STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	ORDER SETTING AVOIDED
Rates for Electric Utility Purchases from	)	COST INPUT PARAMETERS
Qualifying Facilities - 2014	)	

HEARD: Monday, July 7, 2014, at 1:30 p.m., Tuesday, July 8, 2014, at 9:00 a.m., Wednesday, July 9, 2014, at 9:00 a.m., and Thursday, July 10, 2014, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Susan W. Rabon, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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For Carolina Industrial Group for Fair Utility Rates I, II, and III:

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For the Using and Consuming Public:

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BY THE COMMISSION: These are the 2014 biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C.A 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates that are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. The 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 jurisdiction, the FERC delegated the implementation of these rules to the 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.

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[1] FERC Stats. & Regs. 30,128 (1980) in Docket No. RM79-55 (Order No. 69), see also 45 Fed. Reg. 12,214 (1980).

The Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and approved other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements and interconnection charges.

This proceeding also is a result of the mandate of 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 utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" for purposes of G.S. 62-156 is more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) includes only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding users of other types of renewable resources.

On February 25, 2014, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing. For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (the Sub 136 proceeding), the Commission initiated the 2014 avoided cost proceeding in advance of the filing of new proposed rates, stating that such rates would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments, particularly capacity payments, including, but not limited to, whether a 2.0 performance adjustment factor (PAF) for run-of-river hydroelectric facilities with no storage capability should be continued, whether avoided capacity payments are more appropriately calculated based on installed capacity rather than a per-kWh capacity payment, and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided costs. Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU) and New River Light and Power Company (New River) were made parties to the proceeding. The Commission established May 30, 2014, as the deadline for interventions by interested persons; scheduled an evidentiary hearing for July 7, 2014, at 1:30 p.m.; and required that direct testimony and exhibits regarding the proper method to determine avoided costs payments, particularly capacity payments, be filed by April 17, 2014, responsive testimony be filed by May 30, 2014, and rebuttal testimony by June 20, 2014.

The following parties filed timely petitions to intervene that were granted by the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Carolina Utility Customers Association, Inc.; the Carolina Industrial Customers for Fair Utility

Rates I, II, and III (CIGFUR); the North Carolina Waste Awareness and Reduction Network (NC WARN); the Environmental Defense Fund (EDF); the Southern Alliance for Clean Energy (SACE); the North Carolina Hydro Group (NC Hydro Group); The Alliance for Solar Choice (TASC); the Public Works Commission of the City of Fayetteville; the North Carolina Chapter of the Sierra Club and the Natural Resources Defense Council (Sierra Club/NRDC); and Google, Inc.

On April 11, 2014, DEC, DEP, DNCP, NCSEA, CIGFUR, SACE and the Public Staff filed a joint motion requesting an eight-day extension to the deadline for the filing of direct testimony to April 25, 2014, an extension of the remaining due dates for filing testimony, and a rescheduling of the evidentiary hearing. By Order dated April 16, 2014, the Presiding Commissioner extended the deadline to file direct testimony and exhibits until April 25, 2014, but left the remainder of the procedural schedule and the hearing date as established in the Commission's Order dated February 25, 2014. WCU and New River filed Joint Comments and Proposed Rates on April 17, 2014.

On April 25, 2014, the parties filed the following direct testimony: DEC and DEP filed the testimony of Kendal C. Bowman, the testimony and exhibit of Glen A. Snider and the testimony and exhibit of Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams with two appendices that were treated as exhibits and the testimony of Bruce E. Petrie with one appendix that was treated as an exhibit; EDF filed the testimony and exhibit of Diane Munns; NCSEA filed the testimony of Greg Ness, the testimony and exhibit of Michael Cohen, and the testimony and exhibits of R. Thomas Beach; TASC filed the testimony and exhibits of Anne Smart; SACE filed the testimony and exhibits of Karl R. Rábago; NC Hydro Group filed the testimony of Andrew C. Givens; NC WARN filed the testimony and exhibit of Nancy LaPlaca; and the Public Staff filed the testimony and exhibit of Dr. Laurence D. Kirsch and the testimony of Dr. Richard E. Brown. On May 20, 2014, NCSEA filed a motion for leave to file the direct testimony of K. Zoe G. Hanes adopting the direct testimony of Greg Ness which was granted by Order dated May 29, 2014.

On May 30, 2014, the parties filed the following supplemental direct and responsive testimony: DEC and DEP filed the testimony of Kendal C. Bowman, the testimony and exhibit of Glen A. Snider and the testimony of Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams and Bruce E. Petrie, the testimony of James R. Bailey and Robert S. Wright, each with one appendix that was treated as an exhibit; NCSEA filed the testimony and exhibit of K. Zoë Gamble Hanes, the testimony of Michael Cohen and R. Thomas Beach, and the testimony and exhibit of Katie B. Rever; TASC filed the testimony and exhibits of J. Richard Hornby; SACE filed the testimony of Karl R. Rábago; Sierra Club/NRDC filed the testimony and exhibit of Dr. Alvaro E. Pereira; NC Hydro Group filed the testimony of Andrew C. Givens; NC WARN filed the testimony of Nancy LaPlaca with two attachments that were treated as exhibits; and the Public Staff filed confidential and public versions of the testimony of John Robert Hinton, the testimony of Kennie D. Ellis, and the responsive testimony of Dr. Richard E. Brown.

EDF filed the rebuttal testimony of Diane Munns on June 19, 2014. The other parties filed rebuttal testimony on June 20, 2014, as follows: DEC and DEP filed confidential and public versions of the testimony of Kendal C. Bowman, and the testimony of Glen A. Snider and Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams and Bruce E. Petrie; NCSEA filed the testimony of K. Zoë Gamble Hanes, Jonathan M. Gross, and Angela Whitener Maier, and confidential and public versions of the testimony of R. Thomas Beach; TASC filed the testimony and exhibits of J. Richard Hornby; SACE filed the testimony and exhibits of Karl R. Rábago; and the Public Staff filed the testimony and exhibits of Kennie D. Ellis and the testimony of Dr. Richard E. Brown.

Also on June 20, 2014, the NC Hydro Group filed a motion for a one-day extension to file rebuttal testimony which was granted by Order issued June 23, 2014. On June 24, 2014, DEC and DEP filed the Stipulation of Settlement among DEC, DEP and the NC Hydro Group. This stipulation provided that, because of the state policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, the stipulating parties had agreed that DEC and DEP would continue to use the currently-approved 2.0 PAF to calculate the avoided cost rates for small hydro QFs of five MW or less and that small hydro QFs of five MW or less, otherwise eligible for power purchase contracts with DEC or DEP, would have the option of contract terms of five, ten, and 15 years, with the same hour options that small hydro QFs have at this time under DEC's Schedule PP-H and DEP's Schedule CSP-29. In addition, the stipulating parties further agreed that DEC and DEP would include and incorporate the foregoing in their proposed avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31, 2020.

On June 24, 2014, DEC and DEP filed a corrected version of the rebuttal testimony of Kendal C. Bowman, stating that they had discovered that the confidential information in the testimony was disclosed without authorization and that the corrected testimony removed that information from the record. On July 3, 2014, Sierra Club/NRDC filed a motion to excuse their witness, Mr. Pereira, from appearing at the evidentiary hearing in this matter and to accept his pre-filed direct testimony into the record of the evidentiary hearing as if given orally at the hearing, indicating that all of the parties had agreed to stipulate to Mr. Pereira's testimony and waive their right to cross-examine him at the evidentiary hearing.

DNCP, by motion filed July 7, 2014, requested that the Commission excuse the appearance of its witnesses Bailey and Wright at the evidentiary hearing and allow the introduction of their prefiled responding testimony into the record at such hearing. In support of this motion, DNCP stated that it had reached agreement with the parties that had expressed an intention to cross-examine these witnesses at the hearing as follows: (1) counsel for DNCP and NCSEA stipulate to the following statements regarding the testimony of Mr. Bailey and Mr. Wright: (a) an important driver of DNCP's future transmission investments is the expected future load placed on DNCP's transmission system; (b) transmission is constructed to bring generation resources interconnected at

transmission voltages reliably to loads, which can be served from both the transmission or distribution systems; and (c) DNCP has not yet completed or made public a study specific to its system of the impacts of solar generation on its transmission or distribution systems, although such a study is currently underway; and (2) counsel for DNCP and counsel for TASC and SACE agree to certain terms pursuant to which counsel for TASC and SACE could cross-examine DNCP's witnesses Williams and Petrie regarding the testimony and data responses prepared by Mr. Bailey and Mr. Wright. This motion was granted during the hearing on July 7, 2014. DNCP filed the verified response of its witness Bailey pursuant to the stipulation between DNCP and SACE as a late-filed exhibit on July 17, 2014.

On July 8, 2014, counsel for the NC Hydro Group filed a motion asking the Commission to excuse its witness Givens, stating that all parties had agreed to stipulate Mr. Givens' testimony into the record and to waive cross-examination. This motion was granted during the hearing on July 9, 2014.

Various other filings were made and orders issued that are not discussed in this Order, but are included in the record of this proceeding.

FINDINGS OF FACT

1.   It is appropriate for DEC, DEP and DNCP to continue offering standard contracts to QF's under 5-MW_{AC}.

2.   It is appropriate for DEC, DEP and DNCP to continue offering standard contracts with a maximum term of 15 years.

3.   DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should include a condition making contracts under those options 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.

4.   The standard five-year levelized rate option should be offered to all other QFs contracting to sell three MW or less capacity.

5.   It is inappropriate for DEC, DEP and DNCP when negotiating contracts with QFs that are not eligible for standard contracts to employ methods found by the

Commission to be inappropriate in the application of the peaker method when calculating standard contract rates.

6.   The peaker method, as historically relied upon by the Commission to determine avoided cost, has captured the utilities' avoided costs generally and should be retained.

7.   It is inappropriate to approve DNCP's proposed "Net Peaker" method at this time.

8.   It is inappropriate in this docket to approve DEC and DEP's proposal to cap the production cost savings in each hour at the assumed production cost of the most efficient CT.

9.   It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates.

10.   Integration of solar resources into a utility's generation mix, depending in part upon their location, may result in costs and/or benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculations. Thus, it is 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.

11.   It is appropriate to consider hedging and environmental costs outside the scope of such a solar integration study.

12.   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.

13.   Hedging benefits should be valued only over the hedging terms (time period) actually used by DEC, DEP and DNCP. The utilities should calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding.

14.   The costs of carbon emissions control are not sufficiently certain to be included in avoided costs at this time. If in the future carbon costs become known and verifiable, it may be appropriate for those costs to be included at that time.

15.   The generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs.

16.   It is appropriate to include economies of scale in the calculation of the installed cost of a CT. When constructing CT units, utilities are likely to construct up to four units at the same site.

17.   It is inappropriate to include economies of scope in the calculation of the installed cost of a CT. When constructing CT units, utilities are unlikely to construct multiple units at the same time.

18.   It is appropriate to include the cost of land for a greenfield site in the calculation of the installed cost of a CT.

19.   It is appropriate to include transmission interconnection costs, but not network upgrade costs, plus a reasonable contingency adder for a hypothetical plant in relatively early stages of planning and a reasonable estimate of useful life of a CT in the calculation of the installed cost of a CT.

20.   It is appropriate to calculate avoided capacity payments based on a per-kWh capacity payment, rather than on an installed cost per kW basis.

21.   DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the settlement agreements entered into between and among DEC, DEP, DNCP, the Renewable Energy Group and the Public Staff in the Sub 136 proceeding.

22.   DEC, DEP and DNCP should continue to offer an Option A set of avoided capacity rates. Both proposed Option A and Option B capacity rates should be included in the utilities proposed rate filing in phase two of this proceeding.

23.   The availability of a CT is not determinative for purposes of calculating a Performance Adjustment Factor (PAF) because the fixed costs of a peaking unit in the peaker method employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

24.   The 1.2 PAF should be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their respective avoided cost calculations for all QFs other than run-of-the-river hydroelectric facilities with no storage capability.

25.   It is inconsistent with the method employed in the calculation of avoided costs to utilize a 2.0 PAF for run-of–the-river hydro. As the Commission has historically used this calculation it is appropriate to discontinue the use of the 2.0 PAF for run-of-river hydroelectric facilities with no storage capability and no other source of generation in accordance with the stipulation filed by DEC, DEP and the NC Hydro Group.

26. It is premature for DEC, DEP and DNCP 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. The Commission is aware of several ongoing studies and future developments that may further clarify theses costs and benefits for consideration in future proceedings.

27. It is appropriate for the utilities to continue to follow their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

28. It is inappropriate to calculate off-peak avoided energy rates for solar QFs at this time.

29. DNCP's proposal to provide a simple form to be completed by a QF seeking to sell its output to DNCP has merit; the details as to its implementation should be addressed in the next phase of this proceeding.

30. It is premature to retract the 30-month timeframe for completion of construction, given that it was approved shortly before the Commission issued the order initiating this proceeding. This timeframe is the best means of resolving a number of competing issues that were raised in the Sub 136 proceeding.

31. It is appropriate that the currently approved avoided cost rates and tariffs remain available until the date the utilities file new proposed avoided cost rates in compliance with this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider; the testimony of DNCP witnesses Williams and Petrie; the testimony of NCSEA witnesses Hanes, Cohen, Rever, Meier, Gross and Beach; the testimony of SACE witness Rábago; the testimony of TASC witness Hornby; and the testimony of Public Staff witness Hinton.

DEC/DEP witness Bowman testified that DEC and DEP apply the peaker method to establish a standard avoided cost rate structure that is applied to all renewable QFs contracting to sell five MW or less and to all nonrenewable QFs of three MW or less. She noted that this definition of QFs eligible for the standard terms and rates covers a wide range of generation types and sizes. She testified that generally the peaker method is a reasonable approach to assessing a utility's avoided cost, but that using it to establish a single, standard rate cannot reasonably account for all of the differences between the varieties of QFs currently eligible for the standard rate. Similarly, a single set of "standard" terms cannot address issues that may be specific to particular types of QFs or to specific QF projects. Conversely, in a bilateral negotiation, the specific characteristics of a particular QF can be taken into consideration. Witness Bowman testified that the Commission has long acknowledged this in describing the types of

factors that it expected such negotiations should encompass. Accordingly, bilateral negotiations are better suited to accurately measure the avoided cost associated with a particular QF than are standard terms and rates.

Witness Bowman testified that prior to 1985, standard avoided cost tariffs from DEC and DEP were available to all QFs of up to 80 MWs. In Docket No. E-100, Sub 41A, the Commission established a five MW eligibility limit for the standard tariffs. She noted that the small power production industry was in a nascent stage at that time, and, therefore, the Commission established eligibility criteria that ensured that smaller project developers that may not have the resources or expertise to negotiate with a utility, still had access to the standard terms and conditions. Witness Bowman stated that the industry has changed considerably in the past 30 years. The underlying public policy objectives are evolving and the technologies being utilized have changed. In today's environment, developers of even smaller projects tend to be well-experienced and sophisticated entities. Currently, in North Carolina, developers of QFs are routinely planning and developing projects both inside and outside the standard tariff parameters. As a result, Witness Bowman concluded that the prior justification for the five MW threshold simply no longer exists.

In responsive testimony, witness Bowman testified that public policy does not support extending eligibility to ten MW or the contract term to 20 years as proposed by some intervening parties. She further testified that, as witness Snider explained, the biennial process for establishing avoided cost rates results in application of the same rates to QFs even if they are put in service years apart. The effect of the imprecision inherent in that process would be mitigated by limiting the availability of those rates to smaller projects. Conversely, she testified that raising the eligibility cap exacerbates the problem by making more projects eligible for the standard avoided cost rates. She further testified that, given the cost and complexity of developing such facilities, any developer that intends to construct a QF facility that is five MW or larger will undoubtedly be more sophisticated and well-informed. Moreover, the transaction costs associated with bilateral negotiations would be small compared to the overall cost of the QF project. Thus, the policy rationale for requiring standard terms and conditions for certain QFs is inapplicable to the large-scale projects to which some parties wish to apply it.

With respect to G.S. 62-133.8(d), which provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility be of sufficient length to stimulate development of solar energy, witness Bowman agreed on cross-examination that when this was enacted into law, the standard contract options were in place and available. As to the stipulation among DEC, DEP and the North Carolina Hydro Group, she testified that it provided that the five, ten, and 15-year standard rates and contracts would remain available run-of-the-river hydro QFs. Witness Bowman also stated that page 39 of the Annual Report on Corporate Governance filed by Duke Energy on March 31, 2014, indicated that Duke Energy Renewables, a developer of QFs in non-Duke service territories, mostly has contracts

with terms that approximate the estimated useful life of the underlying generation project. She also agreed that solar generally has a warrantied life of 25 years.

DEC/DEP witness Snider testified that the NC REPS compliance requirements, the impact of state and federal tax incentives, and declining solar prices have resulted in a large solar QF development effort in North Carolina. Approximately 1,000 MWs of potential solar projects currently in DEC's and DEP's queues fall in the 100 kW to five MW range. Under the current fixed tariff structure, all 1,000 MWs receive the same price signal which, according to witness Snider, overstates the cumulative value created if all 1,000 MWs were to come to fruition. He further testified that QF contracts represent a long-term fixed price obligation on behalf of DEC and DEP's customers. QFs receive tariff prices that are based largely on forecasts of future fuel prices rather than actual fuel prices. Witness Snider argued that limiting the contract term to a maximum of ten years does not limit the QF's ability to continue to receive income over the life of the asset. He stated that at the expiration of the original contract, the QF has the right under PURPA to enter into another contract with the utility at the then prevailing avoided cost rates assuming (a) the requirements of Section 210 of PURPA are still in place and (b) the QF is still financially and operationally viable. This would better align the QF payment obligation borne by customers with the avoided cost value the QF actually creates.

DNCP witness Williams testified that DNCP does not believe the current size limits are appropriate and that standard rates should be limited to projects 100 kW or less. He testified that PURPA was intended to encourage alternative generation by developing standard terms for "small" projects. Witness Williams stated that this size limit needs to change because QF development activities in DNCP's service territory have changed dramatically in the past year. In most instances, these development projects are not "mom-and-pop" operations; they are owned by sophisticated companies backed by sophisticated financing, often with broad portfolios of renewable generation, that do not require the simplicity and benefits of a standard tariff. He stated that nearly all of the smaller projects being proposed for DNCP's service area are owned by companies that are also pursuing larger projects, or multiple small projects, totaling 100 MW or more in North Carolina. Because solar is easily scalable, companies pursuing very large scale solar development, representing hundreds of millions in investment dollars, are simply building a multitude of sites in exactly five MW increments to avail themselves of the standard contract benefits. According to witness Williams, facilities entitled to the benefits of Schedule 19 are no longer "generally of limited number and size" as previously noted by the Commission in earlier orders.

Witness Williams testified that DNCP believes that levelized rates should only be applied to QFs that qualify for standard contracts (which would be those at 100 kW or less under DNCP's proposal and for a term of ten years or less. A threshold of 100 kW or less would provide better protection for DNCP's customers with respect to risk associated with non-performance, and ultimately would better align payments to QFs with the Company's actual avoided cost. He testified that DNCP believes that the maximum contract duration for levelized rates should be ten years instead of the

currently available 15-year term. If a QF desires 15-year fixed rates (or any term greater than ten years), it should be on a non-levelized basis because of the discrepancy between the payment to the QF and the utility's avoided cost in any particular year that is created by levelization.

In his responsive testimony, witness Williams testified that extending the maximum term of contracts under PURPA to 20 years is unnecessary and adverse to the utility and its customers because of the uncertainty of long-term avoided cost projections. Given this degree of uncertainty, DNCP believes that such long-term projects are therefore not an appropriate basis for fixing rates in a contract. Moreover, with no credit security or performance assurances in a Schedule 19 contract, the Company's exposure to counterparty, equipment performance and other risks are substantially greater for long-term contracts. On cross examination DNCP witnesses Williams and Petrie acknowledged that in negotiations with facilities larger than five MW, DNCP has included newly proposed methods, such as the net-peaker and no capacity in the first three years, which are addressed in this Order.

NCSEA witness Hanes testified that when FLS Energy, Inc. (FLS), first began developing utility-scale solar QFs in North Carolina in 2012, the company developed smaller facilities, primarily one MW or less. However, over time, the size of the QF around which its business model revolves has grown, primarily because of decreasing revenue streams – resulting from decreasing rates and decreasing prices paid for RECs – and the need to spread certain fixed costs over increased generation to improve cost effectiveness. She further testified that FLS's experience in negotiating REC agreements and her observation of other developers attempting to negotiate PPAs is that such negotiations can be protracted, which seems an inefficient use of utility time and resources, QF developer time and resources, often Public Staff time and resources, and, on occasion, Commission time and resources. Additionally, such negotiations add significant additional transactional costs to QF project development. Witness Hanes stated that this, combined with the need for certainty by investors and lenders, has influenced FLS's primary strategy of limiting QF development to less than five MW. In the context of QFs greater than five MW, to her knowledge DEC has entered into PPAs with only six QFs, of which two are solar (or three if Apple's projects are treated as separate contracts). She further testified that since 2010, DEP has entered into PPAs with eight QFs greater than five MW, none of which are solar.

Witness Hanes testified that long-term contracts or PPAs enable investors to calculate return on investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. With increased price certainty for a project, investors typically require a lower return, which, in turn, reduces the cost of financing. She concluded that the inability of a project's revenue stream to cover its cost of capital results in the project not being financeable. As a result, she testified that, in the interests of reducing the cost to finance facilities and therefore encouraging the development of QFs, the Commission should direct the utilities to offer a 20-year terms for the standard offer. She noted that a 20-year term would be consistent with the industry standard term for a PPA that even the unregulated divisions at Duke and Dominion have themselves

secured, the details for which were shown in Hanes Exhibit 1, and NCSEA Bowman Cross-Examination Exhibit No. 1. Witness Hanes testified that no matter how sophisticated QF developers have become, the disparity in size between the three investor-owned utilities in North Carolina and even large solar developers is still enormous. A QF can sell the product only to one buyer, and this buyer may not really want the product. Under this scenario, the developer has minimal leverage and bargaining power when it comes to negotiating with a utility.

NCSEA witness Cohen testified that Strata Solar's (Strata) experience has been similar and that long-term contracts or PPAs are necessary for projects to be developed. He stated that he does not believe that a 20-year term disrupts this balance and, furthermore, that a 20-year term is necessary to encourage QF development in the current environment. The service life of the solar equipment installed by Strata is expected to be a minimum of 20 years. Thus, a 20-year PPA will better match the avoided cost revenue stream to the useful life of the equipment. Witness Cohen stated that the revenue QFs earn from the sale of electricity and RECs has declined dramatically over the past four years, putting the solar industry in North Carolina under considerable cost pressure. In 2010, the price of a solar REC was around $200 per MWh; today, that price is close to five dollars per MWh. More recently, the standard rates for the output generated at Strata's newer farms were reduced by more than 20 percent as result of the 2012 biennial proceeding. Looking forward, witness Cohen stated that the North Carolina tax credit for investing in renewable energy property, G.S. 105-129.16A, is scheduled to expire at the end of 2015, and the federal business energy investment tax credit will be reduced at the end of 2016. For all of these reasons, he stated that reducing the cost to develop the QF, such as through a 20-year PPA, increases the possibility that a project will be cost effective and will actually be developed, particularly in an environment of decreasing revenue streams and increasing difficulty in securing certain types of financing.

With respect to the process of negotiating a PPA with the utilities, witness Cohen testified that the elimination of the standard contract for all but the smallest QFs will dramatically increase the number of QFs negotiating PPAs with the utilities. He stated that the negotiation process already is protracted. PPA negotiations for Strata projects have been on-going for many months, and, to date, many are unsuccessful. He further testified that he is aware of other developers that have had similar experience in attempting to negotiate a PPA. Such a protracted process is an unnecessary waste of time and resources for everyone involved. He asserted that moving to a ten MW upper limit for the standard contract will further streamline the process and mitigate the difficulties QFs currently face as they attempt to negotiate PPAs. At a minimum, he stated that the current five MW size should not be reduced.

NCSEA witness Rever testified that DEC/DEP witness Bowman and DNCP witness Williams stated that solar developers are more experienced and sophisticated, routinely planning and developing projects both inside and outside the standard tariff parameters, but that they ignored the fact that the industry is not actually able routinely to develop projects outside the tariff parameters. She stated that the limited number of

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larger QFs in operation is telling. She further testified that the utilities' current track record with respect to negotiated PPAs calls into question one of their central premises for their proposals – that QFs larger than 100 kW would receive full avoided cost rates through bilateral negotiations with the purchasing utility. Witness Rever stated that it seems highly unlikely that, if the utilities' proposals were approved, more PPAs would be executed at rates and terms agreed upon "bilaterally."

Witness Rever further testified that the utilities' proposal to reduce the eligibility limit for the standard offer PPA would essentially "slow-track" PPA negotiations for QFs larger than 100 kW at the same time that the FERC has evidenced its intent that larger solar projects be fast tracked for purposes of interconnection agreements. She noted that FERC states in its November, 2013 Order No. 792, the package of reforms adopted in its Final Rule will reduce the time and cost to process small (up to 20 MW) generator interconnection requests, maintain reliability, increase energy supply, and remove barriers to the development of new energy resources. She further testified that the utilities' recommendation to reduce the eligibility limit of the standard offer PPA would work to thwart the FERC's desire to remove barriers to development. Finally, she testified that, in the interest of (1) encouraging the development of solar QFs; (2) making the most efficient use of resources; (3) keeping transaction costs to a minimum, and (4) following the FERC's goal of reducing transaction costs and decreasing the time to operation, the Commission should not reduce the eligibility cap for standard offer PPAs.

NCSEA witness Beach testified that the reduction in the standard contract size from five MW to 100 kW as requested by the utilities is likely to significantly slow, if not halt, QF development. With respect to DEC/DEP witness Bowman's reference to the Idaho Commission's decision to allow Idaho Power to reduce its standard contract size from 10 MW to 100 kW in response to what she characterizes as a "tremendous surge" in new and proposed wind QFs in that state, he testified that the practical result of this order has been to halt all further wind development in Idaho, even though wind QFs remain entitled to full avoided cost contracts through negotiations with the Idaho utilities. This experience, as well as the history of QF development where standard offer contracts for QFs over 100 kW have been suspended, he contended, calls into serious question witness Bowman's assertion that, if the utilities are allowed to negotiate rates for QF projects larger than 100 kW, "[t]he utilities will still be required to purchase the output of larger QFs, and the avoided cost requirements would still apply."

SACE witness Rábago testified that DEC/DEP witness Bowman's concern that raising the cap on standard offer contracts to ten MW will result in too much QF development is not a valid concern. He stated that Congress made a policy determination to encourage renewable generation when it enacted PURPA, a fact that utility witnesses persistently have ignored in this proceeding. He asserted that North Carolina ratepayers benefit from increased reliance on cost effective, clean electricity generation, even if those resources are not built by the utility companies. With respect to the length of the standard contract, witness Rábago testified that it is a best practice to set contract length to correspond to the life of solar assets. One entity that

demonstrates this best practice is Duke's unregulated subsidiary, Duke Energy Renewables, which has entered into 20-year (and longer) solar contracts as a matter of course, citing Exhibit 1 to the responsive testimony of NCSEA witness Hanes.

Public Staff witness Hinton testified that the Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by the FERC regulations and has previously rejected efforts by the utilities to lower the five MW threshold for renewable QFs (e.g. Docket No. E-100, Subs 100, 96, 87, and 79), finding this threshold to represent the appropriate balance. He testified that the Public Staff shares this perspective, and that, in addition to ensuring compliance with PURPA, the Public Staff believes that setting the standard threshold at a level that allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale provides ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options that may be available. He further testified that the Commission has concluded in past biennial proceedings that QFs not eligible for the standard long-term levelized rates have the option of "entering into contracts and rates "derived by free and open negotiations with the utility." The Public Staff's investigation of this issue indicates that QFs have had relatively limited success in obtaining negotiated contracts with the utilities in North Carolina. Witness Hinton stated that DEP has yet to execute a single negotiated PPA with a solar QF, DEC has negotiated two such PPAs and DNCP has recently entered into two PPAs with solar QFs with a capacity greater than five MW, one of which the Public Staff was asked informally to resolve disputes that arose; the other is with a subsidiary of Duke Energy Renewables.

Witness Hinton also stated that the Public Staff has been involved to varying degrees in attempts to resolve dispute between utilities and QFs that have arisen during PPA negotiations. Based on the Public Staff's experience and the small number of contracts that have actually been executed, it appears that the process of negotiating PPA contracts has not been very successful. Additionally, responses to Public Staff data requests to the utilities and NCSEA indicate that it may take well in excess of 12 months for the utility to complete an interconnection study for a project with generation capacity greater than five MW. Witness Hinton noted that while QFs maintain the right to petition for arbitration before the Commission, this process is also time consuming and adds significant transaction costs. At the time the testimony was filed, four QFs had filed petitions for arbitration with the Commission. The two arbitrations that were completed were long and contentious proceedings.

Witness Hinton testified that the Commission has previously concluded that the current long-term contract options serve important statewide policy interests while limiting the utilities' exposure to overpayments. He further testified that Section 292.304(d)(2) of the FERC's regulations provides that a QF may choose to sell energy or capacity pursuant to a legally enforceable obligation (LEO) for delivery "over a specified term." As the Commission has recognized in recent orders, the FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred.

According to witness Hinton, the Public Staff finds merit in the arguments raised by both sides with respect to the length of avoided cost contracts. Witness Hinton further testified that, in past proceedings, the Public Staff has maintained that fixed long-term rates needed to be at least 15 years in length in order to ensure that QFs could secure reasonable financing and the Public Staff believes that North Carolina's long-standing policy has been beneficial to QFs. He further stated that the Public Staff has reviewed policies in other states and found some with shorter terms and others with longer terms, but no clear standard term. Witness Hinton noted that a rate for a ten-year term or a variable rate would add an element of risk, and the banking industry would want additional equity in the capital structure relative to the current fixed 15-year terms.

With regard to the proposal by NCSEA's witnesses to extend the contract terms to 20 years, witness Hinton testified that the Public Staff believes that the increased risk to ratepayers that avoided costs could substantially change over that longer period outweighs the financing benefits. He stated that, given the number of currently operating facilities and the number of solar projects in development, it appears that North Carolina's standard 15-year contract has been accepted by the financing community. With respect to DNCP's concern about levelized rates, witness Hinton testified that witness Williams' position seems to be based on the increased possibility that a QF's output will decrease over the long term based on numerous factors, including degraded performance, financial failure, weather, fuel supply, or other risks that could lead to overpayment. This may be a valid concern with regard to QFs that must rely on fuel contracts, the viability of a steam host, or some other external factor that adds risk to future viability. However, according to witness Hinton, a solar generating facility has fairly predictable capital costs, production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams, and, thus, the Public Staff does not recommend reducing the availability of levelized rates.

In rebuttal testimony DEC/DEP witnesses noted that the same avoided cost rates may be applicable to QFs even if they are put in service years apart. During that lengthy interval, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically. According to these witnesses, negotiated contracts eliminate this problem by using more currently calculated avoided cost rates for each contract, which better serve the policy goals of PURPA. In support of requiring most QFs to negotiate contracts, witness Bowman noted that, even before the initiation of this docket, DEC and DEP have been taking steps to further streamline the QF PPA negotiation process. Recognizing the continued growth in proposed QF projects, they undertook to develop a standardized form PPA to be used as the basis for all negotiated QF contracts. Moreover, she stated that they recognize that different types of QFs may require different commercial terms in their PPAs and that they have incorporated that concept into their standard form. Witness Bowman emphasized that the main objective of their proposal is to apply more current avoided cost data to a greater percentage of new QFs.

NCSEA witness Hanes, in rebuttal testimony, argued that the development of QFs is a very capital intensive process and that the negotiations between the developer

and utility come after the developer has sunk considerable capital into a project. Witness Hanes stated that when a utility is slow to negotiate or proffers terms that are objectionable, the developer does not have the option of finding another utility with which to work. She noted that, if a deal cannot be reached, the expenditures made for that site are lost, which puts the developer, no matter its size or level of sophistication, in a very weak negotiating position. Witness Hanes also noted that the timing of the negotiating process has significant implications for every project; because tax equity is an important source of financing for solar QFs and timing issues related to the use of tax credits on an annual basis, a QF project must be put into service by year end. Any possible delay has the potential to jeopardize project finance. The utility retains significant control over the timing of the negotiation process.

Witness Cohen testified that he is aware of PPA negotiations for Strata projects that have been on-going for many months. He testified that he also is aware of efforts by Strata to negotiate PPAs that were abandoned as futile with the project subsequently downsized to five MW in an effort not to lose the money already expended on the project. Because of protracted negotiations on another project, Strata downsized its Mt. Olive project in order to avoid going through the negotiation process again. He testified that Strata has not filed an arbitration proceeding because it can ill afford to alienate the utilities, stating that "they are the only game in town." However, according to witness Cohen, arbitration petitions will likely become a necessary fact of life if the proposal to reduce eligibility for the standard QF contract were to be adopted in this proceeding. In response to a question from a commissioner, witness Cohen testified that Strata has accepted terms it feels are unjust simply to avoid arbitration, stating that the time element is part of why it has done so.

NCSEA rebuttal witness Gross, a certified public accountant, testified that in his experience most commercial banks will not lend to QFs in North Carolina as these banks consider QFs to be nonstandard and higher risk, at least compared to more conventional lending projects. According to witness Gross, only a handful of smaller banks and lending institutions that specialize in lending to projects perceived to have higher risk or complexity are willing to provide permanent debt for QFs. He further testified that the terms of the PPA have been a significant factor in every case of which he is aware in North Carolina for both debt and equity investment underwriting. A lender typically will not provide for a loan term that is longer than the PPA term. Debt and equity investors require long-term PPAs of 15 to 20 years. With respect to the utilities' concerns about nonperformance, he testified that they are unwarranted. Default under the financing arrangements could result in such things as the change of control rights of equity investors being triggered and of the owners being required to pay liquidated damages under loan documents. In addition, he testified that the generating facility is pledged as security for the debt financing and typically the developer is also required to provide a corporate and/or personal guaranty and/or to pledge assets in addition to the generating facility. Witness Gross further stated that, with only a ten-year term, many projects would not be able to secure financing. Finally, he testified that the availability of a 15-year term is a very significant factor, and, even then, in some cases the PPA will not be of sufficient length to allow adequate financing to cover project costs. Therefore,

the Commission should consider increasing the 15-year term in light of the changing circumstances, rather than decreasing it.

NCSEA witness Maier's rebuttal testimony addressed the swine waste-to-energy set aside in the REPS law. She testified that the Pork Council believes the utilities' proposals will make it more difficult for swine waste-fueled QFs to be developed, become operational, and generate the necessary swine waste RECs for compliance to occur. She stated that each of the utilities' proposals will inject uncertainty in project development and has the potential to reduce the return on investment. She testified that, in the interest of (1) encouraging the development of swine waste-fueled QFs; (2) making the most efficient use of resources; and (3) keeping transaction costs to a minimum, the Pork Council believes the Commission should reject the utilities' proposals to reduce the standard offer eligibility threshold to 100 kW and reject their proposals to eliminate the availability of a 15-year fixed term financing option under the standard offer.

<center>DISCUSSION AND CONCLUSIONS</center>

Whether the Commission should require the electric utilities to offer long-term levelized rates to a QF as standard rate options has been an issue in prior avoided cost proceedings, including Docket No. E-100, Subs 79, 81 and 87, in which at least two of DEP, DEC, and DNCP in each proceeding proposed eliminating the ten- and 15-year levelized rate options from the standard rates available to QFs. The utilities contended that these rates are based on long-term projections of costs that are inherently unreliable. They further noted that ten and 15-year levelized rates are not specifically required by either state or federal law. Despite the increasingly competitive wholesale markets that had developed during the 1990's, the Commission rejected the utilities' proposals to eliminate the standard rate options and long-term contract options in all three proceedings. In the 2002 proceeding, in Docket No. E-100, Sub 96, DEC again proposed eliminating ten and 15-year capacity and energy rates, while DNCP proposed eliminating the two-year capacity rate and the ten and 15-year energy and capacity rates. Similarly, in the Sub 100 proceeding in 2004, DEC proposed to limit the availability of ten and 15-year levelized rate options to new projects. DEC contended that perpetually offering standard long-term rate options to QFs renewing contracts beyond their initial terms is unwarranted. It proposed limiting renewing projects to five-year levelized rates. The Commission again rejected these proposals.

While the Commission initiated this docket to investigate the need to alter avoided costs determinations, the evidence presented by the buyers and sellers of QF power fail to justify altering the Commission's earlier decisions on term length and related provisions. As discussed earlier, a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders. The FERC has made clear that its 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 because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its

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financial feasibility, before beginning the construction of a facility. In her responses to cross-examination questions about various Duke Energy Renewables projects, DEC/DEP witness Bowman acknowledged the foregoing by stating that PURPA does not require the best financing, just the ability to secure it. In addition to the foregoing, G.S. 62-133.8(d) provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility "… shall be of sufficient length to stimulate development of solar energy."

In support of their positions with respect to reducing eligibility for standard contracts to 100 kW and eliminating 15-year contracts, DEC and DEP's testimony in this proceeding suggests that the public policy objectives underlying Section 210 of PURPA have outlived the circumstances that led to its enactment or at a minimum evolved beyond being justification for long-term standard contracts and rates for QFs five MW and under. As addressed earlier in this Order, Congress' retention of Section 210 of PURPA in 2005 and the FERC's establishment of a rebuttable presumption that QFs 20 MWs and smaller do not have access to nondiscriminatory wholesale markets, even in areas with markets operated by RTOs, suggest an opposite conclusion. While the utilities testify about solar developers being well-experienced and sophisticated entities that are routinely planning and developing projects both inside and outside the standard tariff parameters, the solar developers' testimony demonstrates that negotiating PPAs for projects that fall outside the standard tariff is a very challenging proposition. While much of this challenge results from interconnection issues, the evidence in the record shows that very few negotiated contracts with QFs larger than five MW have been executed, despite the existence of a large amount of QF development (i.e., CPCNs granted and interconnection requests made).

While witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC's and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts. The FERC's order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF. Indeed, the FERC concluded that ratepayers benefit anyway because of the resulting reduced use of fossil fuels, the addition of smaller increments of capacity, and the resulting diversity of power supply.

As to DNCP's concern about levelized rates, the Commission concludes that experience has shown that there is a limited risk of nonperformance. In addition, the testimony offered by the solar developers as to the restrictions and limitations in their financing offers a measure of assurance that a solar QF's output will not decrease over the long term. The fact that solar QFs do not have to rely on fuel contracts, the viability of a steam host or some other external factor also weighs in favor of allowing levelized rates to continue. A solar generating facility has fairly predictable capital costs,

production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams.

The Commission acknowledges that the negotiation of PPAs is a complicated process and that the interconnection of QFs to the grid is a highly technical process that contains many moving parts to ensure that a QF is reliably and safely interconnected. The Commission notes the evidence that an interconnection study for a project larger than five MW can take well in excess of 12 months for the utility to complete. These delays caused by both negotiating a PPA and the interconnection process place QFs in a difficult position with regard to their ability to secure project financing in a timely fashion and raises transaction costs. The Commission determines that overestimating avoided costs creates costs ultimately borne by ratepayers and underestimating avoided costs creates risks for the QF developers. Failure to calculate accurately a utility's avoided cost means ratepayers will pay for the additional energy and capacity whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission concludes that establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 210 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources.

Several parties to this proceeding presented evidence regarding the difficulty in obtaining a negotiated PPA. The Commission agrees with DEC/DEP witness Bowman that in a bilateral negotiation the specific characteristics of a particular QF can be taken into consideration. In addition a bilateral negotiation can utilize the most up-to-date data. However, the method by which avoided costs are calculated should, to the extent possible, remain consistent in both standard and negotiated contracts. If a method is not applicable to calculating the avoided costs of a QF smaller than five MW, the fact that a QF is greater than five MW does not validate such a method. In an effort to ease the negotiation process and avoid unnecessary and protracted proceedings, the Commission determines not to authorize DEC, DEP and DNCP when negotiating contracts with QFs that are not eligible for standard contracts to employ methods found by the Commission to be inappropriate in the application of the peaker method when calculating standard contract rates.

The Commission must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers. Increasing the maximum cap for eligibility for the standard contract to ten MW and extending the maximum standard contract term to 20 years may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers. Based upon the foregoing, the Commission determines not to approve the proposals to increase the size limit to ten MW and extend the maximum term length to 20 years.

In balancing the costs, benefits and risks to all parties and customers, the Commission recognizes that regulatory continuity and certainty play a role in the

development and implementation of sound utility regulatory policy. The record shows widespread QF development under the existing framework. While the parties have proposed various changes based on competing business models, there is insufficient evidence that the current framework fails to comply with the requirements of PURPA or otherwise disadvantages QFs. Absent such evidence, the Commission determines it inadvisable in this docket to introduce regulatory uncertainty by changing the existing framework.

Based on the evidence in the record, the Commission finds it is appropriate to retain the five MW threshold and 15-year maximum term length. The Commission concludes that DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by SPPs contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-9

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider, the testimony of DNCP witnesses Williams and Petrie, the testimony of NCSEA witness Beach, the testimony of SACE witness Rábago, the testimony of TASC witness Hornby and the testimony of Public Staff witnesses Kirsch and Hinton.

DEC and DEP have used the peaker method to develop their avoided costs in most of the past avoided cost proceedings; DNCP previously used the Differential Revenue Requirement (DRR) method. In the Sub 136 proceeding, in response to the Commission's directive that DNCP file proposed fixed long-term, levelized avoided rates for QFs entitled to standard contracts, DNCP employed the peaker method to calculate the avoided cost rates in its proposed Schedule 19-FP.

In the Sub 136 proceeding, several parties raised issues related to the appropriate method, which can be summarized as follows: (1) the accuracy of the various ways to describe and implement the peaker method and whether other potential methods for determining avoided costs should be used; (2) various changes and refinements to the peaker method, generally including ways in which its implementation can be corrected or improved, specifically including (a) DNCP's proposed use of the net peaker method, and (b) DEC and DEP's proposed cap on avoided energy cost saving at the cost of the avoided CT; (3) the appropriateness of replacing the annual installed cost of a CT with zeroes in the first few years of the period for which rates are being calculated; (4) the relevance of VOS studies and what is and is not appropriately included in avoided cost rates determined pursuant to Section 210 of PURPA; and (5) whether or not technology-specific QF rates, particularly for solar QFs, should be developed. The first three issues will be discussed separately in this section. The

VOS studies and technology-specific rates will be discussed in the section immediately following this section.

DEC/DEP witness Bowman testified that using the peaker method to establish a single, standard rate cannot reasonably account for all of the differences between the varieties of QFs currently eligible for the standard rate. While not recommending that the Commission use a different method, she testified that DEC and DEP have concerns that the current method for calculating avoided capacity and energy costs under the peaker method does not accurately reflect the value of the QFs' capacity and energy to their customers. With respect to avoided capacity rates, she recommended that the Commission establish the parameters of the key inputs used to calculate the installed cost of a CT and to calculate the capacity credits in the standard tariffs in a manner that takes into account the utility's relative need for generating capacity. With respect to energy costs, she recommended that the Commission recognize specific, measurable integration costs associated with intermittent solar generation and adjust for lost production cost benefits associated with the units being avoided through the purchase of QF power. Witness Bowman asserted that the intent of PURPA was not to force utilities to pay for capacity that they do not otherwise need, and that both Order No. 69 and subsequent FERC decisions have reinforced this point. She noted that North Carolina law also contemplates not paying for unneeded QF generation in that "a determination of the avoided energy costs to the utility shall include ... the expected costs of the additional or existing generating capacity which could be displaced ..." G.S. 62-156(b)(2). She testified that DEC and DEP's recommendation seeks to effectuate this concept in allowing avoided capacity credits provided to QFs to incorporate the actual capacity being avoided by the purchase of power from the QF.

DEC/DEP witness Snider testified that the peaker method is designed to determine a utility's marginal capacity and marginal energy cost, and, therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. He asserted that the Commission has recognized the theoretical corollary of the peaker method, which provides that even if a utility's next planned unit is not a simple cycle peaker, the peaker method still accurately represents a valid estimate of the utility's avoided costs. He further testified that simple cycle CTs represent the lowest capital cost resource option from a fixed cost perspective, and, thus, they are the marginal resource of choice. He further testified that avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ($/MWh), include items such as avoided fuel and avoided variable operation and maintenance (O&M) costs. Avoided capacity costs, on the other hand, represent fixed costs associated with construction, financing and staffing of a CT. Witness Snider recommended that the Commission approve the continued use of the peaker method and stated that, if properly applied, the use of the peaker method provides a reasonable and appropriate estimate of the costs that would have otherwise been incurred but for the purchase from a QF facility.

Witness Snider stated that DEC and DEP also believe that application of the peaker method should be refined or modified in several ways. With respect to the calculation of avoided energy rates, he testified that the hourly production cost savings calculated in the system dispatch model should be capped at the production cost of the avoided CT. He stated that this cap simply recognizes that the QF is avoiding the same marginal energy in an hour that the avoided CT would have also avoided, thus, effectively replacing that marginal energy with the CT's lower energy cost. He testified that he believes that capping marginal energy cost in each hour at the avoided energy cost of the CT results in an avoided energy calculation that aligns customer payments for QF energy with the avoidable energy benefit produced by the QF.

DNCP witness Williams testified that it is appropriate for the Commission to revisit the methods used to calculate avoided costs because the existing methods reflect an accumulation of past practices and rulings that no longer accurately reflect DNCP's actual avoided cost. A number of recent changes to the industry justify a re-evaluation of current methods to ensure they are consistent with PURPA. According to witness Williams, for DNCP, the scale of QF development in 2013 and the first quarter of 2014 is over 20 times the total activity seen in the previous five years. As of March 31, 2014, proposed developments total over 600 MW. In comparison, the average load of DNCP's North Carolina service territory in 2013 was less than 500 MW. Witness Williams stated that this shift has had, and continues to have, several impacts: it magnifies the impact of any discrepancies between the sanctioned rates a utility pays for a QF's output and a utility's actual avoided costs; it makes the present biennial avoided cost calculation a less accurate, more dynamic process as the impact of previous QFs on the utility's system can influence the avoided cost of the next incremental QF; and it raises questions with respect to impacts on system operations and reliability of such a sudden development of large quantities of new intermittent resources.

Witness Williams further testified that DNCP does not believe the peaker method, as currently implemented, captures DNCP's avoided costs. He testified that avoided capacity costs should be the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits from the peaker (i.e., the "Net Peaker" method), in order to address the fact that the peaker method as used in the past disregards the value that a CT provides in energy benefits.

DNCP witness Petrie testified that in the Sub 136 proceeding, DNCP adopted the peaker method for its new Schedule 19-FP, and offered for the first time five, ten, and 15-year levelized fixed prices for projects up to five MW in size. He further testified that the peaker method, with some modifications, is the most appropriate way to calculate avoided energy and capacity costs and, with the changes requested by DNCP, produces an appropriate representation of the Company's actual avoided costs. The current peaker method, however, in witness Petrie's opinion, ignores the non-capacity value of a CT and therefore overstates the calculated avoided cost of capacity. He further testified that, because the QF is already compensated for energy via the avoided energy rate (at the utility's marginal energy cost), the value of the CT energy benefit

should be removed from the capacity rate. Under this "Net Peaker Methodology", according to witness Petrie, the avoided capacity costs should equal the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits, including ancillary service benefits, from the CT. He further stated that this method is now relevant because the CT energy-related benefit was not an important distinction when the peaker method was first used. CT performance – due to technology improvements and reduced heat rates – has improved, and the cost of gas relative to other fuels has decreased. Witness Petrie stated that increased run time means that a CT can deliver substantial benefits in terms of energy, including ancillaries, for customers, producing energy below the wholesale power market price in many hours.

He testified that the Net Peaker Method, in his opinion, is an accepted and common industry approach to determining the value of capacity. The value of capacity method was thoroughly analyzed and discussed by all stakeholders – utilities, generator owners, developers, customers, and regulators in three RTO markets. The outcome in each of the three RTO markets was to adopt the Net Peaker method, and it has been in use since at least 2006 in competitive wholesale electricity markets in the U.S. The FERC has accepted the 'net energy and ancillary services revenue offset' concept in the development of capacity market prices, where the energy and ancillary service related values from a CT are subtracted from the CT construction cost. Finally, the Net Peaker method is also consistent with the analysis conducted by utilities for generation planning purposes, whereby DNCP recognizes that adding a new CT to the system provides both capacity and energy value, and to ignore the energy value would understate the benefits and overstate the capacity cost.

On cross-examination, witness Petrie agreed that over the long run, the price produced by PJM's RPM mechanism does not affect the cost of DNCP's future additions, the 3,800 MW DCNP needs to add in the next 15 years. More specifically with respect to the Net Peaker method, witness Petrie agreed that, generally speaking, the choice of the kind of unit that a utility is going to build depends on how often it expects the unit to run. He agreed that baseload plants are built to meet increases in a utility's base load, which is load that is generally there most of the time, with a nuclear plant being an example of this type of plant. The capital costs are very high, the running costs are not as high, and, therefore, the utility chooses a base load plant if the utility plans to run it in numerous hours.

In response to the question of whether there are any supply-side resources other than a CT, that can be built solely for reliability if the utility does not need the energy and is only attempting to meet a capacity need, witness Petrie testified that a CT facility is the closest facility that he is aware of that approaches pure capacity. He testified that DNCP's revised responses to data requests showed that the new CTs were running with a capacity factor lower than ten percent, but that at this point DNCP was simply placing the concept into the record. To calculate rates, the forward looking energy margins from a new CT would be used. He agreed that if DNCP assumed the CTs ran more hours and that they ran for many short increments, that start costs would be

increased, which would increase avoided energy rates using the peaker method. Likewise, higher O&M costs would be incurred.

Public Staff witness Kirsch listed and described numerous methods that can be used to calculate avoided costs and discussed their strengths and weaknesses. With respect to the peaker method, he testified that the strength of this method is that, in theory at least, the marginal capacity costs of all of a utility's resource investments are expected to equal one another in equilibrium. Consequently, the quantitative result is not biased by the choice of one particular technology over another. With regard to the weakness and challenges shared by all methods, he testified that all the methods depend upon data inputs that are uncertain, controversial, or both. Avoided capacity cost estimates depend upon a variety of assumptions about demand growth, construction costs, financing costs, taxes, and so forth. Avoided energy cost estimates depend upon uncertain future fuel prices, capacity factors, heat rates, and non-fuel variable O&M costs of a fleet of generating plants. Because future uncertainties increase with time, methods that depend upon longer-term forecasts are subject to greater error than methods that depend upon shorter-term forecasts, and methods that depend upon forecasts are subject to greater error than methods that depend upon values that are presently known.

On cross-examination, Dr. Kirsch, when asked about the potential for an adjustment to the cost of the CT used for calculating avoided capacity costs because of the improved heat rates and higher capacity factors, testified that the economic theory underlying the peaker method is that the capacity cost of each capacity type is net of the fuel savings attributable to that type. In his testimony, he assumed that a peaking unit would not provide any fuel savings but that fuel savings is not a necessary assumption. In the event that a peaking unit does provide fuel savings because it displaces the power output of old and less efficient power plants, there will be a fuel savings in those hours in which that displacement occurs. However, in those hours in which the new peaking plant is displacing expensive power from old, less-efficient plants, the avoided energy costs in those hours will be the incremental energy costs of those less efficient, high-cost plants. So in going to a net peaker approach, avoided energy costs would need to be calculated on the basis of the high, incremental energy costs of the expensive plants in those hours in which those expensive plants outputs are displaced.

Public Staff witness Hinton testified that the Public Staff supported the continued use of the peaker method. He testified that he reviewed the methods discussed in the testimony of Dr. Kirsch, as well as the testimony filed by other parties. No party proposed that the Commission abandon the peaker method. In view of the testimony of the parties and the Public Staff's investigation, including responses to data requests to several parties, he stated that the Public Staff recommends that the Commission continue to use the peaker method to determine the avoided cost rates for DEC, DEP and DNCP. Witness Hinton testified that DEC, DEP and DNCP indicate future capacity needs in their most recent IRPs. DEC indicates a resource need of approximately 3,358 MWs over the planning period (2013-2028); DEP indicates a resource need of

approximately 3,080 MWs over the same planning period, and DNCP indicates a capacity need of approximately 3,802 MWs.

With respect to DNCP's proposed net peaker method, witness Hinton testified that the Public Staff does not agree with the net peaker adjustment. The Public Staff is not persuaded that the energy benefits of a CT can be separated from its primary purpose of providing peak generating capacity at the least cost to the utility. He stated that the Public Staff maintains that this increase in the frequency and run times of newer CTs does not affect the validity of the traditional application of the peaker method. The peaker method has always assumed that CTs are run more than a nominal amount, and, indeed, in the past the Public Staff proposed adjustments because DEC and DEP were running their CTs at much lower capacity factors than assumed. In addition, the Public Staff stated concerns that the large adjustment estimated by DNCP for these energy benefits is largely dependent on DNCP's ability to accurately forecast market prices or LMPs using utility cost production forecasts, which adds a level of difficulty beyond the forecast of the production costs of a CT. He stated that the Public Staff is not convinced that the increased operation of the newer CTs warrants a 30 percent downward adjustment in avoided capacity rates and has concerns that such treatment could violate PURPA. On cross-examination, witness Hinton testified that he does not believe that these new CTs with their lower heat rates will be the last unit dispatched. According to witness Hinton, all three North Carolina utilities have some high oil-fired CTs that will be used during high demand times, despite their high heat rates. He further stated that his biggest concern is that subtracting energy benefits is inconsistent with the peaker method. The actual cost of installing a hypothetical CT is the underlying basis for the peaker method's valuation of capacity. The energy benefits cannot be segregated from the installed cost of a CT simply because current natural gas prices are low and the new CTs are being run more than they were previously run. In addition, estimating how much energy savings might result is very speculative.

In his responsive testimony, SACE witness Rábago testified that DEC and DEP's recommendation to reduce avoided energy rates by the value of "lost production benefits" seems to conflate the concept of sunk costs with the goal of setting fair and non-discriminatory avoided cost rates. Witness Rábago stated that under DEC/DEP witness Snider's formulation, avoided costs should be reduced in the situation where the QF displaces the operation of a utility generation unit that would itself have displaced the operation of non-cost effective, older additional utility generation units that should not have run anyway. So, even where the QF is economical compared to the avoided unit, it must also be cost effective against all the hypothetical costs that the avoided unit avoided by being part of the utility fleet.

NCSEA witness Beach testified that he has concerns in that, compared to other methods for calculating avoided costs, the peaker method tends to produce lower avoided cost estimates because the least-cost capacity option is used as the proxy for avoided capacity costs, even if the utility is planning to build another, more expensive plant. The peaker method depends on the assumption that the utility's system is operating at an optimal point, such that there is no resource other than a low-cost CT

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that would reduce overall system costs. However, as indicated in the utilities' IRPs, utilities often plan to add resources other than CTs (such as natural gas-fired combined cycles (CCs), which signifies that the utility's system may not always be operating at the "optimal" point of equilibrium. He stated that avoided costs based on the proxy method using the cost of the new plant will be equal to or lower than the avoided cost produced by the peaker method, if the savings in energy costs resulting from the new plant (compared to system marginal energy costs) more than offset the higher capacity costs of the new plant (compared to the least-cost peaker). Therefore, if a utility is planning to add a resource other than a CT, the proxy method may be the more appropriate method to establish the utility's full avoided cost. Given that the Commission determined years ago that the peaker method is an appropriate method for calculating avoided costs for the purposes of the biennial proceeding, the fact that DEC and DEP have used the peaker method for many years, and that both the Commission and the Public Staff are familiar with this method, witness Beach stated that it would be reasonable for the Commission to direct the utilities to continue to use the peaker method to calculate avoided costs. He further stated that the Commission should establish parameters for the inputs used in applying the peaker method. Finally, he testified that the Commission also needs to modify the avoided cost calculation in certain respects to capture more accurately the full range of costs, which solar and other distributed resources allow the utility to avoid.

TASC witness Hornby testified that DNCP's net peaker method should be rejected. He stated that the peaker method is founded on the premise that the utility's long-term avoided cost is its projected system marginal cost of energy in any given hour (which could be from coal units off peak and oil units on peak) plus the fixed cost of a peaking unit. According to witness Hornby, DNCP is essentially proposing that it use the "net cost of new entry" or net CONE method that PJM uses in its forward capacity market. However, he asserted that the net CONE method assumes the owner of the capacity will earn a margin on the sale of energy and ancillary services during peak hours that will equal the difference between the market price of the energy and ancillary services and the owner's cost of providing energy, and that the owner will use that margin to help recover its capital costs. DNCP is not proposing to pay QFs the market price of energy and ancillary services; instead it is proposing to pay QFs its avoided cost of energy. Moreover, he noted, under the peaker method DNCP should pay its avoided fixed cost of capacity, not the QF owner's estimated net cost of capacity. In addition, witness Hornby testified that, consistent with North Carolina's tradition and familiarity, the utilities should continue to use the peaker method to quantify avoided capacity costs using a set of comprehensive, transparent and verifiable input assumptions including land, construction and materials, infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and weighted average cost of capital.

Witness Hornby also testified that the Commission should reject DEC and DEP's proposal to cap the production cost savings calculated in the system dispatch model at the production cost of the CT that DEC/DEP assumed in its peaker method calculation. According to witness Hornby, the rationale DEC/DEP witness Snider presents for this

proposal rests on his premise that DEC/DEP should be calculating the cost of energy it would avoid in each hour by dispatching a gas CT. He stated that this premise is not correct; DEC/DEP should be calculating the cost of energy they would avoid in each hour by purchasing energy from QFs. North Carolina utilities that are planning resource additions other than a new CT in the absence of purchases from QFs should include in their avoided energy costs the net fixed costs of the marginal new resources, i.e., the fixed cost of the marginal resource minus the avoided capacity costs per the peaker method.

On rebuttal, DEC/DEP witness Snider testified that DEC and DEP's rationale for their proposed cost cap adjustment has already been accepted in other jurisdictions. Those that oppose it seem to object to the fact that an avoided CT (within the construct of the peaker method) would serve to reduce a small amount of the marginal energy that the QF is being compensated for in the avoided energy payment. Witness Snider asserted that this adjustment is needed simply to recognize that only the avoided marginal energy benefits above those that would have been created by the avoided CT should be counted in the avoided energy rate calculation.

DNCP witness Williams, in his rebuttal testimony, testified that if the status quo is maintained, DNCP believes the explicit constraints put in place by PURPA would be overstepped, thus providing a subsidy to QF projects above utilities' avoided cost, at the expense of electric utility customers. Also, maintaining the status quo would shift potentially very large risks from the large solar development companies to electric utility customers. He testified that it is critical that the Commission recognize the recent developments in the industry and ensure that the massive surge in development of intermittent QF generation be accompanied by appropriate protections for electric utility customers, who rely on the Commission for oversight of their rates. He further testified that the standard rates that were developed two years ago and that remain in place through November 2014 overstate DNCP's current avoided costs, and there is no mechanism to update them. He also testified that it is inappropriate to maintain the existing method because of significant recent changes in the industry have made the existing rate method inappropriate and no longer in compliance with PURPA. The magnitude of QF development activity has resulted in costs and risks that were once immaterial now becoming potentially large burdens on customers.

<div align="center">DISCUSSION AND CONCLUSIONS</div>

<div align="center">The Peaker Method</div>

In its Order No. 69, the FERC stated the following with respect to ways of determining avoided costs:

> One way is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a QF to meet part of its demand, and supplied its remaining needs from its

own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan excluding the QF, over the total capacity and energy cost of the system (before payment to the QF) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. An optimal capacity expansion plan is defined as "the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

45 Fed. Reg. at 12,214. Thus, at the outset, it is clear that the focus is on the total cost of capacity and energy contained in the utility's capacity expansion plan over its planning cycle with and without QF capacity and energy. This interpretation is reinforced by the inclusion by the FERC in its regulations of Section 292.304(e), which lists the factors the FERC requires be taken into account to the extent practicable when avoided costs are determined.

The question posed in the Commission's Order initiating this proceeding is whether the methods historically relied upon by the Commission to determine avoided cost appropriately capture the full avoided costs. Not surprisingly, the utilities argue that the historically used peaker method overstates avoided costs, while the various intervenors argue that the peaker method understates avoided costs, particularly with respect to solar QFs. In many respects the Public Staff has taken positions that fall somewhat between the other two groups. Despite the wide range of opinions as to the accuracy of the peaker method, there was general consensus that this method be retained.

The Commission has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher capital costs, producing a net cost equal to the capital cost of a peaker. The Commission has further held that a CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, avoided capacity costs should equal the cost of a hypothetical CT and, together with the marginal system running costs, these will equal the cost of any generating plant, including a baseload plant. The testimony of the utilities is replete with references to the next CT that they plan to build, even when such a CT is not projected to be needed until after a new baseload plant. They also refer to using "the avoided CT." For example DEC/DEP witness Snider asserts that in calculating of the avoided energy payment, the hourly production cost savings

calculated in the system dispatch model should be capped at the production cost of the avoided CT.

The evidence shows that DEC, DEP and DNCP indicate future capacity needs in their most recent IRPs. DEC indicates a resource need of approximately 3,358 MWs over the planning period (2013-2028); DEP indicates a resource need of approximately 3,080 MWs over the same planning period, and DNCP indicates a capacity need of approximately 3,802 MWs. Most of this capacity need is shown as being met with baseload capacity. The Commission finds that the cost of the future baseload capacity in the utilities' capacity expansion plans is the appropriate measure for avoided cost purposes. The peaker method, as it was intended to be used, is a reasonable means of determining this cost and thereby for complying with Section 210 of PURPA.

In regards to DNCP's proposed "Net Peaker" method, DNCP supports it on the basis that the current peaker method ignores the non-capacity value of a CT and, therefore, overstates the calculated avoided cost of capacity. DNCP believes that the current peaker method pays a QF the full fixed cost of a CT (including its energy value) and a separate energy payment equal to the marginal (highest) cost of energy. DNCP, therefore, proposes to remove the value of the CT energy benefit from the capacity rate. Under this "Net Peaker" method, the avoided capacity costs should equal the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits, including ancillary service benefits, that the CT will provide. The justification is that CTs in the past ran only limited hours per year and, when they did run, they were the unit on the margin (highest cost). Today, a new CT can be expected to run significantly more often, with an annual capacity factor of five to ten percent.

The Commission is not persuaded that DNCP's proposed adjustment is appropriate for approval in this docket. The Commission finds particularly noteworthy DNCP's responses on cross-examination that there are other supply-side resources that can be built solely for reliability if the utility did not need the energy and that a CT facility is the closest facility to be used to identify pure capacity. Finally, witness Petrie's agreement that without a guarantee that wellhead natural gas prices are going to remain in the range that they were in from 2011 through 2013, the years used by DNCP to develop the expected CT capacity factors and therefore energy benefits, DNCP would not build a CT based on the assumption that it needed energy. He acknowledged that DNCP adds CTs because they are needed for capacity. As witness Petrie acknowledged, because CTs are more efficient now, when DCNP builds them, it "happens to get energy benefits that come along with it." A peaker would not be built for capacity purposes if it were not expected to run for some number of hours, otherwise, it would not be needed for capacity.

As TASC witness Hornby pointed out, the "net cost of new entry," or net CONE method, that PJM uses in its forward capacity market assumes the owner of the capacity will earn a margin on the sale of energy and ancillary services during peak hours that will equal the difference between the market price of the energy and ancillary services and the owner's cost of providing energy, and that the owner will use that

margin to help recover its capital costs. DNCP is not proposing to pay QFs the market price of energy and ancillary services. Finally, of particular concern is the speculative nature of the estimate of the energy benefits and the fact that DNCP used its proposed method to produce a 30 percent downward adjustment in avoided capacity rates.

Based upon the foregoing, the Commission chooses not to approve DNCP's proposed "Net Peaker" method. A CT is the lowest cost capacity option available to a utility and the fact that the newest CTs, when burning low-cost natural gas, may also produce some energy benefit does not justify the change proposed by DNCP. For many of the same reasons, the Commission determines not to approve DEC and DEP's proposed cap on the production cost savings calculated in the system dispatch model used to determine avoided energy costs. DEC and DEP propose to cap the production cost savings in each hour at the production cost of the CT that DEC/DEP assumed in its peaker method calculation. The rationale DEC/DEP witness Snider presents for this proposal rests on his premise that DEC/DEP should be calculating the cost of energy it would avoid in each hour by dispatching a gas CT. The Commission determines that avoided energy rates should be calculated based upon the cost of the energy the utility would avoid in each hour because of QF purchases. To the extent these are older, less-efficient generating units, the higher energy costs of such units should be included in the calculation of avoided energy costs.

The Proposal to Include Zeroes in the Calculation of Capacity Credits

In support of DEC, DEP and DNCP's proposal to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon, DEC/DEP witness Bowman testified that, if the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, the QF should not be compensated for providing that benefit. She stated that PURPA was not intended to force utilities to pay for capacity that they do not otherwise need, and both Order No. 69 and subsequent FERC decisions have reinforced this point, citing City of Ketchikan, Alaska, 94 FERC ¶61,293 (2001)(Ketchikan). She also contended that North Carolina law is premised upon this concept in that "a determination of the avoided energy costs to the utility shall include ... the expected costs of the additional or existing generating capacity which could be displaced ... " G.S. 62-156(b)(2). DEC and DEP's recommendation that zero annual fixed capacity costs should be included for years in which no actual capacity need exists merely seeks to effectuate this concept in practice. DEC/DEP suggest that to appropriately incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRP. DEC/DEP witness Snider asserted that the current approach violates PURPA and results in the utilities' customers paying for QF capacity that does not offset needed utility capacity. As a result, retail customers are paying avoided costs for capacity the utilities do not need – in excess of the utilities' avoided capacity cost, as determined under the peaker method.

DNCP witness Petrie testified that avoided capacity costs are zero in the first three years of the 15 years because DNCP, as part of the generation planning process and in order to maintain reliable service for its customers, will have already planned for and procured its projected capacity needs for at least the next three years at any time. This is because it generally requires approximately three years to develop and construct a new capacity resource (such as a CT or CC), and because DNCP must procure capacity in the PJM capacity auctions three years in advance of when the capacity is projected to be needed. Therefore, in the first few years of the planning horizon, witness Petrie asserted that DNCP has all the capacity it needs and that it will not avoid any capacity costs if new QFs commence operation during this time period. Witness Petrie agreed on cross-examination, however, that the price produced by PJM's capacity auction did not affect, over the long run, the cost of DNCP's future capacity additions – the 3,800 MW witness Petrie had agreed DNCP's IRP showed it needed to add in the next 15 years.

NCSEA witness Beach in responsive testimony recommended that the Commission reject the zero value proposals of DEC, DEP and DNCP for the following reasons: First, the FERC's regulations, as well as precedent, provide that the rate paid to the QF is based on future needs. An avoided cost rate should include the full cost of capacity if the QF purchase will permit the purchasing utility to avoid building or buying future capacity. The expected longer-term costs of future additions of capacity must be considered in the calculation of avoided costs and included in the rates based on those avoided costs. In addition, the FERC's regulations explicitly approve determining avoided costs by comparing (a) the total costs that would be incurred by the utility to meet a specified demand without purchases from new QFs to (b) the total costs that would be incurred if the utility purchased power from one or more QFs to meet part of its demand while meeting the remainder through its expansion plan.
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He further testified that the FERC regulations explicitly state that avoided cost rates for purchases from QFs must take into account "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities." The utility witnesses acknowledge that capacity from solar QFs can be installed with shorter lead times and much more quickly than traditional utility capacity, with construction requiring as little as two months once permitting and such are complete. QF capacity obviously is available in smaller increments, because standard contracts today are limited to no more than five MW. In contrast, typical utility additions of capacity are in much larger increments, as shown by the utilities' current resource plans. These large central station units require significantly longer time to develop, permit, and build. As a result of the long lead times and the large, "lumpy" nature of traditional utility capacity additions, new utility plants are sized to provide much more than the amount of capacity that the utility needs in the year in which the new plant enters service. The result, he explained, is that ratepayers may have to pay for years of extra capacity until demand "catches up" to the last major addition – a fact that is explicit in DNCP's testimony that it has no need for new capacity for the next three years and the conclusion in DEC's and DEP's recent IRPs that, due to the addition of a number of new coal and natural gas units in 2011 through 2013, these utilities do not need

capacity until 2016 or 2017. He further testified that, because QF capacity can be built in smaller increments and with shorter lead times, QF development can match more closely the utility's future load growth and future capacity needs, with less excess capacity. The result of this benefit is that QFs can be paid the full value of the CT's capacity in years before the utility has a need, at a cost to the ratepayer that is no higher than what the utility would have incurred "but for" QFs. As a result, it would underpay QFs, in violation of PURPA requirements, if QF capacity rates assume that QF capacity has zero capacity value until the year the next utility unit would be installed.

Witness Beach also testified that, in fact, the utilities' proposal is likely to cause QFs under long-term contracts to always be underpaid. He noted DNCP witness Petrie's testimony that it will always be the case that DNCP will have all the capacity it needs in the first few years of the planning horizon. The result of the utility proposal would be to underpay QFs systematically compared to the utility costs that the QF enables the utility to avoid, in violation of PURPA's full avoided cost principle. He further testified that another problem with the utilities' proposal is that the value of capacity is never zero, even if a utility has excess capacity. There is an active market for short-term capacity in which the North Carolina utilities participate. Even if a utility is "long" on capacity in a particular year, it has an opportunity to sell that excess capacity in the market to earn additional revenues for the benefit of its ratepayers. The value of short-term capacity is apparent in PJM with its organized and visible capacity markets.

Public Staff witness Hinton testified that the Public Staff does not support the utilities' proposal with respect to the inclusion of zeroes. He stated that, while the utilities' position might appear intuitive on the surface, it does not comport with the theory underlying the peaker method. The peaker method is supposed to produce the long-run marginal costs of adding new capacity over the entire planning horizon. For this method to produce the correct total avoided costs, all of the costs of future new capacity have to be included. As a result, the utilities' proposal leads to an understatement of avoided capacity costs and should be rejected if the peaker method is retained.

Witness Hornby testified that witness Snider's recommendation to reduce QF capacity payments for the years in which the utility does not need capacity has two major flaws. First, it has the effect of amplifying pervasive existing incentives for the utility to over-plan and over-build in order to maximize revenues and profits. Second, it effectively precludes ratepayers from ever receiving the benefits of more cost-effective power from QFs except during the imperceptibly small window between a condition of excess capacity and the failure to add utility capacity into the resource plan at some point in the future. That is, QF capacity will almost always be either too early or too late to receive value for its capacity contribution. Under witness Snider's recommended approach, even capacity at a lower price than utility planned capacity will not be fully or fairly compensated.

DISCUSSION AND CONCLUSIONS

The Commission determines that it should not authorize as a generic principle that the avoided cost rate should be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into.

Much of the utilities' arguments in this area are premised on the FERC's Order No. 69, particularly as applied in <u>Ketchikan</u> standing for the proposition that the long-term capacity rate calculated under PURPA can be reduced by the inclusion of zeroes in the early years. The Commission concludes that FERC decisions addressing this issue are not uniform and tend to turn on the unique facts of the case before it. <u>Ketchikan</u> involved several towns with electric distribution systems in Alaska that purchased power pursuant to an arrangement established by the Alaska legislature to lower electric rates for rural customers. The FERC granted relief to the towns based upon the relatively unique facts of that case. More recently, however, the FERC rejected claims bearing some similarities to the claims made by the utilities in this case, that a short-term lack of need because of a recently built plant justifies not making capacity payments. In <u>Hydrodynamics</u> (146 FERC ¶ 61,193), the FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, the FERC made clear that the time period over which the need for capacity needs to be considered is the planning horizon. The FERC's quote from <u>Ketchikan</u> is as follows: "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity." <u>Ketchikan</u>, at 62,062. <u>Hydrodynamics</u> involved an installed capacity limit rather than the inclusion of zeroes. Based on the facts of <u>Hydrodynamics</u>, the FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity that would be avoided.

The Commission is concerned that including zeroes for the first three years in the calculation of capacity rates lowers the avoided cost rate for the entire 15-year period. Thus, depending on the utility's actual needs over the term of the PPA, the resulting avoided cost rates may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. The most recent IRPs for DEC, DEP and DNCP show they need to build or buy over 3,000 MW of capacity over the next 15 years. As conceded by DNCP's witnesses on cross-examination, the cost of that future needed capacity is not changed by the fact that a utility has sufficient capacity in the very near term. Furthermore, while DNCP may not project a need in its first three years due to its participation in the market, it would also be true that the final three years of a QFs long term contract could cover a future need, and, thus, be of more value than the avoided cost rate reflects. It also is significant that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal than they need for the first few years after a large generating unit is placed in rate base. This is in spite of the fact that their ratepayers may be paying a return on most of the investment in the plant for the initial years.

If as witness Snider posited, poor economic conditions, combined with a large influx of QFs, eliminated all future need for utility fossil generation capacity, there would be no future capacity to offset or avoid. The Commission agrees that, under those circumstances, the payment of avoided capacity could be inconsistent with PURPA. That may not be the circumstances in which the utilities find themselves, however. Presently, each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10-11

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider, the testimony of DNCP witness Williams, the testimony of SACE witness Rábago, the testimony of TASC witness Hornby, the testimony of EDF witness Munns, the testimony of NC Warn witness LaPlaca and the testimony of Public Staff witnesses Brown and Hinton.

SACE witness Rábago addressed a value of solar (VOS) analysis, indicating that it is a method for determining the long-term avoided costs of solar generation. According to witness Rábago, in a VOS analysis, the benefits and costs are first identified and grouped, then quantified. VOS results vary depending on specific methods, local energy markets, and other factors, but a growing body of VOS research consistently demonstrates that solar energy has value that significantly exceeds more narrowly calculated avoided costs. He further testified that a VOS analysis is an improvement over traditional PURPA avoided cost methods because it is a calculation of avoided costs that embraces a full range of costs avoided by solar generation, analyzed over the life of the solar generation system. In other words, VOS analysis achieves a better approximation of the "full avoided costs" associated with solar generation. Consequently, VOS studies illustrate the ability of technology-specific analyses to reveal additional avoided costs that are not captured under traditional avoided cost calculations. He further testified that the benefits and costs studied in VOS analysis generally fall into the following categories: energy (including line losses), capacity (both generation capacity and transmission and distribution capacity), grid support services (also referred to as ancillary services), financial risk (fuel price hedging and market price response), security risk (reliability and resilience), environmental benefits (carbon emissions, criteria air pollutants, and others) and social benefits.

Witness Rábago acknowledged that not all of those values can be quantified with enough confidence that they should be incorporated into avoided cost calculations. In addition, solar generation avoids some costs that may not be appropriately factored into PURPA QF rates, even though those costs are real. Witness Rábago stated that solar energy generation technology, at both the utility and distributed scale, allows utilities to avoid a wide range of costs associated with conventional generation options. Witness Rábago noted a report by Crossborder Energy that found that the benefits to a utility from wholesale solar generation range from nine to 15.6 cents per kilowatt-hour, which are 40 percent greater than a utility's costs to purchase and integrate solar resources. According to witness Rábago, these benefits are inherent to solar generation's innate

characteristics – its natural coincidence with peak demand; its ability to avoid transmission capacity costs and line losses by siting smaller systems on the distribution grid closer to load; its scalability; its lack of fuel volatility; and other characteristics.

TASC witness Hornby testified that various studies have quantified at least 14 benefits of distributed solar generation. However, current PURPA regulations only allow utilities to consider eight of those 14 benefits as cost they can avoid by obtaining energy and capacity from QFs. Those eight types of avoided costs to utilities are (i) avoided energy costs (electricity generation), (ii) avoided environmental costs, (iii) avoided capacity costs (generation), (iv) avoided and deferred capacity costs for transmission and distribution, (v) avoided energy losses, (vi) fuel price hedging, (vii) energy market impacts (supply induced price effects) and (viii) ancillary services and grid support. The six additional types of benefits that cause the value of distributed solar generation to exceed the avoided cost rate for purchases from QFs are avoided renewable costs, health benefits, security and resiliency of grid, environmental and safety benefits, effects on economic activity and employment and visibility benefits.

Public Staff witness Brown testified that, to the extent that value categories correspond to actual utility avoided costs, VOS studies can be used to inform utility avoided cost studies. With respect to the eight types of avoided costs recommended by TASC witness Hornby, he testified that he agreed with the first six, which are (1) avoided energy costs (electricity generation), (2) avoided environmental costs, (3) avoided capacity costs (generation), (4) avoided and deferred capacity costs for transmission and distribution, (5) avoided energy losses and (6) fuel price hedging, but did not believe the last two, energy market impacts (supply induced price effects) and ancillary services and grid support, could appropriately be measured or otherwise included in avoided costs.

NC Warn witness LaPlaca testified that distributed solar provides a tangible, measurable value to North Carolina's ratepayers, especially because they include a wide variety of energy, capacity, and social and environmental benefits. She stated that utility concerns that solar PV will negatively impact earnings and profits have grown along with the increase in solar installations. She further testified that it is unlikely the growth of solar generation will be a threat to the reliability of the utility grid for many years to come, if at all. She noted a recent General Electric study commissioned by PJM finding that PJM could increase solar and wind to 30 percent without any "significant" issues. According to witness LaPlaca, this study confirms that the grid can integrate high levels of clean energy without compromising reliability.

Witness LaPlaca also presented a summary taken from the Rocky Mountain Institute ("RMI")'s Review of Solar PV Benefit & Cost Studies. This study describes seven major components impacting the value of solar: (1) energy (energy, energy losses); (2) capacity (generation capacity, transmission and distribution capacity, DPV installed capacity); (3) grid support services (reactive supply & voltage control, regulation & frequency response, energy and generator imbalance, synchronized and supplemental operating reserves, scheduling, forecasting, and system control

& dispatch); (4) financial risk (fuel price hedge, market price response); (5) security risk (reliability and resilience); (6) environmental costs and benefits (carbon emissions, criteria air pollutants, water, land); and (7) social costs and benefits (economic development, jobs, tax revenue).

TASC witness Smart testified that the Commission's desire to create a broader context in this avoided cost proceeding creates a prime opportunity to address the issue of how to fully and fairly value distributed solar resources. Given the broad scope of potential uses for such a method, she stated that she believes it is appropriate to develop a distributed solar valuation method that is relevant to an avoided cost determination, yet broad and versatile enough to serve the Commission's other foreseeable purposes. Witness Smart further stated that there is no single, recognized method, but that there is an emerging body of literature and technical studies that share common approaches. Her testimony included a compilation of studies and reports that have employed relatively similar approaches to determining the VOS or distributed generation resources. Finally, she stated that there are a few important principles that should inform any inquiry into the VOS: (1) any valuation method of solar should seek to leverage the experience of previous work and follow emerging best practices; (2) a long term perspective on DG value is important to fully capture the benefits DG resources bring to the grid over their useful life; and (3) any valuation method should seek to include the full range of potential values (i.e., all potential benefit and cost inputs) to provide a more informed basis for policy decisions. She recommended that the focus at this stage of the proceeding needs to be on constructing a framework that is inclusive of the full range of values associated with distributed solar.

EDF witness Munns recommended that the Commission continue to use the avoided cost methods approved in the last biennial avoided cost case in setting the avoided capacity payment for solar and wind resources until the Commission develops a more comprehensive method for valuing distributed solar resources. For this more comprehensive approach, she recommended that the Commission develop and adopt a new, stand-alone method for avoided cost rates for distributed solar generation, using a full VOS analysis. Under this approach, the Commission would identify all the costs and benefits attributable to distributed solar generation and develop a value for each element of cost and benefit, the net result representing the full avoided cost of distributed solar generation. She recommended that the Commission or Public Staff hire an independent engineering expert to oversee the VOS study process. She suggested that the Commission start this process now because it will take several months to complete. The Commission would then have an opportunity, following a hearing, to approve, reject, or modify the independent expert's proposal for a distributed solar avoided cost method.

In her supplemental testimony, DEC/DEP witness Bowman responded to the testimony of other parties about VOS studies. She testified that key distinctions make the VOS method inappropriate for establishing avoided costs under PURPA. The most obvious distinction is the method used for the Minnesota VOS study, for example, was designed for a different purpose – to achieve state policies through quantifying and

capturing the environmental value of customer-owned solar installations as well as incorporating an array of other values and factors. The VOS method captures Minnesota's assessment of the full value of distributed solar to the utility, its customers, and society by including asserted environmental and social costs in addition to avoided energy and capacity costs. For example, the Minnesota VOS method includes an avoided "social cost of carbon" as part of the value of distributed solar. She further testified that PURPA does not allow the inclusion of externalities or speculative avoided costs, and such inclusion is antithetical to the fundamental principles of PURPA.

DEC/DEP witness Snider testified that a VOS analysis in the context of setting avoided cost rates is not appropriate because such an analysis includes a list of potential benefits that are not "avoidable utility costs." Furthermore, he stated that such studies ignore certain integration costs associated with intermittent solar generation. He stated that VOS studies fail to recognize and delineate between the specific purpose of avoided cost rates under PURPA and that of policy-driven initiatives like renewable tax incentives, net energy metering and renewable portfolio standards. He further testified that avoided cost rates are appropriately focused on the value of the utility avoided capacity and energy, not on the value of the resource being proposed in place of the utility generation.

DNCP witness Williams testified that DNCP does not reflect some asserted benefits in its rates because the benefits do not result in an avoided cost to the utility itself; the benefits are highly uncertain or speculative; and/or the benefits cannot be realized in the context of a QF, as the utility does not control the development of the facility. Additionally, he asserted that DNCP's proposed avoided cost rate method fully captures these benefits to the degree allowed under PURPA.

DISCUSSION AND CONCLUSIONS

In the Sub 136 proceeding, considerable testimony was presented about VOS and how it should impact avoided cost calculations. In this proceeding, a number of witnesses have encouraged the development of a new, stand-alone method for avoided cost rates for distributed solar generation, using a VOS analysis. Under this approach, the Commission would identify all the costs and benefits attributable to distributed solar generation and develop a value for each element of cost and benefit, the net result representing the full avoided cost of distributed solar generation.

The Commission agrees that integration of solar resources into a utility's generation mix likely results in costs and/or benefits. 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, require the consideration of additional factors. At this time, as will be discussed more fully in subsequent sections, hedging and environmental costs can be considered more fully outside the scope of such an integration analysis. Otherwise, the Commission believes it is appropriate for the costs and/or benefits attributed to solar integration to be more fully evaluated when future studies and calculation methods have been further developed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Snider and Makovich, the testimony of DNCP witness Petrie, the testimony of SACE witness Rábago, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

TASC Witness Hornby testified that utilities that incur fuel hedging costs have the potential to avoid some of those costs by purchasing from QFs. In addition, even if utilities do not hedge any portion of their fuel supplies, they and their customers still benefit from reducing their exposure to volatile fuel prices. Witness Hornby testified that one approach to estimating the value of avoiding the risk associated with natural gas fired generation is to calculate the difference in cost between buying a specific quantity of gas on a spot basis and buying it at a fixed price under a long-term contract.

The Crossborder study sponsored by NCSEA witness Beach (NCSEA Beach Exhibit 2) indicated that solar generation has no fuel costs, and, thus, avoids the volatility associated with generation sources with costs that depend principally on fossil fuel prices. In its analysis of gas cost forecasts, the Crossborder study indicated that forward market natural gas prices represent a cost of gas that the North Carolina utilities theoretically could fix for the next 15 years, thus, in principle, capturing the fuel price hedging benefit of renewable generation. The Crossborder study also noted that hedging strategies have real costs. For example, DEP incurred $121 million in 2011-2012 in above-market costs to hedge one-half of its 163 billion cubic feet of gas purchases, which reflects a cost premium of $0.74 per MMBtu when spread over the utility's full portfolio of gas purchases. These hedging costs are not included in current avoided cost prices.

SACE witness Rábago also supported the recognition of fuel hedging benefits of solar and other fuel-free renewable generation. He stated that a long-term contract provides a guarantee that the rate paid to the QF will not fluctuate with fuel prices. Witness Rábago testified that for fuel-free resources, in contrast to "traditional" PURPA QFs or other generators that rely on natural gas or biomass fuels, there is no risk that the QF's business will fail due to changes in fuel costs. Witness Rábago testified that quantifying the fuel-price hedging benefits of renewable energy resources may be challenging; however, difficulty is not a justification to set the value at zero.

Public Staff witness Brown testified that PV generation is typically assumed to displace fossil fuel. Because PV generation does not require fuel, and future fossil fuel prices are not known with certainty, to the extent PV generation offsets fuel purchases, it helps to reduce cost uncertainty for the utility. Witness Brown further testified that utilities have the ability to mitigate the impact of fossil fuel price variation on fuel costs by purchasing futures contracts and other forms of hedging. Through hedging, utilities can reduce their exposure to fuel price volatility and provide a financial benefit to the utility and its ratepayers. Even if a utility does not purchase fuel futures, the economic value of avoided fossil fuel usage in a future year can be determined by the futures

price. Witness Brown also noted that even if utilities do not use call options or other approaches to hedge its long-term risk of fuel price volatility, pricing models such as the Black-Scholes method can still be used to estimate the value of the hedge.

DEC and DEP witnesses Snider and Makovich both asserted that the value of fuel price hedging should not be considered in avoided cost calculations. Witness Snider classified fuel hedge value as external to avoided costs. Witness Snider testified that the hedge value of solar QF generation is the same as buying forward fuel. On cross-examination, witness Snider stated that "[y]ou can either buy the gas or you can buy the solar both based on the same gas price forecast." He further testified that the major difference with solar is that one is providing a price signal that can be kept constant for two years. He concluded that solar QF generation is a very ineffective way to hedge fuel. Witness Makovich testified that adding solar power could either improve or reduce cost effective risk management. Whether additional solar can add cost effective risk management depends on the utility's current risk exposure and its generation mix, and that cost effective risk management must be accomplished through managing diversity at the generation portfolio level.

DNCP witness Williams, in his responsive testimony, stated that the current actual hedging costs avoided by QF purchases are small, and, therefore, should not be included in an avoided cost calculation. Witness Williams described the "lost option value" of hedging with solar and indicated that the cost of generation will be higher as a result of hedging if actual fuel prices turn out to be lower than forecasted. Witness Williams further testified that using approaches such as the Black-Scholes option pricing model requires an estimate of the future risk-free rate, and an estimate of future fuel volatility, both of which are difficult to forecast with any accuracy over long time horizons.

In his rebuttal testimony, Public Staff witness Brown agreed with the lost option value scenario described by witness Williams, but noted that the converse scenario could be equally true. The cost of generation will be lower as a result of hedging if actual fuel prices turn out to be higher than forecasted. Witness Brown emphasized that fuel price hedging value is based on avoiding volatility and providing price stability, not on forecasting the cost outcomes of any single scenario. Witness Brown stated that "the fuel price associated with solar facilities is known with certainty. Any unhedged fuel that is not purchased due to the output of a solar QF mathematically results in increased predictability and therefore positive hedging value." Witness Brown stated that hedging benefits of solar purchases should only be treated as an avoided cost for the same horizon that the utilities are hedging fuel. As such, witness Brown recommended that the hedging benefits for a solar QF should only be valued over the hedging terms actually purchased by the utility, which in the case of DEC, DEP and DNCP appear to be over a 12- to 24-month term. The cost, according to witness Brown, would be based on current market prices and added to the energy component of the QF rate.

DISCUSSION AND CONCLUSIONS

The Commission agrees with DEC/DEP witness Makovich's testimony that cost effective hedging depends largely on the variability of input fuel prices and the generation portfolio mix of resources, and the Commission further acknowledges that purchasing solar power can be seen as the equivalent of buying natural gas forwards. As indicated in the Crossborder Study and previous DEP fuel adjustment proceedings,[2] a utility's fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers.

The Commission concludes that there are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation. The Commission agrees with Public Staff witness Brown, however, that these hedging benefits should only be valued over the hedging terms actually used by DEC, DEP and DNCP. As such, the Commission directs the utilities to calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Snider and Makovich, the testimony of DNCP witness Petrie, the testimony of SACE witness Rábago, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

DEC/DEP witness Snider testified that it would not be prudent to explicitly convert a long range planning assumption related to CO_2 into an immediate cost to consumers in the form of incrementally higher avoided cost rates. Inclusion of CO_2 in avoided energy rates would also expose the utilities' customers to both price and volume risk with respect to their total QF cost obligation since such a price increase would also be accompanied in all likelihood by significant incremental QF participation in North Carolina.

DEC/DEP witness Makovich testified that the price of CO_2 emissions is a "politically determined price designed to influence decision making in specific applications." He argued that lack of consensus on carbon emissions displacement and changes in generation mix and associated emissions dictate that such costs should not be included in the calculation of avoided energy costs.

SACE witness Rábago testified that it is unreasonable to ignore the very real and quantifiable forecast costs associated with carbon emissions. He stated that recently

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[2] Docket No. E-2, Sub 1018, and Docket No. E-2, Sub 1031.

proposed federal carbon regulations will impose costs on utilities within the timeframe of QF contracts set in this proceeding. He argued that this makes carbon regulation a real cost to customers that can and will be avoided by entering into long term contracts with QFs now.

NCSEA witness Beach testified that the utilities' current avoided costs do not include the expected future costs of carbon, even though the utilities base their current resource plans on such costs. For example, he noted that DEC and DEP's IRPs recognize the long-term need to reduce CO_2 emissions by maintaining an option to add nuclear generation. DEC's IRP indicates that "the Company believes that it needs to plan for a carbon constrained future." He noted that the ten- and 15-year avoided energy costs extend into the period during which both DEC and DEP take into account CO_2 emissions costs in their selected resource plans. According to witness Beach, it is unfair to QFs to include these nuclear resources in the production cost modeling used to calculate avoided energy costs while at the same time to exclude from that modeling the CO_2 emissions cost assumptions that are instrumental in selecting these resources for the favored resource plan. Further, given the very long lead times to develop nuclear generation, costs are being incurred today to develop the option to add nuclear capacity after 2020, consistent with the IRPs. Accordingly, he stated that, as recommended in the Crossborder Study, the calculation of avoided energy costs should include CO_2 costs on the same basis as the utilities' IRPs. Excluding such costs results in understated avoided energy credits.

TASC witness Hornby also testified that each utility should include the costs of CO_2 emissions in its production cost simulations to determine avoided energy costs because they all assumed a price for carbon emissions in the Reference Cases of their most recent IRPs. He noted that the carbon emission prices that DNCP used in the Reference Case of its most recent IRP are below the low-case forecast in the Synapse 2014 report, while the carbon emission price that DEC and DEP used in their Reference Cases is somewhat above the Synapse low-case forecast. Finally, he testified that EPA, under Section 111(d) of the Clean Air Act, has the obligation to promulgate performance standards for existing sources of GHG. Thus, it is possible they could place such standards into effect earlier than the federal legislation assumed in the Synapse 2014 forecast.

Public Staff witness Kirsch testified that QF power creates environmental benefits by displacing the electrical energy that would otherwise be produced by resources that are more polluting. In addition, when QF power helps defer or replace new capacity that would be more polluting, it results in the long-term displacement of resources that are more polluting. However, he also testified that, to the extent that utilities do not pay for their emissions, as is the case today for carbon dioxide in North Carolina, QFs do not help utilities avoid costs, even though QF power may provide an environmental benefit.

Public Staff witness Hinton stated that the Public Staff believes that the costs of carbon emissions control are not sufficiently certain at this time to be included in avoided costs. He noted that the Commission has historically held that utilities should

not be required to include in their avoided cost calculations externalities that were unknown and uncertain. For example, in its order establishing avoided cost rates in Docket No. E-100, Sub 74, the Commission stated the following: "Quantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." Witness Hinton noted that it is true that the EPA is developing regulations for carbon emission standards from new and existing stationary sources under Sections 111(b) and 111(d) of the Clean Air Act; however, these costs remain speculative and unverifiable. He stated that the Public Staff believes it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable. However, witness Hinton concurred in NCSEA witness Beach's observation that the future generation expansion plans in the avoided cost models are derived from the IRP base expansion plans, which currently include the cost of carbon emissions. This inclusion of carbon is one of the primary reasons the least cost algorithms select new nuclear generation over alternative generation units. He further testified that the apparent inconsistency between the inclusion of assumed carbon costs in the IRPs and the exclusion of such costs in avoided cost production cost models has existed for several years and results from the different purposes of the two proceedings and the different methods utilized in each process.

DISCUSSION AND CONCLUSIONS

While the EPA has proposed to regulate CO_2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time. The end result of the proposed regulations is speculative at best, and, as Public Staff Hinton noted, the Commission has previously concluded that "[q]uantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." If and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-19

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witness Snider, the testimony of DNCP witness Petrie, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

DEC/DEP witness Snider testified that the following general guidelines should be adopted in the calculation of the annual fixed CT capacity costs: (1) cost estimates should be based on the utilities' most recent study of installed CT costs combined with past construction and operations experience; (2) equipment and construction costs should be based on the cost estimate for a four unit greenfield site; (3) direct CT

interconnection costs should be included, but any estimates of downstream transmission and distribution (T&D) system upgrade costs should be excluded; and (4) the equipment and construction costs should represent an expected construction cost with neither a best case nor worst case contingency adder included. He asserted that the annual capacity value of a CT should be calculated incorporating the utilities' most recently approved cost of capital and book life assumptions for a CT, including its recommended 35-year book life. For the contingency adder, he testified that that a five percent contingency adder results in a reasonable expected construction cost.

Regarding DEC and DEP's position that the economies of scale associated with building four CTs at a four-unit CT greenfield site should be used, he testified that DEC's and DEP's demonstrated practice is to build multiple CTs at a single site. He asserted that the multiple unit approach is the most cost-effective approach because it optimizes the economies of scale associated with construction. He stated that the cost of land, site preparation, roadways, gas infrastructure, electric transmission infrastructure, water infrastructure, and administrative and auxiliary buildings is spread across several units (instead of just one or two). On cross-examination, witness Snider agreed that DEC/DEP witness Pintcke testified in the Sub 136 proceeding that generally most of the costs associated with a CT project are EPC (Engineering, Procurement, and Construction) costs, and that the major components of a CT peaking plant construction project are typically the CT itself and the generator step up or GSU transformers. Together, these items account for approximately 60 percent of the EPC costs, while the remainder of the EPC costs are referred to as the balance of plant or BOP costs, which include site work, pre-engineered buildings for plant operators, miscellaneous plant equipment and the like.

With respect to the inclusion of interconnection costs and the exclusion of T&D network system upgrade costs, witness Snider testified that interconnection costs include costs associated with physically connecting the generation source to the transmission system, such as the switchyard and associated equipment costs. He stated that these interconnection costs are included in the calculation of avoided cost rates because they are real costs that will be avoided when the construction of a new CT is avoided and because the QF is fully responsible for the interconnection costs associated with its own facility. Network upgrade costs, he asserted, unlike interconnection costs, involve improvements to the transmission system beyond merely connecting a generation resource to the transmission system. He noted that sometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions will. With respect to the appropriate contingency factor, he testified that DEC and DEP believe a five percent contingency adder represents an "expected case scenario" and is appropriate in the context of building a conventional CT for purposes of the utilities' avoided capacity rates.

DNCP witness Petrie testified that the costs of the next planned CT facility, be it brownfield or greenfield, should be used as the basis of the capital cost of the CT for the calculation of the avoided capacity rate. He stated that DNCP's next CT is to be developed at an existing brownfield site. He argued that land and other

greenfield-related costs should only be included in the avoided capacity rate when the next CT unit will be a greenfield CT. He stated that it was inconsistent to state that CT costs should reflect the utility's future resource plans, but then require DNCP to include costs associated with "a hypothetical CT" that are inconsistent with its actual resource plans. He agreed that the Commission has ruled in the past that DNCP be required to include land costs in its calculation of capacity credits, but only in the circumstances of that proceeding. He asserted that requiring DNCP's ratepayers to bear costs that are not in fact avoided is not just and reasonable, and requiring DNCP to pay capacity rates that include an allowance for land costs that are not avoided will result in the Company paying more than its avoided costs for capacity in violation of PURPA. Witness Petrie conceded on cross-examination that two of DNCP's most recently completed baseload plants (VCHEC and Bear Garden) were both built on greenfield sites, its future Warren County and Brunswick County plants, both CCs, are both located at greenfield sites. He also agreed that as defined by the Commission, the peaker method is supposed to produce the avoided cost of any generating unit, including a baseload plant.

NCSEA witness Beach testified that PURPA requires that the utility's future need for capacity be reflected in the avoided cost calculation; as a result, the use of economies of scale that do not accurately reflect the planned peaking capacity additions for a utility is not appropriate and will produce understated avoided costs. Witness Beach recommended that data used to calculate avoided capacity cost should be the same data used to calculate capacity cost in the IRP and the generation reserve margin study. The cost of future generation capacity set forth in the IRP represents the long-run avoided cost of the utility at the time the IRP is filed at the Commission. The filing of the IRPs by the utilities historically has preceded the filing of their proposed avoided cost rates. Therefore, the input assumptions used in the biennial avoided cost proceeding should match those used in the IRPs filed just two months earlier. Second, he recommended that, to the extent the utilities must rely on data other than IRP data, such data should be taken from publicly available industry sources and should not be adjusted. If the utilities use a "generic" or "hypothetical" CT for the purposes of calculating avoided capacity cost or components thereof, such data should be taken from public and transparent industry sources, such as the EIA or PJM cost of new entry studies. He noted that other states with which he is familiar use such public data to determine key avoided cost components. Third, he recommended that the cost components of the installed cost of a CT should be identical to those used in the IRP and reserve margin calculations. The installed cost of a CT consists of a number of cost components that should be included in the total costs of constructing the CT, of obtaining a firm fuel supply, and of connecting the CT to the utility's network. The cost of land and associated site work are typically included in the installed cost of a CT. Fourth, he testified that a utility is likely to incur costs to construct transmission upgrades when CT capacity is installed, particularly when hundreds of megawatts of CT capacity are installed. He stated that not including such costs in the avoided cost calculation understates the utilities' avoided cost and should not be allowed.

Witness Beach argued that the utilities' approach to economies of scale is arbitrary and not based on specific design criteria for what would eventually occur at a site for new CT capacity. He stated that, in his experience, given the size of the North Carolina utilities, the addition of 800 MW of CT capacity at a single time would be unusual, noting that neither DEC's or DEP's most recent IRPs indicate a planned addition of 800 MW of CT capacity.

Public Staff witness Hinton testified that the Public Staff disagreed with DEC/DEP witness Snider's recommendation that the installed cost of a CT should reflect the economies of scale associated with building a four-unit CT facility. As testified by the Public Staff in the Sub 136 proceeding, the Public Staff believes that the assumed economies of scope (building multiple units at the same time) and scale (building multiple units at the same location) should be based on the utility's future resource plans for capacity additions. He further testified that, given the forward-looking nature of the peaker method and DEC's and DEP's resource plans over the next years, there is no indication that either utility plans to build a four-unit CT plant in the reasonable future from which such economies of scope or scale could be realized. As such, he testified that the Public Staff cannot support the assumed cost reduction associated with a four unit site as being reasonable. Rather, the evidence is more supportive of assuming a lower level of savings and therefore the higher costs associated with a two-unit CT site. Witness Hinton stated that it is not uncommon for utilities to build more than one CT unit at the same site to take advantage of economies of scale; however, he argued that for avoided cost purposes, the size of the plant should be a reasonable match for expected annual system load growth. Given DEC and DEP's expected annual load growth, it is not appropriate to assume a CT plant of more than 800 MWs will be built all at one time for purposes of calculating avoided capacity costs.

Witness Hinton further testified that the Public Staff disagrees with DNCP's recommendation to use the costs associated with a brownfield site, as opposed to including the land costs associated with a greenfield site in projecting the installed cost of a CT. The Public Staff has long supported the inclusion of land costs because the peaker method uses a hypothetical CT as a proxy for pure capacity and is designed to approximate the cost of a new baseload plant. While utilities sometimes add capacity at existing sites, they also build capacity at greenfield sites. He stated that the Commission recognized this in Docket No. E-100, Sub 87, when it required both DEP and DNCP to include the cost of land in the calculation of installed CT costs.

TASC witness Hornby testified that the utilities should use a set of comprehensive, transparent and verifiable input assumptions, including land, construction and materials, the infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and the weighted average cost of capital.

DISCUSSION AND CONCLUSIONS

The Commission notes that the evidence from the Sub 136 proceeding showed that the costs of a four-unit CT used by Astrape for its reserve margin study for both DEP and DEC, including adjustments for economies of scale, were much higher than the capital costs with adjustments for economies of scale proposed by DEP and DEC in the Sub 136 proceeding, using DEP's assumed economies of scale. It appears to be the magnitude of the economies of scale assumed, not the economies of scale themselves, that causes the relatively low proposed installed capital costs. 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. In addition, to the extent a utility applies economies of scale related to the installed cost of multiple CTs at a single location, the utility should provide detail as to the economies being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied.

Economies of scale include the cost benefits associated with building multiple CTs at a single site, for example, if only one administrative building were necessary to service a site with multiple CTs the entire cost of the building could be divided among the units when calculating the costs associated with a single CT. Economies of scope include the cost benefits associated with building multiple CTs at the same time, for example, if a utility were to build multiple CTs at the same time it could conceivably purchase discounted bulk materials and save on employee training etc. The Commission agrees with the utilities that it is appropriate to incorporate economies of scale for the construction of up to four CTs at one site in its calculations. The utilities have demonstrated that such a practice is historically supported and reflects the most likely proxy of future hypothetical CT construction. However, the Commission also agrees with the Public Staff and other parties that it is unlikely that four CTs will be constructed at the same time. The same evidence supporting the inclusion of economies of scale supports the exclusion of economies of scope as the utilities are likely to build at the same site but only to add one CT at a time. Thus, the Commission finds it appropriate to include economies of scale, for up to four units, in the calculation of the installed cost of a CT. Further, the Commission concludes that it is inappropriate to include economies of scope in the calculation of the installed cost of a CT.

The Commission concludes that transmission system impacts, a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, and a reasonable estimate of useful life of a CT are appropriate to include in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs.

With regard to DNCP's argument against the inclusion of land, the peaker method uses a hypothetical CT as a proxy for pure capacity and is designed to approximate the cost of a new baseload plant. New baseload plants typically are built at greenfield sites, which is demonstrated by DNCP's testimony. The Commission concludes that DNCP should be required to include the cost of land in the calculation of installed CT costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Bowman and Snider, the testimony of DNCP witnesses Williams and Petrie, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Ellis.

DEC/DEP witness Bowman testified that DEC and DEP recommend that the Commission continue its current practice of approving standard rates that pay capacity credits on a per-kilowatt-hour (kWh) basis and that it eliminate multiple definitions of peak and off-peak hours within the tariff structure by eliminating DEC's and DEP's respective Option A schedules.

DEC/DEP witness Snider testified that in recognition of the deliverability challenges faced by smaller intermittent QF resources, DEC and DEP recommend that annual capacity be paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the most likely hours to which capacity will have value. He recommended that avoided capacity credits be paid only between the hours of 2:00 p.m. and 7:00 p.m. on non-holiday weekdays during June, July, and August; and between 6:00 a.m. and 9:00 a.m. on non-holiday weekdays during December, January, and February. He asserted that these are the hours that are most influential in resource addition decisions from an IRP perspective as they represent the hours that are within five percent of the load in the highest peak load hour in the summer and in the winter. Witness Snider argued that it would not be appropriate to maintain the current Option B hours within DEC's and DEP's standard tariffs. He further testified that the standard tariff should define a single set of hours as on-peak and that the different definitions between Options A and B allow QFs to choose the definition that produces the most revenues for the QF relative to their operations. He postulated that, while this is beneficial to the QF, it leads to an overstatement of the actual avoided energy benefit since each QF picked its option based on revenue optimization rather than a consistent definition of peak hours based on the utilities' avoided energy cost.

DNCP witness Williams and Petrie testified that DNCP currently calculates avoided capacity payments on a dollars per kWh basis and that it is appropriate to continue to calculate these payments in this manner because it is relatively simple and reasonable because it pays the QF for capacity based upon its contribution to support customer demand during DNCP's on-peak hours. In addition, witness Petrie testified that calculating the avoided costs on a per kWh basis avoids the need for performance testing or complicated availability metrics that would be required under a payment

method based on installed capacity ($/kW). DNCP witnesses Williams and Petrie both testified that paying on an installed capacity approach would require the determination of the proper reliable capacity of the resource in kWs, which is a difficult proposition for intermittent resources.

Witnesses Williams and Petrie both recommended that both Options A and B be eliminated and that a narrower band of on-peak hours and only one definition of on-peak hours be used for both energy and capacity. Witness Petrie proposed that capacity payments be limited to those months and hours that best reflect a facility's capacity value. He testified that this is from 2:00 p.m. to 7:00 p.m. on non-holiday weekdays during June, July, and August; and from 7:00 a.m. to 9:00 a.m. and from 6:00 p.m. to 8:00 p.m. on non-holiday weekdays during January and February. He recommended that only one option be approved because providing multiple options unnecessarily complicates the process and potentially provides options that do not align appropriately with avoided cost principles. According to witness Petrie, for energy, the definition of peak hours should include hours when customer demand is high and when higher cost resources are likely to be dispatched to serve load, which is from 10:00 a.m. to 10:00 p.m. on non-holiday weekdays during April through August, and from 6:00 a.m. to 1:00 p.m. and from 4:00 p.m. to 9:00 p.m. on non-holiday weekdays from October through March.

NCSEA witness Beach testified that Option B represents a reasonable first step for implementing a capacity factor method in North Carolina, as it allows a solar QF to earn capacity credits based on whatever capacity factor it can achieve from its output over the Option B period. However, he testified that Option B should be refined to align more accurately with the utilities' system peaks, thus providing greater benefits to the utility and ratepayers. Specifically, he recommended that Option B should be refined to move the range of hours in the summer from 1:00 p.m. until 9:00 p.m. to 11:00 a.m. until 7:00 p.m. for DEC, and to noon until 8:00 p.m. for DEP. For DEC, for the years 2010-2012, an on-peak period of 11:00 a.m. to 7:00 p.m. captures 69 percent of these peak load hours, compared to 63 percent for a 1:00 p.m. to 9:00 p.m. on-peak period. For DEP, an on-peak period of noon to 8:00 p.m. captures 59 percent of the peak load hours, compared to 58 percent for a 1:00 p.m. to 9:00 p.m. on peak period. He testified further that a summer peak period of from 11:00 a.m. to 7:00 p.m. or from noon to 8:00 p.m. is a reasonable compromise among the on-peak periods used in the non-residential retail rate designs of the North Carolina utilities.

TASC witness Hornby testified that DEC/DEP witness Snider's recommendation would pay for capacity in only 514 hours per year and that this proposed rate design does not satisfy generally accepted principles of utility rate design and discriminates against QFs relative to DEC and DEP. He noted that DEC and DEP have the opportunity to recover their capacity costs over many more hours per year than that proposed for QFs. He further testified that no other DEC or DEP tariffs use an on-peak period of from 2:00 p.m. to 7:00 p.m. in the summer and from 6:00 a.m. to 8:00 a.m. from December through February. Under their rate schedules with demand charges, DEC and DEP have the opportunity to recover capacity costs by applying those demand

charges in on-peak periods that range from 1,564 hours to 1,864 hours per year, which are the times that the capacity and energy have the most value. At the same time, they are proposing that QFs be limited to only 514 hours. Witness Hornby stated that this is inconsistent with the testimony of Jeffrey Bailey in DEC's most recent rate case in Sub 1026. According to witness Hornby, Witness Bailey testified that capacity and energy have the most value to residential customers in 1,524 hours per year. The Time of Use price offerings for residential and nonresidential customers have on-peak hours from noon to 6:00 p.m. on weekdays from June through September and from 7:00 a.m. to 1:00 p.m. on weekdays from October through May. He stated that DEC and DEP could provide no analysis in response to data requests in this proceeding to support any of their recommendations.

Public Staff witness Ellis provided the history of Option B, which was initially proposed by DEC in 2002, in Docket No. E-100, Sub 96. Witness Ellis testified that Option B is consistent with the FERC's Order No. 69. He stated that because DEC, DEP and DNCP are all summer peaking systems, it is appropriate to consider the value of the power provided by generating systems that operate during these times of higher customer demand and to encourage production during periods of time when the cost of the utility-generated electricity is greater. Witness Ellis also testified that, with regard to summer peaks, solar QFs in North Carolina generally generate electricity during the hours with the higher system peaks. He noted that there is a significant alignment of solar output from facilities located in the state with the summer hours during which the North Carolina utilities experience their highest loads and at least partial alignment with the utilities' highest one-hour peak loads. He further noted that for winter peaks, which generally occur in the early morning hours, solar output is greatly reduced, as is its contribution to meeting the highest peak demands of the utilities' systems. He stated that, as discussed in some detail in the Sub 136 proceeding, in a typical configuration, the output of a typical solar photovoltaic system will be at its maximum earlier than a utility's one-hour system peak load, with the result that only a portion of the solar output is available to offset that one-hour peak load. However, if a solar QF has the option of receiving a higher capacity credit during the higher cost on-peak hours, as is done in Option B, it could design its facility so that its output is a better match to the system's demand. The installation of tracking systems and changes such as an adjustment to the tilt or azimuth of fixed solar panels for the purpose of maximizing electricity generation during the specified critical on-peak hours can be used to accomplish this.

Witness Ellis testified that allowing this option is beneficial to ratepayers because under Option A type rates, avoided capacity costs are spread out over all of the hours that are considered on-peak, which for DEC, for example, are 4,160 of the 8,760 total hours in a year. The division of the avoided capacity cost by this large number of hours results in a lower kWh rate than would result if a smaller number of on-peak hours were used. If only an Option A type rate structure is available, a solar facility would likely choose to configure its system to maximize total electricity output during all of the on-peak hours, regardless of the timing of its generation relative to a system's peak load. While this benefits the system in that the utility's load is increasing at the same time as the solar output increases, the solar output would provide greater benefit if it

were better matched to the utility's load. This justifies a rate structure that leads to the maximization of electricity generation during the specified higher cost on-peak hours.

With respect to Option A, witness Ellis testified that the Public Staff believes that Option A is still appropriate for some technologies and that the existence of two options is not administratively burdensome. The purpose of maintaining the two options for QFs is not to maximize the revenues of a QF, as characterized by DEC-DEP witness Snider, but to recognize the differing operating characteristics of resources utilized by QFs and to allow them an opportunity to earn their full avoided capacity costs in a nondiscriminatory manner. In addition, he noted that the Public Staff does not believe that it would be appropriate to dramatically narrow the on peak months and hours as proposed by DNCP. Witness Ellis stated that NCSEA witness Beach's proposed tailoring of the on-peak hours to utility peak load warrants further consideration.

On rebuttal DEC/DEP witness Snider testified that he disagreed with the Public Staff's recommended continuation of Option A and Option B hours because he believes that allowing multiple avoided cost definitions of peak capacity hours for the same utility will, by mathematical definition, result in customers overpaying for QF capacity relative to the avoided cost value the QF's create. He stated that this overpayment stems from individual QFs having the ability to choose from multiple peak definitions that maximize their revenues rather than choosing the peak definition that represents the utility's true avoided capacity cost. Also on rebuttal, DNCP witness Williams expressed the same concern, when afforded these options, he stated, developers will select the option that produces the highest revenue for them, which means the highest cost for electric utility customers, regardless of which option best reflects true avoided cost.

On rebuttal, Public Staff witness Ellis stated that the Public Staff does not agree to DEC/DEP witness Snider's rationale for limiting the hours. While the costs of a combustion turbine are used as a proxy for pure capacity cost under the peaker method, witness Snider's analysis and recommendation treat QF generation as if it only has capacity value if it operates as a peaking resource. This is not an appropriate application of the peaker method. He stated that in numerous proceedings the Commission has recognized that QF capacity has value in hours other than the very narrow band of hours surrounding the expected summer and winter peaks identified by witness Snider. In addition to the foregoing, he testified that allowing a QF the opportunity to receive a capacity payment only during the narrow number of hours and months proposed by witness Snider raises the question of reasonableness, considering that the capacity factors of utility-owned solar and hydroelectric generation indicate that it would be difficult for these generating facilities to recover their capacity costs if they were held to the same standard. He noted that both DEC and DEP's IRPs show a significant need for non-peaking capacity over the next 15 years.

Witness Ellis further testified that the Public Staff conducted its peak load analysis to identify the hours that, for illustrative purposes, are within ten percent of the annual seasonal peaks over the period of 2006 to 2013, the period over which data were readily available. The results of that analysis were set forth in Ellis Exhibits 1 and

2. This analysis indicates that there is a significant need for capacity during the summer between the hours of 12:00 p.m. and 9:00 p.m., with the highest concentration of peaks being between the hours of 1:00 p.m. and 8:00 p.m. The analysis also shows that there is a significant need for capacity during the current non-summer months, with the highest concentration of peaks between 6:00 a.m. and 10:00 a.m., but an additional significant number existing between the hours of 1:00 p.m. and 9:00 p.m. This capacity need is present even if the focus is limited to witness Snider's analysis of peaks within five percent of the annual seasonal peaks. Witness Ellis stated that this illustrates that capacity is needed and has significant value outside of the narrow window advocated by DEC-DEP witness Snider.

<u>DISCUSSION AND CONCLUSIONS</u>

No party to this proceeding recommended that the Commission begin to calculate avoided capacity payments based on a per kW basis, rather than continuing to use the per-kWh capacity payment. The utilities focus was on eliminating options and narrowing the hours over which they would pay capacity, while NCSEA and TASC focused on tailoring the hours to better accommodate the particular characteristics of solar QFs. The Commission agrees with the Public Staff that it is too soon to abandon the offering of Option B, leaving only Option A, so soon after DEP and DNCP stipulated to offering an Option B, with avoided capacity rates calculated using the same on-peak hours as used by DEC in its currently effective Option B rates. The Commission approved the stipulation and included this requirement in its February 18, 2014 Order Establishing Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 136, shortly before it issued the order initiating this proceeding.

The Commission finds merit in the Public Staff argument that QF generation has capacity value at times other than the peak hours. Also, the fact that a QF would evaluate and choose one set of hours to maximize its revenue does not mean that this automatically results in costs higher than avoided costs. The offering of two sets of hours allows QFs to tailor their production to the times that the utilities have the greatest need and recognizes that different resources may provide energy under different time schedules resulting in the same value to the utility. The Commission has recognized in earlier proceedings that QF capacity has value in hours other than the very narrow band of hours surrounding the expected summer and winter peaks identified by the witnesses for DEC, DEP and DNCP. For example, DNCP witness Petrie testified on rebuttal in the Sub 136 proceeding that DNCP was not opposed to adding an Option B type rate offering (so long as the PAF used in the Option B rate offering is 1.2), noting that the definition of on-peak hours in Option B is consistent with customers' current demand patterns, and covers those hours when the system is most likely to experience its peak load. The Commission notes that the hours proposed in this proceeding are not consistent with the on-peak hours and months used for the utilities' Time-of-Use rate schedules.

The Commission concludes that DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules both an Option A and an

Option B, with the avoided capacity rates in Option B calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-25

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Bowman and Snider; the testimony of DNCP witness Petrie; the testimony of NCSEA witness Beach; the testimony of TASC witness Hornby; the testimony of NC Hydro Group witness Givens; the testimony of NC WARN witness LaPlaca; the testimony of Public Staff witness Ellis; and the stipulation amongst DEC, DEP and the NC Hydro Group.

DEC/DEP witnesses Bowman and Snider testified that DEC and DEP are proposing to reduce the PAF to 1.05 to align its application better with the reliability of a natural gas CT, the unit which the QF is presumed to avoid under the peaker method. DEC and DEP's witnesses opposed increasing the PAF for solar and other resources to 2.0, but testified that for existing small hydroelectric QFs, a PAF of 2.0 would continue to be used.

NCSEA witness Beach testified that DEP/DEC witness Snider incorrectly characterizes the PAF as a multiplier that "increases the avoided capacity rate paid by customers and received by the QF." To the contrary, witness Beach stated that the Commission has explained, in the context of discussing a higher PAF for hydro facilities, the use of a PAF does not exceed avoided costs; it simply changes the method by which avoided costs are paid. He noted that the use of a PAF in the calculation of avoided cost rates when using the peaker method is a tradition of long standing in North Carolina. The PAF accounts, in part, for the fact that the QF, like any generating facility, cannot be in operation at all times. The Commission has recognized this fact in the past, in rejecting a prior DEC proposal to reduce the PAF to 1.08, again based solely on the availability of the avoided peaker. He noted that in that order, the Commission determined to retain the 1.2 PAF, and concluded:

> While the peaker methodology (sic) employed by PEC and Duke relies on the cost of a combustion turbine to provide the purest estimate of avoided capacity costs, the fixed costs of a peaking unit represent a proxy for the capacity related portion of the fixed costs for any avoided generating unit. Thus, the availability of a CT is not determinative for purposes of calculating a PAF.

Witness Beach recommended that that the Commission make no change, at this time, to the current PAF structure, stating that the PAF of 1.2 for non-hydro QFs is a reasonable means to adjust the way QF capacity payments are made.

NC WARN witness LaPlaca testified that she believes the current PAF for solar is too low and should be revised upward to at least 2.0 for a number of reasons, including

"the high value of solar during peak summer hours, the fact that solar displaces purchased and hedged fuel for 25 years, reduces water use, reduces pollution and reduces waste treatment and storage," all of which she states add value for North Carolina's ratepayers.

Public Staff witness Ellis described the PAF and its history and noted that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constitute the utility's avoided capacity costs. More specifically, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate 100 percent of the on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled. He stated that a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83 percent of the on-peak hours. He noted that the Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. Witness Ellis further testified that, despite repeated challenges to the PAF, particularly from DEC, the Commission has consistently reaffirmed the use of a 1.2 PAF in the calculation of the utilities' avoided capacity rates.

Witness Ellis stated that the Public Staff finds some merit in the positions of both the utilities and the QFs. There are a number of methods being utilized across the nation to spread capacity payments, all of which are intended to meet the intent of PURPA. He stated that the Commission's prior approvals of the PAFs and the availability of Option B type rates meet the literal requirements and the intent of PURPA. Witness Ellis testified that the Public Staff believes that the reduction of the PAF to 1.05 as proposed by the utilities is unjustified. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. He stated that performance at that level is commensurate with a baseload plant under any definition. He further stated that none of the data provided or arguments made is persuasive to justify a departure from that conclusion. In this regard, it should be considered that when the capacity factors reported by the utilities in their monthly baseload power plant performance filings are averaged over the last three calendar years, none of them operated their baseload fleet at an 83 percent capacity factor, which is the relevant statistic for comparison because QFs are paid for capacity on a kWh basis. For the calendar years of 2011, 2012, and 2013, the baseload plants in the rate bases of DEC, DEP and DNCP averaged capacity factors of 75.67 percent, 74.52 percent, and 74.83 percent, respectively, while recovering all of their capacity costs through rates.

With regard to run-of-river hydro, witness Ellis recounted that starting in 1997, on the ground that it was necessary to put the QFs on equal footing with the utilities' run-of-river hydro in rate base, the Commission ordered that a PAF of 2.0 be utilized by

both DEP and DEC in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation. The use of a 2.0 PAF requires a QF to operate 50 percent of the on-peak hours in order to collect the full capacity credit.

NC Hydro Group witness Andrew Givens testified that the performance characteristics and capacity value of the small independently operated run-of-river hydro facilities are very similar to the utility owned run-of-river hydro. Witness Givens also stated that the capacity credit paid to a non-utility should fully compensate it for the total installed capacity of the hydro plant. He further stated that this is necessary in order to provide equitable treatment with the utilities' run-of-river hydro in rate base. He stated that over the past nearly 20 years the 2.0 PAF has been in effect, QF hydro plants have faced financial difficulties with rates that have been too low and unstable. His recommendation is that, if the PAF method is used in the future, an increase to a level significantly above 2.0 is considered.

The June 24, 2014 stipulation amongst DEC, DEP and the NC Hydro Group agreed to use a PAF of 2.0 for run-of-the-river hydroelectric facilities in proposed rates until December 31, 2020.

DISCUSSION AND CONCLUSIONS

In its Order dated September 29, 2005, the Commission specifically concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. While the Commission stated in its order initiating this proceeding that it would revisit its precedents, it determines that the arguments for altering the PAF are insufficient to modify the PAF at this time. As discussed earlier, the Commission determines that there has been widespread QF development under the existing framework without adverse impacts to utility ratepayers. There is no evidence that the current framework fails to comply with the requirements of Section 210 of PURPA or otherwise disadvantages QFs. Absent such evidence, the Commission determines that the conflicting evidence presented in this docket justifies its continuation going forward. The Commission agrees with NCSEA and the Public Staff that the 1.2 PAF should continue to be used by DEC, DEP and DNCP in their respective avoided cost calculations for all QFs other than run-of-river hydro.

With regard to the 2.0 PAF for run-of-river hydro, no party objected to the stipulation among DEC, DEP and the NC Hydro Group, and the Commission concludes that it should be approved. As the Commission and the General Assembly have traditionally supported run-of-river hydro through specific policies and findings, the Commission finds that it is appropriate to discontinue the use of the 2.0 PAF in accordance with the stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

The evidence supporting these findings of fact is found in the testimony of DEC/ DEP witness Snider; the testimony of DNCP witnesses Williams, Wright and Bailey; the testimony of EDF witness Munns; the testimony of NC WARN witness LaPlaca; the testimony of NCSEA witness Beach; the testimony of SACE witness Rábago; the testimony of TASC witness Hornby; and the testimony of Public Staff witnesses Brown and Hinton.

<u>Ancillary Services and Integration Costs</u>

DEC/DEP witness Snider testified that intermittent QF resources, specifically solar, create integration costs. Witness Snider sponsored as Snider Exhibit 1 the Duke Energy Photovoltaic Integration Study conducted by Pacific Northwest National Laboratory (PNNL Study). Witness Snider recommended that the Commission recognize the integration costs associated with the increased reserve requirements in the Generation section of the PNNL Study that result from the increase in net load variability due to solar PV penetration. Witness Snider recommended that the Commission authorize DEC and DEP to adjust their avoided energy rates to reflect the PNNL study results at the level reflected in the Compliance case, which aligns with the IRP assumptions for PV penetration and was the lowest penetration level considered.

Several parties, including EDF witness Munns, NC WARN witness LaPlaca, SACE witness Rábago, and TASC witness Hornby included grid support or ancillary services as a possible category of solar generation benefits. Public Staff witness Brown testified that existing PV generation facilities are not capable of providing reliable grid support or ancillary services, and that current electrical codes generally preclude inverters that provide ancillary services. Public Staff Witness Brown noted, however, that there are current discussions about potentially modifying the interconnection standard (IEEE 1547) to accommodate inverters capable of providing grid support services. Witness Brown noted that once PV generation facilities are capable of providing grid support, it may be appropriate to evaluate these capabilities to determine whether the services provided result in a utility avoided cost.

NC WARN witness LaPlaca testified that when variable generation resources are spread out over a larger geographic area, and fuel cost savings are included, overall costs are reduced. Public Staff witness Brown agreed that larger balancing authorities can result in a reduction in overall reserve requirements, and that there may be dispatch benefits when aggregating intermittent generation over larger geographic areas due to increased predictability of aggregate information, but noted that the variability from intermittent generation still increases reserve requirements and utility costs.

TASC witness Hornby and NCSEA witness Beach testified that they agreed that generation-related solar integration costs may exist, but they indicated that studies, including the PNNL Study indicate that other solar integration benefits may offset the costs, even at higher levels of solar penetration.

Avoided Transmission and Distribution Capacity

Public Staff witness Brown testified that PV generation may result in avoided transmission capacity benefits to the extent it has the effect of reducing retail electricity purchased from the utility. The power generated by distribution-connected PV facilities does not utilize the transmission system. Therefore, the transmission system does not have to supply any power generated by distribution-connected PV facilities. Witness Brown noted that any generating facility can be located on an existing transmission system at a place that can reduce power flows on heavily loaded transmission lines, but these benefits are highly dependent on siting. On the distribution side, Witness Brown indicated that potential distribution capacity benefits are dependent upon (1) the extent to which the existence of PV has the effect of reducing power flows at the feeder and distribution substation level, and (2) the planning criteria used by the utility. Because distribution feeders have a small geographical footprint and PV generation may not always occur during particular periods of peak load (e.g., due to cloud cover), there is the risk for potential equipment overloads. Therefore, it may be appropriate for a utility to set capacity planning criteria assuming no PV generation, which results in no distribution capacity benefits for PV generation.

NCSEA witness Beach testified that small, distributed QFs with output during the hours of peak demand that is consumed on the distribution system will reduce peak loadings on the transmission system, will make more capacity available on the transmission system to serve load growth, and will allow the utility to avoid building new transmission capacity. He further testified that these avoided peak-related transmission costs are distinct from other generation-related transmission costs associated with interconnecting the avoided generation resource (i.e., a peaker). Witness Beach recommended that the Commission follow the recommendations of the Crossborder Study, in which long-term avoided transmission capacity costs for DEC and DEP were calculated using the NERA regression method, an approach that calculates how a utility's transmission investments change as the demand on its transmission system varies. Witness Beach testified that for DNCP, the Crossborder Study used the PJM rate for network integrated transmission service as a more direct measure of the costs which DNCP can avoid if solar reduces DNCP's peak demand on the PJM grid.

TASC witness Hornby recommended that DEC and DEP use the results of the Crossborder study for avoided transmission cost calculations, and that DNCP use the PJM Network Integrated Transmission Service Rate, adjusted by a 46 percent capacity rate for solar facilities, for avoided transmission capacity cost calculations.

DEC/DEP witness Snider testified that the companies recognize there are potential operational challenges from integrating intermittent generation. DEC and DEP believe a more comprehensive impact analysis is necessary before such a recommendation could be made by a utility, and they are therefore not recommending the addition of transmission and distribution integration costs at this time.

DNCP witnesses Wright and Bailey testified regarding the impact of additional intermittent QF generation on the DNCP transmission and distribution systems. Witness Bailey testified that it is not clear whether additional solar QF generation in DNCP's service territory would actually act to increase or decrease transmission capacity costs. Some of the considerations include lower growth and congestion in the DNCP's North Carolina service territory, the intermittent nature of solar generation, the potential for reverse flow, and winter peak planning requirements. DNCP witness Williams also testified that since DNCP does not control the placement, timing or dispatch of QF facilities, the potential transmission or distribution benefits that can be achieved with the deployment of distributed generation are reduced.

Public Staff witness Brown disagreed with witnesses Beach and Hornby that the Crossborder findings were adequate for establishing avoided transmission costs, and noted that it may not be appropriate to utilize costs from the PJM service territory and their assumed capacity factors for determining avoided costs related to DNCP transmission capacity in North Carolina. Public Staff witness Hinton testified that the Public Staff believes the avoided transmission and distribution model currently used by DNCP in its cost-effectiveness tests for demand side management (DSM) and energy efficiency (EE) programs may be appropriate to use for avoided cost calculation purposes if the demand reductions from solar generation were found to warrant avoided cost treatment. In addition, witness Hinton indicated that DEC is currently revising its existing avoided T&D cost model used for DSM/EE cost-effectiveness purposes. Public Staff witness Brown testified that this model, once revised, may provide a better tool for evaluating the appropriate avoided transmission capacity benefits that a solar QF may provide.

<p style="text-align:center">Line Losses</p>

NCSEA witness Beach, SACE witness Rábago, TASC witness Smart, and TASC witness Hornby testified that distributed generation can provide transmission and distribution line loss benefits and noted that Section 292.304(e) of PURPA, which provides factors for determining avoided costs includes "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." They also noted that the Commission has long recognized line losses at both the distribution and transmission level as an appropriate consideration in determining avoided costs.

Public Staff witness Brown testified regarding line losses in greater detail, noting that the transmission line loss benefits of solar generation, and recognized that the power generated by distribution-connected PV facilities does not utilize the transmission system. Therefore, distribution-connected PV facilities will result in lower transmission losses. PV facilities that are connected to the transmission system, like utility owned generating facilities, can also result in lower transmission losses depending upon where they can be placed on an existing transmission system. On the distribution side, witness

Brown testified that PV generation interconnected at the distribution level may result in line loss benefits by serving local load that would otherwise be served by the distribution system, but utility-scale PV facilities connected to the transmission system do not affect distribution system losses.

NCSEA witness Beach testified that the current avoided cost calculations used in North Carolina correctly are based on the assumption that QF generation helps avoid transmission line losses. However, these losses are calculated assuming a baseload load profile, while solar generation produces power principally during the daytime, higher demand hours, when line losses are higher than average. As a result, he stated that solar avoids more transmission line losses per kWh of output than baseload generation. Witness Beach stated that this fact was noted in the Crossborder Study but that it lacked adequate data to quantify with specificity the additional transmission line loss savings attributable to solar. Based, however on the findings of the PNNL study, witness Beach and witness Hornby recommended that DEC and DEP include a 3.3 percent adjustment to both energy and capacity credits, and that DNCP also use a 3.3 percent adjustment to both energy and capacity credits until a comprehensive study within DNCP's territory can be performed.

Witness Brown in his rebuttal testimony disagreed with the recommendations of TASC witness Hornby and NCSEA witness Beach, noting that the transmission loss calculations from the PNNL study are only based on four power flow snapshots. Witness Brown noted that the study states: "analysis over a long period of time (preferably one year or more) is needed to get a reliable assessment of total loss reduction." Therefore, witness Brown testified that he does not believe that the results of this limited study are appropriate for inclusion in avoided cost calculations at this time, and that there may be other factors that must be considered.

DISCUSSION AND CONCLUSIONS

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. For example, the Electric Power Research Institute is set to release a study, titled The Integrated Grid – Phase II: Development of a Benefit Cost Framework, in the coming months. 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 DNCP 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.

To date, a comprehensive evaluation of solar integration costs in North Carolina has not been undertaken. The Commission agrees with EDF witness Munns that it 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. The PNNL study included as Exhibit 1 to DEC/DEP witness Snider's testimony provides a robust evaluation of several aspects of integrating increasing amounts of solar generation into the utility's generation portfolio, including the impacts of solar PV on ancillary services and generation production cost, as well as voltage and power flows, and a limited evaluation of avoided losses in the transmission and distribution systems. The study points out, however, that it was limited in scope in order "to produce results in a timely manner using available data and analytic tools, to identify areas of concern, measure the degree of impact, and provide guidance for further actions. As a result, the study was limited to energy production cost modeling and steady-state power flow simulations. Potential PV impacts on dynamic system characteristics, such as frequency response and dynamic and transient stabilities, were not included the study scope.

Further, the PNNL study contains a conclusion that further studies are warranted in the sections related to generation, transmission, and distribution. Nonetheless, DEC and DEP propose at this time to include only the costs associated with generation-related ancillary services due to the intermittency of solar, despite the potential for benefits indicated in their transmission snapshot analysis and their distribution modeling.

The penetration rates of solar in DEC and DEP's service territories are not yet at the level at which integration costs reach the lowest thresholds evaluated by the PNNL study. As a result, the Commission concludes that it is premature to apply any selected findings that can be derived from the study. Once all aspects of solar integration are more fully evaluated, the costs proposed to be included now by DEC and DEP, those associated with ancillary services due to the intermittency of solar, may be offset completely or in part by some of the benefits that may be realized. In any event, future developments may provide a better idea of the total costs and benefits of integration and such costs and benefits can be more fully understood.

The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DNCP to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained. Accordingly, the Commission concludes that it is premature for DEC, DEP and DNCP 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. The Commission further concludes that it is appropriate for the utilities to continue to apply their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding of fact is found in the testimony of DEC/DEP witness Snider, the testimony of NCSEA witness Beach, the testimony of SACE witness Rábago and the testimony of TASC witness Hornby.

NCSEA witness Beach argued that the energy credits attributed to solar QFs should be calculated with more granularity to better capture the energy value that solar QFs deliver. Witness Beach maintained that such an approach would allow solar QFs to receive higher energy payments for producing power during higher value, daytime off-peak hours. To support his position, witness Beach cited the Crossborder Study, which he argued showed that the output of a typical solar resource had more avoided energy value than a flat 24x7 block of power. Witness Beach claimed that this showed that the energy payments to solar QFs, which are based on the utilities' average on-peak and off-peak avoided energy costs, should be higher. SACE witness Rábago and TASC witness Hornby testified that they supported witness Beach's proposal on this matter.

In his rebuttal testimony, DEC/DEP witness Snider refuted witness Beach's analysis. Witness Snider noted that witness Beach had only shown that, on an energy basis, typical solar output may have more value than a flat block of base load energy. He stated that witness Beach had failed to consider, however, the reduced energy benefits associated with the intermittent nature of solar generation. Further, witness Snider noted his concern regarding proposals that are designed to optimize the economic results for specific types of QFs. He argued that witness Beach had applied only beneficial aspects of solar generation as the basis to support a proposed solar-specific energy rate without any consideration of the costs associated with solar ramping and intermittency. Witness Snider concluded that such a proposal would unfairly burden customers with additional costs.

<u>DISCUSSION AND CONCLUSIONS</u>

Regardless of whether there is merit to witness Beach's observation that solar QFs may have more energy value than a flat, base load block of energy, the Commission declines to accept witness Beach's proposal to provide a definition of off-peak hours to suit the load profile of the typical solar QF based on the evidence in this record. As witness Snider rightly points out, witness Beach's proposal isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources. The Commission finds it difficult to square such an unbalanced approach with PURPA. Accordingly, the Commission declines to approve witness Beach's proposal to require a definition of off-peak hours to suit the load profile of solar QFs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-30

The evidence supporting these findings of fact is found in the testimony of DNCP witness Williams, the testimony of NCSEA witness Cohen and the testimony of Public Staff witness Ellis.

DNCP witness Williams testified that the Commission established that the legally enforceable obligation (LEO) occurs when the QF has (1) obtained a CPCN (or filed a Report of Proposed Construction (ROPC), if applicable) and (2) indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output to that utility. Witness Williams further testified that DNCP believes that the standard is still too vague to be implemented in a fair manner, particularly with regard to the second prong of the test, as there is not enough guidance regarding what it means for a QF to "commit itself to sell its output." In order to clarify this standard, he stated that DNCP proposes to provide a simple form, to be completed by a QF seeking to sell its output to DNCP, that states that the QF has filed for or received a CPCN from the Commission (or has submitted a ROPC if it falls within the exception to the CPCN obligation), that it is making an offer to sell all of its output to DNCP for a period of at least two years, and that it agrees that a particular date is the date of the LEO. He stated that under current circumstances it is difficult to determine the point in time at which the commitment occurs.

With regard to how much time a QF is currently permitted to achieve commercial operations, DNCP witness Williams testified that DNCP advocates two changes. First, requiring a QF to have established a documented LEO and executed a PPA in advance of DNCP's subsequent rate filing; and, secondly, requiring QF commitment to achieve commercial operations by the later of (1) 30 months from DNCP's previous rate filing, (2) 18 months from the date the Commission approves the rates in the pending biennial period. Regarding the first point, he testified that it is reasonable to require a level of commitment to the then-current rates if a QF wants to remain eligible for them. Requiring a QF to establish a LEO, and to promptly execute a PPA, would preclude eligibility for in subsequent biennial rates, removing any ability for "cherry picking" rates between biennial periods. Regarding the second proposed change, he stated that the provision in the current standard QF contract that allows a QF up to 30 months to construct its facility is unnecessary for experienced solar developers, provides access to rates that may no longer reflect expected avoided costs, and adds significant uncertainty to the utility's resource planning. He recommended that the Commission reduce the development timeline as stated above.

NCSEA witness Cohen testified that DNCP filed this proposal just after the Commission approved the 30-month timeline in its Order issued February 21, 2014. He further testified that rates that have been proposed by a utility but not yet approved by the Commission do not provide an investor with sufficient certainty as to return on investment. According to witness Cohen, it therefore is difficult to secure financing for a project for which final rates are not available. He stated that, therefore, under DNCP's proposal, a developer would only have 18 months to develop a project to commercial

operation, never 30 months. He further stated that while construction can be completed fairly quickly, although not as quickly as DNCP witness Williams suggested, construction is only part of the development process. The interconnection process in particular adds a significant amount of time to the development process.

Public Staff witness Ellis testified that it is not appropriate to retract the 30-month timeframe for completion of construction as proposed by DNCP witnesses Williams, noting that the Commission issued its Order approving this 30-month requirement on February 21, 2014, in the Sub 136 proceeding. He further testified that the Public Staff believes that this approach is the best means to resolve a number of competing issues that were raised in the Sub 136 proceeding and, at a minimum, it is premature to reconsider it at this point in time.

DISCUSSION AND CONCLUSION

With respect to DNCP's proposal to provide a simple form, to be completed by a QF seeking to sell its output to DNCP, in order to establish that a particular date is the date of the LEO, no party expressed any opposition to it, but neither did any party express any support. The Commission is inclined to move toward such an approach, but requests that parties address it in the upcoming phase two of this proceeding. Details, including, but not limited to, the following, should be addressed: how the QF would know it needed to obtain the form, how it would obtain it (e.g., from a specified place on a utility's website), whether or how it could be submitted electronically, and the extent to which the utility could change or withdraw the form without prior Commission approval.

As to DCNP's position that a QF should have to have executed a PPA in advance of DNCP's subsequent rate filing in order to be eligible for the approved avoided cost rates, the Commission, notes that it rejected the execution of contracts as being the trigger point in its order establishing avoided cost rates in the Sub 136 proceeding because the utilities have the ability to delay the execution of contracts with QFs. With recently-approved 30-month timeframe for completion of construction, the Commission agrees with the Public Staff that it is premature to retract it at this time, given that it was approved shortly before the Commission issued the order initiating this proceeding. It is still the best means of resolving a number of competing issues that were raised in the Sub 136 proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The Commission in the Sub 136 proceeding concluded that each QF that (a) has obtained a CPCN or filed an ROPC, as applicable, no later than November 1 of the year in which a biennial proceeding has been initiated, or the actual filing date of proposed rates if later, and (b) has indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output should be entitled to the fixed, long-term avoided costs rates approved in the immediately preceding biennial proceeding. The Commission is aware that the tariffs of the utilities may state November 1, 2014, without the proviso

that the date of the actual filing, if later, controls. To the extent the tariffs state November 1, 2014, they shall be considered amended to include the language "or the actual filing date of proposed rates if later." It is appropriate that the currently approved avoided cost rates and tariffs remain available until 60 days from the date of this Order, which is the date the utilities are required to file new proposed avoided cost rates in compliance with this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP and DNCP shall file proposed avoided cost rates in compliance with this Order, and in compliance with the Commission's Order establishing avoided cost rates in the Sub 136 proceeding to the extent not superseded by this Order, 60 days from the date of this Order.

2. That the currently approved avoided cost rates and tariffs shall remain available until the utilities file new proposed avoided cost rates in compliance with this Order.

3. That the proposed avoided cost rates to be filed in compliance with this Order shall include long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should include a condition making contracts under those options 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.

4. That the proposed avoided cost rates to be filed in compliance with this Order shall include a standard five-year levelized rate option for all other QFs contracting to sell three MW or less capacity.

5. That DEC, DEP and DNCP shall continue to use the peaker method to calculate avoided cost rates, as discussed more specifically herein, without the subtraction of energy benefits associated with a new CT proposed by DNCP, without the cap on production cost savings proposed by DEC and DEP, and without the inclusion of zeroes in any years, all of which would produce rates that are lower than full avoided costs.

6. That, in the calculation of the installed cost a CT, DEC, DEP and DNCP shall use data from publicly available industry sources and tailor it only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

7.	That, in the calculation of the installed cost a CT, DEC, DEP and DNCP shall include transmission interconnection costs (but not network upgrade costs), equipment and construction costs with a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, a reasonable estimate of useful life of a CT, the cost of land for a greenfield site, and economies of scale for up to four CTs constructed on the same site. DEC, DEP and DNCP shall not include any economies of scope associated with the construction of more than one CT at the same time.

8.	That the generation expansion plans used in the avoided cost production cost models for the purpose of calculating avoided energy rates shall be based on IRP expansion plans that take into account only known and quantifiable costs.

9.	That DEC, DEP and DNCP shall calculate and include the fuel hedging benefits associated with purchases of renewable energy, as discussed in this Order, in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding.

10.	That avoided capacity payments shall continue to be based on a per-kWh capacity payment.

11.	That DEC, DEP and DNCP shall continue to calculate and include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreements entered into among DEC, DEP, DNCP and the Public Staff in the Sub 136 proceeding.

12.	DEC, DEP and DNCP shall continue to offer an Option A set of avoided capacity rates and both Option A and Option B capacity rates shall be filed for approval by the Commission in phase two of this proceeding.

13.	That a PAF of 1.2 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their avoided cost calculations for QFs except hydroelectric facilities with no storage capability and no other type of generation.

14.	That a PAF of 2.0 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-F) 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 stipulation filed by DEC, DEP and the NC Hydro Group.

15.	That DEC, DEP and DNCP shall not incorporate the costs and benefits related to solar integration in their avoided cost calculations until such time that future studies and developments have further clarified have been concluded and the Commission has approved such inclusions.

16.   That until such time as the studies are concluded and Commission authorization given, the utilities shall continue to follow their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

17.   That DNCP's proposal for a simple form to be used to determine the date of the commitment of a QF, along with how it should be implemented shall be approved with the details and implementation to be considered in the next phase of this proceeding and the parties are directed to address it in their filings.
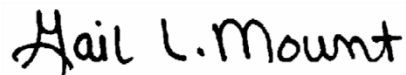
18.   That the 30-month timeframe for completion of construction approved in the Sub 136 proceeding shall not be changed.

19.   That WCU and New River shall file proposed avoided cost rates as directed by the Commission in the Sub 136 proceeding, except as otherwise modified in this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Chief Clerk