.2 Summary of Resolved Issues

DESC, SBA and ORS provided direct, rebuttal (DESC) and surrebuttal (SBA, ORS) testimony as it relates to the Standard Offer PPA, Large QF PPA and Notice of Commitment to Sell Form (NOC).[167] They also provided oral testimony at a hearing held on October 14 and 15, 2019.

The parties have come to what is effectively a negotiated agreement through these various rounds of testimony on several issues originally cited in Mr. Levitas' direct testimony as warranting revision. This is viewed by Power Advisory as evidence that these negotiated terms are fair and reasonable.

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[164] Public Service Commission of Utah, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities – Docket No.15-035-53 Order" Issued January 7, 2016 https://pscdocs.utah.gov/electric/15docs/1503553/2712701503553o.pdf

[165] "25. The Commission denies RMP's Application for authority to amend Schedules 37 and 38 to reduce the contract term of its PURPA PPAs with QFs from 20 years to three years. The Commission concludes that RMP failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers."

Public Service Commission of Wyoming, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities," Docket No. 20000-481-EA-15 (Record No. 14220), June 23, 2016.

Similar decisions reached by the Wyoming PSC for the other utilities, notably PacifiCorp.

[166] Washington State Legislature, Chapter 480-106-050 https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

[167] JDA Chilton did not make specific revisions to PPA terms but rather expressed general concerns with respect to project financeablilty including length of term and price, etc.

Changes DESC made to the Standard Offer and Form PPA in light of input from SBA include:

- Relief would be provided from liquidated damages for interconnecting utility delays both for interconnection facilities and network upgrades.
- Removal of provisions requiring EPC and O&M contracts to be in a form and substance satisfactory to the Buyer.
- DESC provided a form of surety bond in an exhibit to the contract.
- Revisions with respect to Seller's indemnification of the Buyer for Environmental Liability, and personal and property damage.
- Removal of provisions enabling the Buyer to terminate the contract in an Extraordinary Event.
- Maximum duration of Force Majeure extended to 9 months.
- Adding current and prospective investors to the list for whom confidential information may be shared.
- Added a provision that enables the Seller to terminate the contract in the event of high interconnection costs (e.g., $75,000/MW).

Requests that SBA withdrew in light of other concessions made by DESC:

- Completion Date to be based on estimated in-service date per the Interconnection Agreement.
- Early Termination Fee to be based on estimated losses at 95% of projected output in the event of early termination by the Buyer.
- Expansion of Nameplate capacity should not require consent of the Buyer.
- Clarifications with respect to curtailment of output based on "system conditions".
- Deletion of Section 11.6 with respect to the description of liquidated damages.
- Eliminate requirement for the Buyers prior written consent for pledging the agreement or associated revenues to Financing party.
- Removing restrictions with respect to public announcements on the construction and operations of the contracted facility.
- In the event that damages are owed by the Seller, the amount of the Notice of Commitment (NOC) to Sell fee of $5,000 should be deducted from the amount of damages owed.
- Clarification with respect to NOC provision to keep DESC whole for any damages arising from breach of warranty, representation or covenant of the NOC.

- Request that a cure period be added, such that a LEO can be terminated if the Seller ceases to comply with the requirements of the LEO and the deficiency fails to be cured within 10 business days.

In addition, Mr. Horii[168] and Mr. Lawyer[169] representing ORS also presented suggested revisions to the Standard Offer, Form PPA and NOC. Each of the matters below were resolved satisfactorily from ORS' perspective:

- Clarifications in Section 8(iii) of the NOC with respect to "which entity (the QF or DESC) is responsible for installing additional facilities to establish adequate interconnection facilities, and whether the QF is eligible for any payments or damages due to delays." DESC provided clarification.
- Clarifications in Section 6.1(a) of the Standard Offer PPA respect the phrase "expected range of uncertainty based on historical operating experience." DESC revised this section of the PPA.
- Correction of references to SCANA in the forms to Dominion Energy South Carolina, Inc.
- Clarification with respect to "the 'Limiting Provisions' of Section of the Rate PR-1 Tariff". ORS later agreed that no clarification was required.

Ms. Chilton, representing JDA, provided direct testimony with respect to the ability of QF's to obtain regularly available market-rate financing[170]. Her testimony focused on PPA pricing and PPA duration, and did not delve into other terms and conditions of the Standard Offer, Form PPA or NOC. [171]

However, there remain several notable points of difference between the SBA and DESC that need to be resolved. These matters are reviewed in the next sections of this chapter, along with Power Advisory's recommendations for resolution.

4.3 PPA Standard Offer and Terms and Conditions

4.3.1 Liquidated Damages and Extension Payments

As a basic principle, liquidated damages should be the parties' best estimate at the time they sign a contract of the damages that would be caused by a breach of the contract. DESC's original Standard Offer and Form PPA stated that if the Seller is unable to meet the Completion Deadline liquidated damages of $55/kW-AC will apply. The Completion Deadline is set 12-months following

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[168] ORS Horii Direct, p. 45-41.

[169] ORS Lawyer Direct, p. 7.

[170] JDA Chilton Direct, p. 5.

[171] JDA Chilton Direct, p. 6.

the Effective Date (i.e., contract execution date). In addition to Excusable Delays (e.g., triggered by Force Majeure), the Seller can extend the Completion Deadline subject to an Extension Payment of $0.11/kW-AC per day for up to 120 days. As originally drafted, DESC may terminate the PPA if the Completion Deadline is missed.

In his direct testimony, Mr. Levitas stated that the liquidated damages proposed by DESC are excessive and unreasonable and that they are significantly larger than the liquidated damages proposed by Duke and substantially higher than those established by Consumers Energy in Michigan. [172,173] Mr. Levitas asserted that liquidated damages proposed are in excess of any actual damages that would be incurred by DESC and recommended that DESC adopt liquidated damages in the amount of $5,000/MW-AC for first 20 MW, plus $2,000/MW-AC for any capacity above 20 MW.[174]

Mr. Levitas did not have an objection with the Extension Payment in principle, however, he argued that these are excessive when viewed in combination with what he characterized as exorbitant liquidated damages proposed by DESC.[175] That said, Mr. Levitas was concerned that Excusable Delays related to Interconnecting Utility delays "pertains only to the construction of required Interconnection Facilities and doesn't include required Network Upgrades (i.e., necessary improvements to the grid beyond the Delivery Point)".[176]

In his interrogatory response, Mr. Folsom wrote that the liquidated damages amount approximates the value of one year of operation under the PPA and asserted that this is appropriate because it would take approximately one year to find a replacement resource. Further, Mr. Folsom wrote that DESC viewed this amount of liquidated damages to be appropriate because late withdrawal of speculative projects can be disruptive to the connection queue. Mr. Folsom added that DESC did not perform any specific analysis but used their own knowledge and understanding of ratepayer risk.[177]

However, in light of changes to the avoided costs, DESC reduced the liquidated damages amount from $55,000/MW-AC to $41,000/MW-AC. Specifically, in his rebuttal testimony Mr. Kassis stated:

> "Liquidated damages in this context are generally estimated as a proxy amount to compensate the utility for any costs or losses it incurs in obtaining replacement

[172] Note that Duke originally proposed liquidated damages in the amount of 2% of expected project revenues and amended their proposal in response to Mr. Levitas' testimony.

[173] Consumers Energy Company. Standard Offer Tariff and Standard Offer Power Purchase Agreement. Michigan Public Service Commission Case No. U-18090.

[174] SBA Levitas Direct, p. 10.

[175] SBA Levitas Direct, p. 11.

[176] SBA Levitas Direct, p. 11.

[177] DESC Response to First Power Advisory Interrogatories, #1-5.

> capacity and energy due to a QF's non-performance. This is ultimately a business decision that should vary upon the size of the facility.
>
> Contrary to Mr. Levitas's assertion, these liquidated damages are not higher than liquidated damage amounts in prior DESC negotiated power purchase agreements. Further, Mr. Levitas reduces the basis of liquidated damages for larger projects over 20 MW for no apparent reason. However, these larger plants (over 20 MWs) create additional risks for DESC's reliance on this energy because it must factor delivery of this energy into its resource planning and larger facilities could lead to greater losses if the energy is not delivered pursuant to the terms of the agreement. Nevertheless, as a result of DESC's amended solar avoided cost, DESC reduced this amount from $55/kW-AC to $41/kW-AC in its revised filing submitted on September 20, 2019."[178]

In Mr. Levitas' surrebuttal testimony, he stated he did not believe the reduction to be sufficient and referred to Duke's acceptance of lower liquidated damages; specifically, he states:

> "In its revised filing, DESC has reduced that amount to $41,000/MW. While SCSBA appreciates this reduction, the [liquidated damages] are still extremely high – for example, a 50 MW project would face more than $2 million in liquidated damages – and also bear no reasonable relationship to actual damages that DESC would suffer in the event that a contracted Facility fails to be placed in service. Mr. Kassis acknowledges that [liquidated damages] must bear some relationship to actual damages, stating that "Liquidated damages in this context are generally estimated as a proxy amount to compensate the utility for any costs or losses it incurs in obtaining replacement capacity and energy due to a QF's non-performance." It is hard to fathom how the loss of a single project from the resource plan could cause millions of dollars of damage to the utility.
>
> With respect to energy purchases, to the extent that DESC would enter into long-term contracts in the absence of QF supply, it would be easy enough for it to do so upon early termination of a QF PPA and recover its actual damages. Where damages are so easily measured, there is simply no need for liquidated damages. And given declining natural gas prices and DESC's insistence that long-term PURPA PPAs are bad for ratepayers, it's very hard to understand why Mr. Kassis thinks the company would be damaged if it had to procure energy in another fashion. Any damages are likely to be largely administrative in nature. The reason that I proposed a reduced per MW [liquidated damage] amount over 20 MW is because such administrative damages are not proportional to the size of the

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[178] DESC Kassis Rebuttal, p. 18-19.

> facility and are not likely to be substantially greater in the case of a 50 MW facility that with a 20 MW one."[179]

During witness examination by Vice Chairman Williams, Mr. Kassis was asked to describe the nature of costs and losses that would be experienced by DESC. Mr. Kassis responded by stating:

> "…the actual calculation is based on the capacity, it's based on the avoided cost, and it's based on the length of a year -- the term, which was -- which is what we believe it would take to replace that resource. Granted, avoided cost is -- is low, so it drives the number down lower, which was the change. But we also recognized in the market, that it would take approximately a year to replace that resources, so it's -- it includes the – the avoided energy. We believe it reasonably compensates us for opportunities -- say, for instance, for another developer to bring in a project, who then could essentially reach finance, etc. -- our administrative costs. So those – that formulated approach isn't anything different or new, it's the same one we've used on -- on a 1,048 megawatts that we've signed or -- or have commercially operated so far."[180]

During witness direct examination by Mr. Adams, Mr. Levitas stated that the "single biggest open issue is the amount of liquidated damages or LDs Dominion would require a QF to pay if the PPA is terminated without the facility having been placed in service" and urged the adoption of Duke's proposed formula.[181]

Power Advisory Assessment

The two sides are far apart on this issue. In fact, DESC's liquidated damages under the $41,000/MW-AC formula for a 5 MW plant would be 8.2 times that proposed by SBA and 10.3 times for a 30 MW plant.

By contrast, Duke and SBA agreed on a formula for liquidated damages that yields a much lower amount. The agreed upon formula is the average annual estimated capacity payments under the Agreement over the Term for up to 15 MW and $10,000/MW-AC thereafter.[182]

The damages to the purchasing utility are largely mitigated by the fact that PPA pricing is based on avoided costs which in turn are based on the incremental cost of energy and capacity but for the purchase from the QF the utility would generate or purchase. Therefore, we believe that it is inappropriate that the liquidated damages should approximate one year of payments at avoided cost rates as proposed by DESC. By definition PPA payments reflect utility costs. Therefore, Power

[179] SBA Levitas Surrebuttal, p. 4-5.

[180] Hearing Vol. 1, p. 117 (DESC Kassis).

[181] Hearing Vol. 2, p. 445 line 12 to p.446 line 16 (SBA Levitas).

[182] Duke proposed this and Mr. Levitas agreed to it during the Duke Hearing, (Vol. 1, p. 315 lines 1-22).

Advisory believes that the liquidated damages proposed by DESC are too high. A more reasonable formula for liquidated damages would be the one agreed upon by Duke and SBA.

4.3.2 Guaranteed Energy Production

In DESC's Standard Offer and Form PPA, the Seller estimates the expected annual output of Net Energy for each year of the contract term ("Contract Quantity"). The Guaranteed Energy Production is eighty-five percent (85%) of the Contract Quantity. A Shortfall occurs if the Facility fails to deliver the Guaranteed Energy Production in any particular Contract Year. If there is a Shortfall, the Seller is subject to Performance Liquidated Damages which must be paid within 30 days of receipt of an invoice. The Buyer can terminate the PPA if the Facility fails to deliver eighty-five percent (85%) of the Guaranteed Energy Production in any two consecutive Contract Years.

In his direct testimony, Mr. Levitas asserts that DESC's proposal is not commercially reasonable, though SBA acknowledges that this contract provision varies widely in the industry. SBA recommends that DESC should adopt the Duke shortfall amounts (i.e., 70%) and DESC should adopt Duke's approach which is calculated based on a rolling two-year average.[183]

In his rebuttal testimony Mr. Kassis states that the Guaranteed Energy Production provision is "purely a commercial matter to address risk arising from a QF's failure to perform in accordance with the contract".[184] He goes on to state that the Standard Offer and Form PPA stipulates "that the QF will operate at and maintain an expected performance of 95 percent", and thus DESC has provided additional flexibility by defining Shortfalls at or below 85 percent. Further, the Seller is in the best position to address such shortfall. Mr. Kassis further says that the termination provision is reasonable because the "QF can, in large measure, control the variables affecting its ability to meet this requirement".[185]

The effect of termination would be that the parties would enter into a new PURPA PPA at new avoided cost rates. Duke's PPAs do not contain this termination provision. SBA suggests that LDs should be the Buyer's sole remedy in the event of a Shortfall.[186]

During witness examination by Vice Chairman Williams, Mr. Kassis was asked about the reasonableness of the termination provisions associated with the Guaranteed Energy Production. Mr. Kassis responded:

> "…every developer that we've signed a contract with has been able to reach that

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[183] SBA Levitas Direct, p. 14.

[184] DESC Kassis Rebuttal, p. 20.

[185] DESC Kassis Rebuttal, p. 21.

[186] SBA Levitas Surrebuttal, p. 6.

production level and -- unless they have a major issue with equipment or programming of things like inverters… if you don't meet the provision two years in a row, which means you're essentially neglecting the asset, then somebody else should have the opportunity to take advantage of providing a resource. That's simply a measure to keep the assets very -- as reliable as you can get with an intermittent resource is what our expectations are."[187]

Vice Chairman Williams also asked Mr. Kassis about use of other remedies, rather than termination, who responded:

> "…when you put provisions that like that, then people actually commit and follow through and do what they're going to say they're going to do in the contract."[188]

During direct witness examination by Mr. Adams, when discussing termination due to a Shortfall, Mr. Levitas stated that "termination would, in fact, serve no purpose because under PURPA, the QF would be entitled to enter into a new PPA." [189]

Power Advisory Assessment

On an annual basis solar output is very predictable. While Power Advisory is concerned about consistency between DESC and Duke terms and conditions given that facilities will be located within the same state, we do not recommend a lowest common denominator approach to establishing terms and conditions.

In the San Diego Gas & Electric Company's Standard Offer PPA in California, the Guaranteed Energy Production (GEP) is equal to 70% of the average Contract Quantity over a 2-year period for wind and 85% for all other technologies. In the case that this GEP is not met, the seller pays liquidated damages, but the contract is not terminated. [190]

In the Avista Corporation's Standard Offer PPA contract in Washington State, on a monthly basis, if the monthly production is less than 90% of the month's Net Output Estimate for the corresponding month, then a Shortfall Energy Price applies for the Shortfall Energy which is the lower of the Market Energy Price and the Avoided Cost Rate. The contract is not terminated. [191]

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[187] Hearing Vol. 1, p. 118 (DESC Kassis).

[188] Hearing Vol. 1, p. 119 (DESC Kassis).

[189] Hearing Testimony, Vol. 2, p. 447 (SBA Levitas).

[190] Renewable Market Adjusting Tariff Power Purchase Agreement, approved by California Public Utilities Commission in Decision 13-05-034 effective May 23, 2013.

[191] Avista Corporation, Washington, Standard form of Power Purchase Agreement for Qualifying Facilities with Capacity of 5 MW or less, Rev 08/2019.

In the Puget Sound Energy Standard Offer PPA contract in Washington State, the Seller is responsible for providing at least the Annual REC Quantity specified in the REC Contract, which is executed in conjunction with the PPA. [192] If the facility does not generate enough RECs in a given year then they need to source the shortfall from a third party. The contract is not terminated.

While we are mindful of inconsistencies between DESC and Duke, we do not agree that this is sufficient reason to lower the bar, especially if the guaranteed amount is easily achievable.

That said, Power Advisory has not found precedent in other contracts to include contract termination in the event of a shortfall. While following the termination the QF can enter into another PURPA PPA, this would potentially be at a lower rate. Our research indicates that providing a termination right for a PPA where pricing is based on avoided costs and thereby reflects the buyer's cost of generating or purchasing the power is outside the norm. Therefore, we believe such a provision disproportionately increases project risks relative to the harm that would be realized by customers and believe that the termination if the Facility fails to deliver 85% of the Guaranteed Energy Production in any two consecutive Contract Years right should be eliminated.

4.3.3 Energy Storage

In Mr. Levitas' direct testimony, he pointed out that the DESC PPA is silent on energy storage, despite requirements from Act 62. He noted that energy storage would typically only be considered for facilities greater than 2 MW, therefore absence of language leaves it up to PPA negotiation without Commission oversight.[193]

In Mr. Kassis' rebuttal testimony he states that per the Settlement Agreement filed in Docket No. 2017-370-E on November 30, 2018, DESC agreed to file with the Commission for its approval either "proposed avoided cost rates for energy and capacity that provide accurate pricing for storage as a separate resource; or proposed technology-neutral avoided cost rates for energy and capacity that provide accurate pricing for dispatchable renewable generating facilities such as solar + storage (e.g., hourly pricing)." [194]

Mr. Kassis goes on to quote Section 14 of Act 62 which states, "[t]he provisions of Section 58-41-20 shall not be interpreted to supersede the conditions of any settlement entered into by an electrical utility and filed with the commission prior to the adoption of this act."

Therefore, as explained by Mr. Kassis, DESC plans to meet its obligation under the Settlement by making a filing with the Commission on or before December 31, 2019, and that Act 62 requires

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[192] Puget Sound Energy, Washington, Schedule 91, Power Purchase Agreement, effective February 10, 2017.

[193] SBA Levitas Direct, p. 15.

[194] DESC Kassis Rebuttal, p. 23.

that each utility's avoided cost methodology account for energy storage, but it does not expressly address, much less mandate, terms and conditions.[195]

During direct witness examination by Mr. Adams, when discussing termination due to a Shortfall, Mr. Levitas stated:

> "Dominion has not proposed contractual terms for the inclusion of energy storage devices. As you know, they're required to propose a solar-plus storage rate, but as things stand, developers will have no idea how to qualify for that rate. And, again in contrast, Duke has proposed an energy storage protocol in its Large QF PPA and has now agreed to incorporate the same protocol in its Standard Offer PPA."[196]

Power Advisory Assessment

Power Advisory believes that it would have been desirable for DESC to outline the provisions for energy storage as part of this proceeding. However, given that Act 62 is not intended to "supersede the conditions of any settlement entered into by an electrical utility and filed with the commission", we do not find a reason for DESC to be required to provide terms and conditions related to energy storage at this time. More importantly, imposing associated terms and conditions would deprive the parties from the opportunity to negotiate provisions of these terms and conditions.

4.3.4 Termination Payment

Per DESC's proposed Standard Offer and Form PPA, if Buyer terminates the agreement due to an event of default on or after the Commercial Operation (with some prescribed exceptions), the Seller will be required to pay a Termination Payment according to the following formula, which results in a price floor on damages. As demonstrated by the formula below, the floor increases the Termination Payment to a level that is likely to be greater than cost of the replacement energy.[197]

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[195] DESC Kassis Rebuttal, p. 23.

[196] Hearing Vol. 2, p. 447 lines 7-15 (SBA Levitas).

[197] DESC Folsom Amended Exhibit JEF-1 to Direct Testimony, Section 11.4.

Termination Payment is the NPV of

$$(RE_{price} - \text{Net Energy Rate}) \times (Dt_{erm} \times E_{daily}) + C + O$$

Where:

RE_{price} is price per kWh for commercially available renewable energy from a substantially similar renewable facility located in the same state in the same applicable market(s)

(RE_{price} – Net Energy Rate) shall not be 50% of the Net Energy Rate (i.e., based avoided costs)

D_{term} is the number of days remaining on the term

E_{daily} is the expected daily kWh of Net Energy to be delivered during the remainder of the term, and no less than the Contract quantities

C is all reasonable costs and expenses incurred by Buyer resulting from event of default (e.g., legal fees)

O is all other amounts such as owed by the Seller (e.g., overdue Delay Damages, Extension Payments, etc.)

In his direct testimony, Mr. Levitas argues that this provision is not commercially reasonable and should be deleted. He says that since payments under the contract are based on avoided costs and DESC is not assigning a capacity value, there should be little harm to the Buyer for termination. Mr. Levitas goes on to point out that "Witness Folsom emphasizes how bad PURPA PPAs are for ratepayers, in which case they should welcome any that go away".[198]

Further, Mr. Levitas asserts that the floor on damages established is completely unreasonable. If Net Energy Rate is $32/MWh and market price for renewable energy is $34/MWh, damages would be set to $16/MWh, even though the actual incremental cost of procuring replacement renewable energy would $2/MWh. Further, there is no reason to base the cost of procuring replacement energy on renewable energy, as DESC is not buying RECs and contract price is based on avoided energy.[199]

Overall, Mr. Levitas states opposition to post-COD damages, but if they are included, Shortfall LDs payable should be clearly waived. SBA recommends that the Termination Payment reflect the

[198] SBA Levitas Direct, p. 18.

[199] SBA Levitas Direct, p. 18.

Duke approach such that DESC is made whole for any overpayment to the Seller relative to applicable avoided cost rates.[200]

In his rebuttal testimony, Mr. Kassis emphasized that the approach to the measurement of damage was reasonable, stating:

> "DESC accounts for these generating assets in its resource plan and relies on these plants performing pursuant to the contract. Moreover, Mr. Levitas fails to take into account that when a QF terminates after COD, DESC incurs damages in the form of lost opportunities, e.g., self-build, RFP, or other competitive solicitation or procurement options."[201]

During direct witness examination by Mr. Adams, when discussing the termination payment, Mr. Levitas stated that:

> "Dominion proposes a totally unreasonable 50 percent floor on such damages that could potentially result in a massive and unjustified windfall to the Company. I explain this in detail in both my direct and surrebuttal testimony. And I would also note that there is no comparable floor on Dominion's damages to the QF should they be in breach of the agreement resulting in termination."[202]

During examination by Vice Chairman Williams, when asked about DESC's termination payment, Mr. Levitas stated that DESC's proposal is "unprecedented in my experience and -- and, if I had to say, maybe the single most unreasonable thing in the whole document."[203]

Power Advisory Assessment

The proposed Termination Payment does not appear to be consistent with any actual damages or consequences experienced by DESC as a result of contract termination. As discussed below, it is common that the termination fee may include compensation to the buyer for any over payment, lost value (i.e., difference between the contract and market price) or legal fees associated with termination. Some jurisdictions may include cost of replacement energy over a period of time (i.e., 24 months), while others leave the determination of termination payments up to commercially reasonable negotiations.

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[200] SBA Levitas Direct, p. 19.

[201] DESC Kassis Rebuttal, p. 25 lines 15-19.

[202] Hearing Vol. 2, p. 448 lines 3-11 (SBA Levitas).

[203] Hearing Vol. 2, p. 495 (SBA Levitas).

Some examples of how other jurisdictions treat termination payments resulting from Seller default follow:

- Duke Energy Carolinas, LLC (North Carolina)[204] - The termination fee equals the amount of (a) the minimum monthly charges which would have been payable during the unexpired term of the Agreement plus (b) the Early Termination Charge. The Early Termination Fee is the total Energy and/or Capacity credits received in excess of the sum of what would have been received under the Variable Rate for Energy and/or Capacity Credits applicable at the initial term of the contract period and as updated every two years, plus interest.

- Pacific Power & Light Company (Oregon)[205] - The termination fee is the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for the Average Annual Generation that Seller was otherwise obligated to provide at the Mechanical Availability Guarantee for a period of twenty-four (24) months from the date of termination, plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, plus the estimated administrative cost to the utility to acquire replacement power.

- San Diego Gas & Electric Company (California)[206] - If either Party exercises a termination right after the Commercial Operation Date, the non-defaulting Party shall calculate a settlement amount ("Settlement Amount") equal to the amount of the non-defaulting Party's aggregate Losses and Costs less any Gains, determined as of the Early Termination Date. (Note, the terms Gains, Losses and Costs, are defined terms, however open to commercially reasonable interpretation.)

- Avista Corporation (Washington)[207] - In the event of default or early termination due to failure to perform, Avista can retain the contract security.

Therefore, Power Advisory recommends that DESC remove the floor on damages and amend the formula to reflect the cost of replacement energy at the then-current costs of replacement energy, as follows:

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[204] Duke Energy Carolinas, LLC. Terms and Conditions for the Purchase of Electric Power. Effective March 1, 2016. NCUC Docket No. E-100 Sub 140.

[205] Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016.

[206] Renewable Market Adjusting Tariff Power Purchase Agreement, approved by California Public Utilities Commission in Decision 13-05-034 effective May 23, 2013.

[207] Avista Corporation, Washington, Standard form of Power Purchase Agreement for Qualifying Facilities with Capacity of 5 MW or less, Rev 08/2019.

Termination Payment is the NPV of

$$(Rate_{RE} - \text{Net Energy Rate}) \times (D_{term} \times E_{daily}) + C + O$$

Where:

$Rate_{RE}$ is the is price per kWh of replacement energy

($Rate_{RE}$ – Net Energy Rate) shall not be less than zero

D_{term} is the number of days remaining on the term

E_{daily} is the expected daily kWh of Net Energy to be delivered during the remainder of the term, and no less than the Contract quantities

C is all reasonable costs and expenses incurred by Buyer resulting from event of default (e.g., legal fees)

O is all other amounts such as owed by the Seller (e.g., overdue Delay Damages, Extension Payments, etc.)

4.4 Notice of Commitment to Sell Form

The following is a summary of areas of dispute between SBA and DESC with respect to DESC's proposed NOC form.

4.4.1 Limiting PPA Eligibility Following Termination

DESC's proposed NOC form states that if a QF submits an executed NOC form but fails to execute a PPA in a timely fashion, in addition to termination of the LEO, the QF will not be eligible for fixed-pricing for a period of two years.

Mr. Levitas states in his direct testimony that restricting eligibility for fixed-pricing for a period of two years is "overly harsh and not authorized by PURPA". Mr. Levitas recommends that a QF who fails to perform should be liable for the same damages per the Standard Offer and Form PPA (i.e., Mr. Levitas recommends $5,000/MW-AC for first 20 MW, plus $2,000/MW-AC for any capacity above 20 MW.)[208]

[208] SBA Levitas Direct, p. 25-26.

Mr. Kassis, in his rebuttal testimony, stated that DESC has concerns with respect to gaming, and that in "its Reform NOPR, the FERC proposes varying rates for energy, which further supports inclusion of this provision." [209]

During witness cross examination conducted by Mr. Adams (on behalf of SBA), Mr. Kassis acknowledged that the NOPR is not a binding regulation, is subject to public comment, and may be amended or not ultimately be promulgated.[210]

Power Advisory Assessment

While it is reasonable that DESC would want to prevent speculation, restricting the ability to pursue fixed-pricing is inconsistent with PURPA. Therefore, Power Advisory recommends adopting Mr. Levitas' recommendation of implementing damages per the Standard Offer and Form PPA for failure to execute a PPA in a timely fashion.

4.4.2 365 Day In-service Deadline

DESC's proposed NOC form states that the seller must deliver power within 365 days of submitting the NOC form.

In Mr. Levitas' direct testimony, he states that the NOC form establishes a commitment to enter into a PPA within 30 days, which would have sufficient requirements with respect to in-service deadlines. If the in-service deadline is to remain, it should only be applicable when there are sufficient network resources for interconnection at the time of the deadline.[211]

In his direct testimony, Mr. Folsom asserts that QF's cannot be viewed as having to make a substantial commitment if the project is more than a year from actual power delivery. He also references similar precedents established in other jurisdictions; for example, Idaho has a requirement to deliver power within 365 of establishing a LEO. More stringent requirements in other jurisdictions have also been upheld, for example, Texas has a 90-day delivery window.[212]

In is surrebuttal testimony, Mr. Levitas stated that SBA is "prepared to accept DESC's proposed requirement that Seller commence delivery within 365 days of its Notice of Commitment to Sell, provided that such obligation is subject to the same Excusable Delays as the in-service deadline under DESC's proposed PPAs."[213]

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[209] DESC Kassis Rebuttal, p. 36.

[210] Hearing Vol. 1, p. 68 (DESC Kassis).

[211] SBA Levitas Direct, p. 28.

[212] DESC Folsom Direct, p. 24.

[213] SBA Levitas Surrebuttal, p. 12.

Power Advisory Assessment

Power Advisory believes that Mr. Levitas' proposal has merit and is reasonable. It is logical to align PPA terms with LEO requirements, and that the NOC form acknowledge Excusable Delays that would impact the in-service deadline.

4.4.3 Eligibility Pre-Conditions

In addition to other pre-conditions (i.e., commitment, site control, fee), DESC's proposed NOC form states the QF is required to have secured all land-use approvals and environmental permits that would be required to have the facility in service within 365 days. Further, the Seller is required to have an executed System Impact Study Agreement.

In his direct testimony, Mr. Levitas states that environmental permits and land use approvals are expensive and time consuming and that it is unreasonable to incur such expenses without securing a price for the project. This is not a requirement of the PPA, and there is no logic for having more onerous requirements in LEO. Further, the Seller should only be required to execute a System Impact Study Agreement if one has been tendered to it by the DESC.[214]

Mr. Folsom, in his direct testimony, emphasized that the "NOC Form is purely a creature of the Act". QFs can submit a NOC without attempting to negotiate with DESC. In DESC's view, QFs must make substantial commitments to sell output in order to establish a LEO. States have discretion with respect to LEOs and the proposal reflects DESC institutional knowledge and experience (e.g., need to reduce speculative projects).[215] Mr. Folsom also cites precedent from other jurisdictions implementing "control-and-approval" concepts in the LEO framework.[216]

In his rebuttal testimony, Mr. Kassis quotes:

> "Reform NOPR, the FERC specifically permits states to require a QF to make a showing that it has "satisfied or, is in the process of undertaking, at least some" enumerated items in the Reform NOPR, such as obtaining site control, filing an interconnection application, securing permitting, and certain other "reasonable criteria to allow the QF to demonstrate its commercial viability and financial commitment.""[217]

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[214] SBA Levitas Direct, p. 27.

[215] DESC Folsom Direct, p. 21-22.

[216] DESC Folsom Direct, p. 25.

[217] DESC Kassis Rebuttal, p. 37.

Mr. Kassis also notes that Mr. Horii finds these provisions reasonable.[218]

During direct witness examination by Mr. Adams, Mr. Levitas emphasised that requiring permits prior to securing pricing certainty would be unreasonable and stated that it is "not a reasonable requirement without the QF knowing what its project economics are."[219] Mr. Levitas goes on to state:

> "I also don't believe it's consistent with PURPA to require that a seller at either established interconnection service or signed a system impact study agreement as a condition of LEO formation because this improperly places control over LEO formation in the hands of the utility." [220]

Power Advisory Assessment

Power Advisory recommends that since SBA has agreed to the 365-day in-service date requirement, that QFs be allowed to secure permits after formation of a LEO. This makes it consistent with the PPAs which do not require permits be obtained before execution. Also, the requirement is unnecessarily onerous on the QF. In fact, DESC is making it more onerous to form a LEO than to enter into a PPA. The QF already has to meet the requirement of being in-service within 365 days or risk termination and liquidated damages. This requirement alone will result in QFs with viable projects moving forward with LEO formation.

[218] DESC Kassis Rebuttal, p. 37.

[219] Hearing Vol 2, p. 449 (SBA Levitas).

[220] Hearing Vol 2, p. 449-450 (SBA Levitas).

RATE PR – AVOIDED COSTS METHODOLOGY

METHODOLOGY FOR DETERMINING AVOIDED COSTS FOR POWER PURCHASE AGREEMENTS WITH SMALL POWER PRODUCERS UNDER THE PURPA AND S.C. ACT NO. 62 OF 2019

AVAILABILITY

This tariff sets forth the methodology approved by the Public Service Commission of South Carolina in Docket No. 2019-184-E for computing the avoided energy and capacity costs associated with Power Purchase Agreements (“PPA”) provided under the provisions of S.C. Code Ann. § 58-41-20 and the Public Utility Regulatory Policies Act (“PURPA”).

A. Methodology for Determining Avoided Costs

1. **Methodology.** A Difference in Revenue Requirements (“DRR”) methodology is used to calculate both the energy component and the capacity component of its avoided costs by comparing a base case and a change case.

2. **Avoided Energy Costs – Base Case**. The base case for determining avoided energy costs is defined by DESC’s existing fleet of generators and the hourly load profile to be served by these generators, including the solar facilities with which DESC has executed a PPA and the solar facilities that have executed a Notice of Commitment (“NOC”).

3. **Avoided Energy Costs – Change Case**. The change case for determining avoided energy costs is the same as the base case with the addition of a zero-cost purchase transaction modeled after the appropriate energy profile for the resource under consideration.

4. **Avoided Energy Cost – As Determined**. The avoided energy cost equals the difference between the base case costs and the change case costs.

5. **Avoided Capacity Cost – Base Case**. The base case for determining avoided capacity cost is the resource plan for meeting DESC’s system load reflecting the future capacity resource additions that the generating resource under consideration would be most likely to displace.

6. **Avoided Capacity Cost – Change Case**. The change case for determining avoided capacity costs is the same as the base case with the addition of a zero-cost purchase transaction reflecting the size and profile of the resource under consideration (or for the Standard Offer Contract and PR-1, 93 MW). The base and change cases are identical except for the zero-cost purchase transaction.

7. **Avoided Capacity Cost – As Determined**. The avoided capacity cost equals the difference between the incremental capacity costs in the base resource case and the change case. For a solar generation resource, the Effective Load Carrying Capability calculation will be applied to the levelized change in revenue requirements to determine the avoided capacity cost credit, which may be stated as either a $/kW or a $/kWh. For a non-solar generation resource, the levelized change in revenue requirements may be stated as either a $/kW or a $/kWh credit and may be paid during the specific time periods in which the avoided capacity cost is realized.

8. **Characteristics and Profile of the Generation Source**. The Change Case for both energy and capacity reflects the characteristics and profile of the generation source proposed (e.g., solar, wind, battery, and biomass). The profile used will reasonably reflect the resource being proposed.

B. Elements of Avoided Cost

The final avoided cost calculation shall reflect consideration of the following factors, some of which may have a zero or negative value.

RATE PR – AVOIDED COSTS METHODOLOGY

METHODOLOGY FOR DETERMINING AVOIDED COSTS FOR POWER PURCHASE AGREEMENTS WITH SMALL POWER PRODUCERS UNDER THE PURPA AND S.C. ACT NO. 62 OF 2019

	Components
1	Avoided Energy Costs
2	Avoided Capacity Costs
3	Ancillary Services
4	Transmission & Distribution Capacity
5	Utility Integration & Interconnection Costs
6	Utility Administration Costs
7	Variable Environmental Costs
8	Other Locational Cost or Benefits
9	Line Losses
10	Other Costs
11	**Total Value of New Resource**

1. **Avoided Energy Costs**. The avoided energy costs calculated using the DRR are adjusted to remove the cost of criteria pollutants and environmental costs.

2. **Avoided Capacity Costs.** The avoided capacity cost, if any, calculated using the DRR.

3. **Ancillary Services** The cost or value of ancillary services reflect the Company's engineering assessment of those attributes. The Company's current assessment of those attributes indicates that such costs or benefits if any will be project specific but not generic to renewable generating resources and thus not included in the DRR analysis.

4. **Transmission & Distribution Capacity.** To the extent that transmission capacity is avoided it will be determined based on engineering assessments and will be captured here.

5. **Utility Integration & Interconnection Costs.** Incremental utility integration and interconnection costs associated with the resource under consideration, if any, apart from those paid directly by the generation owner, based on engineering assessments.

6. **Utility Administration Costs.** Any incremental administrative costs associated with the additional resource as determined by the utility.

7. **Variable Environmental Costs.** Variable environmental compliance costs reflect the market cost of lime and other catalysts and of SO_2 and NO_x emission allowances. CO_2 emission costs will be included in the model at such time as those costs are imposed on DESC.

8. **Line Loses**. The cumulative marginal line losses avoided associated with delivering power across the system

9. **Other Locational Considerations.** Other locational considerations will be evaluated based on engineering analysis on a project by project basis. To the extent that distribution capacity is avoided it will be determined based on engineering assessments and will be captured here.

10. **Other Costs.** To the extent that other costs are identified through engineering analysis or operating experience, they will be quantified and reflected in the calculation.

C. Updates

The Company may update these factors and analyses in Section B from time to time as more current information and data become available. The "Methodology for Determining Avoided Costs" (Section A) may not be updated without prior Commission approval pursuant to Section 58-41-20(A) of S.C. Act No. 62 of 2019.