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Sep 09 2014

September 9, 2014

VIA ELECTRONIC FILING

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Docket No. E-100, Sub 140
Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s Proposed Order

Dear Ms. Mount:

Please find enclosed for filing in the above-referenced docket Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s Proposed Order. An electronic copy is being emailed to briefs@ncuc.net.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Charles A. Castle
Associate General Counsel

Enclosure
cc: Parties of Record

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CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s Proposed Order has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 9th day of September, 2014.

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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 Rates for Electric Utility Purchases from Qualifying Facilities - 2014	)))))))	**DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, INC.'S PROPOSED ORDER**

HEARD: Monday, July 7, 2014, at 1:30 p.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, July 8, 2014, at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, July 9, 2014, at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Thursday, July 10, 2014 at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

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BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Federal Energy Regulatory Commission's ("FERC") regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under N.C. Gen. Stat. § 62-156(b) to establish rates for small power producers as that term is defined in N.C. Gen. Stat. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the FERC and of State regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards and are not

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owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities" ("QFs"), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

With respect to electric utilities subject to state regulation, the FERC delegated the implementation of these rules to State regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission has implemented Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other

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matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also results from the mandate of N.C. Gen Stat. §62-156, which was enacted by the General Assembly in 1979. This statute provides that, "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" as used in N.C. Gen. Stat. §62-156 is more restrictive than the PURPA definition of that term, in that N.C. Gen. Stat. §62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding other types of renewable resources.

On February 25, 2014, the Commission issued its *Order Establishing Biennial Proceeding and Scheduling Hearing* (Scheduling Order). The Scheduling Order made Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP); New River Light & Power Company (New River), and Western Carolina University (WCU) parties to this proceeding to facilitate the determination of avoided cost rates.

In its February 21, 2014 Order in Docket No. E-100, Sub 136, the prior biennial avoided cost proceeding, the Commission had stated:

> The Commission recognizes the potential magnitude of the impacts on generation, transmission, and distribution systems of both smaller distributed and utility-scale solar photovoltaic projects that are proposed to be constructed in North Carolina. The potentially disruptive implications, both positive and negative, of this changing landscape merit further consideration – more than was provided during this proceeding – and have relevance to multiple other proceedings before the Commission, including integrated resource planning, REPS compliance, future avoided cost determinations, and others. The Commission also recognizes, as

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> previously discussed, that it may no longer be appropriate to continue building upon the previously established PAF framework to determine avoided capacity cost rates given the new emerging QF landscape. With that in mind, the Commission will revisit its precedents, including whether a 2.0 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 methodologies historically relied upon by the Commission to determine avoided cost capture the full avoided costs.
>
> As a result, the Commission will consider these issues in a broader context in its next biennial avoided cost proceeding in advance of the filing of proposed rates. This will allow for further consideration of the value of solar proposition proffered by NCSEA and its witness Rábago, the materials presented in the Crossborder Study, the system impact study that is being developed by DEC and DEP, the cap on capacity payments requested by DNCP, and other issues that the Public Staff and other parties may wish to have considered.

The Scheduling Order stated that the Commission would consider these issues prior to the filing of new proposed rates, which will be required by a subsequent Commission order in this Docket. The Commission scheduled an evidentiary hearing to begin July 7, 2014 to consider changes to the methodology 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 methodologies historically relied upon by the Commission to determine avoided cost capture the full avoided costs.

The Scheduling Order required all parties to file direct testimony and exhibits by April 17, 2014; responsive testimony by May 30, 2014; and rebuttal testimony by June 20, 2014. Other persons desiring to become parties were initially required to seek permission to intervene by May 30, 2014.

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The North Carolina Sustainable Energy Association (NCSEA), North Carolina Waste Awareness and Reduction Network (NC WARN), the Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR), Carolina Utility Customers Association, Inc. (CUCA), Southern Alliance for Clean Energy (SACE), the Environmental Defense Fund (EDF), the North Carolina Hydro Group (NC Hydro Group), the Alliance for Solar Choice (TASC), the Public Works Commission of Fayetteville (FPWC), the Sierra Club and the Natural Resources Defense Council (NRDC) and Google Inc. filed petitions to intervene before the May 30, 2014 deadline, all of which were granted. The Public Staff's participation is recognized pursuant to North Carolina statute.

On April 11, 2014, the parties filed a joint motion to extend deadlines for the filing of direct testimony, responsive testimony and rebuttal testimony and to reschedule the evidentiary hearing. On April 16, 2014, the Commission extended the deadline to file direct testimony until April 25, 2014 but ruled that the procedural schedule and hearing date otherwise remained unchanged.

Direct, responsive and rebuttal testimony was filed by various parties in April, May and June 2014. WCU and New River filed joint comments and proposed rates. DEC and DEP jointly filed testimony of Kendal C. Bowman (direct, responsive and rebuttal), Glen Snider (direct, responsive and rebuttal) and Larry Makovich (direct, responsive and rebuttal); DNCP filed testimony of Roger T. Williams (direct, responsive and rebuttal), Bruce E. Petrie (direct, responsive and rebuttal), James R. Bailey (responsive) and Robert S. Wright (responsive); the Public Staff filed the testimony of Dr. Laurence D. Kirsch (direct), Dr. Richard E. Brown (direct, responsive and rebuttal), John R. Hinton (responsive and rebuttal) and Kennie D. Ellis (responsive); EDF filed the

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testimony of Diane Munns (direct and rebuttal); NC Hydro Group filed the testimony of Andrew C. Givens (direct and responsive); NCSEA filed the testimony of R. Thomas Beach (direct, responsive and rebuttal), Greg Ness (direct), Zoe G. Hanes (direct, responsive and rebuttal), Michael Cohen (direct and responsive), Katie B. Rever (responsive), Angela Whitener Maier (rebuttal) and Jonathan M. Gross (rebuttal); NC WARN filed the testimony of Nancy LaPlaca (direct and responsive); NRDC and Sierra Club filed testimony of Alvaro E. Pereira (responsive); SACE filed the testimony of Karl Rabago (direct, responsive and rebuttal); and TASC filed the testimony of Anne Smart (direct) and J. Richard Hornby (responsive and rebuttal).

On June 24, 2014, DEC and DEP filed a Stipulation of Settlement with the NC Hydro Group.

The evidentiary hearing was held as scheduled, beginning July 7, 2014 and concluding July 10, 2014. On September 3, 2014, DEC, DEP and the Public Staff filed a Joint Motion for Extension of Time for all parties to file proposed orders until Tuesday, September 9, 2014. By Order issued September 4, 2014, the Commission allowed the requested extension of time. Proposed orders were filed by September 9, 2014. More than 180 consumer statements have also been filed with the Commission.

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

Based on the foregoing, all of the parties' testimonies, exhibits and other filings, and the entire record in this proceeding, the Commission now makes the following:

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FINDINGS OF FACT

Peaker Methodology

1. The peaker methodology is the most reasonable and appropriate methodology to fully capture the utilities' avoided costs, and DEC and DEP shall continue to use the peaker methodology to calculate avoided cost rates for the purpose of compensating QFs under PURPA.

Contract Terms and Conditions

2. DEC and DEP shall offer long-term levelized capacity payments and energy payments for five-year, ten-year and fifteen-year periods as standard options to hydroelectric QFs owned or operated by small power producers as defined in N.C. Gen. Stat. § 62-3(27a) contracting to sell 5 MW or less capacity.

3. DEC and DEP shall offer long-term levelized capacity payments and energy payments for five-year and ten-year periods as standard options to non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 100 kW or less capacity.

Avoided Capacity Costs

4. DEC and DEP shall calculate capacity payments to be paid on a per-kilowatt-hour (kWh) basis.

5. The calculation of capacity credits for purposes of establishing long-term levelized capacity payments shall take into account the utility's relative need for generating capacity.

6. DEC and DEP should maintain internal consistency between the Integrated Resource Plans ("IRP") dockets and the biennial avoided cost dockets that

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they file in the same year to the extent it is practicable. Changing market conditions or new or revised cost studies, however, may require DEC or DEP to update the information and assumptions from the IRP before they make their biennial avoided cost filings.

7. DEC and DEP shall base their avoided capacity cost on economies of scale associated with the average cost of building four combustion turbine ("CT") units at a greenfield site.

8. DEC and DEP shall include direct CT interconnection costs in the calculation of the annual fixed CT capacity costs, but any estimates of transmission and distribution ("T&D") system upgrade costs shall be excluded.

9. With respect to their avoided capacity costs, it is appropriate for DEC and DEP to use a contingency factor of 5% in calculating their respective CT construction cost in this docket.

10. DEC and DEP shall calculate the annual capacity value of a CT incorporating their respective most recently approved cost of capital and book life assumptions for the CT. It is appropriate for DEC and DEP to use a 35-year book life in calculating their annual fixed CT capacity costs in this docket.

11. A PAF of 2.0 should continue to be utilized by DEC and DEP in their respective avoided cost calculations for run-of-the-river hydroelectric ("hydro") facilities with no storage capability and no other type of generation.

12. A PAF of 1.05 shall be utilized by DEC and DEP in their respective avoided cost calculations for all QFs other than run-of-the-river hydroelectric facilities.

13. Capacity credits should be paid over a distinct set of seasonal on-peak hours that represent the hours when capacity is most likely to have the highest value to

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customers during peak conditions. DEC and DEP should calculate and include in their next avoided cost rate schedules the same on-peak hours (for both summer months and non-summer months) as they have recommended in this proceeding.

Avoided Energy Costs

14. There is a clear consensus that the intermittent nature of solar generation imposes costs on the utility system into which it is connected, particularly in the area of maintaining generation and regulation reserves.

15. As solar integration costs must be forward-looking, using the utilities' statutory renewable energy portfolio obligations as a guideline to assume a two-percent solar penetration level to calculate a generation-related solar integration charge for the DEC and DEP systems is reasonable.

16. The solar integration costs identified in the compliance scenario of the Duke Energy Photovoltaic Integration Study ("Duke PV Study") provide a reasonable estimate of the known and measurable generation-related solar integration costs for DEC and DEP in this docket. The costs used for purposes of this docket shall be included at the lowest end of the identified range of integration costs in the compliance scenario within the Duke PV Study.

17. There is not sufficient data to assess the distribution- and transmission-related costs and benefits of solar integration on the utilities' T&D systems at this time. DEC and DEP are directed to undertake an analysis of the costs and benefits of solar integration into their T&D systems with the goal of presenting that analysis in the next biennial avoided cost proceeding.

18. Multiple definitions of on-peak hours lead to DEC, DEP and their

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customers paying more for capacity and energy from QFs than they should. DEC and DEP shall not be required to maintain multiple definitions of on-peak and off-peak hours for purposes of calculating their avoided cost rates.

19. Under the peaker methodology, avoided energy costs should be calculated as the marginal energy cost that the utility would have incurred but for its purchases of power from the QF.

20. In the past, the peaker methodology has not accounted for the lost energy value of an avoided CT because avoided CTs had little or no energy value. Newer CTs, however, provide more energy value than older CTs.

21. More frequent dispatch of newer CTs demonstrates that there are hours during which the energy from new CTs is at or below DEC's and DEP's marginal cost of energy. Because DEC, DEP, and their customers would have had the benefit of such energy value from an avoided CT, but for QF purchases that avoided the CT, it is appropriate to recognize the lost energy value in calculating their avoided energy rates. Capping marginal energy costs at the production cost of the avoided CT is a reasonable way to approximately the lost energy value of the avoided CT.

22. The use of daylight hours to define on-peak energy hours would not better align the on-peak definition with DEC's and DEP's hourly loads and related hourly costs and would likely result in unfairly burdening customers with additional avoided costs. DEC and DEP shall continue to use the Option B hours for on-peak energy calculations.

23. Potential future costs of compliance with Environmental Protection Agency regulations requiring reductions in CO_2 emissions that have not been finalized or

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approved, or put into effect are not sufficiently known or quantifiable to justify their inclusion in avoided cost calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence for this finding of fact is found in the testimony and exhibits of DEC/DEP witness Snider, NCSEA witness Beach, and the testimony of Public Staff witnesses Kirsch and Hinton.

DEP and DEC witness Snider testified that avoided cost rates are the rates established by the Commission for power that North Carolina utilities purchase from QFs. He explained that the rates are referred to as "avoided cost rates" because PURPA provides that the rates to be paid to QFs should be at or below what it would have cost for the utility to generate the power itself (i.e. the utility's avoided costs). Under PURPA, state regulators, such as this Commission, have the discretion to determine the specific methodology to be used to determine what constitutes avoided cost; however, such state regulators must follow PURPA guidance that avoided costs should reflect the costs of energy and capacity that would have otherwise been incurred by a utility but for the purchase from the QF supplier. As a result, witness Snider stated that customers should be indifferent since they are neither benefited from nor harmed by the purchase from a QF. (Tr. Vol. 1 at 175)

Witness Snider testified that DEC and DEP have consistently used the "peaker methodology" to determine avoided capacity and energy costs for setting the avoided cost rates paid to QFs. He stated that the peaker methodology 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.

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More specifically, the peaker methodology approximates a utility's avoided energy cost through estimates produced by generation production cost modeling. This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a peaker CT plus the variable marginal energy costs of running the system will produce the marginal capacity and energy cost that a utility avoids by purchasing power from a QF. (Tr. Vol. 1 at 176)

Witness Snider testified that the Commission has also recognized the theoretical corollary of the peaker methodology, which provides that even if a utility's next planned unit is not a simple cycle peaker, the "peaker methodology" still accurately represents a valid estimate of the utility's avoided costs. He explained that this fact is supported by the resource planning process in which building incremental peakers for capacity and relying on the remaining system for marginal energy is always an option within the planning process. Witness Snider stated 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. According to witness Snider, the utility only selects more expensive capital facilities, such as natural gas combined cycle baseload units, when the incremental efficiency of the unit (as compared to a simple cycle peaker) provides enough marginal energy value to more than compensate for the incremental capital. He further stated that in that scenario, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost no greater than the capital costs of a peaker. (Id.)

NCSEA witness Beach testified that there are a number of methods for calculating avoided costs that are widely used; including the proxy method, the differential revenue requirement (DRR) method, the peaker method, and market pricing. He stated that some

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states have implemented competitive solicitations to award contracts to QF resources, although such processes typically do not result in published avoided cost prices, and he asserted that a recent decision of the FERC calls this practice into question. (Tr. Vol. 5 at 140)

Witness Beach described the operation and relative merits of each of these methods. He described the proxy method as generally estimating avoided costs based on the projected capacity and energy costs of the next planned unit within the utility's current Integrated Resource Plan ("IRP"). Witness Beach described the proxy method as the simplest of the avoided cost methods because it relies on utility plant-specific data for the proxy resource and avoids the need for long-term modeling of system-wide marginal energy costs. (Tr. Vol. 5 at 139)

Witness Beach testified that the DRR method calculates the difference in the utility's overall generation costs with and without QF capacity. The underlying assumption of this method is that the QF capacity reduces the utility's revenue requirement, and the avoided costs are equal to the present value of the difference in total generation costs with and without QF power. He described that the DRR approach can be based on modeling from the most recent IRP, but that the complexity and lack of transparency of the modeling needed to implement the DRR method is a central problem of the method, as is the need to separate the stream of revenue requirements into energy and capacity components. (Tr. Vol. 5 at 140)

Witness Beach also explained that, in states that have competitive day-ahead markets for energy, with visible, hourly prices, the use of those prices has been approved for the purposes of establishing rates paid to QFs for energy. He elaborated that states that have transparent capacity markets have used those prices to set capacity rates for

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QFs. For example, North Carolina allows QFs in DNCP's service territory the option to take energy and capacity payments based on market prices in the PJM Interconnection markets where DNCP operates. (Tr. Vol. 5 at 141-42)

Witness Beach noted that the Commission has long approved the use of the "peaker" methodology to calculate the avoided costs of DEP and DEC, and, for the first time in the 2012 avoided cost proceeding, it also required DNCP to calculate its avoided cost using this same method. He described that the peaker method assumes that a QF allows the utility to reduce the marginal generation on its system and to avoid building a peaking unit. According to the theory underlying the peaker method, if the utility's generating system is operating in equilibrium, at the optimal point, the cost of a peaker will be the least-cost source of new capacity, and new generation will have to be less expensive than a peaker plus the system marginal cost. Thus, the peaker method involves a dual calculation: the avoided energy costs are determined by the projected, system-wide marginal cost of energy; and the avoided capacity costs are established by determining the cost of a generic or hypothetical natural gas fired CT. Witness Beach testified that, compared to other methods for calculating avoided costs, the peaker method tends to produce lower avoided cost estimates, given that the least-cost capacity option is used as a basis for the avoided cost of capacity. (Tr. Vol. 5 at 142)

Witness Beach testified that 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 that would reduce overall system costs. However, he stated that, as indicated in IRPs, utilities often plan to add resources other than CTs (such as natural gas-fired combined cycles or "CCs"), indicating that the utility's system may not always

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be operating at the "optimal" point of equilibrium. The higher capital costs of the planned avoidable resource may be justifiable if that new plant's energy costs are below system marginal energy costs. He further noted that the peaker method requires modeling of the utility's system-wide marginal costs in each hour, which then are used to produce avoided energy prices. Such modeling is complex, uses many assumptions (some of which may be confidential and whose impact on the results may not be transparent), and requires resources and capabilities which may not be available to any party except the utility. (Tr. Vol. 5 at 143)

Witness Beach stated 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. He emphasized that, given 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, it would be reasonable for the Commission to direct the utilities to continue to use the peaker method to calculate avoided costs. (Tr. Vol. 5 at 144-45)

Public Staff witness Kirsch also testified that the peaker method quantifies avoided capacity costs according to the annualized costs of a pure peaking generating plant and quantifies avoided energy costs by calculating the highest marginal running cost of a utility's generating system for each hour of the year. He explained that the theoretical basis of the peaker method is that, assuming the utility's generating system has an optimal resource mix, the per-unit fixed costs (including capital costs) of a new plant net of fuel savings will be identical for all types of generating plants. For example, at the optimum, the per-unit fixed costs of a new coal-fired generating plant, net of its fuel savings, will equal the per-unit fixed costs of a new combined-cycle plant net of its fuel

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savings. A peaking plant (such as a combustion turbine) is used to measure avoided capacity costs under this method because it has the highest fuel costs per MWh and, therefore, has no fuel savings, thereby making it a proxy for pure capacity. Witness Kirsch opined that, in theory, avoided costs that are based upon the combination of the fixed costs of the peaking plant and the highest marginal running cost of a utility's generating system will constitute the avoided costs attributable to any kind of generating plant. (Tr. Vol. 7 at 94-95)

Witness Kirsch noted that the first 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. He stated that a second strength is that the method produces values for avoided capacity costs that are independent of fuel forecasts, which is not the case for a method such as the DRR method. An additional strength is that the use of a production cost simulation model allows hourly avoided energy costs to be grouped into on- and off-peak periods. Witness Kirsch stated that, because of its theoretical foundation and its relative lack of dependence upon forecasted future conditions, the peaker method is a reasonable means of quantifying avoided capacity costs for QFs in general. He added that, because the avoided capacity costs of all resource types should be the same when there is a perfectly efficient mix of generating technologies, the combination of such avoided capacity costs with system marginal energy costs means that the peaker method produces reasonable results even if baseload or intermediate units, rather than peaking units, are likely to be the utility's next capacity resource(s). Witness Kirsch noted that the weakness of this method is that

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power systems are often in disequilibrium: they often have too much or too little capacity relative to load; and they sometimes have a non-optimal mix of baseload, intermediate, and peaking units. To the extent these factors are present, adjustments may be warranted. (Tr. Vol. 7 at 95)

Witness Kirsch, like NCSEA witness Beach, also explains the relative merits and weaknesses of several other calculation methodologies. According to witness Kirsch, the dispatch method uses a security constrained economic dispatch model to calculate the utility's cost of power production and power purchases with and without QFs. Witness Kirsch explained that this method has the strength of providing accurate estimates of avoided energy costs, to the extent that the input data are correct, but has the weakness of greater complexity than the production cost simulation method. He also described the DRR method similarly to NCSEA witness Beach, and noted that its strengths lie in the fact that it is based on a theoretically plausible approach for estimating the cost savings attributable to QF power and the utility's actual plans, and it can provide an estimate of the long-term cost savings associated with QF power, thus providing a reasonable basis for setting the QF price in a long-term contract. Witness Kirsch stated that its weaknesses related to its reliance upon assumptions about the costs of the generation expansion plan, which is particularly problematic for longer-term forecasts and that it can be difficult to separate the total avoided costs into appropriate avoided capacity costs and avoided energy costs. (Tr. Vol. 7 at)

Witness Kirsch also described the proxy method, and identified the strength of this method is its reliance upon the utility's future investment plans, which tie its result to the expected course of future events. The key weakness of this method is that it is based

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upon an erroneous conception of how power systems work and how costs are incurred. According to witness Kirsch, the proxy unit method ignores the cost savings associated with using a mix of different types of capacity, produces avoided cost estimates that generally over-estimate the costs that QF will help the utility avoid and that confuse the capacity costs that are avoided by QFs with the energy costs that are avoided by QFs. Witness Kirsch explained that the average incremental cost method sets avoided costs equal to the average capacity and energy costs of the entire fleet of resources included in the utility's long-term resource plan. He indicated that its strength was its simplicity, but that its weakness was that, being based upon gross averages, its results bear little or no relationship to the change in utility costs that accompanies a change in QF capacity or a change in QF power output. Finally, witness Kirsch described the competitive bidding method, but noted that it may have limited applicability, however, given a recent FERC decision, wherein the FERC found certain Montana Public Service Commission rules to be inconsistent with PURPA and its own implementing regulations because "requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to [the QF] obtaining a legally enforceable obligation…" He stated that the strength of this method is that, if the bidding process is properly designed and if there are multiple bidders, it can produce accurate market- based estimates of avoided costs; while the weakness is that competitive bidding processes can be difficult to design properly, there may be few bidders, and a well-designed process with an independent evaluator may be costly to administer. (Tr. Vol. 7 at 99-103)

Witness Kirsch testified that, in North Carolina, avoided costs are being determined using the peaker method, with a natural-gas fired combustion turbine serving

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as the peaking unit for determining avoided capacity costs. The combustion turbine's installed cost per kilowatt includes plant equipment and installation, fixed operations and maintenance ("O&M"), taxes, and property acquisition, gas pipeline, and electric transmission costs. Projected avoided energy costs are derived by simulating the operation of the utility's system with and without the presence of 100 MW or 150 MW of hypothetical QF capacity, and then calculating avoided energy costs as the difference in the energy costs between the two simulations. He stated that the primary determinant of avoided energy costs is the fuel price forecast in combination with the projected generation mixes. (Tr. Vol. 7 at 104-5)

Public Staff witness Hinton testified that he had reviewed the methods discussed in the testimony of Public Staff witness Kirsch, and the testimony filed by other parties, and he noted that 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, witness Hinton testified that the Public Staff recommended that the peaker method continue to be utilized to determine the avoided cost rates for DEC, DEP, and DNCP. (Tr. Vol. 7 at 160-62)

Based on the foregoing, and the consideration of the testimony submitted in this case, the Commission finds and concludes that the peaker methodology remains the most appropriate method through which to calculate avoided cost rates in North Carolina. Importantly, no party testified that the Commission should implement a different or new methodology to calculate avoided cost rates, and this has been the methodology in North Carolina for over the last twenty years. Further, the relative strengths of this method, as described in testimony from the parties, outweigh the weaknesses, and the continued use of this method is reasonable and appropriate estimate of the costs that would have

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otherwise been incurred by the utility but for the purchase of power from a QF facility. Moreover, the peaker method will allow the utilities to fully capture their avoided costs for purposes of setting rates to compensate QFs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 2-3

The evidence for these findings of fact is found in the testimony and exhibits of DEC and DEP witnesses Bowman and Snider, NCSEA witnesses Hanes, Cohen, Beach, Gross, Rever and Meier, SACE witness Rabago and Public Staff witness Hinton.

DEC/DEP witness Bowman specifically proposed that the Commission lower the capacity eligibility limit for standard avoided cost tariffs from 5 MW to 100 kW given the state of the QF marketplace in North Carolina. Witness Bowman stated the peaker methodology is a reasonable approach to assessing a utility's avoided cost, but 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. (Tr. Vol. 1 at 78)

Witness Bowman explained that the Commission has long acknowledged this in describing the types of factors that it expected that such negotiations should encompass, including (1) the availability of the QF during the utility's peak periods; (2) the expected reliability of the QF; (3) the utility's ability to dispatch the QF; (4) the coordination of the QF's scheduled outages with the utility's scheduled outages; and (5) the usefulness of the QF during system emergencies. *See e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities.* at 13-14, Docket No. E-100, Sub 53 (May 7,

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1987). Accordingly, she testified that bilateral negotiations are better suited to accurately measure the avoided cost associated with a particular QF than are standard terms and rates. (Tr. Vol. 1 at 78)

Witness Bowman stated that the 5 MW limit has existed since 1985 and that it was adopted when the small power production industry was in a nascent stage. She emphasized that the industry has changed considerably in the past 30 years, the underlying public policy objectives have evolved, and the technologies being utilized have changed. In today's environment, developers of even smaller projects tend to be well-experienced and sophisticated entities, and developers of QFs in North Carolina are routinely planning and developing projects both inside and outside the standard tariff parameters. As a result, according to witness Bowman, the prior justification for the 5 MW threshold simply no longer exists, and the higher eligibility threshold reduces DEC's and DEP's ability to manage growth in their systems on an orderly basis and reduces the Commission's ability to assure that consumers have reliable power at the least possible cost. (Tr. Vol. 1 at 79)

Witness Bowman explained that FERC, in Order No. 69, acknowledged that standard one-size-fits-all avoided cost rates cannot account for the differences between QFs of various sizes and types. FERC, however, also noted the concern that smaller QFs could not bear the transactional costs of negotiating individualized bilateral rates. In balancing those issues, FERC concluded that it was reasonable to require the States implementing PURPA to make standard rates and terms available to QFs of 100 kW and smaller. (Tr. Vol. 1 at 80)

Witness Bowman stated that lowering the eligibility limit for standard rates to 100

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kW will, to a greater extent, allow rates offered to QFs to be based on a more precise assessment of the costs that particular QFs allow the purchasing utilities to avoid and will help ensure that QF capacity is actually needed by the utility. She testified that the Idaho Commission has taken the similar step of reducing the eligible size for its standard rates to facilities 100 kW and under. The Idaho Commission concluded that it was preferable to establish avoided cost rates for differing types of QFs, particularly intermittent generation, outside of the standard avoided cost process rather than developing a standard rate that would adequately address the divergent types and sizes of QFs. Witness Bowman emphasized that the utilities will still be required to purchase the output of larger QFs, and the avoided cost requirements would still apply. The larger QFs, however, would receive avoided cost rates through bilateral negotiations with the purchasing utility and not through the applicable standard avoided cost tariff. At the same time, consistent with PURPA and FERC regulations, the standard rates will still be available to smaller QFs that may not be able to justify the cost and effort of negotiating separate rates. (Tr. Vol. 1 at 80-81)

DEC and DEP witness Snider testified that moving the tariff eligibility limit from 5MW to 100kW will allow the utilities to send the appropriate price signal through individual price offerings to QFs above 100kW. From a resource planning perspective, both the need for a resource and the relative economic value of a resource changes over time. Time sensitive variables, such as fuel prices, load forecasts, economic conditions, technology efficiencies, environmental regulations, level of QF participation, among other factors, all impact the need for any given type of resource as well as the economic

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value of the resource, and a tariff that is only updated every two years is not dynamic enough to value large amounts of QF capacity accurately. (Tr. Vol. 1 at 211)

Witness Snider explained that this is a pressing issue for DEC and DEP due to the large solar QF development effort in North Carolina that has resulted from the culmination of the compliance requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard ("NCREPS" or "REPS"), the impact of state and federal tax incentives, and declining solar prices. Approximately 1,000 MWs of potential solar projects in DEC's and DEP's territories currently fall in the 100 kW to 5 MW range. Witness Snider noted that under the current fixed tariff structure, all 1,000 MWs receive the same price signal, which overstates the cumulative value created if all 1,000 MWs were to come to fruition. He testified that, in addition to changing market conditions over the two year period in which standard avoided cost tariff rates are fixed, the sheer amount of QF interest changes the economic value from the 1st MW of QF capacity to the 1,000th MW of QF capacity. Holding all other variables constant, each block of solar that comes online diminishes the value created from the next block of solar. From an energy perspective, since solar resources have very similar output profiles they tend to reduce traditional utility generation in the same daylight hours. The first blocks of solar reduce the most expensive units, while the next blocks reduce less expensive units. Witness Snider provided specific examples illustrating that both the avoided energy and capacity value created by solar QFs changes with increasing levels of solar adoption. He emphasized that given the current level of expressed QF interest, it is no longer appropriate to offer the same avoided cost rate to such a large quantity of QF

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providers as it results in paying above avoided cost in the aggregate. (Tr. Vol. 1 at 212-14)

In their respective direct testimonies, NCSEA witnesses Hanes and Cohen[1] both recommended an increase to the capacity eligible for the standard tariff to 10 MW and also that the Commission require the utilities to offer long-term levelized capacity payments and energy payments for a 20-year term, in addition to the 5-, 10- and 15-year terms, as a standard option for QFs. Witnesses Hanes and Cohen asserted that long term PPAs enable investors to calculate the return on the investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. They stated that with increased price certainty for a project, investors typically require a lower return, which in turn reduces the cost of financing and reduces the overall cost of the project, making it more likely to be developed. Witnesses Hanes and Cohen stated that a 20 year term does not disrupt the balance the Commission has historically managed between the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. They further testified that a 20 year term is justified given the recent and expected reductions in revenue for QFs due to reductions in REC prices and standard rates, and the expected expiration of the North Carolina energy tax credit (ETC). (Tr. Vol. 4 at 136-37 and 174-76)

Witnesses Hanes and Cohen stated that moving to a 10 MW upper limit for the standard contract will allow solar developers to spread those fixed costs over a larger project size, thereby reducing the overall per MW cost of a project. They stated that the trend in North Carolina was toward larger solar projects due to their relative cost-

[1] In general, the respective testimony of NCSEA witnesses Hanes and Cohen were identical and will be referred to collectively.

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effectiveness. Witnesses Hanes and Cohen also testified that standard contracts, allow for the avoidance of negotiations with the utility, which they alleged could be protracted. They testified that moving to a 10 MW upper limit for the standard contract will further streamline the process and partially mitigate the difficulties QFs currently face as they attempt to negotiate PPAs for facilities greater than 5 MW in size. They also alleged that extending the standard offer would not result in an onslaught of development, rather, it will allow those projects that have a realistic chance to be developed, to be developed more efficiently at a lower transaction cost. They pointed to Tennessee, Oregon and California as states with standard offers open to QFs at 10 MWs and above. (Tr. Vol. 4 at 138-39 and 178-81)

NCSEA witness Beach also supported the addition of a 20 year term for standard contracts, as he stated it would more closely match the useful life of QF facilities and better capture the long-term costs which QF generation will allow the utilities to avoid. He stated that new QF whose plant has a useful life of at least 20 years, but which is limited to an initial 15-year contract, has no choice today but to accept the 15-year contract, then sign a 5-year contract – at unknown and probably lower shorter-term prices – when the initial contract expires. Witness Beach stated that this result fails to reflect the full long-term avoided costs that the QF will avoid over 20-plus years, and increases the costs and risks associated with developing and financing these projects. (Tr. Vol. 5 at 167) SACE witness Rabago also supported this proposal for similar reasons, testifying that intermittent resources such as solar and wind energy provide a long-term, reliable hedge against fluctuations in fuel costs, and should have access to rates for terms of 20 and 25 years for this reason. (Tr. Vol. 6 at 151)

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In supplemental testimony, DEC/DEP witness Bowman stated that the goals of PURPA and the public interest would be better served by reducing the eligibility to 100 kW. She stated that the effect of the imprecision inherent in the avoided cost rate setting process would be mitigated by limiting the availability of those rates to smaller projects, while raising the eligibility cap would simply exacerbate the problem by making more projects eligible for the standard avoided cost rates. Witness Bowman asserted that increasing the eligibility cap for standard avoided cost rates would increase the already extraordinary amount of QF generation proposed for North Carolina. She stated that both NCSEA witnesses Cohen and Hanes acknowledged that raising the eligibility cap would make it easier for developers to build larger QF facilities, which are more profitable for developers due to economies of scale, and that QF developers would pursue such projects if they could do so under standard terms and conditions. Witness Bowman surmised that increasing the eligibility cap for standard avoided cost rates would lead developers to increase the size of their projects significantly, and as such, even if the number of proposed projects did not change, the net effect would be an enormous increase in the amount of proposed QF capacity, which would have the same effect on customers as the "onslaught of development" that NCSEA witness Hanes argued would not occur. (Tr. Vol. 1 at 102-03)

Witness Bowman further testified that increasing the maximum capacity cap would not be consistent with PURPA's purpose of encouraging development of QFs. PURPA is intended to support the development of QFs, but not at all costs, nor is it intended as a means to make any and all QFs viable. While making the standard avoided cost rates available to larger QFs may make it easier to develop such facilities, it will do

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so by expanding the use of avoided cost rates that are set only every two years. Witness Bowman asserted that the biennial avoided cost rate process results in the application of rates that do not precisely reflect a utility's current avoided cost results to multiple projects. She testified that increasing the eligibility cap for standard avoided cost rates will simply apply a less than precise avoided cost rate to a much larger amount of QF capacity, with the only beneficiaries of such a change in policy would be the QF developers themselves. Witness Bowman emphasized that none of the alleged resulting cost savings from larger QF development would inure to the benefit of customers because the rates paid to QFs (and borne by the DEC's and DEP's customers) are based on the utilities' avoided costs, not the cost incurred by the developers to construct the QF facility. She concluded that facilitating the construction of larger QFs would only serve to improve the developers' profit margins, with no actual benefit to the Companies' customers. (Tr. Vol. 1 at 103-04)

Witness Bowman also testified that increasing the maximum capacity cap would not be consistent with the Commission's previously stated policies for establishing an eligibility cap for standard terms and conditions. PURPA and FERC regulations only require that standard terms and conditions be available to QFs of 100 kw or less, primarily to prevent small QF projects from being burdened with disproportionate transaction costs. Similarly, in Docket E-100, Sub 41A, the Commission established the current eligibility limit for standard avoided cost rates based on the view that developers of smaller projects may not have the "resources or the expertise to negotiate a contract with a utility." She emphasized that such policy concerns are simply not as relevant in the context of larger QF projects, and that given the cost and complexity of developing

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such facilities, any developer that intends to construct a QF facility that is 5 MW or larger will undoubtedly be more sophisticated and well-informed. Witness Bowman also pointed out that the transaction costs associated with bilateral negotiations would be small compared to the overall cost of the QF project. She asserted that 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. (Tr. Vol. 1 at 104-05)

Witness Bowman further testified that the Commission should not extend the maximum standard contract term from 15 to 20 years. The Commission consistently has recognized that this issue warrants regular re-evaluation in light of changing circumstances, and that this issue requires balancing the desire to encourage the development of certain types of QFs against the risks and burdens that long-term contracts place on customers. Witness Bowman stated that, in particular, the Commission has observed that long-term QF contracts pose a risk of stranded costs and overpayments on utility customers, particularly given the challenges of accurately predicting a utility's avoided cost over a long period of time. She noted that PURPA allows for, but does not require, that QFs be offered long term contracts, and that "long term" in the utility industry refers to terms far less than 20 years. Witness Bowman explained that long term QF contracts impose risks on public utilities and their customers by locking them into purchased power costs based on long term projections of costs, with these risks being particularly acute in terms of energy cost projections, which are difficult to project accurately over an extended time period. Long term avoided cost rate contracts typically assume that energy costs continue to escalate unabated over the entire term of the contract and the effect of such assumed escalation results in rates that assume that

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future energy costs will always be much higher than current energy costs. She emphasized that long term avoided cost projections are never entirely accurate, but the longer the term of the projection, the more inaccurate they are likely to be. Thus, increasing the maximum term of standard QF contracts will necessarily push the avoided cost rates paid to QFs further away from the purchasing utility's true avoided costs and will increase the risk that the utility's customers will bear costs in excess of the utility's avoided cost. (Tr. Vol. 1 at 105-07)

Witness Bowman asserted that there is no justification for requiring utilities and their customers to incur the additional risks and adverse effects of requiring even longer terms for standard QF contracts, particularly when QF development in North Carolina is extraordinarily robust and shows no signs of decreasing. She stated that in terms of balancing the need to encourage QF development against the risks associated with longer term contracts, there is no question that risks of 20-year standard QF contracts far outweigh the "benefits" associated with encouraging even greater QF development. Witness Bowman further stated that over a 20-year period, a 15-year contract and a 5-year contract will more accurately reflect a utility's avoided cost than a single 20-year contract, thereby better achieving the core principle of PURPA that QFs should receive payments that are no more than the purchasing utility's avoided cost. (Tr. Vol. 1 at 108-10)

Witness Bowman rebutted SACE witness Rabago's testimony by stating that neither DEC nor DEP regularly enters into 20- to 25-year fixed energy price contracts. She stated that whenever a utility does enter into PPA of any significant duration (i.e., one year or more), it will tie energy costs to actual energy market prices either by

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providing the fuel itself through a tolling arrangement or linking the energy rates under the PPA to a market index. DEC and DEP have, under very limited circumstances, entered into longer term fixed price contracts to meet the State's animal waste set-aside compliance requirements under Senate Bill 3, but these contracts are very much the exception, not the rule, and were driven by policy mandates, not prevailing market conditions. According to witness Bowman, the Companies' power purchasing practices suggest that QF contracts should be shorter, not longer. (Tr. Vol. 1 at 111)

Witness Bowman reiterated that increasing the maximum term of standard QF contracts to 20 years will increase the risks that customers bear for such contracts. She noted that if the Commission acceded to NCSEA witnesses Cohen's and Hanes' proposal, the same QF projects will be developed, but the developers will benefit from the lowered financing cost. In that regard, lowering the development costs of QFs benefits the QF developers only; the purchasing utility's and their customers continue to bear the burden of paying the QFs the utility's full avoided cost. Witness Bowman concluded that NCSEA witnesses Cohen and Hanes are proposing that the Commission impose additional risks on utilities and their customers through longer term standard contracts so that QF developers can obtain improved profit margins. (Tr. Vol. 1 at 112)

Witness Bowman also rebuts arguments from NCSEA witnesses Hanes and Cohen relating to expiring tax credits and declining REC costs. She states that state (and federal) policy makers may choose to implement measures to encourage or subsidize QF development outside of the limits of PURPA, but the presence or absence of such QF benefits are irrelevant to the implementation of PURPA and in no way diminish PURPA's fundamental principle that rates established under PURPA shall be no more

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than the purchasing utility's avoided cost. Witness Bowman testified that it would be inappropriate for the Commission to effectively undo that policy decision by manipulating the avoided cost process to increase QFs' profit margins to offset the loss of the tax incentives. It would have been just as inappropriate for the Commission to adjust avoided cost calculations downward when the tax incentives and Senate Bill 3 were implemented to account for the fact that QFs would be obtaining those benefits. Witness Bowman asserted that the issues raised by witnesses Cohen and Hanes are wholly outside the scope of PURPA and should play no part in the Commission's administration of the avoided cost process. (Tr. Vol. 1 at 113-14)

In his supplemental testimony, DEC/DEP witness Snider also agreed that the Commission should limit fixed price standard contracts to 10 years in duration. He stated that QF contracts represent a long-term fixed price obligation on behalf of the Companies' customers, and the QF obligation is essentially the equivalent of a long-term fixed price fuel purchase in which the Companies' customers are guaranteeing fixed payments today for future power deliveries based on today's forecast of future fuel prices. Witness Snider opined that the further out in time this fixed price guarantee is made, the greater the uncertainty surrounding these future price expectations; therefore, the longer the contract term, the greater the volumetric risk associated with the QF purchase. (Tr. Vol. 1 at 219-220)

Witness Snider emphasized that at the expiry of an 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 are still in place and the PURPA is still in place, and (b) the QF is still financially and operationally viable. The

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then prevailing prices would represent the market pricing at that point in time. According to witness Snider, this would better align the QF payment obligation borne by customers with the avoided cost value the QF actually creates. (Tr. Vol. 1 at 224-25)

NC Hydro Group witness Givens testified that his group opposed the proposed change of the eligibility limit for standard tariffs. He was not aware of any operating hydro plant in the state that is less than 100 kW, thus meaning that none of the hydro plants in the state would be covered by the standard tariffs. Therefore, he stated that all of the details that are laid out in the tariff, and approved by the Commission. would be open to discussion and negotiation each time a contract is renewed or a new contract is proposed. Witness Givens cautioned that this would create a complication that would be burdensome for small renewable generators and should be unnecessary in the development process. In addition, he stated that a standard tariff provides operators and developers reliable financial and operating information concerning the feasibility of a project. The absence of a tariff covering these basic issues of the relationship would stymie the execution of subsequent contracts for existing hydro plants, and new agreements for plants that are being redeveloped. (Tr. Vol. 4 at 34-35)

In his supplemental testimony, NCSEA witness Cohen reiterated that a reduction in the eligibility threshold for the standard tariff would be detrimental to QF development by making more projects subject to negotiation with the utility. He asserted that this proposal would lead to additional administrative costs and burdens to all parties due to the protracted nature of the negotiation process. Witness Cohen stated that Strata Solar has strived to avoid arbitration and has worked to develop good working relationships with the utility staff who handle the contracting, engineering and construction tasks

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needed to bring a solar farm on-line. He also noted that the process in North Carolina relating to PPA negotiation and interconnection takes longer in than in other states. He asserted that arbitration petitions will likely become a necessary fact of life if the proposal to reduce eligibility for the standard QF contract put forward by the utilities were to be adopted in this proceeding. (Tr. Vol. 4 at 184-87)

In response to the proposal to eliminate the 15-year term option in the standard tariff, witness Cohen recommended that the proposal should be rejected and an additional 20 year option be added to the tariff. He stated that the FERC has addressed the issue of over-payment and under payment under a long term contract in a number of cases, each time making clear that the risks balance out over the term. Further, he suggested that the insinuation that a QF will cease to perform in the later years of the contract ignores the realities of project finance. Because the QF is, under ordinary and customary circumstances, leveraged over the anticipated life of the facility, the QF cannot cease to perform without defaulting under its financing arrangements. Witness Cohen also stated that a long term variable energy rate contract would not encourage the development of QFs, particularly solar, because such generators do not make fuel spread decisions on whether to operate. He stated that due to the high fixed costs and near zero variable costs, solar generators are motivated to maximize production whenever possible. Once constructed, there is little a solar generation facility can do to change its costs. Witness Cohen asserted that any rate/term structure proposed must parallel the cost structure of a solar facility (i.e., long-term, fixed) to ensure economic feasibility and, therefore, the ability to secure financing. (Tr. Vol. 4 at 191-92)

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NCSEA witness Hanes restated many of the points made by witness Cohen, and added that currently, for projects greater than 5 MW, there is no guarantee that a negotiated PPA will have financeable terms. She stated that the proposal by the utilities to reduce the eligibility limit will further frustrate the achievement of economies of scale and financing and will lead to increased administrative burdens on the regulators and utilities. Witness Hanes alleged that requiring a greater number of parties to negotiate necessarily will result in an increased number of arbitration proceedings, and the lack of evidence of substantial numbers of QFs over 5 MWs is telling in this regard. She stated that the eligibility threshold should not be lowered, but rather increased to 10 MW to encourage the development of QFs, make the most efficient use of Commission, Public Staff, utility and QF resources and keep transaction costs to a minimum. Witness Hanes testified that this will not result in a QF "gold rush," but will rather enable those QFs that have a realistic chance of being developed to come to fruition. Witness Hanes restated much of Witness Cohen's testimony on the proposal to eliminate the 15 year term option from the standard tariff, and further testified that a 20 year term would reduce financing costs for QFs, and that such terms are consistent with contracts received by the unregulated affiliate operations of DEC and DEP, many of which on projects outside of North Carolina. (Tr. Vol. 4 at 142-49)

NCSEA witness Rever stated that the recommendation to reduce the eligibility threshold for the standard tariff overlooks the primary benefit or advantage of standard offer rates and terms, which is the elimination of the need to negotiate a PPA. She stated, like witnesses Cohen and Hanes, that the elimination of the transactional costs associated with negotiating a PPA further enhances the efficiencies of scale inherent in larger solar

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developments. She further asserted that it was very difficult to negotiate a financeable PPA and that DEC and DEP did not have a successful track record in negotiating PPAs with projects greater than 5 MWs. (Tr. Vol. 2 at 149-51)

NCSEA witness Beach testified that is important to know that the practical result of the Idaho order referenced by DEC/DEP witness Bowman has been to halt further wind development in Idaho, even though wind QFs are entitled to negotiate with the Idaho utilities. He asserts that this experience, and the experience in California, portends that if the monopoly utilities are allowed to negotiate, and refuse to accept certain pricing or contract terms, they are no longer "required" to purchase power from larger QFs, and it is doubtful that an "avoided cost requirement" would remain in place and that negotiations between larger QFs and the utilities will not be fruitful. Witness Beach testified that his conclusion is reinforced by the recent unsuccessful history of utility contracting in North Carolina with solar QFs larger than 5 MW, who must negotiate rates and contract terms with the utilities. (Tr. Vol. 5 at 184-85)

Public Staff witness Hinton testified that the Public Staff is concerned that, at a minimum, the reduction in the threshold for standard contracts to 100 kW would impose additional burdens on the Commission and the Public Staff as well as on the QFs. He noted that in prior decisions, 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, finding it to represent the appropriate balance between "the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other." He testified that Public Staff supported setting the standard

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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 did acknowledge that the Public Staff was aware that the number of QFs 5 proposed in North Carolina since the passage of S.L. 2007-397 (commonly referred to as Senate Bill 3) is larger than any prior level of activity that the State has experienced and that many of these proposed QFs are at or near the five MW threshold. Witness Hinton stated that based on the Public Staff's experience and the small number of contracts that have actually been executed, it appeared that the process of negotiating PPA contracts has not been very successful with the North Carolina utilities. (Tr. Vol. 7 at 167-72)

With respect to the term lengths for standard contracts, witness Hinton noted that the Commission has previously concluded that the current long-term contract options serve important statewide policy interests, particularly those set forth within N.C. Gen. Stat. §§ 62-156 and 62-133.8, while limiting the utilities' exposure to overpayments. He stated that FERC regulations provide the option for a QF to sell capacity and energy "over a specified term," but that such term remains a matter of judgment. He testified that the Public Staff believes that North Carolina's long-standing policy of providing 15 year terms has been highly beneficial to QFs. The Public Staff reviewed policies in other states and found some with shorter terms and others with longer terms, but no clear standard term. Witness Hinton stated that with regard to the proposal by NCSEA witnesses Cohen and Hanes to extend the contract terms to 20 years, the Public Staff agrees that such an extension would likely facilitate financing. However, the Public Staff also believes that the increased risk that avoided costs could substantially change over

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that longer period outweighs the financing benefits to ratepayers. Witness Hinton concluded that it is appropriate for the Commission to consider whether a shorter term structure provides sufficient opportunities for QFs to obtain financing, but that Public Staff believes that the currently available 15-year term in North Carolina is satisfactory, and the Commission should continue to monitor the amount of actual QF development and the stability of avoided cost rates. (Tr. Vol. 7 at 181-86)

In rebuttal, DEC/DEP witness Bowman stated that PURPA only requires that standard contracts be offered to QFs of 100 kW or less, and that 26 states use a capacity eligibility limit of less than 5 MW for standard QF PPAs, with 20 of those states using an eligibility limit of 100 kW. She emphasized that the utilities would still be legally bound by PURPA and North Carolina law to accept the full output of larger QFs at avoided cost rates and that the suggestion made by NCSEA witness Beach that utilities may simply “refuse” to negotiate PPAs and therefore are not truly “required” to purchase power from QFs in the absence of a standard PPA is baseless and inaccurate. Witness Bowman also stated that witnesses Beach, Rever, and Hinton were incorrect and relied upon interconnection request data mistakenly provided by DEC and DEP, not PPA negotiation information, to reach their conclusions. She noted that based on DEC’s and DEP’s updated data request responses, DEP had received 9 requests to negotiate PPAs with solar QFs larger than 5 MWs and DEC had received 5 such requests. (Tr. Vol. 1 at 132-33)

She stated that DEC and DEP do not believe that negotiation of commercial terms for PPAs has impeded the development of otherwise viable QFs. She testified that DEC and DEP have endeavored to further streamline the QF PPA negotiation process, including developing a standardized form PPA to be used as the basis for all negotiated

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QF contracts and refining and improving their avoided cost calculation process over the past several months. In combination with the use of their standard PPA, the improved ability to quickly provide updated avoided cost data will ensure that DEC and DEP can respond promptly and efficiently to PPA negotiation requests. (Tr. Vol. 1 at 135-137)

Witness Bowman further noted that although a large number of new QFs have been proposed, the number of counterparties with whom the Companies would need to negotiate new QF PPAs is considerably smaller. For example, since 2010, DEC and DEP have received 457 interconnection requests from solar QFs over 100 kW, with 338 of those requests (74% of the total) being made by only nine different developers, with one developer submitting 140 requests alone. She stated that DEC and DEP expect that once PPA terms are established for a particular project, essentially the same terms and conditions can be applied to the developers' other projects with little or no modification. Witness Bowman also stated that reducing the eligibility criteria would not lead to more arbitrations. DEC and DEP have negotiated numerous QF PPAs since the inception of PURPA and very few of those negotiations have resulted in arbitrations; to that point, Public Staff witness Hinton only cites two instances in which arbitrations requests have been brought against either DEC or DEP. She concluded that given this history, it is illogical to assume that lowering the eligibility cap is likely to result in a flood of arbitration requests. (Tr. Vol. 1 at 137-38)

Witness Bowman also stated that the arguments in favor or adding a 20 year term to the standard tariff focus exclusively on the potential benefit to QFs. She testified that NCSEA witnesses argue that longer term PPAs equate to lower financing costs for QF projects, but provide no corresponding benefit to electric customers or discussion of the

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added risks that longer term contracts impose on the purchasing utility and its customers. PURPA specifically requires a balancing of the goal of encouraging QF development and the interests of the State's electric customers, and witness Bowman agreed with the observation of Public Staff witness Hinton that the risk to ratepayers posed by 20-year QF contracts outweighs the financing benefits QFs might realize from such agreements. Witness Bowman further noted that the PPAs secured by Duke Energy Renewables were developed under a number of different regulatory regimes and under varying circumstances, and attempting to make comparisons between those arrangements and the policy that the Commission should adopt for the specific purpose of establishing terms for the standard QF contract would be a purposeless exercise. She reiterated that limiting standard QF contracts to 10 years would benefit customers by reducing the risks associated with those contracts and providing for avoided cost rates that more closely reflect the purchasing utility's actual avoided costs, and no party has presented evidence to suggest that 10-year standard QF contracts would prevent QFs from obtaining financing or otherwise prevent them from being developed. (Tr. Vol. 1 at 141-42)

Witness Bowman also testified DEC and DEP reached a stipulation and settlement agreement ("Stipulation") with the NC Hydro Group. DEC, DEP and the NC Hydro Group agree that N.C. Gen. Stat § 62-156 codifies the State's policy to promote and support small hydro QFs and that there is a small and relatively finite amount of small hydro capacity in the state and the Commission has relied upon this policy to distinguish small hydro QFs from other QFs in requiring the use of a 2.0 PAF. As such, she stated that DEC and DEP agree to continue to use the currently approved 2.0 PAF for small hydro QFs of 5 MWs or less until December 31, 2020. Additionally small hydro

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QFs shall have the option of contract terms of 5, 10 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 until December 31, 2020. Witness Bowman testified that DEC, DEP and the NC Hydro Group believe that this settlement is in the public interest as consistent with the North Carolina state policy. (Tr. Vol. 1 at 166-67)

NCSEA witness Hanes testified again on rebuttal that increasing the eligibility for the standard tariff would allow those projects that have a realistic chance of being developed to do so at minimal transaction cost. She stated that developing a project to commercial operation is a difficult proposition, involving a combination of factors. Witness Hanes stated that increasing the eligibility for the standard contract for project up to 10 MW does not guarantee that it can satisfy the other necessary criteria for developing a project, but it should facilitate development of feasible projects at a lesser transaction cost. In order to ensure that QF development is cost effective, a developer must look for any and every opportunity to decrease the cost of development. Witness Hanes concluded that in recognition of the unequal bargaining positions and in the interest of encouraging the development of QFs, making the most efficient use of Commission, Public Staff, Utility and QF resources and keeping transaction costs to a minimum, the Commission should, at the very least, reject the proposal by the Utilities to reduce eligibility for the standard offer and, instead, adopt the proposal put forward by the NCSEA witnesses to increase the term of the standard offer to 20 years and up to 10 MW in size. (Tr. Vol. 4 at 155-60)

NCSEA witness Gross testified QFs are typically financed with a combination of debt and equity. He indicated that the term of the PPA has been a significant factor for

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both debt and equity investment underwriting, with lenders generally not allowing for terms greater than the term for contracted revenues and equity investors also requiring long term PPAs, generally 15-20 years or more, in order to consider an investment based on their underwriting criteria. He stated that, in his experience, the economics of a typical QF in North Carolina would not support the increase in annual debt service required for a ten-year term loan versus the annual debt service required for a fifteen-year term loan, assuming the same amount of loan principal had to be borrowed. Witness Gross testified that financing QFs is becoming increasingly difficult, both in securing debt financing and arranging equity investors. He stated that the availability of a 15-year term is a very significant factor and, even then, in some cases will not be of sufficient length to allow for adequate financing to cover project cost. Witness Gross stated that he did not believe the pre-tax yields achieved by QF developers in the current market are excessive. (Tr. Vol. 4 at 207-216)

NCSEA witness Meier testified that the changes to the avoided cost scheme proposed by DEC and DEP will have a negative impact on the economics of swine waste-to-energy systems and will thus negatively impact all of the electric power suppliers' ability to comply with the REPS set aside and, ultimately, this could undermine the policy goals underlying the program. According to witness Meier, each of these proposals will inject uncertainty in project development and has the potential to reduce the return on investment. She stated that swine waste-to-energy projects already operate on small margins and are difficult to finance given a number of risks involved. She testified that any added uncertainty or costs (like the cost of negotiating a PPA for a project larger than 100kW) or reduction on the return on investment will make siting

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projects much harder. Witness Meier stated that lowering the eligibility cap for the standard offer PPA from 5 MW to 100 kW means added cost and uncertainty regarding the terms for any project over 100 kW. She also alleged that financing a project without the availability of a 15- year fixed term option will be extremely difficult. (Tr. Vol. 2 at 166-68)

SACE witness Rabago testified on rebuttal that it is a best practice to set contract length to correspond to the life of solar assets. He added that long term contracts enable utility ratepayers to ultimately realize the benefit of stable, reliable, pollution-free energy from renewable energy QFs. He further testified that long term contracts improve investor certainty, reduce transaction, financing, and administrative costs, and support the objective of advancing renewable energy generation in North Carolina. (Tr. Vol. 6 at 181)

On cross-examination, DEC/DEP witness Bowman stated that under the settlement, small hydro facilities would still be eligible for the 5, 10 and 15 year terms under the standard tariff, even if other QFs would not be eligible. She stated that such treatment was consistent with the special treatment granted small hydroelectric facilities under North Carolina law. Witness Bowman also acknowledged that a number of DEC's and DEP's proposals in this proceeding had previously been rejected by the Commission in prior proceedings, but reiterated that this proceeding was initiated specifically to revisit many issues with respect to the Commission's implementation of PURPA. (Tr. Vol. 1 at 423) Witness Bowman also stated that DEC had signed contracts with 3 solar QFs over 5 MW in size, and that DEP had not signed any with solar QFs over 5 MW over the past 5 years. (Id. at 429) She also clarified that DEC and DEP had provided incorrect

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information in response to a data request regarding PPA requests, instead providing information on interconnection requests, and that the actual response indicated that DEP had received 9 requests to negotiate PPAs from solar developers, while DEC had received 5 such requests. (Tr. Vol. 1 at 440-41) She also stated that many of the PPAs entered into by DEC's and DEP's commercial affiliate, Duke Energy Renewables, the projects were in different jurisdictions and had different term lengths. (Tr. Vol. 1 at 447-50)

Witness Bowman also testified that DEC and DEP are willing to add staff to negotiate the contracts, and that administrative burden for the Commission and Public Staff would come into play if there are actual arbitrations. (Tr. Vol. 2 at 47-48) She added that only 9 counterparties make up approximately 73 percent of the combined interconnection queue, so there would not be an inordinate amount of arbitrations. (Id.). Witness Bowman confirmed that the reasoning behind the proposed reduction in capacity size for tariff eligibility related to allowing for more orderly management of QF growth and provide for more accurate and timely avoided cost data, and she did not have reason to think any less QF capacity would ultimately be built. (Tr. Vol. 2 at 95-96) As part of the data updates that would be incorporated into more timely avoided cost information, witness Bowman stated that such updates would reflect changes in fuel prices, CT costs, capacity needs, environmental compliance costs and total QF capacity added to the systems. (Tr. Vol. 3 at 55-58)

Witness Bowman testified that the expected growth of small hydroelectric QFs in North Carolina over the next 5 years is only 5.5 MWs, and that such facilities remain specifically promoted by state law in the context of avoided cost. (Tr. Vol. 3 at 119) She

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also emphasized that the energy landscape has changed significantly over the last 10 years, and that DEC and DEP now face an interconnection queue of over 3000 MWs of solar projects. (Tr. Vol. 3 at 120) She noted that more than two-thirds of the current combined interconnection queue is for projects over 5 MWs, and clearly such developers are not concerned about negotiating contracts with DEC or DEP. (Tr. Vol. 3 at 123) She stated that DEC and DEP do not know what the fruition rates will be for solar projects in the future, nor do they have any insight into which projects within their interconnection queue are real or "phantom." (Tr. Vol. 3 at 130) Witness Bowman further testified that keeping the standard tariff eligibility limit small would enable the utilities to account for differences between different types of QFs through negotiation. (Tr. Vol. 3 at 133)

In response to questions from the Commission, witness Bowman stated that streamlining the interconnection process and standardizing the larger PPA contracts would help developers continue to construct QF projects. (Tr. Vol. 3 at 147-150) She also acknowledged that avoided cost payments are recovered from all customers and the utilities have typically recommended lower rates than the Public Staff. (Tr. Vol. 3 at 150-151)

On cross-examination, DEC and DEP witness Snider stated that most of the solar facilities that have been constructed in North Carolina are under 5 MWs in size, but that most of the facilities in DEC's and DEP's interconnection queues were over 5 MW. (Tr. Vol. 1 at 433) He further stated that approximately two-thirds of the combined interconnection queue was made up of project greater than 5 MWs in capacity. (Tr. Vol. 2 at 45) He also elaborated that allowing QFs above 100 kW to be priced on a dynamic

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basis sends a more appropriate economic signal than holding a constant price for two years. (Tr. Vol. 2 at 96)

On cross-examination, NCSEA witness Cohen stated that the dramatic declines in REC prices and costs of solar construction have benefited utility customers. (Tr. Vol. 4 at 228) He also acknowledged that Strata Solar is one of the biggest solar developers in North Carolina and in the entire country, and had approximately 35-40 projects under development in North Carolina. (Tr. Vol. 4 at 226 and 238) Witness Cohen also acknowledged that in June 2014, he sent an email to several Duke Energy employees, stating that “we have been and remain very pleased with both the process and the pace of working with Duke PPAs,” and continuing to state “[t]o be very clear, our frustration reference in SNL Article/Testimony related to our downsized projects for the 20 MW was more nuanced than as described, and mainly revolved around the process leading up to starting negotiations for a PPA, primarily within the interconnection process, which is what led us to downsize." (Tr. Vol. 4 at 232; DEC/DEP Cohen Cross Ex. No. 1) Witness Cohen went on to state that they must maintain good business relationships with DEC and DEP as a business necessity, and that they have taken steps to avoid arbitration because arbitration could sour the business relationship. (Tr. Vol. 4 at 253-54)

NCSEA witness Hanes stated that FLS has approximately 100 MWs in its North Carolina development pipeline and that it has an internal team of dedicated structured finance and legal professionals. (Tr. Vol. 4 at 241) She further testified that FLS manages renewable energy investments for some of the largest banks and insurance companies in the country and that they have asset management, maintenance and accounting teams that provide a full suite of services. (Tr. Vol. 4 at 242) She also acknowledged that QF

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developers have multiple revenue streams, including REC sales and federal and state tax incentives. (Tr. Vol. 4 at 243-44)

On cross-examination, Public Staff witness Hinton testified that the QF environment has changed dramatically since the initial 5 MW threshold was adopted. (Tr. Vol. 7 at 265) He agreed that utility customers bear the risk of overpayment to QFs, and that the Commission should consider that in striking the balance with encouraging QFs. (Tr. Vol. 7 at 264) He also acknowledged that the number of QFs proposed in North Carolina is larger than any prior level of activity experienced, and that this was also a factor the Commission should take into account when balancing risks with the level of encouragement for QFs. (Tr. Vol. 7 at 263) Witness Hinton testified that any benefits realized by QFs in terms of lower transaction costs are retained by the QF and are not passed along to utility customers. (Tr. Vol. 7 at 268-69)

Based on the foregoing, and as explained in further detail below, the Commission finds and concludes that reducing the standard tariff eligibility from 5 MW to 100 kW for all non-hydroelectric QFs is reasonable and appropriate at this time. The Commission further finds and concludes that limiting the terms of standard tariff contracts to 5 and 10 year options is also reasonable and appropriate at this time. The Commission also finds that retaining the 5 MW eligibility and 15 year term options for the next 5 years for small hydroelectric facilities is also reasonable given the state policy, codified in N.C. Gen. Stat. § 62-3(27a) and 62-156, specifically encouraging the development of such facilities in the avoided cost context.

In Order No. 69, which promulgated the FERC's rules implementing PURPA, the FERC established the requirement for standard tariffs for small QFs of 100 kW or less,

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based on the concern that smaller QFs could not bear the transactional costs of negotiating individualized bilateral rates. *Order No. 69*, FERC Stats. & Regs., Regs. Preambles 1977-1981 P30, 128 at 52 (1980). In that Order, the FERC also recognized that standard one-size-fits-all avoided cost rates cannot account for the differences between QFs of various sizes and types. *Id*. In balancing those issues, FERC concluded that it was reasonable to require the States implementing PURPA to make standard rates and terms available to QFs of 100 kW and smaller, and this requirement is set forth in 18 C.F.R. 292.304(c)(2). In its own implementation of PURPA, since 1985, this Commission has made the standard tariff open to larger QFs, up to 5 MW, so as to ensure that smaller project developers, who may not have the resources or expertise to negotiate with a utility, still had access to the standard terms and conditions. *Order Establishing Levelized Rates and Cogenerated Power and Maintaining Interconnection and Wheeling Prices*, Docket No. E-100, Sub 41A (Jan. 22, 1985). It is now almost 30 years after the Commission initially set that eligibility threshold and the drastically different circumstances in the QF marketplace in North Carolina provide more than adequate justification to revisit this issue. Moreover, as many witnesses have noted, the very purpose of this docket is to explore the calculation of avoided costs and re-evaluate these structural issues that relate to the Commission's implementation of PURPA. In its implementation of PURPA, including the issues of capacity eligibility and contract term for the standard avoided cost tariffs, the Commission has historically attempted to balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. See, e.g., *Order Establishing Standard Rates & Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 136 (Feb. 21,

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2014) at 11. It is again through this lens of balance that we have evaluated these issues relating to eligibility and term.

The North Carolina QF marketplace is extraordinarily robust under current conditions. DEC and DEP currently have in excess of 2800 MWs of proposed QF capacity in their combined interconnection queues, representing almost 360 projects; based on the data provided by DEC and DEP, these represent significant increases from even less than 2 years ago. North Carolina is in the top 10 states in the country in terms of installed solar capacity and in each weekly staff conference, the Commission's agenda is full of reports of proposed construction and CPCN applications from QF developers, primarily solar. This is a much different situation than existed 5 years ago; declining solar commodity and construction costs, the growing market for RECs and beneficial state and federal tax policy initiatives have all contributed to the exponential growth of renewable energy installations. As stated by NCSEA witnesses Hanes and Cohen, developers such as FLS and Strata have multi-state operations and sophisticated internal accounting, legal, tax and operational staff to manage portfolios of projects both in North Carolina and across the country. Such developers have both the resources or expertise to negotiate with a utility to sell power; and it is telling that these developers often choose to size their projects at the current eligibility limit of 5 MW so as to gain access to the standard tariff rates. Though several parties have acknowledged that many proposed projects will not ultimately ever come to fruition, the pending, proposed increases in QF capacity are material and are reflective of at least some measure of speculation in this market. To the development community, the standard tariff represents a certain and defined metric, which proves helpful in obtaining financing for their projects.

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From the utility perspective, the standard tariff enables any eligible QF to sell them power at the approved avoided cost rates over one of stated term options. The utility has no discretion to negotiate or deviate from the standard tariff rates or terms and conditions, regardless of the circumstances, and the utility must take the power delivered from eligible projects regardless of actual system need. The expenses related to the purchase of QF power are simply passed along to the utility's customers, and the utility and its customers remain obligated to purchase such power at the fixed prices over the duration of the long term contract entered into with the QF. For projects that are not eligible for the standard tariff, the utility will negotiate with the QF (on behalf of its customers) and if the QF believes that they are being denied the opportunity to sell its power at the utility's avoided costs, or otherwise being discriminated against, it may petition this Commission for arbitration pursuant to N.C. Gen. Stat. § 62-40.

There has been no dispute amongst the parties that the standard tariff, with the current eligibility limit of 5 MWs and the 15 year term option, is certainly encouraging the development of QFs in this state. However, under current and projected market conditions, that encouragement is not being equitably balanced against the risk of overpayment and stranded costs to the utility's customers. The standard tariff does represent a long-term, fixed price obligation that a utility's customers must bear, and the greater the amount of capacity and energy being purchased pursuant to that long-term, fixed price obligation, the greater the risk the utility's customers will bear. This risk can be particularly acute where, as here, the price is largely derived from a long-term fundamental fuel forecast, which will always be either too low or too high. At this point, a re-balancing of this equation in favor of utility customers is required, and the proposals

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to move the eligibility up to 10 MW and add a term option for 20 years are ill-conceived and exacerbate the current imbalance.

The eligibility limit of 5 MW is a holdover from the nascent stages of QF development in North Carolina and across the country, and the reasoning underlying that deviation from the 100 kW FERC standard is no longer present at the 5 MW size today. Sophisticated and well capitalized developers are using the standard tariff to develop projects at 5 MW, so many more parties than the "smaller developers without the resources or expertise to negotiate bilateral rates," are utilizing this tool in a manner that was not contemplated in either Order No. 69 or the Commission's Order in Docket No. E-100, Sub 41A setting the 5 MW standard.

PURPA, and the FERC's rules implementing it, specifically contemplated that QFs, except for those less than 100 kW, would negotiate with utilities regarding the price at which to sell their power, and the law provides the QFs with information and the appropriate standard for that price (i.e., avoided cost) to act as a backstop against utility noncompliance with the law. It bears noting here that the utilities, when negotiating to purchase power under PURPA, are purchasing this power on behalf of their customers and must do so at no greater than their avoided costs; as such, their obligation remains to comply with the law at least cost to their customers. And contrary to the suggestion of some parties in this docket, the utilities cannot simply nullify PURPA by refusing to or failing to negotiate with QFs in good faith.

The benefits of negotiated QF contracts to utility customers lie in relative timeliness and accuracy of the information being used to calculate the avoided cost rates for the QF. It allows for the delivery of appropriate price signals to the QFs and reflects a

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more real-time and accurate data set with respect to the capacity and energy needs of the purchasing utility. The testimony of Public Staff and other intervenor witnesses about the possibility for additional arbitrations has been well-considered here, but the Commission believes that the risk of arbitrations and administrative workload should not outweigh the cost-related risks to utility customers related to overpayments and stranded costs arising from more significant proliferation of QF standard tariff contracts. The Commission is mindful of the proposed improvements to the interconnection process and standardization of larger QF PPAs discussed by the utilities to mitigate the concern related to arbitrations and will continue to evaluate this issue over time.

In addition to the above, as it pertains more specifically to the settlement entered into between DEC, DEP and the NC Hydro Group, the Commission finds that due to the specific North Carolina policies promoting and advancing such QFs, the continuation of the eligibility standard of 5 MW and 15 year term option for small hydroelectric facilities is in the public interest. Such QFs retain a special designation under state policy, and as such, this differential treatment is appropriate under the circumstances. Further, the policy considerations expressed above with respect to other QFs, in terms of the projected growth and impact on utility customers, are simply not applicable to small hydro QFs. The undisputed testimony in the record establishes that their projected growth over the term of the settlement will only be approximately 5.5 MWs, and the incremental impact to customers arising from this growth will be minimal. For these reasons, the Commission approves the settlement as reasonable and in the public interest.

Based on the reasoning set forth above, the Commission hereby concludes that the utilities should be required to offer long-term levelized capacity payments and energy

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payments for five-year and ten-year periods as standard options to non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 100 kW or less capacity. The Commission further concludes, pursuant to N.C. Gen. Stat. §§ 62-3(27a) and 62-156, that the utilities should be required to offer long-term levelized capacity payments and energy payments for five-year, ten-year and fifteen-year periods as standard options to hydroelectric QFs owned or operated by small power producers as defined in N.C. Gen. Stat. § 62-3(27a) contracting to sell 5 MW or less capacity.

AVOIDED CAPACITY COSTS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is found in the testimony and exhibits of DEC/DEP witness Snider and the testimony of Public Staff witness Kirsch.

Public Staff witness Kirsch testified that, generally speaking, as a matter of efficiency, the utilities want to pay resources for the capacity value of their capacity and the energy value of their energy. As a matter of equity, it does not matter whether the payments are made on a per-kW or per-kWh basis, so long as each QF resource receives a total number of dollars approximating the utility costs that are avoided because of the resource's provision of capacity and energy. As a matter of simplicity, billing and payment systems should be easily administered given the large number of potential distributed energy resources. Paying for QF capacity on per-kWh approach is more appropriate because it does a better job of encouraging resources to be available during the on-peak hours when capacity is needed most. Per kWh pricing gives resources a strong incentive to be generating as fully as possible during the hours a utility needs them

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most because they do not receive a capacity payment when they are not generating. (Tr. Vol. 7 at 110)

Witness Snider testified that DEC and DEP recognize that traditional methods of paying for capacity based on requirements of deliverability or after-the-fact comparisons to system peak are particularly problematic for smaller intermittent QF resources. To overcome these deliverability challenges and the coincident peak (CP) demand metering challenges, 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 in which capacity will have value. Snider stated that the goal of defining these hours will be to provide certainty to generators and to overcome the issues associated with deliverability based billing or after-the-fact CP based billing. Furthermore, the identification of these hours will incent development of solar projects that maximize output at times when capacity has the most value to the Companies' customers. Array orientation, angle and tracking options can be optimized to achieve maximum payment while considering the tradeoff of the cost of such tracking mechanisms. (Tr. Vol. 1 at 197-99)

Based on the foregoing, and in consideration of the testimony submitted in this case, the Commission finds and concludes that paying for capacity on a per-kWh basis eliminates the potential difficulties smaller intermittent QF resources would face with the per-kW method while providing incentives for the development of solar projects that maximize output at times when capacity has the most value to the customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony and exhibits of

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DEC and DEP witnesses Bowman, Snider and Makovich, NCSEA witness Beach, SACE witness Rabago and Public Staff witness Hinton.

DEC and DEP witness Bowman testified that DEC and DEP proposed that the Commission modify the application of the peaker methodology to allow the utilities to calculate the capacity credits in the standard tariffs in a manner that takes into account the utility's relative need for generating capacity. She stated that one principal aspect of PURPA was, and remains, that QFs should be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to incur to serve its customers. 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, then the QF should not be compensated for providing that benefit. Witness Bowman testified that PURPA was not intended to force utilities to pay for capacity that it does not otherwise need, and both Order No. 69 and subsequent FERC decisions have reinforced this point. She added that North Carolina law also contemplates 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 …" N.C. Gen. Stat. § 62-156(b)(2). She noted that DEC's and DEP's recommendation merely seeks to effectuate this concept in practice to allow avoided capacity credits provided to QFs to incorporate that actual capacity being avoided by the purchase of power from the QF. (Tr. Vol. 1 at 82-84)

DEC/DEP witness Makovich testified that the utility's need for additional capacity changes as expectations regarding future reserve margins and new power plant costs and lead times change. As a result, he stated that economic efficiency requires a

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periodic update of avoided cost prices to reflect expected short run marginal costs of power production and to reflect the latest costs, needs and timing of capacity development. Witness Makovich stated that the value of capacity has a time dimension that shouldn't be ignored; it is low the majority of the time because the aggregate consumer level of demand is typically low compared to the existing capacity available to operate at that point in time. He added that the value of capacity is high when available capacity is just sufficient to meet aggregate consumer demands at a given point in time with the desired reserve margin, and in that case, the value of capacity reflects its replacement cost because existing capacity is not an available alternative. Witness Makovich stated that with any source of capacity, it should be paid for the net dependable capability it provides when the power system needs capacity. He further noted that the ultimate objective is to provide consumers with efficient power supply, and it is inefficient to pay someone to add capacity before it is needed. (Tr. Vol. 1 at 309-11, 317)

DEC/DEP witness Snider testified that to appropriately incorporate the need for capacity into the rate calculation, 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 utility's most recently filed IRP, with specific adjustments as required. He stated that the utility's IRP presents a 15-year resource plan that identifies when the next generation unit is needed for reliability purposes, and prior to the year in which the next generation unit is needed, the utility does not have a capacity need to avoid. He continued that the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. (Tr. Vol. 1 at 193-94)

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Witness Snider testified that the IRP forecast for needed new generation accounts for both existing and forecasted QFs that defer the need for the next utility generator. In determining when new capacity is first needed, the utility would first remove all undesignated QFs (QFs not yet under contract) to see if the need for capacity moves forward in time. He explained that this will allow the utility to more accurately forecast the next year in which additional capacity is required, and that this adjustment would ensure that the new QFs are being compensated for capacity for years in which there are an actual capacity need to avoid. (Tr. Vol. 1 at 194-95)

Witness Snider testified that accounting for the timing of needed capacity more accurately value the capacity being delivered by the QF, consistent with the intent of PURPA. He stated that PURPA's clear intent is to estimate costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. He provided the example where economic conditions combined with a large influx of QFs eliminated all future need for utility fossil generation capacity; in such an example, incremental QFs would still avoid marginal fuel and production costs (avoided energy value); however, there would be no fixed costs to offset or avoid. He pointed out that, under those circumstances, the payment of avoided capacity would clearly be inconsistent with PURPA, but that under the current avoided capacity cost calculation, customers would continue to pay for QF capacity even though there is no capacity cost to be avoided. Witness Snider noted that while today's situation is not to the extreme of the example above, the same principle applies. This PURPA principle requires the recognition that if the utility's first avoidable capacity need is several years in the future,

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then the present avoided capacity rate should only reflect value in that future period when there is a capacity need to avoid. (Tr. Vol. 1 at 195-96)

Witness Snider explained that under the tariff, QFs would still receive a capacity payment in years prior to the utility's first capacity need. DEC's and DEP's proposed change simply implies the capacity rate received by the QF would reflect a lower annual payment to account for the initial years in which no avoidable capacity costs would be included in the rate derivation. Witness Snider clarified that, in essence, the QF will receive capacity payments immediately in recognition of future avoided capacity so long as the utility has an avoidable capacity need sometime within the life of the tariff period. He stated that, with the adjustments suggested, the utility's customers would only be paying QF capacity payments equal to the economic value of an associated avoided utility capacity cost. (Tr. Vol. 1 at 196)

NCSEA witness Beach disagreed with DEC's and DEP's proposal to account for the relative need for capacity within the avoided capacity cost calculation. He testified that an avoided cost rate should include capacity if the QF purchase will permit the purchasing utility to avoid building or buying future capacity, and the expected longer-term costs of future additions of capacity must be considered in the calculation of avoided costs and in the rates based on those avoided costs. He added that the FERC regulations explicitly approve determining avoided costs by comparing (1) the total costs that would be incurred by the utility to meet a specified demand without purchases from new QFs to (2) 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. (Tr. Vol. 5 at 178)

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He 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." He stated that the utility testimony acknowledges 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 is complete. Witness Beach testified that QF capacity is available in smaller increments, given that standard contracts today are limited to no more than 5 MW, or would be limited to a maximum of 10 MW under the proposals of NCSEA witnesses Hanes and Cohen. He added that most of the QFs in North Carolina are 5 MW or smaller, in contrast to the typical utility additions of capacity are in increments of at least 100 MW, and often more, as shown by the utilities' current resource plans. (Tr. Vol. 5 at 178)

He stated that these large central station units require significantly longer time to develop, permit, and build, and as a result, new utility plants must be sized to provide much more than the amount of capacity which the utility needs in the year in which the new plant enters service. Witness Beach testified that the result is that ratepayers may have to pay for years of excess capacity until demand "catches up" to the last major addition – a fact that is explicit in the conclusion in DEC's and DEP's 2012 IRPs that, due to the addition of a number of new coal and natural gas units in 2011-2013, these utilities have excess capacity until 2016 or 2017. He explained 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

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peaker'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, according to witness Beach, 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. (Tr. Vol. 5 at 179-80)

Witness Beach further testified that the value of capacity is never zero, even if a utility has excess capacity. He stated that there is an active market for short-term capacity in which the North Carolina utilities participate, and 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. He testified that the value of short-term capacity is apparent in control areas such as the PJM Interconnection which have organized and visible capacity markets, and if a QF contract has such a short term (for example, one or two years) that it will not enable the utility to avoid new generation (e.g. the peaker), then it could be appropriate to set the QF capacity rate for that short term contract at the short-term market cost of capacity, but not to zero. (Tr. Vol. 5 at 182)

Witness Beach further stated that the utilities and the Commission have numerous tools available to regulate the pace and extent of QF development. He stated that QFs must obtain certificates of public convenience and necessity (CPCNs) from the Commission and that need can be an issue in granting CPCNs. He also noted that in this case all of the utilities have asked the Commission to throw one important "off switch" that would be likely to significantly slow, if not halt, QF development – the reduction in the standard contract size from 5 MW to 100 kW. (Tr. Vol. 5 at 183)

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SACE witness Rabago also disagreed with DEC's and DEP's recommendation and stated that it has two major flaws. He stated that 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. Also, he testified that it effectively precludes ratepayers from ever receiving the benefits of more cost-effective energy from QFs except during the imperceptibly small window between a condition of excess capacity and the failure to load utility capacity into the resource plan at some point in the future. He asserted that QF capacity will almost always be either too early or too late to receive value for its capacity contribution. Witness Rabago concluded that under witness Snider's recommended approach, even capacity at a lower price than utility planned capacity will not be fully or fairly compensated. (Tr. Vol. 6 at 170-71)

Public Staff witness Hinton also disagreed with DEC's and DEP's proposal, particularly if the Commission continues to utilize the peaker method. He stated that, while the utilities' position appears intuitive on the surface, it does not comport with the theory underlying the peaker method. According to witness Hinton, for the peaker method to produce the correct total avoided cost, both energy and capacity costs over the relevant time period have to be included because the peaker method is supposed to produce the long-run marginal costs of adding new capacity over the entire planning horizon. He testified that the utilities' proposal to include zeroes for the early years of the planning period leads to an understatement of avoided capacity costs and should be rejected if the peaker method is retained. (Tr. Vol. 7 at 162)

Witness Hinton stated that the appropriate perspective to use when setting avoided costs is the long term; it simply seems unfair to treat some QFs differently than

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others because they happen to bring their facilities on line during a short-term capacity-rich period. He also stated that if one were to accept the argument that capacity payments should be reduced for QFs because the utility's planning reserve margin may be sufficient over the short-term, then it also would be reasonable to argue that QF capacity should be paid a premium over "equilibrium" avoided costs if offered when the utility's planning reserve margin is below the target for the short term because the QF is addressing a more critical situation. He added that a fundamental premise of prudent utility planning is to ensure that a utility has adequate capacity in place to meet its resource and reserve margin needs; otherwise a utility runs the risk of violating NERC's reliability standards. A utility should always have sufficient capacity over the short-term to meet these standards and, indeed, may have adequate capacity in the short term because of the lumpiness effect of a recent capacity addition. He testified that for a utility with a substantial long-term need for capacity additions, short-term resource adequacy or lumpiness does not reduce the cost of the future planned capacity additions that can be avoided by the addition of QF capacity. Witness Hinton stated that, in theory, the peaker method produces the avoided energy and capacity cost of those future additions by combining the full capital cost of a CT with the marginal system running costs over the entire planning period, and including zeroes in the calculation of avoided capacity costs or paying capacity payments only when reserve margins are low does not comport with that theory. (Tr. Vol. 7 at 163-64)

Witness Hinton testified that if the utilities were using the proxy method, which may not reflect an avoided capacity cost until the next planned capacity addition, then delaying capacity payments might be a reasonable approach. An aspect of the proxy method is that the proposed unit is often a combined cycle (CC) that has a higher installed capital cost per kW than a simple cycle CT. He stated that these higher costs translate into higher avoided capacity costs, which tend to provide added cash flows to offset the loss of capacity payments for the early years of the planning period when no capacity is needed. He testified that eliminating capacity payments until the time when the first avoidable capacity is needed is not an appropriate adjustment to make if avoided costs are calculated using the peaker method. Further, witness Hinton stated that in its 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. (Tr. Vol. 7 at 163-64)

Public Staff witness Kirsch provided certain perspective on the issues that had plagued the prior implementation of PURPA at various state commissions. He noted that the history of the implementation of PURPA pricing has been marred by some spectacular errors in the quantification of avoided costs, due primarily to gross misforecasts of future market conditions (as in California) or by arbitrary legislative or regulatory fiat (as in New York). He testified that less spectacular failures have been instances in which QF investments have been inefficiently discouraged (as by failures to recognize the value of QF capacity in situations involving power system capacity levels that are only modestly above target) or inefficiently encouraged (as by payments for QF capacity when a utility has excess system capacity over the planning horizon). (Tr. Vol. 7 at 106)

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On rebuttal, DEC and DEP witness Snider clarified that the adjustment for relative need for capacity simply reduces the levelized capacity payment by excluding CT value of deferral benefits until the time when there is an actual capacity need to defer as shown in the DEC and DEP IRPs. He further identified three overarching reasons why the Commission should consider a utility's relative need for capacity in the calculation of avoided cost rates. First, he stated that it is inconsistent with PURPA for the Commission to calculate avoidable capacity benefits prior to years in which such avoidable customer benefits exist. Second, he added this specific adjustment is effectively the only tool the Commission has to efficiently regulate the volume of QF capacity that is cost-effective for the State of North Carolina. And third, he testified that adjusting capacity payments based on the relative need for capacity just makes simple common sense. (Tr. Vol. 1 at 269)

Witness Snider responded that SACE witness Rabago apparently does not understand the regulatory process in North Carolina. He emphasized that utilities do not unilaterally decide the nature, size or timing of their generation additions and must obtain from the Commission a CPCN before constructing an electric generating facility. To do so, the utility must show that the proposed addition is needed and that adding it is consistent with the utility's obligation to provide reliable electric service on a least-cost basis. He stated that absent the utility's and the Commission's complete abdication of its responsibilities, a utility cannot and will not overbuild generation in this State. (Tr. Vol. 1 at 270)

Witness Snider also testified that he was uncertain as to the basis for witness Hinton's position. He states that witness Hinton asserts that including the utility's

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relative need for capacity in the calculation of avoided cost is inconsistent with the peaker method. He notes that witness Hinton stated, "[f]or the peaker method to produce the correct total avoided cost, both energy and capacity costs over the relevant time period have to be included. This is because the peaker method is supposed to produce the long-run marginal costs of adding new capacity over the entire planning horizon." Witness Snider testified that this quote seems to support the recognition of a utility's relative capacity need in the calculation of avoidable capacity costs, rather than to assume erroneously that the utilities have a perpetual capacity need. (Tr. Vol. 1 at 271-72)

Witness Snider posited an example where the country entered a deep national economic recession which resulted in the utilities not having a projected capacity need until 7 years from now. Now assume a QF signs up for the 5-year avoided cost rate. He stated that under these circumstances, witness Hinton would suggest the QF receive 5 years of avoidable capacity payments and energy payments even though the utilities' customers received no avoidable capacity benefits. Witness Snider testified that this simply does not make sense nor does it imply that the "peaker method" is no longer an appropriate approach for determining avoided costs. To the contrary, if appropriately applied in this situation, the peaker method would recognize the utility's relative need for capacity over the 5 years was zero, but still appropriately pay the QF for the levelized marginal avoided energy value the QF created during 5-year contract. If the same QF entered into a 15-year contract rather than a 5-year contract, the QF would have immediately started to receive both an avoided energy payment and an avoided capacity payment based on the utility's 15-year levelized marginal energy value and the levelized avoidable capacity need in years 8 through 15. Witness Snider contested that this is fully

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consistent with witness Hinton's earlier assertion that, "[f]or the peaker method to produce the correct total avoided cost, both energy and capacity costs over the relevant time period have to be included." (Tr. Vol. 1 at 272)

In further response to witness Hinton, witness Snider testified that there should be no equity concern related to QFs coming online during different periods. He stated that a QF that is developed during a period of acute capacity need provides greater value and should receive greater compensation for capacity than a QF that comes online during a period of capacity surplus. He emphasized that to suggest otherwise ignores a basic principle of PURPA that a QF should only be paid for capacity if and to the extent it allows the purchasing utility to avoid capacity costs. (Tr. Vol. 1 at 273)

Witness Snider again provided an example where several hundred MWs of QFs came online this year pushing the utility's next capacity need out for several years. Now suppose next year, new QFs sign up with the utility. He stated that holding all other factors equal, it would certainly be "fair" to pay the second round of QFs less than the first round of QFs given the reduction in relative capacity need in year 2. Witness Snider explained that without the recognition of a relative reduction in capacity value as proposed by the Company, all QFs irrespective of cumulative quantity would receive an identical capacity payment. However, not all of the QFs created an equal avoided capacity benefit for customers. He noted that this is why it is imperative for the Commission to send the appropriate price signal to QFs that reflects the utility's relative need for capacity and to ensure that utility customers reasonably pay for capacity that reflects the true need of the utility. (Tr. Vol. 1 at 273)

Witness Snider also disagreed with NCSEA witness Beach's assertions that the

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smaller size and shorter lead time of QFs make them a preferred resource compared to "lumpy" utility-built resources. He states that witness Beach's position has no merit within the context of the peaker method because (1) in reality, if a baseload unit is selected within the planning process it is because it is more cost-effective than the less "lumpy" CT all things considered; and (2) QFs are not actually developed in a manner that reflects the utility need. Witness Snider testified that unless the Commission adopts the recommendations of DEC and DEP to reflect the relative need for capacity in the calculation of the capacity payment, it will effectively have no mechanism to regulate the amount of QF capacity for which utility customers are ultimately responsible for paying. (Tr. Vol. 1 at 274-75)

Witness Snider also disputed witness Beach's assertion that the Commission could simply deny a CPCN to a QF based on lack of need. He stated that this is generally not the case for QFs because the CPCN process for QFs is largely pro forma. Witness Snider testified that the CPCN process provides limited opportunity for the Commission to effectively regulate QF development. He further stated that witness Beach's testimony regarding the ability to sell excess capacity is also incorrect. Witness Snider explained that multi-year mid-term capacity markets are fairly illiquid and difficult to price, and neighboring markets often face the same economic conditions as North Carolina, leaving them in surplus or shortage positions, which undercuts the assumption that "excess" capacity could be easily or profitably off-loaded in the surrounding markets. He described that this is why DEC and DEP have very rarely sold or purchased off-system capacity in the manner suggested by witness Beach. He also stated that the entire suggestion seems at odds with the basic principles of PURPA, given that one of the

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keystone principles of PURPA is that a utility is not required to pay QFs for capacity if the utility does not need capacity. Witness Snider concluded that this principle would have little meaning if the definition of a utility's need is expanded to include speculative, hypothetical sales of excess capacity. (Tr. Vol. 1 at 276-77)

On cross-examination, DEC and DEP witness Snider testified that both utilities were projecting 1.4 percent annual load growth, and that DEC did not have a capacity need until 2016, and DEP did not have a need until 2018. (Tr. Vol. 1 at 398-99) He also stated that he did not believe that either utility had significant excess capacity. (Id.) Witness Snider further clarified that the Utilities' proposal would be to back out the undesignated renewable resources already in the utility's respective plans and see if the need was accelerated so that we were not penalizing renewable resources that have already allowed DEC or DEP to defer that generation need. (Tr. Vol. 3 at 62) He stated that, for example, in the DEP IRP, if we were to back out all of our REPS compliance undesignated renewables and that first need was in 2017, DEP would propose to use zeroes up until 2017. (Id.) In this way, witness Snider explained that DEC and DEP would make an adjustment to credit renewables that are already in the plan for any deferral value that they create. (Id.) Witness Snider further testified that DEC and DEP rely upon all QFs that have signed PPAs or that are included in their respective REPS compliance plans for capacity planning purposes. (Tr. Vol. 3 at 62-63)

Witness Snider also clarified when parties refer to DEC and DEP using "zeroes," it does not mean the QFs will not get paid capacity credits during those years. (Tr. Vol. 3 at 112) As an example, he stated that should a QF sign a 10-year contract, where there was not an avoidable need during the first 2 year, from year 3 forward they would get

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credited for deferring or avoiding CT capacity, and that that collective value created in that eight years would be levelized and paid throughout the entire term of the contract. (Tr. Vol. 3 at 113) He emphasized that the QF would start receiving immediate avoided capacity payments in day one of the contract, even though it created no value until Year 3, due to the levelization of the payment. (Id.) Witness Snider further testified that one does not have to presume a perpetual need for capacity under the peaker method for it to be a valid method. (Tr. Vol. 3 at 113-14)

Witness Snider also testified that neither DEC nor DEP would attempt to somehow overbuild its system to ward off QF development, and the utilities are not motivated to reduce QF payments so that it can build capacity itself. (Tr. Vol. 3 at 152-53) He stated that the proposals from DEC and DEP arise from the utilities desire to more accurately reflect its avoided costs. (Id.) He also stated that by reflecting a relative need for capacity would impact the capacity payment over the life of the contract; in essence, the less the need, the lower the payment; the greater the need, the greater the payment, consistent with DEC's and DEP's interpretation of PURPA. (Tr. Vol. 3 at 166) He described this effect as existing on a continuum with no short-term need on one end and immediate need on the other; and the QF is compensated for the actual value being created, consistent with PURPA. (Tr. Vol. 3 at 167-68) He further testified that this accurately reflects the long term avoided cost of the utility and creates appropriate price signals for QFs. (Tr. Vol. 3 at 170)

On cross-examination, NCSEA witness Beach testified that QF development will not match the utility's need for capacity or its load growth. (Tr. Vol. 5 at 233-34) He also stated that the utility's need for capacity should be reflected through the avoided cost

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rate (Tr. Vol. 5 at 234) He stated that in terms of the setting of avoided cost rates, as, for example, a solar penetration in a state grows, there have been numerous studies that have shown the capacity value of solar will decline as you add more solar to a system. (Tr. Vol. 5 at 237) Witness Beach also acknowledged that he was not familiar with the CPCN process in North Carolina. (Tr. Vol. 5 at 235)

On cross-examination, Public Staff witness Hinton testified that DEC's and DEP's projected QF growth was not expected to exceed its entire capacity over their respective planning periods. He also stated that an overbuilt CT could create a capacity surplus over a short-term period, and that the utility would likely receive recovery through rates of its capacity investment if it was overbuilt for a short period of time. (Tr. Vol. 7 at 235-36) Witness Hinton also said that, under Public Staff's view, if a QF signs a 10-year contract with a utility, the avoided capacity payments it receives under are not going to be affected regardless of whether the utility is showing a need for capacity in year 2 in its IRP or in year 9 in its IRP. (Tr. Vol. 7 at 259-60) Witness Hinton also stated that the calculation of avoided capacity cost can be a messy process, and the most conservative approach for the Commission would be protect the cost paid by utility customers from increasing. (Tr. Vol. 7 at 275-76)

Based on the foregoing, the Commission finds and concludes that avoided capacity credits to QFs should be adjusted to reflect the purchasing utility's relative need for additional generating capacity. Given the interpretive guidance provided by the FERC on this issue, as well as the need to revisit it driven by the substantial growth of the QF market in North Carolina, the desire to send appropriate price signals to QF relating to the timing of development, the need to appropriately capture the actual capacity value

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being delivered by QFs over time and the lack of other means to control the influx of QFs to avoid overbuilding, the Commission believes that adjusting the avoided capacity value to account for relative need is a reasonable and appropriate step at this time. We find that such an adjustment appropriately captures the full capacity cost actually being avoided through the power purchase from a QF, and we find that this approach is consistent with the application of the peaker methodology.

The FERC has, on a number of occasions, provided its interpretation of the requirements of PURPA as it pertains to compensation for QFs for the avoidance of future generating capacity. In *Order No. 69*, the FERC explicitly held, as a fundamental premise, that "[w]hile the utility is legally obligated to purchase energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load." The FERC has further elaborated on this concept to state that :

> an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity. Thus, while utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require the utility to pay for capacity it does not need. *City of Ketchikan, Alaska, Copper Valley Electric Association, Inc., City of Petersburg, Alaska, City of Wrangell, Alaska,* 94 FERC 61,293 (2001)*(citing Order No. 69, supra note* 5 at 25-26).

This year, the FERC again restated this implementation premise when it reasoned that "when the demand for capacity is zero, the cost for capacity may also be zero." *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 at p.18 (2014). In this way, FERC has established that utility need for capacity is an essential element in the calculation of avoided capacity credits, and a component that must inform the rate offered so as to avoid an overbuilding situation with QF capacity. FERC regulations also itemize

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considerations to be taken into account in the establishment of avoided cost rates, namely the relationship of the availability of capacity and energy from a QF to the ability of the utility to avoid costs, including capacity deferrals. See 18 C.F.R. § 292.304(e)(3). As such, the FERC has clearly stated that utilities should not be forced to pay QFs for capacity, or energy, that it does not in fact need to meet its load obligations.

Both NCSEA witness Beach and DEC/DEP witness Snider testified that the utility's need for capacity should be reflected through the avoided cost rate, thereby sending a direct price signal to QFs either encouraging or discouraging new capacity at that point in time. Similarly, several witnesses, namely DEC/DEP witnesses Makovich and Snider, further described that capacity value certainly has a time dimension and is not static in nature. As such, to recognize that time dimension and elastic nature of capacity need and value, one must value capacity within the standard rates based on the facts and circumstances involved.

Assuming a perpetual need, as witness Hinton would have the Commission continue to do, simply ignores the dynamic nature of a utility's planning and evolving needs, and would abandon any attempt to incent development during periods of higher need, or temper development during periods of oversupply. Given the fact that the Commission re-sets avoided cost tariff rates biennially, short term capacity surpluses and needs, and not simply long term plans, should be taken into account because we do take the opportunity to update and review these tariffs with some frequency. While the Commission has, in prior dockets, rejected similar proposals from the utilities during periods of scant QF development, it is necessary at this time to re-evaluate this approach given the projections of substantial and material QF penetration over the coming years.

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The Commission also finds that the approach advocated by DEC/DEP witness Snider balances the need to reflect appropriate capacity value with the need for QFs to receive a fixed payment stream over the life of a contract to obtain financing. In this way, the avoided capacity payment will not ever, in fact, be zero, but will merely reflect a reduction in the levelized payment reflecting the relative value being provided to the utility and its customers of the duration of the contract.

Incorporating these adjustments in the actual avoided capacity rate is all the more necessary because it is the most equitable mechanism through which the Commission can both encourage QF development and manage the risk of overpayment, overbuilding and stranded costs on utility customers. Commission Rule R8-64, pertaining to CPCNs for QFs, does not mandate that a QF establish a need for its facility to receive a certification, nor does the Commission believe that such a requirement comports with the legal requirements related to the implementation of PURPA. FERC regulations, specifically 18 C.F.R. § 292.304(e), contemplate that such matters relating to relative value and need shall be taken into account in the establishment of avoided cost rates, and the evaluation of relative capacity value is an important aspect to ensuring that such rates are just and reasonable to utility customers. Further, as noted previously, witnesses from both sides of this argument have acknowledged that the capacity credit is an appropriate mechanism to provide explicit price signals to QFs relating to the utility's actual need for generating capacity. To continue to set the capacity credit without regard for the benefits of such price signals would, in our estimation, provide an excessive benefit to QFs at the expense of utility's customers and compromise the reasonableness of the rates such customers are forced to pay for such power.

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Capacity valuation and capacity planning are inherently dynamic and fluid processes and the Commission finds that the standard tariff rates must account for that dynamic nature to create an environment where customers are paying for the true value being delivered, and QFs are provided with direct signals regarding relative timing of utility capacity needs. Based on the well-developed record on this issue, the Commission hereby concludes that in the calculation of avoided capacity credits, the utility shall account for and reflect the relative need for capacity in its rate, as proposed and detailed by DEC and DEP witness Snider.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

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

DEC/DEP witness Snider proposed that cost estimates be based on DEC's and DEP's most recent study of installed CT costs combined with past construction and operations experience. (Tr. Vol. 1 at 184)

NCSEA witness Beach testified that there should be consistency between the utilities' IRPs, which include generation reserve margins studies and contemporaneous avoided cost calculations. He further testified that the input assumptions, such as taxes, financing costs, gas pipeline and connection facilities, electric network interconnection facilities, and costs, used to calculate the installed cost of a CT for the IRP should be "identical" to those used to calculate the installed cost of a CT for the avoided cost proceeding. (Tr. Vol. 4 at 152) TASC witness Hornby agreed with witness Beach that the costs associated with the construction of the CT should mirror DEC's and DEP's IRPs. (Tr. Vol. 5 at 33)

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In response to witness Beach's recommendation, witness Snider testified that DEC and DEP attempt to maintain internal consistency between the IRP and avoided cost dockets, but at certain times, changes in fuel prices, environmental regulations, plant retirements, and new cost studies, etc., may necessitate an update from the IRP to the avoided cost docket. (Tr. Vol. 1 at 242)

The Commission concludes that the input assumptions should be based on DEC's and DEP's most recent CT cost study and operational experience. Because the IRPs and the utilities' proposed avoided cost rates are typically filed within a few months of each other, the Commission believes that information presented in the IRP should be generally consistent with that used to calculate avoided costs.

The IRP is used for planning purposes, however. The strictures that apply to the development of avoided cost rates are not applicable to a utility's planning process. A utility may take a conservative approach in its planning process and provide for a range of possibilities and assumptions. In developing avoided costs, however, the utility is proposing rates that will ultimately be paid by its customers; as such, DEC and DEP should account for any updates from the IRPs to the avoided cost proceeding that will enhance the accuracy or robustness of their avoided cost calculations. Therefore, the Commission agrees with witness Snider that changes in fuel prices or new cost studies may necessitate an update from the IRPs to the avoided cost docket. The Commission further notes that Commission Rule R8-67(b)(1)(iv) requires electric power suppliers to include the current and projected avoided cost rates for each year in their REPS compliance plans. With this requirement, the Commission does not believe it must now additionally mandate rigid adherence to using all of the information contained in the IRP

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in the avoided cost proceeding. The Commission concludes that DEC and DEP are not required to base their avoided cost calculations on the same inputs as in their IRPs if changing circumstances or new or updated cost studies necessitate an update to the avoided cost assumptions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony and exhibits of DEC/DEP witness Snider, witness Makovich, NCSEA witness Beach, TASC witness Hornby, and Public Staff witness Hinton.

Witness Snider testified that DEC and DEP look to construct their facilities as efficiently and economically as possible. (Tr. Vol. 3 at 73) Similar to his pre-filed testimony in Docket No. E-100, Sub 136 and his stated position in the EPCOR arbitration[2], DEC/DEP witness Snider testified in this proceeding that the avoided capacity cost should reflect the economies of scale associated with building four CTs at a greenfield site. Witness Snider supported his recommendation by noting that, of all of DEP's CT sites, only the Asheville site has fewer than four CTs. Three of DEC's four CT sites have four or more units; DEC's fourth CT site is a two-unit site that is used as a back-up source of generation for nuclear site. (Id.) He further elaborated that, at the Richmond site, there were four simple cycles and two CCs, which were not all built simultaneously. (Tr. Vol. 3 at 74) He noted that many of DEC's and DEP's facilities have more than four units at the site or are located with CCs or coal plants, which leads to extensive economies of scale with shared infrastructure, shared land, shared buildings, shared warehousing, and shared staff, parts, and maintenance. (Tr. Vol. 2 at 16-17)

Witness Snider explained that the multiple-unit approach is the most cost-

[2] *Order on Arbitration*, Docket No. E-2, Sub 966 (Jan. 26, 2011) ("EPCOR arbitration").

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effective approach to developing CTs because it optimizes the economies of scale associated with construction. (Tr. Vol. 1 at 186) He acknowledged that, in practice, the Companies would first evaluate brownfield sites to locate a CT, because existing infrastructure would already be in place. Use of a brownfield site in the recognition of economies of scale, however, yields a lower cost than use of a greenfield site. Nevertheless, he recommended a four-unit greenfield site as a reasonable, balanced estimate for avoided construction costs for a CT. (Tr. Vol. 1 at 185-86)

In response to a question from Commissioner Bailey, witness Makovich endorsed witness Snider's proposal to use a four CT per site, noting that economies of scale are seen in the larger nuclear power plants, larger coal plants and taller wind towers. Thus, witness Makovich concluded, utilities typically take advantage of multiple sites for CTs. (Tr. Vol. 3 at 159)

NCSEA recommended a one-unit CT site be used in calculating the avoided capacity cost. Witness Beach asserted that the utilities should not be permitted to adjust the installed cost of a CT for economies of scale. He noted that historically DEP had adjusted the installed cost of a CT for economies of scale based on a four-unit site and that DEC had done so for the first time in 2012. Witness Beach contested this adjustment as arbitrary and not based on specific design criteria. In witness Beach's experience, the addition of 800 MW of CT capacity at a single time would be unusual. Neither DEC nor DEP had included 800 MW of planned additions in their most recent IRPs. He further noted that the first CT addition shown in DEP's 2013 IRP is 126 MW of fast start capacity in 2013 and 403 MW in 2027. According to witness Beach, DEC's 2013 IRP shows the next addition to be 403 MW of capacity in 2022. Witness Beach concluded by

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stating that because PURPA requires that a utility's future need for capacity be reflected in the avoided cost calculation, the economies of scale should reflect the planned peaking capacity additions for a utility. (Tr. Vol. 5 at 153-54)

Commissioner Brown-Bland asked witness Beach whether he agreed that there should be no adjustment made for economies of scale or whether economies of scope should be removed. In response, witness Beach responded that there were different considerations that go into siting new generation. He could not say that no economies of scale or scope would be available, but without looking at a lot of detail, he could not say whether they would exist. (Tr. Vol. 5 at 253-54)

The Public Staff and TASC both recommended use of a two-unit CT site for use in calculating the avoided capacity cost. Witness Hinton testified that the assumed economies of scope (building multiple units at the same time) and economies of scale (building multiple units at the same location) should be based on future resource plans for adding capacity. He acknowledged that DEC and DEP had historically built multiple units at its generation sites, but he and TASC witness Hornby noted that the Companies' respective 2013 IRPs indicated a two-unit CT configuration for DEC in 2022 and a two-unit CT plant for DEP in 2027. (Tr. Vol. 7 at 166; Tr. Vol. 5 at 34) As such, witness Hinton opined that neither utility planned to build a four-unit CT in the reasonable future from which such economies of scope and scale could be realized. He concluded that the evidence supported a lower level of savings and the higher costs associated with a two-unit CT. In support of his conclusion, he cited the affidavit of NERA economist Nieto, which had been originally filed in the EPCOR arbitration in 2010. (Tr. Vol. 7 at 165-67) The cited portion of the 2010 affidavit provided that, after reviewing the evidence

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provided on future CT additions and expected system load growth over the utility's resource plan time horizons, affiant Nieto did not see a justification for the assumed number of units and the associated CT capacity addition that PEC [now DEP] had used in its avoided cost computation. (Tr. Vol. 7 at 166) Affiant Nieto did submit testimony in this proceeding, however.

On cross-examination, Public Staff witness Hinton agreed that DEC had not incorporated "economies of scale" in their cost analysis or cost projection in past avoided cost filings. He acknowledged, however, that DEC and DEP had both assumed four-unit sites in their avoided cost filings prior to 2012. He indicated that "Progress"[3] had taken advantage of incorporating economies of scale that ultimately led to lower avoided cost rates. Moreover, he noted that the Companies had merged, and that they have learned best practices from each other's business practices. (Tr. Vol. 7 at 198-99)

In his supplemental testimony, witness Snider disagreed with the use of a one-unit CT site calculating avoided capacity rates. Witness Snider countered witness Beach's proposal to use a one-unit site by noting that a single-unit site would most likely be placed at a brownfield site to achieve existing economies of scale, resulting in a cost per kW that would be similar to, or even lower than, the four-unit greenfield estimate. (Tr. Vol. 1 at 242) Witness Snider also testified in response to a question on cross-examination from NCSEA's counsel that the result of assuming that a one-unit site will be built without any shared infrastructure would be inconsistent with the Companies' past and future plans and would result in higher costs. (Tr. Vol. 2 at 20)

Witness Snider also rebutted the proposal to use a two-unit site. Witness Snider agreed that Public Staff witness Hinton had based his recommendation on information in

[3] Progress Energy Carolinas, Inc. is now DEP.

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the Companies' IRPs, but witness Snider explained that the incremental CT units in the Companies' IRPs are likely to be sited at brownfield sites that already have existing generation and shared infrastructure. Thus, witness Snider concluded, the fact that the IRPs show that DEC and DEP may add two CTs does not mean that the new units will be constructed on a two-unit site. To the contrary, testified witness Snider, "past experience shows that the Companies will almost certainly place the new units on a site large enough to accommodate multiple CTs, or even CCs and CTs on a single site." (Tr. Vol. 1 at 282) As examples, witness Snider cited DEP's Smith and Lee sites that host nine and eight CTs respectively, with some in simple cycle mode and some in CC configuration. (*Id.*)

On cross-examination by the Public Staff, witness Snider explained that the economies of scale he referred to were larger than the economies of scope, which he characterized as minor. (Tr. Vol. 3 at 73) He explained that shared infrastructure constitute the vast majority of the economies of scale. (*Id.*) He agreed that there were limits to building facilities as economically and efficiently as possible, in that putting 20 CTs at a site would be difficult. Witness Snider noted, however, that the utilities have traditionally added generation at existing sites, but not all at the same time. According to witness Snider, it was recognized in the original development of the site that there would be further development. (Tr. Vol. 3 at 74) In response to a question from Commissioner Brown-Bland, witness Snider elaborated whether DEC's and DEP's proposal included economies of scale and economies of scope. He indicated it included both. Witness Snider also testified that DEC and DEP may realize economies of scope, however, not related to a particular site because the six jurisdictions may also need CTs at a similar time. (Tr. Vol. 2 at 78-79) As an example, witness Snider explained that the Company

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may buy two units for DEP and, at the same time, have a need for CTs in Florida. Therefore, DEP may get economies of scope from the turbine provider, even if the turbines are not all located at the same site. (T. Vol. 4 at 67) Excluding those economies of scope may result in upward pressure on the costs without recognizing those further economies. (*Id*.)

In the EPCOR arbitration, Progress Energy Carolinas, Inc. (now DEP) had submitted a list of existing CTs, which showed an average of 4.2 CTs per site. (Public Staff Snider Cross Ex. 1; Tr. Vol. 3 at 80) Witness Snider agreed on cross-examination that the list was supportive of DEPs recommendation to use a four-unit site in that proceeding, but he also noted that information in addition to that reflected on the list supported DEP's recommendation in the EPCOR arbitration. As an example, witness Snider noted that the list only credits the Asheville site as a two-unit site. He disclosed that those two units, however, are co-located with two coal units, resulting in economies of scale in the sharing of staff, land, and switchyard. In addition, he noted the reason for a small one CT site was the need for small CTs for nuclear back standing or off-site emergency procedures. Those CTs are not the types of turbines that are being discussed in an avoided cost proceeding. (Tr. Vol. 3 at 80-81)

Also on cross-examination, witness Snider also discussed the number of single CTs that DEC and DEP were planning to build at their various sites with the amount of capacity that typically gets built at a site. First, he agreed that, according to the Commission's June 30, 2014 order approving the utilities' 2013 IRPs, DEP's annual MW growth rate was 171 MW. (Public Staff Snider Cross Ex.. 1; Tr. Vol. 3 at 89-90) He further agreed that the current CT technology has a 220 MW winter rating and that four

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of them built at a single site would be in excess of 840 MW. He generally agreed that 840 MW would equal DEP's annual load growth for four and a half years, but noted that was true if building for just retail load growth. He then explained that many of DEP's and DEC's recent additions have come from retirements and that the Companies do not build for just retail load growth, so wholesale load growth would also have to be considered. (Tr. Vol. 3 at 90) He also testified that numerous DEC and DEP sites had more than 800 MW. (Tr. Vol. 4 at 66)

Also in response to cross-examination by counsel for the Public Staff, witness Snider agreed that DEP's IRP showed an addition of 126 MW of CT resources in 2018, but he explained that 126 MW was a placeholder for fast-start CTs in the Asheville region and are not the F-frame type CTs in the context of this proceeding. (Tr. Vol. 3 at 91) Next, witness Snider indicated that, although DEP's IRP shows only two CTs being built in 2027, it also showed additions of 843 MW from combined cycles with a Herzog[4] on the back. Witness Snider stated that the addition of 843 MW at a single site was the same size, approximately, as four F-frame turbines. (T. Vol. 3 at 92-93)

Witness Snider also testified about testimony submitted in Docket No. E-100, Sub 136, by Theodore Pintcke, Vice President and Senior Project Development Director of Black & Veatch, on cost savings from building multiple sites. Witness Snider agreed that Mr. Pintcke had indicated that approximately 60 percent of the cost of a CT construction project is mainly the CT and the generator step up, and approximately 40% is the balance of plant ("BOP") costs. Witness Snider agreed that Mr. Pintcke's testimony had indicated that the BOP costs constituted approximately 40% of the total EPC cost and

[4] Although the transcript states Herzog, DEC and DEP respectfully submit that it stands for heat recovery steam generator.

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that reasonable cost savings for a four-unit site can be 25% or more of the BOP costs. In response to a cross-examination question by counsel for Public Staff, witness Snider then agreed that assuming a 25% cost savings as Mr. Pintcke did, building on multiple sites can save 25% of the 40% BOP costs. (Tr. Vol. 3 at 98-99)

In response to a question from Commissioner Bailey, witness Snider noted that over the previous couple of years, the prices on high-efficiency CTs remained flat, which translates to a dollar decrease. In the past, when the economy was booming, the costs of copper, aluminum, metals, and labor were up dramatically. With the recession, those costs significantly decreased, while the machines were getting more efficient and larger. Witness Snider concluded that on a dollar-per-kW basis over the past ten years, the Companies were seeing larger economies of scale. (Tr. Vol. 3 at 162)

The Commission finds and concludes that the record in this proceeding supports DEC's and DEP's including economies of scale and scope for a four-unit CT site in their calculation of avoided capacity cost rates. The evidence of DEC's and DEP's past construction and operational experiences on this issue is compelling. As witness Snider testified, siting multiple CTs at a single site is the most cost-effective approach to developing CTs because it optimizes economies of scale associated with multi-unit sites. Spreading the cost of land, site preparation, roadways, and infrastructure lowers the cost of CTs and, for that reason, DEC and DEP have historically built CTs at sites with four or more units. The evidence in the record bears this out, because it showed that all of DEP's CT sites have four or more CTs, except the Asheville site. Moreover, three of DEC's four CT sites have four or more units; DEC's fourth CT site is a two-unit site that is used as a back-up source of generation for nuclear site. Finally, the evidence showed that

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DEC and DEP planned to continue to build CTs at sites where they could realize economies of scale. Therefore, the Commission agrees with DEC's and DEP's recommendations on this issue.

The Commission is not persuaded by the arguments of NCSEA, TASC, or the Public Staff on this issue. Adoption of witness Hinton's, witness Hornby's and witness Beach's proposals on this issue will increase costs that are ultimately borne by their customers. In addition, contrary to their assertions, economies of scale are not dependent upon building all of the CTs at the same time. The Companies' past practices show that they instead intend to maximize economies of scale and of scope. Although the Companies may initially project to build a two-unit CT, the evidence shows that they develop sites to accommodate additional units in order to maximize economies of scale. As witness Snider indicated, past experience shows that DEC and DEP will place the new units on a site large enough to accommodate multiple CTs, or even CCs and CTs on a single site. Despite this practice, DEC and DEP recommended that a greenfield, rather than a brownfield, be used to calculate the economies of scale, even though the evidence supports DEC and DEP proposing the lower-cost brownfield. This adjustment may result in DEC's and DEP's four-unit economies of scale calculations being somewhat more conservative than they could be. Furthermore, the record indicated that DEC and DEP can achieve economies of scope by having affiliates that may be able to use equipment that DEC and DEP purchase but cannot use at one particular site at that time. Therefore, based on the foregoing, the Commission approves the Companies' proposal to continue to calculate the economies of scale using the average cost of a four-unit CT site as reasonable, balanced, and supported by the record as a whole.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is found in the testimony and exhibits of DEC/DEP witness Snider, NCSEA witness Beach, and Public Staff witnesses Brown and Hinton.

DEC/DEP witness Snider recommended that the calculation of avoided capacity costs include interconnection costs, but exclude T&D network system upgrade costs. In his direct testimony, he contrasted interconnection costs, which include the costs of physically connecting the generation source to the transmission system, with network upgrades, which involve improvements to the transmission system. Witness Snider testified that interconnection costs are included in the calculation of avoided cost rates because they are real costs that will be avoided when avoiding the construction of a new CT. He further noted that a QF is fully responsible for the interconnection costs associated with its own facility. (Tr. Vol. 1 at 186-87)

Network upgrades, on the other hand, involve improvements to the transmission system beyond connecting a generation resource to the transmission system, noted witness Snider. Such upgrades are needed to accommodate an anticipated increase in power flows as growing load is met from sources such as new generating facilities or new power purchases. Witness Snider acknowledged that a utility's construction of a new generation facility will sometimes require transmission upgrades, but he cautioned that not all generation additions require such upgrades. He listed a number of factors that would require the addition of upgrades downstream, which include the current state of the transmission system, the amount and type of generation being added to the system, and the location of new generation. (Tr. Vol. 1 at 187) In addition, witness Snider described

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some network upgrades as minor, such as a bank of capacitors, and some as major, such as construction of a new transmission line. Utilities will try to plan their generation additions to avoid or minimize the need for network upgrades. (*Id.*)

He noted that placing intermittent generation on a circuit does not change the need for transmission infrastructure at the time of the circuit's peak since the transmission infrastructure needs to bring in power from elsewhere on the system at times when generation is not available. As load grows on a circuit, intermittent generation does not alleviate the need for incremental transmission investment, and as such, should not be credited with avoided transmission system upgrade costs. (Tr. Vol. 1 at 187-88, 243-44)

Public Staff witness Hinton testified that T&D rates as applied to the cost-effectiveness tests would be appropriate to use for avoided cost calculation purposes if the demand reductions from solar generation were found to warrant avoided costs treatment. (Tr. Vol. 7 at 188) Witness Snider agreed that if QFs had the identical impact on the transmission system as energy efficiency ("EE") programs did, that the transmission benefits of EE would need to be consistent with the transmission benefits of QFs. But witness Snider did not agree that this is the case, noting that an EE program permanently reduces peak demand through the installation of more energy efficiency devices, whereas an intermittent solar QF resource is not guaranteed to be available at the time of the circuit's peak. Thus the utility does not avoid investment in the circuit. (Tr. Vol. 1 at 278-79)

Public Staff witness Brown supported witness Snider's position, noting that transmission capacity benefits should be based on the avoidance of future transmission system costs. He stated that this is less favorable for utility-scale solar when compared to

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traditional generation because the PV facility cannot be dispatched to modify transmission line power flows. Witness Brown also states that it is unclear whether transmission-connected PV facilities, in general, provide more or less transmission capacity benefit than utility-owned generation. (Tr. Vol. 7 at 349-50)

On cross-examination by NCSEA's counsel, witness Snider indicated that transmission system upgrade costs were included in the CT cost that was calculated for the generation reserve margin studies conducted by DEC and DEP for the 2012 IRP proceeding. (Tr. Vol. 2 at 21)

NCSEA proposed transmission upgrade costs should be included in the utilities' avoided capacity cost calculations. NCSEA witness Beach testified that a utility is likely to incur costs to construct transmission upgrades when CT capacity is installed, particularly when hundreds of MW are installed. (Tr. Vol. 5 at 152)

The Public Staff also supported inclusion of the costs of avoided transmission upgrades in calculating avoided capacity costs. Witness Hinton acknowledged, however, that some CTs require transmission upgrades and some do not. He recalled that the Richmond plant had required "a lot" of system upgrades. (Tr. Vol. 7 at 199) He noted that DEP had not previously included transmission system upgrades in their avoided cost filings, but DEC had done so. Consequently, the Public Staff believed they should be included. (Tr. Vol. 7 at 200) He also noted that transmission upgrade costs were included in the cost of new entry studies in RTOs that he had reviewed over the years. (Tr. Vol. 7 at 199-200) Witness Hinton acknowledged, however, that the issue was "fuzzy." (Tr. Vol. 7 at 200)

Based on the record before it, the Commission concludes that it is reasonable and

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appropriate that the utilities continue to include interconnection costs in their calculations of avoided capacity cost rates. However, the Commission also concludes that the record in this proceeding does support including network T&D upgrades as part of the cost of a CT. In reaching this conclusion, the Commission relies upon PURPA. A foundational premise of PURPA is that a utility cannot be required to pay a QF more than its actual avoided cost, and, therefore, costs that are not actually avoided should not be considered in establishing a utility's avoided cost rates. The FERC has spoken to this issue as well, observing that, for purposes of determining avoided cost rates, transmission costs can be included in avoided cost only if there are "actual determinations of expected cost of the upgrades to the . . . transmission system that that the QF will permit the purchasing utility to avoid." *Cal. Pub. Utils. Comm'n*., 133 FERC ¶ 61,059 (2010), *Order Denying Rehearing*, 134 FERC ¶ 61,044 (2011).

With regard to the costs of physically interconnecting the generation source to the transmission system, both DEC and DEP propose to include them in their avoided cost calculations because they are actual, demonstrable costs. With respect to T&D upgrades resulting from the installation of a CT, however, the evidence at best tended to show that they may only be occasionally necessary. As Public Staff witness Hinton stated, sometimes the addition of a CT requires upgrades to the transmission system; sometimes it does not. If they are required, sometimes the upgrades may be major; sometimes they may be minor. Thus, the necessity for, and cost of, T&D upgrades being avoided as a result of purchasing power from a QF has not been shown to be measurable or certain. Speculative, unquantified costs are not an appropriate element of a utility's avoided costs.

The Commission also finds that the difference in the cost recovery for the

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interconnection costs and downstream T&D upgrades supports its decision on this issue. When DEC and DEP add a generation facility from a QF, the QF is fully responsible for interconnection costs associated with its own facility, which prevents the utility's customers from ultimately bearing those costs. Therefore, interconnection costs are truly avoided by the utility, and, ultimately, its customers, by virtue of the utility's purchasing power from the QF. As noted by witness Snider, however, the cost of the network system upgrade that is needed to accommodate generation, whether QF or not, is paid by the utility, and, ultimately, its customers. Therefore, even if required, the cost for network upgrades is not avoided by the utility and its customers. The Commission does not believe it is appropriate for the utilities to include unspecified, uncertain costs that are ultimately borne by customers in calculating avoided capacity costs. Accordingly, the Commission approves the recommendation by DEC and DEP to include interconnection costs but to exclude costs relating to T&D network upgrades in their avoided capacity cost calculations.

With respect to the fact that DEC and DEP included transmission network upgrades in the CT cost that was calculated for the generation reserve margin studies in the 2012 IRP proceeding, the Commission notes, as it has before in this Order, that the strictures that apply to the development of avoided cost rates are not applicable to a utility's planning process. A utility may take a conservative approach in its planning process and assume some level of system upgrades may be necessitated by the installation of a CT. Such a practice, however, does not convert speculative assumptions regarding possible transmission upgrades in a reserve margin study to definitive costs that will be ultimately borne by customers.

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The Commission further acknowledges that DEC may have previously included estimates of avoided network transmission upgrade costs in its avoided capacity cost calculations. Nevertheless, the Commission does not believe that this past practice mandates that DEC and DEP include costs in future filings.

Based on the foregoing, the Commission concludes that DEC and DEP shall include direct CT interconnection costs in the calculation of the annual fixed CT capacity costs, but any estimates of T&D system upgrade costs shall be excluded.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the testimony of DEC/DEP witness Snider and testimony offered on cross-examination by Public Staff witness Hinton.

Witness Snider first defined contingency adders as the specific provision for unforeseeable elements of costs within a defined project scope, which is particularly important where previous experience has shown that the unforeseeable events which will increase costs are likely to occur. The Companies proposed to use a 5% contingency adder because it represents an "expected case scenario" in the context of building a conventional CT for avoided cost purposes (Tr. Vol. 1 at 188) To show that 5% represented an expected case scenario, witness Snider recounted DEC's and DEP's experiences with constructing CTs. He testified that DEP has completed four projects involving plants with CT technology – the Wayne County CT, the Smith CC, the Lee CC and the Sutton CC. The original project estimate for those projects included contingency adders of 3-5%. All of these projects were completed below the budgeted levels, inclusive of the stated contingency. Witness Snider further testified that only the Wayne

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County CT required using any of its contingency, while the rest of the projects came in below budget, resulting in negative contingency. (Tr. Vol. 1 at 189)

Witness Snider next testified that DEC's experiences were consistent with DEP's. According to witness Snider, the initial project estimates for DEC's Buck CC and Dan River new CC contained 4% contingency adders. Both came in under budget, using none of the contingency included in the original cost estimate. Based on those experiences, witness Snider argued that no contingency adder was necessary for simple cycle CTs because they are less complex than the recent construction of CCs and because previous projects the Companies built used essentially zero contingency. (Tr. Vol. 1 at 189; Tr. Vol. 2 at 61-62) Witness Snider instead supported the use of a 5% contingency adder, however, as consistent with DEC and DEP seeking a balanced approach to calculating avoided capacity cost rates. (Tr. Vol. 1 at 189-90)

Counsel for NCSEA cross-examined witness Snider about his position on contingency by asking about the contingency adder proposed by Mr. Pintcke on behalf of DEC and DEP in Docket No. E-100, Sub 136. Witness Snider agreed that Mr. Pintcke had used a 10% contingency, but he explained, however, that Mr. Pintcke was asked to provide a general contingency estimate that was not related to a North Carolina project. (Tr. Vol. 2 at 24) On redirect, witness Snider testified that he had responded to NCSEA counsel's question about contingency on the BOP estimate while thinking that she was asking about contingency applied to the entire plant, not simply BOP cost. (Tr. Vol. 3 at 114) Witness Snider then clarified that BOP was 40% of the entire plant and that Mr. Pintcke's recommended contingency adder for the entire plant was 4-8% as shown on page 10 of his testimony. (NCSEA Snider Cross Ex. 1, Tr. Vol. 3 at 115)

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In response to questions from counsel for NC WARN and from Commissioner Brown-Bland, witness Snider noted that once a contingency is determined in the avoided cost proceeding context, it becomes a real cost, as if the contingency has actually happened. As a result, customers will be charged for it. (Tr. Vol. 2 at 62; Tr. Vol. 4 at 47)

Although the Public Staff neither opposed DEC's and DEP's proposed contingency adder amount nor presented its own alternative recommendation in pre-filed testimony, witness Hinton testified in response to cross-examination by NCSEA counsel that the Public Staff believed a higher contingency would be a better reflection of an expected cost. He noted that there had been a nine percent contingency factor when DEC built Buck and Dan River. Witness Hinton acknowledged, however, that it was "an area of debate" whether it would be 5% or 10% (Tr. Vol. 7 at 201) He also testified that he had looked at PJM studies and other studies, as well as IRPs in the TVA to form his opinion on contingency. (Tr. Vol. 7 at 201-02)

Based on the record in this proceeding, the Commission agrees with DEC and DEP that a 5% contingency adder is reasonable. In so concluding, the Commission notes that no party contested DEC's or DEP's past experiences with contingency adders discussed by witness Snider. Although witness Hinton did not pre-file testimony on this issue, he recalled on cross-examination that DEC's Buck and Dan River project had a 9% contingency factor. He later clarified on cross-examination, however, that Buck and Dan River were CCs that were more complex than simple CTs to build. (Tr. Vol. 7 at 270) Furthermore, he did not contest in either pre-filed testimony or otherwise, that both the Buck and Dan River CCs were completed under budget and used none of the contingency

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in the original cost estimate. Moreover, while evidence about contingency factors used in other jurisdictions by other utilities may be somewhat relevant to this discussion, the Commission believes that the most compelling evidence to consider in determining an appropriate contingency adder is the utility's most recent operational experiences in building CTs. In this case, DEC's and DEP's operational experiences in building CTs, which are less complex to construct than CCs, clearly support a contingency adder for DEC and DEP of 5%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is found in the testimony of DEC/DEP witness Snider.

DEC and DEP recommended a 35-year book life for use in calculating avoided capacity cost. Witness Snider testified that 35 years is a reasonable assumption for the useful life, noting that the vast majority of the CTs on the Companies' systems have operated or are expected to operate for 35 years or more. Moreover, witness Snider testified that the Companies' combined experience with building and operating dozens of CTs for more than four decades demonstrates that CTs have useful life expectancies of more than 35 years. Thus, witness Snider concluded, the Companies' actual experience could support a longer useful CT life than 35 years. (Tr. Vol. 1 at 192)

In addition, witness Snider referred to the useful life assumptions applied in the Companies' most recent general rate cases in each of the Companies' independently completed updated depreciation studies that support their proposed depreciation rates. He noted that DEP's most recent depreciation study uses a 40-year useful life for its CTs. DEC's most recent depreciation study considered the lifespan of a new CT to be 35-40

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years with an emphasis on 35 years based on utilization. (Tr. Vol. 1 at 190-93)

Based on the record in this proceeding, the Commission concludes that 35 years is a reasonable assumption for the useful life of a CT. Avoided capacity rates should reflect the capital costs that the purchasing utility actually avoids if it purchases power from a QF rather than generating the power itself. PURPA directs that rates paid by customers should not exceed the purchasing utility's avoided cost. Thus, the Commission agrees that the best reference points to use for determining the useful life of a CT in setting avoided cost rates are: (1) the actual operating lives of the utility's CT fleet; and (2) the CT useful life assumptions used in setting the utility's base rates. The actual operating lives of a utility's CTs are relevant in assessing the capacity cost assumed to be avoided by purchasing from a QF, and the useful life assumptions used for ratemaking measures the avoided costs from the customers' perspective. In this case, the evidence showed that the CTs on DEC's and DEP's system had operated or were expected to operate for 35 years or more. No party presented evidence contesting this. In addition, the Companies' most recent depreciation studies use a 40-year useful life for DEP and a 35-40 year useful life for DEC. Thus, the Commission finds that in terms of how long a CT should be expected to operate and in terms of the costs customers bear for a CT in rate base, the Companies have justified the use of a 35- to 40-year useful life. Accordingly, the Commission is persuaded that the use of a 35-year useful life for CT is a reasonable assumption.

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

The evidence supporting these findings of fact are found in the testimony of DEC/DEP witnesses Bowman and Snider, EDF witness Munns, NCSEA witnesses Maier

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and Beach, NC Hydro Group witness Givens, NC Warn witness LaPlaca, SACE witness Rabago, and Public Staff witnesses Kirsch and Ellis.

DEC/DEP's Position

Both DEC and DEP proposed to reduce the PAF "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 methodology." (Tr. Vol. 1 at 84) For this reason, DEC/DEP witnesses Bowman and Snider proposed a PAF of 1.05 for new contracts with non-hydro QFs. With respect to small hydro QFs, however, witness Bowman initially proposed to "grandfather" the 2.0 for existing small hydro facilities. (Tr. Vol. 1 at 86)

In their direct testimonies, witnesses Bowman and Snider both explained that the PAF was a multiplier applied to the avoided capacity rates paid to QFs. Application of the PAF increases the avoided capacity rate paid by customers and received by the QF. (Tr. Vol. 1 at 31, 199) Witness Bowman testified the PAF was established to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of avoided capacity payments. (Tr. Vol. 1 at 84)

In her supplemental testimony, witness Bowman took issue with recommendations to increase the PAF for non-hydro QFs to a 2.0. She testified that a PAF of 2.0 would allow a QF with a 1 MW capacity that can only operate during 50% of the on-peak hours to be compensated as if it is delivering 1 MW of capacity value. She concluded that such a result overpays for the capacity that the QF is actually delivering and allowing the purchasing utility to avoid. (Tr. Vol. 1 at 121-22)

In his direct testimony, DEC/DEP witness Snider explained that, although multiple perspectives have been offered as a rationale of the 1.2 PAF, the PAF should

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reflect the value of the capacity that is actually being avoided. (Tr. Vol. 1 at 201; *see also*, T. Vol. 3 at 110-111) At the current 1.2 PAF, QFs are receiving an avoided capacity payment that is not consistent with the CT or the wholesale generators to which they are being compared. (Tr. Vol. 1 at 258; Tr. Vol. 3 at 111) Witness Snider explained that an appropriate consideration as a basis for a PAF is the starting reliability of the avoided CT. He noted that data compiled for the years 2011 through 2013 showed the Companies' large frame CTs had a successful start rate of approximately 99%. He also testified that DEC and DEP generally allow a third party generator to receive its full contractual capacity payment so long as they maintain a minimum availability level, which is usually in the range of 94% to 98%. This level of reliability would equate to a PAF of 1.02 to 1.06. Based on the projected reliability of new CTs, and viewing the QF capacity purchase similarly to traditional wholesale power purchases, witness Snider testified that a range of 1.02 to 1.06 PAF was justified. Based on that range, DEC and DEP recommended a PAF of 1.05. (Tr. Vol. 1 at 200-02)

Witnesses Bowman and Snider both testified that inclusion of societal benefits in a PAF conflicts with PURPA and with the NCREPS cost caps put in place by the North Carolina General Assembly. Both further noted that these cost caps were designed to limit customer expenses that are above the utilities' avoided costs. Witness Bowman testified that increasing the PAF to 2.0 for non-hydro QFs would be inconsistent with both the General Assembly's intent in passing Senate Bill 3 and with PURPA. With respect to Senate Bill 3, she acknowledged that it is designed to encourage renewable generation by establishing a REPS for the state's utilities, but noted that it contained limits to costs incurred in pursuing that policy. Witness Bowman observed that the

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provisions of Senate Bill 3 that limit the costs incurred by the utilities, and ultimately recovered from their customers, focus specifically on costs incurred in excess of avoided costs. Given that Senate Bill 3 restricted the costs that customers would incur based on the utility's avoided cost rates, witness Bowman concluded that it would be inconsistent with the intent of Senate Bill 3 to increase the avoided capacity rates paid to solar and wind QFs by 67%, which would be the result if the PAF for non-hydro QFs was increased from 1.2 to 2.0. (Tr. Vol. 1 at 122-23) Recalling her previous testimony in Docket No. E-100, Sub 136, witness Bowman stated that such an increase in the PAF could cost customers an incremental $150 million for every 1,000 MW of new solar capacity over the life of 15-year PPAs. Although she had not updated that analysis for this docket, witness Bowman testified that she believed that this earlier estimate may be conservative because it was based on the Companies' then proposed avoided cost rates, which were lower than the ones the Commission ultimately approved. (Tr. Vol. 1 at 123)

Witness Snider likewise pointed to NCREPS to dispute the inclusion of benefits outside of directly avoidable utility costs in a PAF. In addressing the claim that the PAF should be increased to reflect benefits of solar QFs in his rebuttal testimony, witness Snider referred to his supplemental testimony. There, he demonstrated that the inclusion of externalities in the avoided cost calculation would essentially circumvent the legislative intent of the cap on REC payments by artificially including these externalities as part of the utilities' avoided costs. (Tr. Vol. 1 at 228, 249) Treatment of items such as economic benefits as an avoided utility cost artificially reduces the cost of the renewable energy certificate ("REC"), according to witness Snider's analysis. Thus, he concluded that "the more one includes as a utility avoided cost, the less can be characterized as an

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incremental cost, thereby effectively nullifying the explicit statutory cost limitations relating to REPS compliance." (Tr. Vol. 1 at 228)

With respect to PURPA, witnesses Bowman and Snider testified that it also provided no basis for increasing the PAF to 2.0. They explained that the factors relied upon by NC WARN witness LaPlaca and EDF witness Munns were not appropriately considered in establishing avoided costs because they were not related to QFs' actual ability to allow a utility to avoid costs on behalf of its customers. A PAF should not be inflated to 2.0 to act as a proxy for the benefits of solar QFs or DEC's and DEP's compliance with environmental regulations. (Tr. Vol. 1 at 125-26, 233)

Witness Snider also rebutted NCSEA witness Beach's contention that a PAF is required as an adjustment to account for a CT cost levelization that, according to Mr. Beach, should be conducted only over the first 10-15 year period of a CT's life as contrasted to the current practice of levelization over the CT's entire 35 year useful life. Witness Snider corrected witness Beach's example that assumed that the QF avoids the first 15 years of a CT's revenue requirements by point out that a 15 year contract simply defers the CT's investment. To that end, witness Snider used a value of deferral analysis framework. He states that this form of value of deferral economic analysis is commonly used in capital planning decisions within the industry. He also demonstrates how witness Beach's recommendation would result in overpayment by customers relative to the capacity value that QFs provide. (Tr. Vol. 1 at 253-56)

Witnesses Bowman and Snider also both disputed the suggestion that a 1.2 or 2.0 PAF is necessary to place the QFs "on par" with utilities to avoid "discrimination" in terms of capital cost recovery. They both explained that a QF's regulated rates and a

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QF's right to avoided cost rates are intended to be distinct and different. (Tr. Vol. 1 at 124, 250) In so doing, they contrasted a regulated utility recovering its investment in a generating facility with a QF under a PURPA cost recovery framework. (Tr. Vol. 1 at , 123-125, 250) To illustrate this contrast, witness Bowman noted that if a public utility installs a solar facility it earns nothing on the capital it has invested in that plant unless and until the utility has a rate case and the Commission determines that the capital was prudently incurred and should be included in rate base. In contrast, a solar facility is guaranteed compensation though avoided cost rates upon commencing commercial operation. Next, witness Bowman noted that a public utility only earns a Commission-established return on the capital invested in its solar facility. The utility receives no "energy" payments from customers because it incurs no fuel costs and very little operating expenses. Solar QFs, however, receive avoided cost payments tied to the utility's costs, not the cost the QF developer spent to build the QF. Her testimony continued to elaborate that solar QFs receive both avoided energy and avoided capacity payments, which contribute in large part to solar QFs' recovery of and return on its capital investment because a solar QF has no fuel costs to defray.

Witness Bowman also contrasted the treatment of incentives or subsidies by a utility constructing a solar facility and a solar QF. If a utility receives incentives or subsidies for constructing a solar facility, the benefits ultimately flow to the customers because they lower the utility's revenue requirement. If a solar QF receives incentives or subsidies, they flow the developer's bottom line.

Witness Bowman also pointed out that a utility's recovery of the capital it invests in utility plant is based on the rate of return established by the Commission. Solar QFs

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are not subject to such regulation and do not have to make their financial results public. (Tr. Vol. 1 at 124-25)

To further illustrate the differences in the cost recovery methods between a utility and a QF, witness Snider offered a hypothetical example that compared the cost recovery of a utility building a solar facility with the cost recovery of a QF building a solar facility. He provided that the utility's total avoided capacity and energy cost is $60/MWh, comprised of a $20/MWh avoided capacity cost and a $40/MWh avoided energy cost. For the example, witness Snider assumed that the utility and a solar QF had the same cost to build a solar facility and that such cost equated to $50/MWh, including a return on investment. Witness Snider also assumed that the operating costs were zero because the solar facility has no fuel expense. Thus, the total avoided cost value of $60/MWh would exceed the required return for both the QF and the utility. Under the peaker method of cost recovery, the QF would receive both the $20/MWh capacity rate and the $40/MWh energy rate to compensate it for its capital investment, resulting in an incremental return on investment for the QF of $10/MWh. The utility, however, would only be allowed to recover its costs of $50/MWh in a capital investment because the value of the capital investment would be prudent from a customer's perspective. (Tr. Vol. 1 at 251-53)

Witness Snider also disputed the Public Staff's justifications for a 1.2 PAF. A PAF of 1.2 effectively means that a QF must only be available 83% of the peak hours to receive payments equivalent to 100% of a utility's full avoided capacity costs. Witness Snider provided three reasons why he disagreed with the Public Staff's position that a QF that is available 83% of the peak hours should be entitled to full avoided capacity costs. First, DEC and DEP proposed capacity payment hours already allow solar facilities to be

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unavailable the vast majority of hours in a year without a capacity payment penalty. Witness Snider offered an example. He described a November morning when the utilities might have multiple units offline for routine maintenance or nuclear refueling. Should a cold front cause retail load to approach the amount of available generation, the avoided CT would have capacity value on that November morning while solar generation would not. Because the system capacity need is outside the defined capacity hours, however, the solar provider would not be penalized for not being available. (Tr. Vol.1 at 257-58) Second, witness Snider specifically stated that if a merchant provider delivered only 83% of the time it was called upon to do so, it would not receive a full capacity payment, but would instead likely incur a penalty. (Tr. Vol. 1 at 258) Third, witness Snider testified that he was unaware of any other jurisdiction that uses a PAF or equivalent. (Tr. Vol. 1 at 258-59; Tr. Vol. 3 at 112)

Witness Snider next testified that he found witness Ellis's reliance on average capacity factors for baseload plants to justify a 1.2 PAF to be flawed. (Tr. Vol. 1 at 259) He noted that if the Companies' units were only available 83% of the peak hours, the Companies would not have a reliable system. (Tr. Vol. 3 at 111; Tr. Vol. 4 at 54-55) Witness Snider explained that witness Ellis's comparison was not an "apples to apples" comparison because he failed to compare solar facilities' annual average capacity factors of approximately 20% with the 75% capacity factor he cites for the utilities' baseload units. (Tr. Vol. 1 at 25; Tr. Vol. 4 at 114) Annual capacity factors and on-peak availability are "two entirely different metrics." (Tr. Vol. 1 at 259-60) As witness Snider explained, capacity factor is the amount of energy produced during a certain time period, divided by the total energy that could have been produced if the resource had operated at

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full load during the entire time period. Witness Snider compared that with availability, which considers what percent of the period hours the unit was either running or simply available to run. (Tr. Vol. 1 at 260) To illustrate, witness Snider noted that peaking units, such as a CT, typically operate at capacity factors of less than 10%, because it is only economic to dispatch peaking units during periods of peak demand. In contrast, however, witness Snider explained that with a starting reliability of over 95%, they are almost always available during peak periods. He further explained that baseload plants have high capacity factors because it is economic to dispatch such resources to meet baseload energy needs. In low load hours, even baseload coal plants or natural gas CCs may be off-line, but still available. In contrast, solar resources are either producing or not producing; therefore, their capacity factor essentially equals their availability. Witness Snider concluded that a CT's capacity value stems from its on-peak availability, not its annual capacity factor. (Tr. Vol. 1 at 260-61)

In response to a question from Commissioner Brown-Bland, witness Snider elaborated on why a 1.05 PAF is appropriately based on an availability level of a CT at 95%. He noted that the 95% availability level did not compare with capacity factor, because a capacity factor is not what determines capacity value. Witness Snider explained that the value of capacity is determined by the availability factor, because capacity value comes in the ability to be called up and dispatched when needed. (Tr. Vol. 4 at 53) For intermittent resources, the capacity factor is the same as the availability factor because a solar provider is unable to produce when it is offline. (Tr. Vol. 4 at 53) He noted that the Public Staff incorrectly used annual capacity factors to propose a PAF, instead of availability factors. Witness Snider observed that if his fleet had an 83%

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availability factor during peak periods, DEC and DEP would be unable to hold a 14.5% reserve margin. Witness Snider then concluded that the 95% availability factor was more appropriate to use than the Public Staff's 83% capacity factor because the 95% reflects the unit being avoided. It is based on the availability of the turbines and not the capacity factor; thus, he concluded it was more appropriate than the 83% capacity factor as a basis for the PAF. (Tr. Vol. 4 at 53-56)

In the summary of her rebuttal testimony, witness Bowman reported that DEC, DEP and NC Hydro Group had previously filed a Stipulation in this docket. In support of the Stipulation, she noted that the stipulating parties agreed that N.C. Gen Stat. § 62-156 codifies the State's policy to promote and support small hydro QFs and that there is a small and relatively finite amount of small hydro capacity in the State. Furthermore, the stipulating parties did not believe this amount would increase greatly in the near future. (Tr. Vol. 3 at 120) The stipulating parties agreed, therefore, to use the currently approved 2.0 PAF for small hydro of 5MW or less until expiration of the Stipulation on December 31, 2020. (Tr. Vol. 1 at 166-67)

In response to questions from Commissioner Brown-Bland about whether the 2.0 PAF for hydro resulted in costs in excess of avoided costs, witness Bowman explained that the limited and finite amount of hydro resources led her to believe it would not be an issue for ratepayers. She acknowledged that N.C. Gen. Stat. § 62-156 did not specifically authorize exceeding avoided costs and that PURPA provides that avoided cost shall not be exceeded. Nevertheless, witness Bowman stated that North Carolina General Statutes, previous Commission precedent, and the limited and finite amount of hydro resources justified retaining the 2.0 PAF for hydro. (Tr. Vol. 4 at 41-43)

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On cross-examination, witness Bowman repeatedly acknowledged that in previous biennial proceedings, the Commission had approved the use of a 1.2 PAF. She witness Snider also agreed that DEC had requested a PAF of about 1.05 in the past, based on similar arguments. (Tr. Vol. 1 at 405-06) Ms. Bowman also acknowledged that the Commission has previously concluded that the 2.0 PAF for hydro facilities did not change a utility's avoided costs, but instead changed the manner in which those avoided costs were paid to the QF. Nevertheless, witnesses Bowman and Snider observed that the Commission's Scheduling Order establishing this proceeding indicated that it was prepared to revisit its previous decisions on the PAF. (Tr. Vol. 1 at 405-08)

On redirect, witness Bowman agreed that there was a specific statute that relates directly to payments for avoided cost for hydro facilities. Witness Bowman described this statute as being the context of the implementation of avoided cost. She acknowledged that swine, solar and poultry resources are specifically promoted through a state statute, but noted distinguished that statute as being outside the avoided cost context and pertaining to RECs requirements. She further noted that swine resources are typically developed by relying on the price of the REC as a total cost. (T. Vol. 3 at 120-21)

<u>EDF's Position</u>

Witness Munns recounted the 2006 avoided cost case with respect to the origination of the 2.0 PAF for run-of-the-river hydro and the 1.2 PA for wind and solar resources. She opined that the 2.0 PAF puts the hydro facilities on equal footing with run-of-the-river hydro as reflected in the utilities' rate bases. She further noted that utilities recover their "full capacity costs," regardless of stream flows. Witness Munns

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then recounted that the Commission had stated although the utilities did not have wind or solar in their rate bases, the resources would be treated like run-of-the-river hydro and be "given a PAF in excess of one for avoided cost purposes." (Tr. Vol. 1 at 24)

Witness Munns recommended that, until the Commission develops a more comprehensive methodology, it should continue to use a 1.2 PAF, which is consistent, she stated, with an 83% capacity factor. (Tr. Vol. 1 at 27)

NCSEA's Position

NCSEA opposed the Companies' proposal for the Commission to approve a 1.05 PAF for non-hydro QFs. Its witnesses espoused several reasons why the Commission should maintain the 1.2 PAF.

In her rebuttal testimony, witness Maier testified that she opposed reducing swine waste-fueled qualified QFs from 1.2 to 1.05. In a footnote to her pre-filed testimony, she likened the policy supporting hydro facilities, codified in N.C. Gen. Stat. § 62-153, with those promoting solar and animal waste in N.C. Gen. Stat. §62-138(d), (e), and (f). Witness Maier testified that the PAF of 1.05 for swine-waste projects will lower their revenue and make them less viable. (Tr. Vol. 2 at 167-68)

In his response testimony, NCSEA witness Beach opposed reducing the PAF to a 1.05 in order to put the QF on par with a CT with respect to availability. Witness Beach opined that was inconsistent with the "full purpose" for the PAF. (Tr. Vol. 5 at 223) He instead justified the PAF as a reasonable means to adjust the way QF capacity payments are made to account for the levelization of QF capacity payments compared to the utility's front-loaded rate base recovery of the avoided peaker's cost, for the fact that QFs only receive 15-20 year contracts, compared to the avoided capacity rates which are

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levelized over 30 years to match utility cost recovery and the pay for performance structure of QF rates where the QF assumes all the risks for development, construction, and operations, thereby reducing risk to customers. (Tr. Vol. 5 at 223)

Witness Beach took issue with witness Snider's characterization of the PAF as a multiplier and noted that the PAF was "a tradition of long standing" in North Carolina. (Tr. Vol. 5 at 185) The PAF accounts for the fact that a QF, like any generating facility, cannot be in operation at all times; thus use of the PAF allows a QF to have a reasonable number of outages and still receive total payments equal to the utility's avoided costs. Witness Beach also noted that the Commission had previously concluded that "fairness" required that the QF be given a reasonable opportunity to recover the costs it avoids when it displaces a utility plant, which can recover its costs through rate base, independent of resource availability. (Tr. Vol. 5 at 187)

Witness Beach opined that the PAF should be based on the utility's cost recovery for a peaker. He explained that a utility places the capacity-related costs of a peaker into its rate base and recovers the costs through a revenue requirement, which allows it to earn an authorized return on that rate base. The rate base depreciates gradually over the 35-year life of the unit so the utility recovers more in the early years and less over time. Witness Beach noted that, in contrast, the QF is paid a rate that reflects the avoided capacity cost on a levelized basis in an equal amount each year. According to witness Beach, the issue is that the QF only as a contract for 15 years. The levelized QF capacity payments in a 20year QF contract understate the avoided capacity costs by 18% over 20 years. This justifies, in Mr. Beach's opinion, a PAF in the range of 1.18 to 1.29. Mr. Beach concluded that this would not be an issue if QFs had contracts for 35 years, which

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allowed them to recover costs over the same period that the utility can recover costs. (Tr. Vol. 5 at 187-89)

Witness Beach further stated that the purpose of a PAF is to provide the QF with the opportunity to earn a capacity credit equal to the cost which it allows the utility to avoid. Witness Beach noted that the utility places the capacity-related costs of a new peaker into its rate case and recovers the costs through its revenue requirement. This allows it to earn an authorized return on that rate base. The rate base for the peaker depreciates gradually over the 35-year life of unit, so the utility's recovery of the peaker's costs is highest in early years and then decreases over time. (Tr. Vol. 5 at 188)

NC Hydro Group's Position

Witness Givens described the small hydro industry in North Carolina and in the NC Hydro Group. According to witness Givens, there are 32 small hydro plants operating in North Carolina at this time, varying in size from 168 kW to over 5,000 kW in capacity. This amounts to approximately 36 MW. Witness Givens also disclosed that there are at least 5 other plants that are being developed or considered for redevelopment, and this may add 5.5 MW of capacity. (Tr. Vol. 4 at 29) Other than the restoration of older facilities, the only new hydro generation in the State in recent decades has been the addition of generation on existing dams, such as Corps of Engineer projects. (*Id.*)

NC Hydro Group proposed that the 2.0 PAF for small hydro should continue in the calculation of the 2014 avoided cost rates. He acknowledged that the PAF was an "awkward methodology" for calculating capacity value, but he nonetheless indicated that maintaining the 2.0 was required to equate with the Companies' recovery of their full capacity costs for their small hydro and large, run-of-river plants. (Tr. Vol. 4 at 33)

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Witness Givens noted that, based on the financial difficulties that hydro plants have faced with rates that have been unstable and too low, a PAF at a level significantly higher than 2.0 may be appropriate. (*Id*.)

In his rebuttal testimony, he proposed that a PAF that reflects the reliability and availability of the utility plants, as discussed by DEC and DEP, should be included. He proposed amending the calculation of the capacity credit all together. (Tr. Vol. 4 at 35-37)

NC WARN's Position

NC WARN recommended through the testimony of witness LaPlaca that the Commission revise the PAF for solar from 1.2 to at least 2.0 because of the high value of solar during peak summer hours, and because solar displaces purchased and hedged fuel for 25 years, reduces water use, reduces pollution, and reduces waste treatment and storage. (Tr. Vol. 5 at 283-85) In response to questions from Commissioner Brown-Bland, witness LaPlaca noted that she was not an engineer but testified that she considered the unaccounted for benefits of solar as justification for a 2.0 PAF. (Tr. Vol. 5 at 320)

SACE's Position

SACE opposes the utilities' proposal to revise the PAF from 1.2 to 1.05 for non-hydro facilities. Witness Rabago testified that the PAF was designed to correct for improper discrimination in rates for QF facilities as compared to utility-owned assets. (Tr. Vol. 6 at 170) In his rebuttal testimony, witness Rabago testified that a PAF performs "several important functions at this time" and should not be eliminated. (Tr. Vol. 6 at 182-83) In response to a question from Commissioner Brown-Bland, witness Rabago

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opined that the justification for the PAF in the first place was to create fairness between different kinds of resources and ownership structures. He stated that the Commission was not overpaying with a 1.2 PAF. He proposed a loss-of-load probability driven, effective load-carrying capability kind of analysis instead of just assigning a "PAF-type" number, but he did acknowledge that the Commission may want to "grandfather" those PAFs in. He concluded, however, that getting the methodology right is better than trying figure out what the right PAF should be. (Tr. Vol. 6 at 66)

<u>Public Staff's Position</u>

The Public Staff opposed DEC's and DEP's recommendation on the PAF and recommended that the Commission maintain the 1.2 PAF. Witness Kirsch described the PAF as mechanism by which small QF that are eligible for the standard rates are paid a rate that is some multiple of the utility's approved avoided capacity costs averaged over on-peak hours. (Tr. Vol. 7 at 110) Witness Kirsch further testified that the purpose of the PAF was to allow QFs being paid under the standard rates the opportunity of being paid the utility's full avoided capacity costs. He explained that a PAF of 1.2 allows a QF to receive 100% of avoided capacity costs if it operates in 83% of the on-peak hours. (Tr. Vol. 7 at 111) Witness Ellis testified about past Commission precedent in support of retention of the previously approved 1.2 PAF. (Tr. Vol. 7 at 125-26)

Witness Ellis conceded that the Public Staff recognized that a utility has an obligation to serve that a QF does not have and that PURPA requires the utilities to purchase energy, and, in most circumstances, capacity from QFs. Nevertheless, witness Ellis stated that both suffer consequences for non-performance. He acknowledged that the utilities' proposal had "some merit" but stated that the Commission's prior approvals

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of the previous PAFs and the availability of Option B type rates meet the requirements and intent of PURPA. (Tr. Vol. 7 at 124-25)

Witness Ellis further indicated that the proposed 1.05 PAF was not justified. He reiterated the Commission's previous conclusions that a 1.2 PAF reflects its judgment that, if a QF is available 83% of the "relevant time," it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. In witness Ellis's opinion, performance at that level is commensurate with a baseload plant. Witness Ellis cited the capacity factors reported by the utilities in their monthly baseload power plant performance filings, averaged over the last three calendar years. He stated that none of the utilities operated their baseload fleet at an 83% capacity factor, while recovering all of their capacity costs through rates. For the calendar years 2011, 2012, and 2013, the baseload plants in the rate bases of DEC and DEP averaged capacity factors of 75.67% and 74.52%, respectively. (Tr. Vol. 7 at 125-26)

He also agreed that if the Commission used the average baseload 75% capacity factors that he cited to set a PAF, it would result in a PAF of 1.33. Witness Ellis indicated that a PAF that high might risk overpayments, but it would be "worth exploring" for some technologies. (Tr. Vol. 7 at 307)

The Public Staff supported continuation of the 2.0 PAF for hydro. (Tr. Vol. 7 at 148) In response to questions by Commissioner Brown-Bland, witness Ellis testified that he did not believe the continuation of the PAF of 2.0 for hydro would result in payments in excess of avoided costs. (Tr. Vol. 7 at 307)

The Public Staff did not support, however, increasing the PAF to 2.0 for solar as the best way to recognize the potential benefits that solar and other intermittent resources

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may provide to ratepayers. Instead the Public Staff believed that the Option B approach is appropriate because it recognizes the energy and capacity contributions that intermittent resources provide and the costs and benefits of integrating those resources.

Discussion and Conclusions

The Commission has traditionally used a PAF in calculating avoided capacity cost rates for utilizes using the peaker methodology. The PAF recognizes that a generating facility cannot be in operation at all times; therefore, it increases the capacity rates, allowing a QF to experience a reasonable number of outages and still receive payments equal to the utility's capital costs. If the utility's avoided capacity rates were set only at the utility's avoided costs without a PAF, a QF would not receive full capacity payments unless it operated 100% of the on-peak hours throughout the year.

Until the 1996 avoided cost proceeding in Docket No. E-100, Sub 79, the Commission approved a PAF of 1.2 for the calculation of avoided cost rates for all QFs. In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued June 19, 1997 ("Sub 79 Order") approving avoided cost rates in that docket, the Commission approved a PAF of 2.0 for hydro QFs with no storage capability and no other type of generation, which was intended to allow such QFs to recover their full capacity payments if they operate 50% of the on-peak hours. The 1.2 PAF established by the Commission in previous cases for QFs other than run-of-the-river hydro reflected the Commission's judgment that if a unit is available and operates 83% of the time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Although the Commission has traditionally applied a PAF of 2.0 for hydro and

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1.2 for non-hydro, it has nonetheless directed that additional review of the amount of or the rationale behind, establishing the PAF may be warranted in light of changing circumstances. As discussed with respect to Finding of Fact Nos.2-3, the QF landscape has changed drastically since 1996, and solar QFs in particular continue to experience rapid development. In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued February 22, in Docket No. E-100, Sub 136, ("Sub 136 Order") the Commission stated:

> The Commission recognizes that applying the rationale provided in previous Commission Orders for setting a PAF of 2.0 for run-of-the-river hydro facilities with no storage capability could result in a PAF of 2.0 for other QFs with intermittent fuel sources. However, the Commission also recognizes that these rationales may need to be revisited.

Additionally, in its Scheduling Order, the Commission specifically noted that the purpose of an evidentiary hearing in this matter was, among other things, to receive testimony on whether a 2.0 PAF for run-of-river hydro facilities with no storage capability should be continued.

In revisiting the rationale behind the PAF, the Commission is guided by PURPA's underlying principle that the rates paid to QFs shall not exceed the incremental cost of self-generated power or purchased power that the purchasing utility would not incur but for the purchase of power from a QF. See 19 C.F.R. 292.101(b)(6). In other words, the rates paid to a QF cannot exceed the purchasing utility's avoided cost. Applying a PAF for the purpose of providing capacity payments to a QF in excess of the capacity value that it provides or to ensure the QF's profitability would not be consistent with the underlying principles of PURPA.

As witness Snider noted, the parties have asserted multiple rationales for the PAF,

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including that it is intended to put the QF on par with the utility in terms of cost recovery, or that it is intended to act as a proxy for societal benefits resulting from solar power. Therefore, at the outset of its discussion of this issue, the Commission clarifies the purpose of the PAF. The PAF is intended to allow QFs to operate less than 100% of the on-peak hours to receive the full capacity payments to which they are entitled. The PAF is not intended to ensure full capacity payments to QFs that are not reasonably available during on-peak hours or to make up for operational deficiencies of certain types of generation. A QF is not entitled to full capacity payments (i.e., payments equal to the purchasing utility's avoided capacity costs) regardless of how it operates. Rather, a QF is entitled to full capacity payments if it operates with reasonable reliability and availability during the on-peak hours.

PAF for non-hydro facilities

Consistent with its previous decisions on this issue, the Commission continues to find that it would be unreasonable to hold QFs to a standard that requires 100% availability during peak hours to receive payments equivalent to the purchasing utility's full avoided cost. All generating utilities, including the avoided CT, experience some outages. Therefore, the Commission believes that it is reasonable to apply a PAF to ensure that a QF operating with an equivalent availability of an avoided CT receives the full capacity value of the CT.

Viewed against that backdrop and based on a careful review of all of the arguments presented on this issue, the Commission concludes that the PAF should reflect the capacity value of the avoided unit, which means that the PAF should be established based on the reliability of the CT. The Commission agrees with the testimony of witness

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Snider that the appropriate measure of the CT's capacity value to the utility is its starting reliability. The record in this proceeding indicates that DEC's and DEP's CT fleet is available at least 95% of the on-peak hours. As explained by witness Snider, a 95% availability translates to a 1.05 PAF. The Commission's conclusion is supported by testimony that DEC and DEP structure their purchase power contracts with third party generators to receive their full contractual capacity so long as they maintain a minimum availability level, ranging from 94% to 98%. This minimum availability level and the starting reliability of a CT both support DEC's and DEP's proposed PAF of 1.05.

Opponents of DEC's and DEP's proposed PAF of 1.05 and proponents of an increase in the PAF to 2.0 for solar and wind QFs generally raise four arguments in support of their positions. First, they argue that VOS studies suggest additional benefits outside of directly paying avoidable utility costs justify the increased PAF. Second, they make comparisons to a utility's cost recovery mechanism or the utility's ability to recover capital as a basis for the PAF to put the QF on "equal footing" to the utility. Third, as asserted by witness Beach, the PAF offsets underestimation of avoided costs attributable to the levelized nature of QF contracts. Fourth, if the avoided CT has an on-peak reliability of less than 100%, the PAF is required to allow the QF to receive an equivalent CT avoided capacity payment. The Commission will address each of these arguments in turn.

With respect to using the PAF to capture societal benefits resulting from VOS studies, the Commission notes that this is outside the purpose of the PAF. Moreover, the Commission agrees with the testimonies of witnesses Snider and Bowman that inclusion of these costs in the PAF may thwart the intent of Senate Bill 3 by reducing the true cost

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of a REC, as explained by witness Snider. Moreover, no party actually presented discernable, quantifiable costs that would be included in calculating the PAF. A central principle of PURPA is that avoided costs should include only the energy and capacity costs that a utility actually avoids when it purchases from a QF. As the Commission has previously discussed in this order, including speculative costs that may or may not arise in the future violates this principle and imposes additional costs on customers in excess of the utility's actual avoided costs. In addition, maintaining the PAF at 1.2 or increasing it to 2.0 as a method to capture "avoided costs" relating to potential future carbon regulations or uncertain or unquantified external benefits of solar or other QF facilities would likely make calculation of the PAF more complex and less transparent.

The Commission also does not find that a PAF of 2.0 should be applied to swine waste as proposed by NCSEA. The General Assembly codified a state policy toward encouraging small hydro in N.C. Gen. Stat. § 62-156, that pertains to calculations of avoided cost. The statutory REPS "set-asides" cited by witness Maier, on the other hand, for solar, swine, and poultry resources, pertain to RECs, which are incremental to avoided costs. In other words, the General Assembly has already established a process for encouraging those "set-aside" resources. With that process in place, the evidence in the record does not provide the justification to now increase the rates paid to swine waste providers by 67%.

The Commission is also unpersuaded by arguments that a 1.2 or 2.0 PAF is necessary or appropriate for putting the QFs on par with public utilities in terms of capital cost recovery. The Commission recognizes that vast differences exist between cost recovery for utilities and the PURPA avoided cost framework. For example, a utility

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may be entitled to recover from its customers its prudently incurred cost of building and operating a solar facility, but such recovery will be limited to the utility's actual costs. Consequently, a utility may recover its cost to construct a facility, but will receive little in terms of "energy" costs (i.e., fuel and variable O&M costs) because solar facilities incur virtually no energy costs for the utility to recover. Conversely, a solar QF receives capacity and energy payments from the purchasing utility, and the energy payments comprise the bulk of payment that the QF receives. Moreover, these payments are based on the purchasing utility's costs, regardless of the costs that the QF incurs to install and operate its facility. Finally, and significantly, a QF is not constrained in terms of earning a Commission-approved reasonable rate of return on its investment or the recovery of expenses it actually incurs. The Commission concludes that nothing in PURPA dictates that the Commission must apply a PAF to avoid discrimination on account of these differences. Certainly, no other jurisdiction has so found. A PAF is not intended to provide a false equivalency between the cost recovery for a utility and a QF.

The Commission is further not persuaded by the arguments of witness Beach that levelized capacity payments for a 15-year contract understate the utility's avoided capacity cost thereby necessitating the PAF. Applying the principle of value of deferral economic analysis, witness Beach should have made his comparison by assuming that that the QF contract deferred the investment in the CT for 15 years. Instead, he incorrectly assumed that the 15-year QF contract fully avoids the first 15 years of revenue requirements associated with the CT. It does not. As noted by witness Snider, the 15-year QF contract instead defers this investment for 15 years. Therefore, the Commission finds that adoption of witness Beach's rationale would overcompensate QFs.

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The Commission also does not agree with the Public Staff's position that a QF that is available 83% of peak hours is operating in a reasonable manner and should be allowed to recover the utility's full avoided costs through a 1.2 PAF. The PAF is intended to recognize that all generation is subject to periods of unavailability and to allow QFs the opportunity to earn full avoided capacity credit even if it experiences such periods of unavailability during on-peak hours. Stated another way, the PAF should allow a 5 MW QF to earn 5 MW of avoided capacity payments even if the QF experiences outages of the type and duration common to generating resources. Therefore, as witness Ellis observed, the PAF should allow a QF that operates in a "reasonable manner" to earn full avoided capacity credit notwithstanding such outages.

For several reasons, however, the Commission finds that 83% availability during peak periods does not represent a level of operations and reliability that justifies 100% capacity credit for a QF. First, generation availability of only 83% during system peak periods does not constitute a reasonable level of reliability. For example, if a utility's generating fleet was only 83% available during system peaks, it would not have sufficient resources to meet its peak load, even if it carried 20% reserves (120% x 83% = 99.6%7). It is not reasonable to conclude that availability levels that are unacceptable for a utility's generation should be deemed sufficient to guarantee 100% capacity credit for a QF.

Second, witness Ellis attempts to justify his conclusion that 83% on-peak availability for a QF warrants 100% avoided capacity credit by noting that DEC's and DEP's base load generation has an annual capacity factor of 75%. That justification is neither apt nor persuasive. Witness Ellis's position contains two critical errors. The first error is that it uses the capacity factor of the utilities' generation, not the availability

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factor. The true measure of the capacity value provided by dispatchable resources, such as the utilities' baseload plants, is their availability. If a dispatchable resource is able to operate, but is not dispatched for economic reasons, the resource is still providing capacity value by virtue of its availability. Capacity factor, on the other hand, only defines what percentage of hours a resource actually operates, witness Ellis, therefore, has understated the capacity value of the capacity value that the utilities' resources provide by looking only at capacity factor. The second error in witness Ellis' argument is that he relies on annual capacity factors as the basis for his conclusion as to what constitutes a reasonable level of on-peak availability**.** Because it is a year-round measure, annual capacity factor incorporates numerous circumstances that are inapplicable to an assessment of the adequacy of on-peak availability, including planned outages during shoulder months and periods when units are not dispatched at night during minimum load periods. The combination of these errors renders the 75% figure relied upon by witness Ellis wholly irrelevant to the question of what level of QF performance is required during peak periods to justify 100% avoided capacity credit.

Third, as witness Snider notes, that the average availability of DEC's and DEP's CT generation is 98.5%. Applying that level of on-peak availability to the present issue results in a PAF of approximately 1.015% (98.5% x 1.015 = 100%). In previous avoided rate proceedings, the Commission has declined to base the PAF on the availability of an average CT. *See e.g., Order Establishing Standard Rates and Contract terms for Qualifying Facilities,* at 21, Docket No. E-100, Sub 100 (Sept. 29, 2005) (holding that availability of a CT is not determinative for purposes of calculating the PAF) ("2005 Avoided Cost Order"). In those cases, the arguments presented were based on the peaker

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methodology's use of CT capacity to calculate avoided capacity costs. 2005 Avoided Cost Order at 18-19. The Commission, however, found that the peaker method did not assume that a CT is always avoided by purchasing power from a QF, but rather that CT capacity was used as the nearest approximation to pure capacity costs. 2005 Avoided Cost Order at 22. The Commission, therefore, concluded that it was not necessary that the PAF be set at a level that required QFs to operate as reliably as CTs. *Id.* As we noted in the Scheduling Order, however,, "it may no longer be appropriate to continue building upon the previously established PAF framework to determine avoided capacity rates given the new emerging QF landscape." Scheduling Order at 1, *citing* Sub 136 Order at 31.

Moreover, in this proceeding, the Commission is not requiring that QFs maintain a level of availability equivalent to the utility's CT fleet. Nevertheless, the Commission finds that the average availability of the utility's CT fleet provides meaningful guidance as to the level of availability QFs should be expected to provide in order to receive 100% because it is indicative of the level of reliability that the utilities expect to realize from their own generation.

Based upon the evidence in this proceeding, the Commission concludes that the 83% on-peak availability underlying a PAF of 1.2 is not a sufficient level of reliability to warrant a QF receiving 100% capacity credit. Accordingly, the Commission finds that continuing use of a 1.2 PAF for non-hydro QFs will no longer be required.

Conversely, the 1.05 PAF proposed by DEC and DEP is reasonable. With a PAF of 1.05, a QF will only have to achieve 95% availability during peak hours in order to obtain 100% avoided capacity credit. That is a level of availability that is less than the

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utilities' CT exhibit on a year-round basis. Furthermore, as witness Snider noted, DEC and DEP normally require third party's to achieve 94% to 98% reliability in order to receive 100% of their capacity payments when the utilities enter into power purchase agreements. Thus, 95% availability for QFs is in the lower end of the range of reliability that the utilities expect from other power providers. Based on the foregoing, the Commission concludes that DEC's and DEP's proposal to apply a 1.05 PAF to the capacity rates for non-hydro QFs should be approved.

PAF for Hydro QFs

Based on the evidence presented at the evidentiary hearing and the Stipulation entered into by DEC, DEP, and NC Hydro Group, the Commission concludes that the 2.0 PAF should continue as provided for the Stipulation.

As discussed earlier, the Commission has long recognized the State's policy of encouraging hydro facilities in N.C. Gen, Stat. §62-156. *See e.g., Order*, at 12, Docket No. E-100, Sub 41A (Jan. 22, 1985) (discussing that many of the risks associated with standard long-term levelized rate options are either not presented or tend to be minimized in the case of hydro facilities). This policy has provided justification for the Commission to previously approve a 2.0 PAF for run-of-the-river hydro facilities Nevertheless, the Commission must balance this policy with the risks to consumers from DEC and DEP paying more for power from a small hydro than is appropriate. The Commission finds that the Stipulation strikes an appropriate balance of the State's policy in encouraging hydro with the risk of overpayment for hydro power by DEC's and DEP's customers. As the uncontested evidence showed, there is a relatively small amount of hydro resources in this State, and these resources are essentially finite. The Stipulation reflects that NC

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Hydro Group, DEC and DEP do not predict a large amount of hydro being developed in the future. Based on the foregoing, the Commission concludes that a 2.0 PAF for hydro, as outlined in the Stipulation, is reasonable, appropriate, and in the public interest. DEC and DEP shall continue as approved in previous avoided cost dockets to apply a 2.0 PAF to their calculation of avoided capacity rates for run-of-the-river hydro QFs otherwise eligible for DEP's Schedule CSP and DEC's Schedule PP(H).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the testimony of DEC/DEP witness Snider, NCSEA witness Beach, TASC witness Hornsby, and Public Staff witness Ellis.

The Companies recommended that capacity credits be paid over a distinct set of seasonal on-peak hours that represent the hours when capacity is most likely to have the highest value to customers during peak conditions. Witness Snider testified in his supplemental testimony that the Companies had completed a review of the historic load trends, and that review indicated that the utilities' peak load conditions occur between 2 pm and 7 pm (Hour Ending (HE) 15 through HE 19) in June, July, and August and between 6 am and 9 am (HE 7 through HE 9) in December, January, and February. According to witness Snider, these are the most influential in resource addition decisions from an IRP perspective as they represent the hours that are within 5% of the load in the highest peak load hour in summer and that of winter. (Tr. Vol. 1 at 235-36) These pre-defined hours identify when the utility is most likely to be resource constrained; therefore, witness Snider described these hours as the hours when capacity is most likely to have the highest value to customers during system peak conditions. (Tr. Vol. 1 at 239-

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40) He also noted that the pre-determined hours he recommended will incent development of solar projects to maximize output when capacity has the most value to the utility's ratepayers. (Tr. Vol. 1 at 237)

Witness Snider summarized his recommendation that the Commission allow DEC and DEP to adopt on-peak capacity hours of 2 pm to 7 pm during weekdays in June through August and 6 am to 9 am during weekdays in December, January, and February. With respect to on-peak energy hours, witness Snider believed that the current Option B hours of 1 pm to 9 pm during weekdays in June through September and 6 am to 1 pm during weekday in October through May remain appropriate. Both sets of hours should exclude the current holidays designated in DEC's and DEP's tariffs, witness Snider recommended. (Tr. Vol. 1 at 240) In his rebuttal testimony, witness Snider compared and contrasted witness Beach's proposed summer peak hours. Witness Snider stated that NCSEA's proposal to shift the current Option B hours is intended to define peak hours to maximize solar QF revenues, rather than aligning them with peak hours where the avoided energy value of the solar QFs is actually created. (Tr. Vol. 1 at 268) Witness Beach's hours largely overlapped with current on-peak hours, except that witness Beach proposed to exchange the 7 pm and 8 pm hours for the 11 am and 12 am hours for DEC's Option B on-peak definition; for DEP, witness Beach proposed to exchange the 8 pm hour for the noon hour. Witness Snider demonstrated that the average load during the hours witness Beach proposed eliminating from the peak definitions are actually higher than the average loads in the hours he proposes adding to the peak hour definitions. (Tr. Vol. 1 at 268)

On cross-examination by NCSEA's counsel, witness Snider agreed that DEC and

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DEP seek to reduce the number of peak hours per capacity payment from approximately 1800 hours to 500 hours. He acknowledged that witness Beach had not proposed to change the number of Option B hours, but he noted that witness Beach had proposed to shift hours to better align with solar output instead of the utilities' avoided cost. This shift results in more capacity payments being paid to solar providers, according to witness Snider. (Tr. Vol. 1 at 418-19)

In response to a question from Commissioner Brown-Bland about the inclusion of winter hours in his Option B, witness Snider indicated that the Option B hours that DEC and DEP proposed contained about five hours in the summer and three in the winter, so it was 5/8s weighted to summer and 3/8s weighted to winter. Peaking resources have capacity value to meet both summer and winter peaks. Witness Snider explained that without winter in the definition, then any QF that helps with meeting winter peak would be paid zero. Witness Snider further explained that although DEC and DEP based their determination of need for capacity on their summer peak, the capacity added to meet the summer peak also has capacity value in the winter. He observed that solar output is not available in the winter when needed, but he stated that there is a need for winter capacity to meet winter peaks that a CT provides. (Tr. Vol. 4 at 69-72)

In his rebuttal testimony, TASC witness Hornby opposed DEC's and DEP's proposal with respect to the Option B hours. He opined that witness Snider's proposal was contrary to PURPA in that it appeared to discriminate against QFs relative to DEC and DEP. He also characterized it as not just and reasonable and apparently contrary to the public interest. With respect to his claim of discrimination, witness Hornby first noted that witness Snider proposed 514 capacity on-peak hours per year, but proposed to

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retain the current definition of on-peak hours for energy credits. Witness Hornby concluded that Mr. Snider's proposal was discriminatory because DEC and DEP could recover their capacity costs by applying demand charges in on-peak periods that range by rate schedule from 1,564 hours per year to 1,864 hours per year. (Tr. Vol. 5 at 58-62)

Witness Hornby next testified why he believed that DEC's and DEP's proposal was not just and reasonable. He claimed that it did not provide QFs a financial incentive to maximize their generation during all of the hours in which that generation has the most value to the Companies' customers. Witness Hornby noted that DEC and DEP had recently worked with the Public Staff to identify hours in which capacity and energy have the most value to residential customers. They identified 1,524 on-peak hours per year and those hours are for on-peak periods of 12 to 6 pm on weekdays from June through September, and 7 am to 1 pm on weekdays from October through May. (T. Vol. 5 at 62-53)

Witness Hornby also testified that Mr. Snider's proposal did not appear to be in the public interest because it could discourage development of solar generation QFs in North Carolina by reducing the annual amount of capacity credits those QFs can earn. He noted that witness Snider had not produced any data to support his assertions about the impact of his proposal on QFs or whether it would incent QFs to develop solar projects to maximize output. (Tr. Vol. 5 at 63-64)

NCSEA witness Beach testified that in the 2012 biennial proceeding, the Commission had approved an Option B approach to payment for capacity credits, which is intended to allow a QF to earn payments for avoided capacity costs over a shorter number of hours that are aligned with the utility's peak. He cited the Public Staff's

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opinion at the time that Option B allowed solar QFs to configure their systems to maximize generation during critical on-peak hours. Witness Beach generally discussed two methodologies for assigning accredited capacity to renewable energy facilities using wind or solar resources. The first was the Effective Load Carrying Capacity ("ELCC") method, which witness Beach described as complex and expensive; the second was the Capacity Factor Approach. The ELCC method uses a production simulation model of the electric system in question to calculate the probability in each of the 8,760 hours of the year that electric resources will be inadequate to serve demand – the loss-of-load-probability. The Capacity Factor Approach sets the capacity value of a renewable resource based on its demonstrated capacity factor during certain critical hours of peak demand. (Tr. Vol. 5 at 170-72)

Witness Beach further testified that DEC's most recent IRP assumed a solar resource's capacity value is 50% of its nameplate. Dominion's most recent IRP, he continued, assigns a capacity value of 39% of nameplate to solar. PJM assigns capacity values of 46% of nameplate for a fixed array and 58% of nameplate for a single-axis tracking system.

Witness Beach concluded that Option B represented "a reasonable first step" to implementing the capacity factor method in North Carolina because it allows a solar QF to earn capacity credits on the capacity factor it can achieve from its output over the Option B period. (Tr. Vol. 5 at 172) Witness Beach proposed to adjust Option B in a manner that he claimed would provide benefits to the utility and ratepayers. He proposed shifting the existing summer Option B hours from 1 pm to 9 pm to 11 am to 7 pm for DEC and from 1 pm to 9 pm to noon to 8 pm for DEP. He illustrated this shift by

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showing the top 700 load hours for DEC and the top 1040 hours for DEP, respectively, by hour of the day during the summer season and for the years 2010-2012. He claimed for DEC that his proposed shift captures 69% of these peak hours, compared to 63% for existing Option B. He also claimed for DEP that his proposed shift captured 59% of the peak load hours, compared to 58% for existing Option B. Moreover, he noted that the summer peak periods he proposed are a reasonable compromise among the on-peak periods used in the non-residential rate designs of North Carolina utilities. (Tr. Vol. 5 at 172-73)

In his rebuttal testimony, witness Beach testified that because DEC and DEP were summer peaking utilities, modifying Option B to include an on-peak period in winter months that has equal weight as the summer peak period is unreasonable. Witness Beach's Tables 1 and 2, in his rebuttal testimony, showed the majority of load hours occurred during the months of June and September in years 2006-2012 for DEC and DEP. (Tr. Vol. 5 at 200-01) Witness Beach noted that although the utilities occasionally experience winter storms resulting in periods of high demand, peak demands are higher and more frequent in the hot weather conditions of summer. (Tr. Vol. 5 at 201) Witness Beach also testified that, when their loads are combined for review, the majority of hours with loads within 5% of system peak fell in the summer months. (Tr. Vol. 5 at 200-03) Witness Beach also produced a graph (Figure 1) that showed that the combined DEC and DEP loads on the 2012 summer peak day which were above 95% of the system peak fell between noon and 7 pm. For the 2012 winter peak, his graph (Figure 2) showed that no loads came within 5% of system peak. Based on his analysis, witness Beach concluded that continuing the Option B structure, which includes a peak period focused on the

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summer months of June to September was reasonable. (Tr. Vol. 5 at 201-03)

Witness Beach also noted that the on-peak periods should examine a range of possible periods and determine which one best captures when a utility expects to experience peak demands and should be used for both energy and capacity rates, consistently with on-peak periods used in utilities' retail rate schedules.

Witness Beach concluded that adopting the on-peak hours for Option B recommended by DEC and DEP would be unfair. He indicated that if capacity credits are allocated equally to all DEC/DEP proposed on-peak hours, it would result in 37% of the Companies' avoided capacity credits being attributed to winter demands when only 2% of the Companies' peak demands within 5% of the system peak actually occur in winter. According to witness Beach, this would discriminate against solar QFs whose output will be lower from 6 am to 9 am on winter mornings than during hot, sunny summer afternoons when load are closer to system peak. (Tr. Vol. 5 at 203-04)

Witness Beach also took issue with the analysis presented in witness Snider's testimony that looked at a single year to support his proposal. According to witness Beach, DEC and DEP did not examine other recent years, and they did not examine whether other periods might capture more top load hours. Witness Beach instead recommended that the Commission should adopt a peak period based on analysis that considers loads in multiple years and analyzes a number of possible on-peak hours. Witness Beach also noted that Public Staff witness Ellis had stated that witness Beach's proposal "appears to have merit and warrants further consideration." (Tr. Vol. 5 at 206)

Witness Beach presented another graph (Figure 3) that showed that NCSEA's proposed on-peak period captures 98% of the top 100 load hours that fall in the summer

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months from June to September, while the DEC and DEP proposal includes only 73% of such hours. (Tr. Vol. 5 at 204-05)

On cross-examination by counsel for DEC and DEP, witness Beach agreed with the utilities that the period chosen for the Option B hours should be the period that best represents their top load hours. Witness Beach indicated that NCSEA's recommended set of hours included almost all of the hours that were within 5% of peak and included more of them than the utilities proposed. (Tr. Vol. 5 at 256) In response to a question from Commissioner Bailey, he disagreed with DEC's and DEP's assessment that he proposed the shift in hours to best meet solar output. (Tr. Vol. 5 at 256-57)

Public Staff witness Ellis provided background on the currently approved Option B. He recounted that DEC initially proposed it in 2002 in Docket No. E-100, Sub 96 in order to align the on-peak and off-peak hours with the periods corresponding to the times where DEC's customer demand and cost of generation are highest. This resulted in a reduction of on-peak hours compared to before, but DEC stated that this new rate structure would benefit solar QFs because of how they operate. DEC retained its Option A hours as well. (Tr. Vol. 7 at 127-28)

Witness Ellis further testified that, in the 2004 biennial proceeding, DEC proposed to eliminate the Option A set of rates, but retain Option B, because Option B is more closely aligned with the highest hours of DEC's system peak and a higher per kWh rate when capacity is most needed. Option A's set of on-peak hours spreads capacity credits over 4,160 on-peak hours a year. Option B spreads those credits over 1,860 on-peak hours per year. This was intended to reduce the need for a higher PAF at that time, according to witness Ellis. (Tr. Vol. 128)

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Witness Ellis further indicated that this approach was consistent with FERC Order 69, which provided that:

> Some technologies such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based in part on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance for some capacity value and an energy component that reflect the avoided energy costs at the time of peak.

Because DEC and DEP are summer peaking systems, it is appropriate to consider the value of the power provided by generating systems that operate during the times of higher customer demand and to encourage production during periods of time when the cost of the utility-generated electricity is greater. (Tr. Vol. 7 at 128-30)

According to witness Ellis, solar QFs in North Carolina generate electricity during the hours of higher system peaks, and there is significant output from solar facilities with the summer hours during which the utilities experience their highest loads and at least partial alignment with the utilities' highest one-hour peak loads. For winter peaks, witness Ellis stated that solar output is greatly reduced and does not contribute toward meeting the highest peak demands. (Tr. Vol. 7 at 130-31)

Witness Ellis further testified that the output of a solar facility 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 peak load. If the solar QF may receive a higher capacity credit during the higher cost peak load hours, such as Option B hours, it could design its facility so that its output is a better match to the system's demand. Tracking systems and adjustments to the facility to maximize critical on-peak hours will

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accomplish this. (Tr. Vol. 7 at 131) Witness Ellis explained that ratepayers benefit from this because under traditional rates, avoided capacity costs are spread out over all the hours that are considered on-peak. Division of the avoided capacity by a large number of hours results in a lower kWh rate than would result if a smaller number were used. Thus, a solar facility will likely configure its system to maximize its output during all of the on-peak hours. Witness Ellis concluded that matching solar output to the utility's load justifies a rate structure that leads to this result.

Witness Ellis disagreed with witness Snider's proposed reduction in Option B hours because they treat QF generation as if it only has capacity value as a peaking resource. Witness Ellis testified that the Commission has previously recognized that QF capacity has value in hours other than the very narrow band of hours surrounding the winter and summer peaks. (Tr. Vol. 7 at 141) Like witness Beach, witness Ellis commented that witness Snider only included one year of data in his analysis of this issue. Subsequently on cross-examination by counsel for DEC and DEP, however, witness Ellis confirmed that his review of the data that DEC/DEP witness Snider used to support his proposed hours for capacity payments revealed that witness Snider had included years 2010-2013. (Tr. Vol. 7 at 249)

Witness Ellis also noted that although under witness Snider's proposal, QFs have to generate fewer hours to receive their full capacity payment, those fewer hours occur during six months, not the 12 months included in Option B and in far fewer hours per weekday for the six months proposed. Almost two-thirds of the 515 hours occur only in the three months of June, July, and August, ignoring that September is included in the definition of the utilities' time-of-use tariffs and that the utilities conduct significant

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maintenance in the summer months. Witness Ellis opined that this maintenance can result in the need for capacity in May and October. With respect to witness Snider's proposed months and hours, witness Ellis testified that they presented a risk that the QF will lose a significant portion of avoided capacity costs because of relatively limited unforced outages, despite their presence in numerous other hours and months with significant loads. (Tr. Vol. 7 at 142)

Witness Ellis undertook his own analysis of DEC's and DEP's peak load, which he described in his rebuttal testimony. His analysis was to identify the hours within 10% of the annual seasonal peaks over the period of 2008-2013. Witness Ellis testified that the results of his analysis, as shown on Ellis Exhibits 1 and 2, showed that there is a significant need for capacity during the summer between 12 pm and 9 pm, with the highest concentration of peaks from 1 pm to 8 pm. His analysis also showed a significant need for capacity during the current non-summer months, with the highest concentration of peaks between 6 am and 10 am, but an additional significant number existing between 1 pm and 9 pm. Witness Ellis concluded that his analysis showed that capacity was needed and had a significant value outside of the hours recommended by witness Snider. (Tr. Vol. 7 at 143-44) Witness Ellis then recommended that the Commission preserve Option B, particularly since it had not been in effect for very long. (Tr. Vol. 7 at 144-45)

On cross-examination by counsel for NCSEA, witness Ellis testified that he had completed his own analysis of DEC's and DEP's peak load, looking at seasonal peaks from 2006 to 2013. He agreed that he reviewed the same data as NCSEA witness Beach. Witness Ellis also testified that he agreed that witness Beach's recommended range of hours for Option B captures more peak load hours than witness Snider's. (Tr. Vol. 7 at

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Subsequently on cross-examination by counsel for DEC and DEP, witness Ellis testified that his analysis showed a significant need for capacity during the summer months between the hours of 12 pm and 9 pm. He further confirmed that his analysis showed the highest concentration of peaks were between the hours of 1 pm and 8 pm. (Tr. Vol. 7 at 250) Witness Ellis agreed that witness Beach proposed to change DEC's Option B hours to remove two hours, 7 pm and 8 pm, that fell within the range of hours that Public Staff's analysis had identified as showing a significant need for capacity. (*Id.*) Witness Ellis offered that this was why the Public Staff had not recommended changes in the currently approved Option B hours. (*Id.*)

Witness Ellis then agreed that witness Beach proposed to add two hours, 11 pm and 12 pm, to DEC's Option B to replace the ones he removed. Witness Ellis confirmed that those added hours fell outside of his range of hours for which he found the highest concentration of peaks. (Tr. Vol. 7 at 253)

With respect to DEP's Option B hours, witness Ellis agreed that witness Beach had swapped out the 8 pm hour that fell within the range of hours with significant capacity need, according to the Public Staff's own analysis. Witness Ellis also confirmed that witness Beach had then inserted the 12 pm hour into DEP's Option B hours. Witness Ellis agreed that the 12 pm hour fell outside the range of hours that witness Ellis had identified as showing the highest concentration of peaks. (Tr. Vol. 7 at 253-54)

Witness Ellis further testified that he recalled witness Beach testifying that within the Option B peak hours, the hours of 7 pm and 8 pm are hours during which solar facilities only produce a small or negligible amount of power. Witness Ellis also

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remembered witness Beach testifying that he recommended adding hours to on-peak Option B hours that occur when a solar facility can produce at approximately 80% capacity. (Tr. Vol. 7 at 255)

The Commission finds that there is a clear consensus among the parties that, for purposes of implementing avoided capacity rates, on-peak hours should be defined based on the periods during which a utility most needs capacity, which is during its highest load periods. Despite that agreement, there is considerable disparity among the parties as to how best to achieve that goal for DEC and DEP. The utilities propose to use a relatively focused definition comprising 515 hours. The Public Staff proposes that DEC and DEP should be required to maintain the on-peak hours currently defined in their Option A and Option B tariffs. NCSEA witness Beach argues that the definition of on-peak hours in Option B should be changed hours from 1 pm to 9 pm to 11 am to 7 pm for DEC and from 1 pm to 9 pm to noon to 8 pm for DEP.

As set forth elsewhere in this Order, the Commission has concluded that the goals of PURPA are best served if avoided cost rates are set based on a single definition for on-peak hours. The issue, therefore, is which of the proposed on-peak definitions for DEC's and DEP's avoided capacity best represents the period during which the utilities most need capacity.

Turning first to NCSEA witness Beach's proposal, the Commission finds that witness Beach's revised version of the Option B on-peak definition is not reasonable. Both DEC/DEP witness Snider and Public Staff witness Ellis found that witness Beach's proposal had removed hours during which DEC and DEP had significant capacity needs. In fact, it appears that that the utilities' load during the hours removed by witness Beach

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tends to be greater than the load during the hours that he proposed to add to the definition of on-peak hours. It is undisputed the adjustment proposed by witness Beach would greatly benefit the members of NCSEA, on whose behalf witness Beach testified in this proceeding. That is, the hours he proposed to remove from the definition of the peak periods are ones during which solar QFs are unlikely to operate and the hours he proposed to include are ones during which solar QFs are expected to operate significantly. The Commission cannot accept a definition of on-peak hours for avoided capacity purposes that is derived by excluding hours of significant capacity need for the utilities and replacing them with hours during which the utilities' need for capacity is less acute. With regard to the proposal put forward by DEC and DEP, the Commission finds that the utilities have provided a reasonable basis for their proposed definition of on-peak hours for avoided capacity purposes. There are a broad range of hours during which a QF may provide some capacity value. For example, unexpected generation outages or extraordinary, unseasonable weather can create a need for power even during the fall and spring shoulder months. However, the goal in this proceeding is to identify the periods during which utilities should be required to make avoided capacity payments to QFs. The critical component of that inquiry is ascertaining which load periods drive the utilities' resource expansion plans. By aligning the on-peak hours with the utility's planning needs, the on-peak definition will be focused on periods when QF output is most likely to allow the purchasing utility to avoid incremental capacity additions. This is precisely what witness Snider proposed. He testified that DEC's and DEP's proposed on-peak definition for avoided capacity purposes was developed by focusing on the summer and winter hours during which loads have been within 5% of the seasonal system

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peaks. He noted that these hours are the most influential for resource addition decisions from an IRP perspective. Further, contrary to witness Beach's assertions, it is clear that DEP and DEC analyzed four years of load data (2010-2013) in developing their proposal. The result is a definition of on-peak hours that captures the hours when the utilities most need capacity. This is demonstrated by the fact that the proposed definition captured 96% of the summer hours that were within 5% of DEC's summer peak and 92% of summer hours that were within 5% of DEP's summer peak for 2013. This is particularly important given that DEC and DEP both focus on their summer peak load for resource planning purposes.

Although DEC and DEP focus their resource plans on summer peak needs, witness Snider acknowledged that the utilities often experience very high load periods during the winter. He further explained that winter peaks tend to be more volatile and unpredictable than summer peak loads. Accordingly, witness Snider acknowledged that new resources provide capacity value during summer and the winter peak periods. DEC's and DEP's proposed definition of on-peak hours for avoided capacity recognizes that value by considering both the summer and winter peak periods. In this way DEC's and DEP's proposal captures the capacity value that QFs can provide in both periods and provides QFs with the opportunity to be paid for delivering such value during both seasons.

Some parties expressed concern that the more focused definition of on-peak hours proposed by DEC and DEP includes only 515 hours. The basis of their concern appears to be that this may make it more difficult for QFs to earn 100% of the capacity payments available to them. However, the question at hand is whether the proposed definition

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accurately describes the hours during which the utilities need capacity and, therefore, should be required to pay QFs for the capacity value they deliver. Whether a properly crafted definition of on-peak hours makes it easier or harder for a particular QF to obtain capacity payments is not germane to this issue. Furthermore, it is not clear that a more narrow definition of on-peak hours necessarily makes it more difficult for QFs to realize capacity payments. To the contrary, fewer on-peak hours means that a QF has to run fewer hours to obtain 100% capacity credit for its output. In addition, as part of this Order, the Commission has concluded that QFs should still continue to receive the benefit of a PAF to be applied to the avoided capacity rates paid to QFs. This provides QFs the opportunity to earn 100% capacity credit even if they cannot operate during all on-peak hours.

In summary, the Commission finds that DEC's and DEP's proposed definition of on-peak hours for avoided capacity purposes reasonably assesses the utilities capacity needs and provides QFs the opportunity to receive capacity payments when they provide power to help meet those needs. The Commission, therefore, concludes that the proposed definitions are reasonable and are approved for use in this docket.

AVOIDED ENERGY COSTS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14, 15, 16 and 17

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

DEC and DEP propose to apply an integration cost charge to solar QFs due to the intermittent nature of such resources. (Tr. Vol. 1 at 204) DEC/DEP witness Snider

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testified that the Duke Energy Photovoltaic Integration Study, attached to his testimony as Snider Exhibit No. 1 ("Duke PV Study"), showed that integration of solar QFs into the DEC and DEP systems results in costs that "slightly reduce the avoided energy benefits" derived from those resources. (*Id.*) These costs are a result of increased costs to maintain day-ahead planning reserves and regulation reserves on the utilities' systems due to the unpredictability of the solar QFs' output. (Tr. Vol. 1 at 204-05) The Duke PV study analyzed these costs under three scenarios assuming different levels of solar penetration on the DEC and DEP systems over a ten year period. (*Id.*) The amount of installed solar capacity assumed in these cases ranged from 673 MW up to 6,800 MW on the DEC and DEP systems collectively. (Snider Exhibit No. 1, Table ES.1) The low end of these assumptions is based on the amount of solar capacity estimated by DEC and DEP to fulfill their statutory obligations related to solar generation under Senate Bill 3.

The Duke PV Study showed that, as solar penetration levels grow, the integration costs imposed on the utilities increase. (Snider Exhibit No. 1 at ix) To reach that conclusion, the Duke PV Study used generation dispatch and planning models as well as production cost models. (Snider Exhibit No. 1 Section 2.2.1) They also utilized a specific modeling tool to project the output of the solar generation assumed in each scenario. (*Id.*) Based on these modeling analyses, the Duke PV Study concluded that the cost of integrating solar generation into the DEC and DEP systems would range between $1.43/MWh to $9.82/MWh, depending upon the level of solar penetration assumed. DEC/DEP witness Makovich generally supported the concept of including an integration charge for intermittent resources. (Tr. Vol. 1 at 323-24) He noted that integration of solar resources creates incremental costs associated with cycling and ramping of other

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generation to account for the intermittent operation of solar generation. (Tr. Vol. 1 at 323) To that point, witness Makovich cited the results of several studies in the cost of integrating wind resources into existing utility systems. (Tr. Vol. 1 at 324) He noted that these results generally show that integrations costs increase as the penetration of intermittent resources increases. (Tr. Vol. 1 at 323)

Witness Snider testified that DEC and DEP proposed to include an integration charge at the low end of the integration costs found by Duke PV Study, which is based on only the amount of solar penetration necessary to satisfy the requirements of Senate Bill 3. Witness Snider's observation is supported by the data presented by DEC/DEP witness Makovich pertaining to studies of the cost of integrating wind resources, almost all of which determined that the cost of integrating such resources exceeded $1.43/MWh.

On cross-examination, witness Snider acknowledged that DEC's and DEP's proposed integration charge for solar QFs was based on a penetration level of 2% of the utilities' system peak load and that the current level of solar penetration on the utilities' system is approximately 1% of system peak load. (Tr. Vol. 2 at 27-28) Witness Snider explained, however, that the proposed integrations charge was based on the lowest level of penetration studied in the Duke PV Study. (Tr. Vol. 2 at 28-29) He also noted that this penetration level was based on the amount of solar generation required to meet DEC's and DEP's obligations under Senate Bill 3. (Tr. Vol. 2 at 29) Witness Snider further explained that the Duke PV Study was a forward-looking study to assess the impact of integrating new solar resources. The study, therefore, could not be limited to the present level of solar penetration on the DEC and DEP systems. (Tr. Vol. 2 at 28) Witness Snider also testified that the integration charge proposed by DEC and DEP is

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lower than the integration costs for intermittent resources calculated by studies from other jurisdictions, as well as the Crossborder Study introduced by NCSEA. (Tr. Vol. 2 at 10-11) Witness Snider agreed that DEC and DEP were proposing to apply the integration charge only to solar QFs because of its intermittency and because there are no wind projects pending in the DEC or DEP service territory, which is the other major type of intermittent QF generation. (Tr. Vol. 2 at 40-41)

Although DEC and DEP propose to apply the generation-related solar integration charge described above, they are not proposing to make an adjustment to their avoided cost calculations for T&D costs and benefits associated with the integration of solar QFs. On cross-examination, witness Snider testified that the Duke PV Study indicated that installation of solar resources could impact DEC's and DEP's T&D costs and that some of those impacts could be positive (i.e., could reduce T&D costs). (Tr. Vol. 1 at 363) Specifically, witness Snider acknowledged that the Duke PV Study had identified reduction of line losses as one such potential positive impact from the installation of solar generation. (Tr. Vol. 2 at 36; Tr. Vol. 3 at 36) Witness Snider explained that DEC and DEP were not proposing any adjustment to avoided cost rates for solar QFs to account for positive or negative impacts on T&D costs at this time. Witness Snider noted that the Duke PV Study only looked at power flow snapshots of four hours in assessing the impact of solar integration on transmission costs. (Tr. Vol. 2 at 36) He also testified that the Duke PV Study only examined a portion of DEC's and DEP's T&D system. (Tr. Vol. 3 at 43) He further testified that the Duke PV Study specifically found that the issue of impacts of solar integration on the T&D systems required further study and that beneficial aspects, such as reduction of line losses, may be offset by T&D costs imposed

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by solar integration. (Tr. Vol. 2 at 10)

As to the possibility that adding solar generation to the DEC and DEP systems could reduce transmission capacity costs, witness Snider testified that the intermittency of solar generation made that unlikely. (Tr. Vol. 1 at 278) He explained that transmission planners could not rely on solar generation to operate at any given time and therefore could not count on it to reduce load on the transmission system when assessing the need for new transmission facilities. (*Id.*) He further explained that this distinguished solar generation from EE programs, which generally can be relied upon to reduce demand and loadings on the transmission system and therefore do provide a transmission benefit. (*Id.*)

Witness Snider concluded that DEC and DEP do not yet have sufficient information to accurately assess the costs and benefits to their T&D systems from the integration of solar generation. (Tr. Vol. 3 at 36) He noted that such analysis required further detailed modeling of the DEC and DEP systems and that DEC and DEP intended to undertake further analysis of the impact of solar integration on T&D costs. (*Id.*) DEC/DEP witnesses Bowman and Snider both testified on cross-examination that DEC and DEP intended to undertake further study of the costs and benefits of integrating solar generation into the utilities' T&D systems. (Tr. Vol. 3 at 31 and 34)

TASC witness Hornby testified that solar integration costs can offset the benefits provided by solar generation (Tr. Vol. 3 at 54) He noted that the Duke PV Study observed that operational and technological improvements could help DEC and DEP make a "smooth transition toward the high-PV energy mix." (*Id.*) He also referenced a presentation on net-metered, distributed solar generation in California, which he

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represented showed that it was "unlikely" that such generation would cause a net increase in costs for "operating costs for regulation and load following." (*Id.*) He, therefore, recommended that the Commission consider the "limits" of estimates of the impact of solar generation on North Carolina utilities. He further concluded that, if the Commission were to adopt an integration adjustment for solar QFs, it should be no more than the $1.43/MWh, which represents the first year integration cost in the lowest penetration level evaluated in the Duke PV Study.

NCSEA witness Beach supported the application of an integration adjustment for solar QFs. (Tr. Vol. 5 at 166) In so doing, he noted that the integration cost proposed by DEC and DEP was lower than the $3/MWh integration cost cited in his Crossborder Study from similar studies in other jurisdictions. (Tr. Vol. 5 at 166) In addition, witness Beach argued for two additional adjustments. First, he argued that DEC and DEP should adjust avoided energy rates for estimated annual reduction in line losses. (Tr. Vol. 5 at 156) Witness Beach proposed that the adjustment should be based on a 3.3% reduction in line losses, which he derived from the average of the four power flow "snapshots" contained in the Duke PV Study. (Tr. Vol.5 at 156-57)

Second, witness Beach argued that the avoided cost rates for solar QFs should be adjusted to reflect avoided transmission capacity costs associated with the installation of distributed solar generation. (Tr. Vol. 5 at 157-59) Witness Beach based this proposal on the assumption that small QFs connected to a utility's distribution system reduce peak loadings on the transmission system and therefore allow the utility to avoid building new transmission facilities. (Tr. Vol. 5 at 157) Witness Beach, therefore, proposed that DEC be required to provide avoided transmission cost credit based on an estimated annual

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transmission cost of $54.08/kW-year. (Tr. Vol. 5 at 158) Witness Beach claimed that he based his proposed avoided transmission cost charge on the Crossborder Study, which estimated avoided transmission cost on the DEC system based on a regression analysis of the general transmission system costs reflected in DEC's FERC Form 1. (*Id.*) However, the Crossborder Study assumed an annual transmission cost for DEC of $37.45/kW-year. (Beach Exhibit 1 at 12) Witness Beach claimed that the difference is a result of updated calculations in that the lower figure was based on the combined cost of T&D additions with the distribution backed out based on certain assumptions, and the higher number purports to be based on the projected cost of transmission additions only. (Tr. Vol. 5 at 159) No power flow models or other modeling were used to derive witness Beach's proposed DEC avoided transmission cost credit. Witness Beach did not propose a specific transmission charge credit for DEP.

Although witness Beach proposed adjustments based on the impact of integrating solar generation on the DEC and DEP transmission systems, he did not make any such recommendation regarding the potential impact on the DEC and DEP distribution systems. Witness Beach agreed with the conclusion in the Duke PV Study that the addition of solar generation can have costs and benefits for the distribution system. (Tr. Vol. 5 at 163) He concluded, however, that DEC and DEP did not currently have the requisite substation data to adequately assess those costs and benefits. (*Id.*) Therefore, witness Beach declined to propose the inclusion of avoided distribution costs associated with the integration of solar QFs in DEC's or DEP's avoided cost rates. (*Id.*) He did, however, recommend that the Commission direct DEC and DEP to gather the data necessary to analyze these costs and benefits. (Tr. Vol. 5 at 164)

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Public Staff witness Hinton did not make any specific recommendations regarding the costs or benefits of solar integration. However, he noted that, "if the 'demand reductions' from solar generation were found to warrant avoided cost treatment," he believed that the T&D rates applied to measure the cost-effectiveness of demand-side management ("DSM") and EE programs provided an appropriate basis for calculating avoided T&D costs. (Tr. Vol. 7 at 188) He also opined, however, that the T&D rates stipulated to by DEC in Docket No. E-7, Sub 1032 were too high for that purpose. (*Id.*)

Public Staff witness Brown did not make specific recommendations regarding costs and benefits of solar integration to be reflected in DEC's or DEP's avoided cost calculations. He did, however, make several general observations relevant to this issue. Witness Brown observed that there are potential costs and benefits from the integration of solar generation. He noted that small-scale solar generation connected at the distribution level could "possibly" have transmission capacity benefits to the extent that such generation reduces the use of a utility's transmission system. (Tr. Vol. 7 at 349) Witness Brown explained that "technically" any generation (including solar) can be located at a place that reduces power flows on heavily loaded transmission facilities. (Tr. Vol. 7 at 350) He noted, however, that any such benefit is highly dependent on where the generation is sited and that utilities have no influence over where solar QFs are located. (*Id.*) He also observed that larger solar facilities tend to connect to a utility's transmission system and, in such case, do not necessarily provide a transmission capacity benefit. (Tr. Vol. 7 at 349) Similarly, witness Brown testified that solar generation connected at the distribution level (as opposed to transmission-connected solar generation) may provide benefits in terms of reduced transmission line losses, but the

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existence and extent of such benefits is highly dependent on where the generation is located. (Tr. Vol. 7 at 352) As to distribution benefits, witness Brown opined that transmission-connected solar generation does not provide such benefits. (Tr. Vol. 7 at 350) He also testified that the benefits of solar generation connected at the distribution level were uncertain. Witness Brown noted that to the extent such generation reduced loading on distribution facilities, it may allow a utility to defer investment in such facilities. (Tr. Vol. 7 at 351) However, he also observed that due to the uncertainty as to whether a solar facility will be available when needed, a utility could plan its distribution system additions "without the load-masking" effect of assuming that the solar generation will always be available to serve load on the distribution feeder during times of peak loading. (*Id.*)

In addition to the potential benefits discussed above, Public Staff witness Brown also discussed the potential costs imposed from solar integration. In terms of the impact on a utility's generation, witness Brown noted that the possibility of solar production changing suddenly and drastically due to its intermittency can impose a number of costs, including increased need for reserve margins and spinning reserves. (Tr. Vol. 7 at 361-62) This intermittency can also increase a utility's cost of frequency regulation and frequency reserves, as well as increase wear on generation that has to be cycled more often to account for the discontinuous operation of solar resources. (Tr. Vol. 7 at 363-65) Witness Brown stated that he believed that the $1.43/MWh solar integration cost described in the Duke PV Study represented the collective cost of these generation-related impacts at a 2% solar penetration. (Tr. Vol. 7 at 365)

With regard to solar integration costs related to T&D, witness Brown noted that

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because solar generation cannot be controlled in the same way as traditional generating resources it could cause a utility to incur incremental costs in the area of voltage regulation. (Tr. Vol. 7 at 366) In that regard, witness Brown quoted the Duke PV Study, which observed that during light-load periods DEC's and DEP's existing voltage control devices were not able to handle overvoltage issues and recommended that mitigation measures should be investigated. (Tr. Vol. 7 at 366-67) Witness Brown further noted that the changes in output inherent in solar operations can increase the wear on certain types of T&D equipment, such as load tap changes, voltage regulators, and switched capacitor banks. (Tr. Vol. 7 at 330) He concluded that the increased use of those types of facilities could increase maintenance requirements and decrease the facilities' useful life. (*Id.*)

Based upon the foregoing, the Commission concludes that DEC and DEP should be allowed to adjust the avoided energy payments to solar QFs for the generation-related costs of integrating solar resources into its system. The Commission further concludes that the solar integration costs presented in the compliance scenario of the Duke PV Study is a reasonable estimate of the known and measurable generation-related solar integration costs for use in this docket.

In reaching these conclusions, the Commission has relied on the fact that there is a clear consensus that the intermittent nature of solar generation imposes costs on the utility system into which it is connected, particularly in the area of maintaining generation and regulation reserves. Witnesses for DEC, DEP, Public Staff, NCSEA and TASC all agree that a utility's need to compensate for the intermittency of solar generation requires the utility to maintain higher levels of reserves to ensure system

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reliability. Thus, there is agreement that the generation-related costs of solar integration are known costs. The Commission further finds that for DEC and DEP such costs are measurable. The solar integration charge proposed by DEC and DEP is supported by analysis reflected in the Duke PV Study. It is based on detailed modeling of the effects of various levels of solar penetration on the DEC and DEP generating systems. No party has raised any objections or challenges to the methodology used in the Duke PV Study to assess these generation-related solar integration costs. Moreover, DEC and DEP have proposed to base the integration charge on the lowest solar penetration level assessed in the Duke PV Study, which produced the lowest solar integration cost of the scenarios analyzed in that study. In fact, the resulting solar integration cost of $1.43/MWh is lower than the typical solar integration costs cited by NCSEA witness Beach in his Crossborder Study from similar analyses from other jurisdictions.

During the hearing, it was noted that the scenario that produced the lowest solar integration cost was based on an assumed 2% solar penetration level in 2014 and that the current level of solar penetration on the DEC and DEP systems is approximately 1%. The Commission finds, however, that compliance solar penetration scenario is a reasonable basis upon which to calculate a generation-related solar integration charge for the DEC and DEP systems. As witness Snider noted, the assessment of solar integration costs must be forward-looking. The solar integration charge applies to new solar QFs, not existing ones. This means that a penetration level in excess of current levels must be used. Moreover, this solar penetration scenario represents the amount of solar generation needed to fulfill DEC's and DEP's obligations under Senate Bill 3 to produce a certain amount of energy from solar resources. While it may not be possible to predict precisely

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how much solar generation will actually be added to the DEC and DEP systems over the next few years, using the utilities' statutory renewable energy portfolio obligations as a guideline for such projections is reasonable, if not conservative. Finally, Table ES.1 of the Duke PV Study showed that the lowest penetration level scenario assumed that by the end of 2016 there would be 943 MW of solar generation on the DEC and DEP systems, collectively. That represents an increase of approximately 640 MW of solar installed solar generation during that time. Given that DEC and DEP currently have nearly 3,000 MW of new solar projects in their interconnection queues, the assumed amount of new solar generation in the lowest penetration case is reasonable.

In approving a generation-related integration charge for solar QFs only, the Commission is cognizant of PURPA's requirement that avoided cost rates not discriminate against QFs. (18 C.F.R. § 292.304(a)(1)(ii)). In this case, however, there is a reasoned basis for distinguishing solar QFs from other QFs. As noted by Public Staff witness Brown, solar generation is prone to sudden and drastic changes in output due to uncontrollable factors such as cloud cover. This type of intermittency is what causes solar to impose generation-related integration costs and distinguishes it from non-intermittent QFs, such as biomass and co-generating facilities. Arguably, wind QFs may exhibit the same kind of intermittency and, therefore, also create generation-related integration costs as solar QFs. As witness Snider stated, neither DEC nor DEP are currently faced with integrating any wind projects into their systems. Accordingly, the Commission finds that it is reasonable and not discriminatory to approve a generation-related integration charge to be applied only to solar QFs under present circumstances.

With regard to the T&D impacts of solar integration, the Commission finds that

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the record in this proceeding does not support the imposition of additional avoided costs or integration charges at this time. DEC/DEP witness Snider and NCSEA witness Beach agree that presently there is not sufficient data available to assess the distribution-related costs and benefits of solar integration. With regard to transmission-related integration impacts, NCSEA witness Beach argues that the Commission should require DEC, DEP and DNCP to include two transmission-related benefits in its calculation of avoided costs: 1) a reduction in transmission line losses, and 2) avoided transmission capacity costs. For several reasons, the Commission concludes that imposing such additions to avoided cost rates is not justified by the record in this proceeding.

As to avoided line losses, witness Beach relies on the Duke PV Study for the proposition that adding additional solar generation to the utilities' system would reduce line losses. The Duke PV Study included the observation that the modeling analysis showed a reduction in transmission line losses between when the "with solar generation" case was compared to the "without solar generation" case. However, the transmission analysis was based on only "snapshots" of four days, one in each season. As a result, the Duke PV Study cautioned that the transmission assessment was only preliminary and that analysis over longer periods of time is needed to develop reliable data. (Snider Ex. 1 at x) The Duke PV Study further observed that the "snapshot" approach is consistent with typical transmission planning procedures, but "is inadequate for [solar] integration analysis due to the variable nature of [solar] production.' (Snider Ex. 1 at vii footnote 1) The Commission also notes that, as witness Brown observed, the potential for any generation to reduce line losses on a utility's transmission system is highly dependent on where the generation is located and how it is interconnected to the utility's system.

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Accordingly, the Commission finds that the preliminary transmission analysis set forth in the Duke PV Study is not sufficient to support the imposition of increased costs on North Carolina ratepayers in the form of assumed reductions in transmission line losses from solar integration. However, the study does suggest that reduction of line losses is among the potential benefits of increased distributed solar generation that warrants further study.

As with line losses, the Commission finds that there is insufficient support to warrant witness Beach's proposed adjustment to avoided costs for avoided transmission capacity costs associated with new solar QFs. The underlying assumption of witness Beach's proposal is that distributed solar generation can reduce the amount of load on the transmission system, thereby allowing the utility to avoid or defer investment in new transmission capacity. However, the validity of that assumption depends upon how the generation is interconnected to the utility system. Solar generation connected at the transmission level likely would not allow a utility to avoid transmission capacity costs. Even solar generation connected to the utility's distribution system may not produce such avoided costs depending upon where it is located and whether there is a significant risk of back feed onto the transmission system. Moreover, transmission capacity benefits of solar integration depend upon the utility assuming that the distribution-side solar generation actually operates during peak periods, thereby reducing load on the transmission system. As Public Staff witness Brown pointed out, it may be reasonable for the utility not to include the load-carrying capability of solar generation for T&D planning purposes given the uncertainty of solar generation's output. Similarly, DEC/DEP witness Snider noted that because transmission planners have no guarantee as to when solar generation will operate and how much energy it will produce, they cannot

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rely on such resources to carry load for system planning purposes. Based on the evidence presented, there appears to be significant doubt as to whether distributed solar generation provides transmission capacity benefits, and if so, how much benefit it provides.

With regard to witness Beach's specific proposal to base avoided transmission capacity benefits on the DEC system on an assumed avoided transmission cost of $54.08/kW-year, the Commission finds that the proposal is without adequate support in the record. First, witness Beach's proposal is based on the Crossborder Study analysis. That analysis was made using a general regression model and the transmission data contained in DEC's FERC Form 1. Given that solar generation's impact on a utility's transmission system is dependent on a number of factors, it is not clear that the approach adopted by the Crossborder Study provides a reliable estimate of those impacts. For example, it is not clear whether this generalized approach adequately assesses which transmission additions may be unavoidable or whether there are parts of the utility system where the addition of solar generation will provide no transmission capacity benefit at all. The only check on the analysis in the Crossborder Study is the conclusion in the study that the avoided transmission capacity cost estimates are "broadly" consistent with the T&D benefits stipulated to by DEC for DSM and EE. (Beach Exhibit 1 at 134 (citing stipulation in Docket No. E-7, Sub 1032)) However, the validity of that confirmation is called into question by the testimony of witness Hinton, who testified that the T&D costs reflected in Docket No. E-7, Sub 1032 are too high to be used for avoided cost calculations. Further doubt is cast on witness Beach's use of avoided transmission cost for DSM and EE programs to support his analysis because, as witness Snider points out, solar generation is not comparable to DSM and EE programs for transmission capacity

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and transmission planning purposes. This is because the load reducing effects of DSM and EE are more predictable and reliable than solar generation. Thus, the Commission cannot conclude that the Crossborder Study adequately supports the imposition of an adjustment to avoided costs for assumed avoided transmission capacity costs from solar integration. Finally, putting aside the open questions regarding the Crossborder Study on this issue, witness Beach's proposal is made even more problematic because it is not consistent with the Crossborder Study's result. He bases his proposal on the assumption that DEC's avoided cost of transmission capacity is $54.08/kW-year. Conversely the Crossborder Study shows that DEC's avoided cost of transmission capacity to be $37.45/kW-year. Witness Beach states that the change is due to updating the transmission costs used, but provides no detail to support the 44% increase in DEC's assumed avoided transmission cost.

Finally, the Commission is persuaded that there are likely T&D-related costs and benefits from the integration of solar generation into a utility's system. Witness Beach's proposals focus solely on assumed benefits, however, without regard to potential costs. This is not the balanced approach that this issue requires.

Although the record in this proceeding does not support the imposition of any adjustments to account for the T&D impacts of solar integration, the evidence supports the conclusion that these impacts may be substantial and therefore should be considered in determining the avoided costs associated with solar QFs. Witnesses Bowman and Snider testified that DEC and DEP intend to further analyze this matter. The Commission finds that such further analysis is warranted and directs DEC and DEP to undertake it with the goal of presenting the analysis in the next biennial avoided cost

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proceeding, with such proposed adjustments to avoided cost calculations as the analysis justifies.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is found in the testimony of DEC and DEP witnesses Snider and Bowman and Public Staff witness Ellis. Currently, DEC, DEP and DNCP offer two alternative avoided cost rate schedules – an Option A and Option B. The difference between these rate schedules is that they use different definitions of on-peak and off-peak hours. In this proceeding, DEC, DEP and DNCP advocate for the elimination of multiple definitions of on-peak and off-peak hours.

In his direct testimony, DEC/DEP witness Snider stated that maintaining multiple definitions of on-peak and off-peak hours encouraged QFs to select the definition that optimized its revenues based on the QFs' expected hours of operation. (Tr. Vol. 1 at 211) He conceded that such optionality was financially beneficial to QFs. (Tr. Vol. 1 at 210) However, he argued that such an arrangement led to overstatement of the actual avoided energy benefits provided by QFs, compared to the application of a single, consistent definition of on-peak and off-peak hours. (Tr. Vol. 1 at 211)

The Public Staff opposes the utilities' proposal to eliminate multiple on-peak and off-peak definitions in their avoided cost rate tariffs. Public Staff witness Ellis argued in his direct testimony that the purpose of maintaining multiple definitions of on-peak and off-peak hours is not to allow QFs to maximize the revenues they receive, but rather to "recognize the differing operating characteristics" of QFs and to allow them an "opportunity to earn their full avoided capacity costs in a non-discriminatory manner." (Tr. Vol. 7 at 133) Witness Ellis conceded that DEC's Option A, for example, defines

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on-peak hours much more broadly than its Option B. (Tr. Vol. 7 at 132) However, Option B encouraged solar QFs to configure their facilities to best match their operation to the narrower definition of on-peak hours, which results in a better match between the solar QFs output and the utility's load. (*Id.*) He also opined that Option A should be retained because it is still "appropriate for some [QF] technologies and not administratively burdensome." (Tr. Vol. 7 at 133)

In his rebuttal testimony, DEC/DEP witness Snider took issue with Public Staff witness Ellis' characterization that allowing multiple definitions of on-peak and off-peak is an appropriate way to recognize operational difference among QFs. (Tr. Vol. 1 at 262) Witness Snider explained that, given an option, QFs will select the definition of on-peak hours that best fits its own operational characteristics in order to maximize the revenues it will receive. (*Id.*) As a result, the availability of multiple definitions of on-peak and off-peak results in the utility's and their customers overpaying for QF capacity relative to the capacity value provided. (*Id.*)

To illustrate his point, witness Snider provided an example of a utility required to offer QFs the option of three different on-peak definitions. (Tr. Vol. 1 at 262-65) In that example, three different 1 MW QFs each selected a different definition of on-peak hours. Because the output of the three QFs did not overlap, the purchasing utility received only 1 MW of capacity value from them, collectively. The utility's calculated cost of avoided capacity was $50/day. However, because each of the QFs was able to select an on-peak definition that best conformed to their hours of operation, the utility in the illustration had to pay the QFs $93.75 for the day, nearly twice the capacity value that the utility actually received. Witness Snider concluded that if QFs are allowed to select from among

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multiple definitions of "peak hours" to maximize the revenues that they receive, ratepayers will be forced to overpay for QF capacity.

On cross-examination, DEC/DEP witnesses Bowman and Snider acknowledged that providing multiple definitions of on-peak and off-peak hours provided flexibility for QFs. (Tr. Vol. 1 at 412) Witness Bowman also acknowledged that DEC had agreed in the 2012 avoided cost proceeding to offer an Option A and Option B definition of on-peak and off-peak hours as part of a broader settlement agreement. (Tr. Vol. 1 at 414) She also agreed that the Commission had rejected DEC's requests in previous proceedings to eliminate multiple definitions of on-peak and off-peak hours in its avoided cost rate tariffs (Tr. Vol. 1 at 409-12) Witness Snider noted, however, that in those previous cases DEC had argued for the use of a single definition of on-peak and off-peak hours on the grounds of administrative efficiency. (Tr. Vol. 1 at 412-13) He went on to explain that DEC and DEP were not making an argument in this case based on administrative ease; rather the utilities' position was based on the fact that allowing QFs to select from among multiple on-peak definitions results inevitably in the purchasing utility overpaying for QF capacity. (*Id.*) Witness Snider explained that if a QF provides 1 MW during nighttime hours and another QF provides 1 MW during daytime hours, the purchasing utility is receiving at most 1 MW of capacity value from the two QFs, collectively. (Tr. Vol. 1 at 413) However, if the QFs are able to select from among peak hour definitions and chose the ones that best conform to their hours of operation, the utility will necessarily pay for more than 1 MW capacity.

In response to questions from Commissioner Brown-Bland, witness Snider testified that use of multiple definitions of on-peak and off-peak hours will always result

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in overpayments to QFs, unless a QF inadvertently selects a definition of on-peak hours that is suboptimal for it. (Tr. Vol. 4 at 47-48) He acknowledged that different definitions of on-peak hours can be reasonable. (Tr. Vol. 4 at 49) For example, a broad definition of on-peak hours recognizes capacity value in a large number of hours and dilutes the capacity value for each hour (i.e., spreads the avoided capacity costs over a larger number of hours). On the other hand, a narrow definition of on-peak hours recognizes capacity value in a few hours and ascribes a relatively high hourly value to that capacity. (*Id.*) Either definition may be defensible on its own, but they cannot both be applied simultaneously without forcing the utility to overpay for capacity. (Tr. Vol. 4 at 49-50)

The issue at hand (i.e., whether multiple definitions of on-peak and off-peak hours should be used for avoided cost purposes) is distinct from the issue of which definition of on-peak hours should be applied in calculating avoided cost rates, which is addressed elsewhere in this order. The evidence presented on the latter issue, however, reveals a consensus as to the goal of defining on-peak hours in the context of avoided cost rates. TASC witness Hornby states that on-peak hours should accurately reflect the periods when generation has the most value to the purchasing utilities' customers. (Tr. Vol. 5 at 62) Similarly, NCSEA witness Beach (Tr. Vol. 5 at 172) and SACE witness Rabago (Tr. Vol. 6 at 163) agree that the definition of on-peak hours should align with the purchasing utilities' peak loads in order to provide the greatest benefit to the purchasing utility and its customers. In fact, witness Beach testified at length as to the detailed analysis of DEC's and DEP's loads, system peaks and capacity needs that he undertook to demonstrate why his proposed definition of on-peak hours is superior to DEC's and DEP's proposed definition. (Tr. Vol. 5 at 198-206) Even Public Staff witness Ellis, who

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advocates for the retention of multiple definitions of on-peak hours, acknowledged on-peak hours should be based on the purchasing utility's system peak loads (Tr. Vol. 7 at 133) and opposed DEC's and DEP's proposal to narrow the definition of on-peak hours, in part, because it did not align with Public Staff's view of when those utilities have capacity needs. (Tr. Vol. 7 at 143)

Based on the foregoing and the Commission's interpretation of the requirements of PURPA, the Commission finds that the goal of defining on-peak hours for purposes of avoided cost rates is to identify those periods when the purchasing utility most needs capacity and energy. PURPA requires that payments to QFs be no more than the purchasing utility's alternative cost of capacity and energy. QFs, therefore, should receive avoided capacity payments and on-peak avoided energy payments only when they are, in fact, allowing the purchasing utility to avoid capacity and high cost energy. That goal can only be met if the definition of on-peak hours conforms to the periods when the purchasing utility most needs capacity and would otherwise use high cost energy.

The foregoing strongly suggests that the purposes of PURPA are best served by the use of a single definition of on-peak hours for avoided cost purposes. Simply put, it is difficult to see how multiple definitions of on-peak hours can fulfill the goal of identifying the period when a utility most needs capacity and energy, particularly when there is a significant difference among the definitions. For example, in this case, the potential definitions of on-peak hours for DEC and DEP include Option A (approximately 3,000 hours), Option B (1,861 hours) and DEC's and DEP's proposed definition (515 hours). It is not logical to suggest that all of these widely disparate

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definitions best represent the periods when DEC and DEP most need capacity and energy. Moreover, the Commission is persuaded by DEC's and DEP's analysis of the effect of maintaining multiple definitions of on-peak hours. As long as QFs are free to select the definition of on-peak hours that best fits their respective operational characteristics, the net result will be higher avoided cost payments as compared to the use of a single definition of on-peak hours. That result is not consistent with the underlying principle of PURPA that utilities should pay no more than their avoided costs of capacity and energy for power purchased from QFs. Therefore, the Commission finds that the record in this case provides strong support for the elimination of multiple definitions of on-peak and off-peak hours.

Conversely, the arguments presented in favor of maintaining multiple definitions of on-peak hours are not persuasive. First, the Commission recognizes that DEP and DNCP adopted multiple on-peak definitions for the first time in the most recent avoided cost rate proceeding, Docket No. E-100, Sub 136. However, DEP and DNCP did so pursuant to settlement agreements, which resolved a number of issues and which contained no commitment on the part of the utilities to maintain more than one definition of on-peak hours in future proceedings. Accordingly, the Commission finds that these settlements have no precedential value for the issue at hand.

Second, the Commission's previous determinations denying DEC's requests to use a single definition of on-peak hours are inapposite to the present case. In the 2002 avoided cost proceeding (E-100, Sub 96), DEC proposed for the first time to use a new definition of on-peak hours (Option B) in addition to the definition of on-peak hours that DEC had traditionally used for avoided cost rates (Option A). In the 2004 avoided cost

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proceeding, DEC proposed to eliminate the definition of on-peak used for Option A in order to "simplify" the administration of contracts and metering programs. (*Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* E-100, Sub 100, p. 47 (September 29, 2005)) The Commission found that simplification of DEC's administrative processes was insufficient grounds for the proposal. (*Id.* at 48) In the next avoided cost proceeding (E-100, Sub 106), NCSEA argued that QFs served under DEC's SCG Rider should have the same ability to choose between the Option A and Option B definition of on-peak hours. (*Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, E-100, Sub 106, at 33 (December 19, 2007)) At that time, DEC's SCG Rider only provided for the Option B definition of on-peak hours. DEC argued that NCSEA's proposal should be rejected in order to keep SCG Rider simple and avoid administrative complexity. (*Id.*) In that case, the Commission concluded that "the slight degree of administrative complexity that will result from making [multiple definitions of on-peak hours] available is outweighed by the increased flexibility to the [QFs]." (*Id.* at 34)

In E-100, Sub 100 and E-100, Sub 106, the Commission recognized that allowing QFs to choose from more than one definition of on-peak rates benefitted QFs, giving them the ability to maximize their revenues. Thus, in the absence of a substantial reason to the contrary, the Commission opted to allow QFs such "flexibility." In this case, however, the Commission has been presented with persuasive and unrebutted evidence that the use of multiple definitions of on-peak hours invariably leads to overpayments to QFs. The logic and math underlying witness Snider's arguments to that effect are difficult to refute. Certainly, if given the opportunity, QFs are going to choose the

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definition of on-peak hours that provides them with the best opportunity to optimize their financial results. Under such circumstances, the collective effect of using multiple on-peak hour definitions is that utilities (and their customers) will pay more for capacity and energy from QFs than they should. Thus, unlike E-100, Sub 100 and E-100, Sub 106, the record in this proceeding contains substantial and convincing evidence in opposition to the use of multiple definitions of on-peak hours.

Finally, the Commission is not persuaded that multiple definitions of on-peak and off-peak hours are necessary to allow QFs with varying operational characteristics the opportunity to earn their full avoided capacity costs in a non-discriminatory manner. Establishing on-peak hours for avoided cost purposes is intended to identify the period during which a utility can avoid capacity costs and high energy costs by purchasing power from a QF. That goal can only be accomplished by assessing the purchasing utility's load and capacity needs. The type of QF that might supply the power is not relevant to the inquiry. Certainly, QFs have various operating characteristics. Some QFs may be more capable than others of delivering power during a properly defined on-peak period and therefore may realize greater revenues from avoided capacity and on-peak energy payments than less capable QFs. This difference, however, is not discriminatory. It is well-established in the rate-making context that differences among individuals and groups are permissible and non-discriminatory if the distinction is rooted in factual differences. *See North Carolina Utils. Comm'n. v. Carolina Util. Customers Ass'n.,* 351 NC 223, 524 S.E.2d 10 (2000). Moreover, a QF developer is not entitled to 5 MW of avoided capacity payments merely because it has built a 5 MW QF. If for example, such a QF could operate only at night during low load periods, it would not

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allow the purchasing utility to avoid capacity costs and therefore should not be entitled to avoided capacity payments. Consequently, a QF's opportunity to earn full avoided capacity payments is defined by its ability to deliver power when the purchasing utility needs capacity (i.e., during a properly defined on-peak period). Although certain types of QFs may be less capable of delivering power when it is most needed by the purchasing utility, it is not appropriate to address this circumstance by requiring alternative definitions of on-peak hours so that these QFs can realize greater avoided capacity and on-peak energy revenues.

Based on the foregoing and careful review of the evidence presented in this case, the Commission finds that DEC, DEP and DNCP shall not be required to maintain multiple definitions of on-peak and off-peak hours for purposes of avoided cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 19, 20, and 21

DEP and DEC have proposed to modify the peaker method to account for the lost energy value of the combustion turbine assumed to be avoided by purchasing the output of QFs. They refer to this modification in terms of an adjustment to account for lost production value. (Tr. Vol. 1 at 206)

In his direct testimony, DEC/DEP witness Snider stated that an adjustment to the peaker method was necessary to reflect the fact that the current generation of CTs are more efficient and provide more energy value than in prior years. (*Id.*) He noted that in the past CTs provided little or no energy value to a utility's system because of their relatively high operating cost. (*Id.*) This is illustrated by the fact that CTs were expected to run less than 1% of the time. (*Id.*) Under such circumstances, adding a CT to a utility's system would not create any meaningful marginal energy savings for the utility or its customers and, therefore, would not affect the calculation of the purchasing utility's

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avoided energy cost under the peaker method. (*Id.*) Witness Snider explained that these circumstances have changed because modern CTs are more efficient and have lower energy costs, particularly when compared with legacy CT fleets. (Tr. Vol. 1 at 208) As a result, a new CT can reduce a utility's marginal energy cost and its avoided energy cost. (*Id.*) Witness Snider, therefore, concluded that if purchasing power from QFs avoids the construction of a new CT, the marginal energy savings that the new CT would have provided is lost. (*Id.*)

Witness Snider's position is that the marginal energy savings that customers would have realized but for the utility's purchases should be accounted for in calculating DEC's and DEP's avoided energy costs. To that end, he proposed that in calculating their avoided energy rates DEC and DEP cap their hourly marginal energy cost at the production cost of the CT assumed to be avoided by their QF purchases. (Tr. Vol. 1 at 209) Witness Snider reasoned that, but for the QF purchases, the avoided CT would have been available for dispatch and would have displaced higher energy cost resources. (*Id.*) Therefore, capping hourly marginal energy cost at the production cost of the avoided CT for avoided energy purposes puts DEC's and DEP's customers in the same position they would have been in but for the utilities' QF purchases. (*Id.*) Witness Snider further explained that DEC and DEP do not have capacity needs in all years and, therefore, the proposal to cap their hourly marginal energy cost in this manner would only apply to the first year in which they had avoidable capacity needs and to subsequent years. (*Id.*)

In his Response Testimony, SACE witness Rabago objected to DEC's and DEP's proposal to account for the lost production value of an avoided CT. (Tr. Vol. 6 at 171) Witness Rabago interpreted this proposal as reducing avoided energy rates "where the QF

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displaces the operation of non-cost effective" generation. (*Id.*) He concluded, therefore, that DEC's and DEP's proposal required a QF to be "economical against all of the hypothetical costs that the avoided unit avoided by being part of the utility fleet." (*Id.*)

In his Additional Direct Testimony, TASC witness Hornby also argued that the Commission should reject DEC's and DEP's proposal to account for the lost production value of the avoided CT. (Tr. Vol. 5 at 39) Witness Hornby opined that the proposal was premised on the assumption that DEC and DEP would always calculate their avoided marginal energy cost on the cost of dispatching a CT. (*Id.*) He noted that DEC and DEP should be calculating their avoided energy cost based on "the cost of energy it would avoid in each hour by purchasing energy from QFs." (*Id.*) Witness Hornby concluded that DEC's and DEP's proposal was not consistent with that principle and, therefore, should be rejected. (*Id.*)

In his rebuttal testimony, DEC/DEP witness Snider opined that TASC witness Rabago had misinterpreted DEC's and DEP's proposal to account for the lost energy value of an avoided CT. (Tr. Vol. 1 at 282-83) He explained that the adjustment was simply needed to recognize the marginal energy benefits that an avoided CT could have created. (Tr. Vol. 1 at 283) Witness Snider further emphasized that he expected the proposal to have a relatively small impact on avoided energy costs because even new CTs provide only limited marginal energy benefits. (*Id.*)

One of PURPA's fundamental principles is that avoided cost rates should be set so that a utility's customers are indifferent as to whether the utility purchases power from a QF or relies on an alternative source of power. It follows that, under the peaker method, avoided energy costs should be calculated as the marginal energy cost that the

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utility would have incurred but for its purchases of power from QFs. Applying these principles, DEC and DEP have concluded that their avoided energy costs should take into account the energy value associated with the generation avoided by QF purchases. Stated another way, but for DEC's and DEP's QF purchases, they would have the avoided CT available to them and that CT would reduce their marginal energy cost in some hours.

In the past, the peaker methodology as applied by DEC and DEP has not taken the lost energy value of the avoided CT into account. Witness Snider explained that previously such an adjustment was unnecessary because avoided CTs had little or no energy value. New CTs, however, do have such value due to their lower production costs. That proposition is supported by witness Snider's testimony. Similarly, Public Staff witness Hinton confirmed that DNCP's newer vintage CTs do operate more frequently than DNCP's older CTs. (Tr. Vol. 7 at 174) These facts support witness Snider's conclusion that the newer CTs provide more energy value than older CTs. Within the context of economic dispatch of their generating fleet, more frequent dispatch of new CTs can only be interpreted as demonstrating that there are hours during which the energy from new CTs is at or below DEC's and DEP's marginal cost of energy. Given that DEC and DEP and their customers would have had the benefit of such energy value from an avoided CT but for QF purchases that avoided the CT, it is appropriate to recognize the lost energy value in calculating their avoided energy rates.

As to the objections raised by witness Rabago, it appears that he has misinterpreted DEC's and DEP's proposal. Contrary to his arguments, DEC and DEP are not measuring a QF's cost-effectiveness against existing or avoided CTs. They are merely attempting to capture the limited, but measurable, marginal energy benefit that an

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avoided CT would have provided if the utilities had built the CT rather than purchasing power from QFs. Similarly, TASC witness Hornby is mistaken in arguing that DEC's and DEP's proposal assumes that their marginal energy cost will always be based on the production cost of a CT. Rather, the proposal only adjusts DEC's and DEP's marginal energy cost for hours in which it exceeds the production cost of the avoided CT. In all other hours, the marginal energy cost remains unadjusted, regardless of the resource deemed to be providing marginal energy.

With regard to the specific proposal presented by DEC and DEP, the Commission finds that capping marginal energy costs at the production cost of the avoided CT is a reasonable way to approximate the lost energy value of the avoided CT. Under general principles of economic dispatch, if an avoided CT had been built, it would be dispatched before resources with higher production costs. Accordingly, if the avoided CT had been built, it is reasonable to assume that it would displace higher energy cost resources, thereby lowering the utilities' hourly marginal energy cost. Ignoring this fact and setting avoided energy costs without regard to the beneficial effects that an avoided CT would have had, but for QF purchases, results in avoided cost rates that are higher than they should be. The Commission, therefore, finds that DEC's and DEP's proposal is reasonable. The Commission also finds, however, that this adjustment should be limited in accordance with DEC's and DEP's proposal. Therefore, the adjustment to DEC's and DEP's avoided energy cost calculations shall not apply to years prior to DEC's and DEP's first avoidable capacity addition. The premise of the proposed adjustment is that it accounts for the lost production benefits of an avoided CT. It follows that such an adjustment is not appropriate until the avoided resource would have been built, if not for

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the QF purchases that allowed the resource to be avoided.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

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

NCSEA witness Hinton 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. (Tr. Vol. 5 at 145) 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 (*Id.*) 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 24 x7 block of power. (Tr. Vol. 5 at 146) 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. (*Id.*) SACE witness Rabago and TASC witness Hornby testified that they supported witness Beach's proposal on this matter. (Tr. Vol. 6 at 162; Tr. Vol. 5 at 40, respectively)

Public Staff witness Hinton testified that based on a preliminary assessment that there was merit in witness Beach's observations regarding the positive benefits of that solar generation can supply during off-peak hours. (Tr. Vol. 7 at 180) Witness Hinton did not file rebuttal testimony in this docket.

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

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basis typical solar output may have more value than a flat block of base load energy. (Tr. Vol. 1 at 285) Witness Beach had failed to consider, however, the reduced energy benefits associated with the intermittent nature of solar generation. (*Id.*) Further, witness Snider noted his concern regarding proposals that are designed to optimize the economic results for specific types of QFs. (*Id.*) 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. (*Id.*) Witness Snider concluded that such a proposal would unfairly burden customers with additional costs. (*Id.*)

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 cannot accept witness Beach's proposal to provide a definition of off-peak hours to suit the load profile of the typical solar QF. 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. Such an unbalanced approach cannot be squared with PURPA, which requires that the rate paid to QFs must be "just and reasonable to the electric consumer of the [purchasing] utility and in the public interest." (18 C.F.R. § 292.304(a)(1)(i)). Neither of those goals would be served by adopting an avoided cost rate that specifically captures alleged benefits or a particular type of QF while ignoring any potentially countervailing costs. Accordingly, witness Beach's proposal to require a definition of off-peak hours to suit the load profile of solar QFs is rejected.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

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The evidence for this finding of fact is found in the testimony and exhibits of DEC/DEP witnesses Bowman and Snider, Public Staff witnesses Kirsch and Hinton, EDF witness Munns, TASC witness Hornby, NCSEA witness Beach, and NC WARN witness LaPlaca.

On June 2, 2014, the Environmental Protection Agency ("EPA") issued proposed rules intended to require reductions in the nation's CO_2 emissions ("CO_2 Regulations"). These rules are not final, and the comment period on them does not close until October 16, 2014. Currently, EPA does not plan for the CO_2 Regulations to be finalized until June 30, 2015. Further, the Commission also takes notice of the fact that 12 states have initiated a legal challenge to the Clean Power Plan in the United States Court of Appeal for the D.C. Circuit. As proposed, the EPA's new CO_2 Regulations would require the states to meet to certain CO2 emissions targets beginning in 2020. The CO_2 Regulations, however, do not specify how a state (or the utilities within the state) may meet these targets.

Against the background of the EPA's proposed CO_2 Regulations, the issue of whether a utility's avoided costs should include projected carbon costs has been raised in this docket. Some parties argue that such costs remain speculative at this juncture and should not be included in avoided costs. Other parties argue for the inclusion of such costs in avoided cost calculations.

DEC and DEP take the position that carbon costs should not be included in avoided costs at this time. In her direct testimony, DEC/DEP witness Bowman noted that PURPA requires that the rates paid to QFs be no greater than the capacity and energy costs actually avoided by the purchasing utility. (Tr. Vol. 1 at 118-19) She concludes,

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therefore, that including speculative costs associated with proposed rules that may be changed substantially prior to implementation or never implemented at all is inconsistent with that principle. (*Id.*) She also noted that subjecting avoided cost calculations to such conjecture would open the door to a host of equally speculative factors, which would unnecessarily complicate the avoided cost process and potentially introduce a number of inappropriate factors. In DEC/DEP witness Snider's direct testimony, he acknowledged that DEC and DEP include a cost of carbon for long range planning purposes in their IRPs. (Tr. Vol. 1 at 243) However, he explained that while such projections may be appropriate for planning purposes, it would not be appropriate to immediately include them in avoided cost rates that are borne by the utilities' customers without knowing the form, fashion or timing of actual carbon regulation. (*Id.*) He further noted that it was not clear whether future carbon costs should be considered in avoided cost calculations given that purchasing utilities do not receive RECs associated with the energy that they purchase from QFs at avoided cost rates. (*Id.*) He noted that such a situation arguably results in double counting of a QF's contribution to carbon reduction – once when it receives avoided cost payments that include the assumed cost of CO2 compliance and again when it sells the associated REC, which is presumed to embody the environmental attributes of the QF's energy output. (*Id.*)

In his rebuttal testimony, DEC/DEP witness Snider explained that the utilities' consideration of potential carbon costs in their long range IRPs does mean that such speculative costs should be included in avoided cost rates. He noted that carbon regulation has been believed to be imminent for several years. (Tr. Vol. 1 at 288) If utilities had prematurely included speculative carbon compliance costs in their avoided

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cost calculations in response to the possibility of such regulation, the utilities' customers would have borne substantial amounts of unrealized and unwarranted costs. (*Id.*) Furthermore, witness Snider noted that there is a substantial difference between long--term resource planning and ratemaking. (Tr. Vol. 1 at 289) He explained that the goal of long-term resource planning is to allow the utility to meet its service obligations under a range of potential futures. This requires consideration of a number of factors, including those that may be speculative or uncertain. (*Id.*) Moreover, if these uncertainties do not materialize as expected, a utility will change its plans accordingly. Ratemaking, however, requires the Commission to make a current determination that immediately imposes costs on customers. Witness Snider concluded, therefore, that such determinations should be based on actual, not speculative, costs. (*Id.*) Finally, witness Snider argued that EPA's proposed CO_2 Regulations were not a sufficient basis upon which to include carbon costs in avoided cost rates. (Tr. Vol. 1 at 289-90) He noted that the regulations were not final and remained subject to change based on comments and legal challenges. (*Id.*) He also observed that the CO_2 Regulations do not impose a specific carbon cost, but rather set targets for carbon reductions. (*Id.*) He concluded, therefore, that at this time there is not sufficient information to make a reasoned estimate of a utility's carbon compliance costs if the CO_2 Regulations are in fact enacted. (*Id.*)

On cross-examination, DEC/DEP witness Snider acknowledged that the IRPs of DEC and DEP considered potential future carbon costs and that those potential carbon costs were among the factors that led to the inclusion of new nuclear generation in DEC's 2013 IRP. (Tr. Vol. 1 at 454-58)

In response to questions from Commissioner Brown-Bland, DEC/DEP witness

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Snider acknowledged that in dealing with projected costs in the avoided cost context, there is a risk that the projections may prove to be inaccurate and that the avoided cost rates paid over the course of a 15-year QF contract may not match the purchasing utility's then-current avoided cost. (Tr. Vol. 4 at 64) He further acknowledged that this risk applied to projected carbon costs just as it applied to other cost projections. (*Id.*) Witness Snider explained, however, that unlike other types of projected costs, carbon costs have no established basis upon which to be projected. (Tr. Vol. 4 at 65) There are no current carbon emission rules and the EPA's proposed CO_2 regulations are still subject to change. Until the regulations are put in place with definitive guidelines, there is no way to know if a particular utility has to take immediate action to comply with the regulations or whether the utility can wait for several years before incurring incremental compliance costs. (*Id.*) He concluded, therefore, that it was premature to impose projected carbon costs on customers by including them in avoided coat rates. (*Id.*)

Like the utilities, the Public Staff opposed the inclusion of specific estimates of future carbon costs in avoided cost rates at this time. In his direct testimony, Public Staff witness Kirsch observed that avoided costs should include environmental costs actually avoided by a utility's QF purchases. (Tr. Vol. 7 at 90) However, he also noted that given that North Carolina utilities currently do not incur carbon costs, QF purchases do not help them to avoid such costs. (*Id.*)

Public Staff witness Hinton testified that, despite the issuance of EPA's proposed CO_2 Regulations, future carbon costs remained speculative and unverifiable. (Tr. Vol. 7 at 178) He concluded that it would be inappropriate to burden ratepayers with projected carbon costs until they became more certain. (*Id.*) He observed that a key aspect of an

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IRP is to consider multiple future scenarios (including various scenarios regarding future carbon regulation) in arriving at an optimal resources plan. (*Id.*) Thus, witness Hinton concluded that inclusion of scenarios that include future carbon costs in an IRP did not require inclusion of such speculative and unknown costs in avoided cost rates. In taking the position that future carbon costs should not be explicitly added to avoided costs, witness Hinton proposed that, in the interests of consistency, the utilities should calculate their avoided energy costs based on a resource mix that assumes no future carbon costs. (Tr. Vol. 7 at 179-80) On cross-examination, witness Hinton acknowledged that assumed future carbon costs were used by DEC in Docket No. E-7, Sub 1032 to calculate the Portfolio Performance Incentive ("PPI") associated with its Demand-Side Management ("DSM") and Energy Efficiency ("EE") programs. (Tr. Vol. 7 at 205-06) He explained that this meant that the underlying avoided energy rates used to test the cost-effectiveness of DEC's DSM and EE included assumed future carbon costs. (*Id.*) On redirect, Public Staff witness Hinton explained that inclusion of future carbon costs in the PPI is distinguishable from the proposed inclusion of such costs in avoided rates because the PPI is intended as an incentive and there is sufficient latitude in the DSM/EE process to permit such inclusion. (Tr. Vol. 7 at 298-99)

In her direct testimony EDF witness Munns discussed EPA's emerging regulation of carbon emissions. (Tr. Vol. 1 at 25) In so doing, she noted that the CO_2 Regulations are not yet final. She also testified that EPA's rules should be flexible in terms of how individual states meet specified emissions targets and that such flexibility could accommodate a number of compliance measures, including renewable resources, distributed generation and energy efficiency measures. (Tr. Vol. 1 at 26) Initially,

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witness Munns did not recommend inclusion of a specific amount of assumed carbon cost in avoided cost calculations at this time. (*Id.*) Rather, she recommended that the Commission consider adoption of rules that encourage a full range of carbon compliance measures. (*Id.*) She further argued that, until EPA finalizes its CO_2 Regulations and the States have had the opportunity to develop their compliance plans that the Commission should maintain a PAF of 1.2 for solar and wind QFs as a proxy for such carbon costs. (Tr. Vol. 1 at 27)

In her rebuttal testimony, witness Munns testified that because EPA had issued its proposed CO2 Regulations since the filing of her direct testimony she believed that there was now less uncertainty regarding the assumed costs of complying with the proposed regulations. (Tr. Vol. 1 at 36) Rather than recommending a specific amount of carbon costs to be included in avoided cost rates, witness Munns recommended that the Commission undertake a process to develop a stand-alone solar avoided cost rate and that carbon costs be included as a factor in that process. (Tr. Vol. 1 at 42)

On cross-examination, EDF witness Munns acknowledged that EPA's proposed CO2 Regulations were not final and may change. (Tr. Vol. 1 at 51-52) She also acknowledged that costs should only be included in avoided cost calculations if they are "known and measurable." (Tr. Vol. 1 at 52) Witness Munns also clarified that she was not recommending the inclusion of projected carbon compliance costs in avoided costs rates prior to the finalization of EPA's CO_2 Regulations. (Tr. Vol. 1 at 49-50) Rather, she was arguing that the Commission should take steps now to prepare for that eventuality. (*Id.*)

In his direct testimony, TASC witness Hornby argued that DEC, DEP and DNCP

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should be required to include a cost of carbon in their avoided cost calculation and that such amount should be equal to or greater than the carbon costs used in the reference cases in their respective IRPs. (Tr. Vol. 5 at 19) The basis for witness Hornby's position is that inclusion of carbon costs in the reference cases in the IRP's shows that the utilities are expecting to incur carbon costs in the future, and therefore, such costs should be included in the utilities' avoided cost calculations. (Tr. Vol. 5 at 41)

On cross-examination, TASC witness Hornby conceded that, while he was aware of numerous utilities across the country that had considered carbon costs in developing their IRPs, he was not aware of any that included carbon costs in the avoided cost calculations. (Tr. Vol. 5 at 75) He also conceded that inclusion of carbon costs in the avoided cost calculation would increase avoided cost rates borne by customers. (Tr. Vol. 5 at 127)

NCSEA witness Beach also argued that projected carbon costs should be included in DEC's and DEP's avoided cost calculations. (Tr. Vol. 5 at 147-49) Like TASC witness Hornby, witness Beach in his direct testimony relied on the fact that the utilities had considered potential future carbon costs in their IRPs as the basis for his argument. (*Id.*) He suggested that, because the future cost of carbon was one of the factors supporting the inclusion of new nuclear generation in DEC's IRP that it would be unfair to QFs not to include such carbon costs in avoided cost rates. (*Id.*) Witness Beach further suggested that by considering potential carbon costs in their IRPs DEC and DEP must necessarily be ascribing value to avoided carbon emissions. (Tr. Vol. 5 at 192)

In NCSEA witness Beach's rebuttal testimony, he takes issue with Public Staff Hinton's position that because carbon costs are uncertain they should not be included in

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avoided costs at this time. (Tr. Vol. 5 at 207) Witness Beach agrees that carbon costs are uncertain, but nevertheless maintains that they are not likely to be zero. (*Id.*) Therefore, he argues that immediately including carbon costs in avoided cost rates is warranted. (*Id*.) Witness Beach stated that he believes that use of potential carbon costs in planning efforts, such as IRPs, supports the use of such potential costs in the avoided cost context because he views avoided cost rates as serving the same purpose as resource planning – i.e., as a guide to resource selection. (*Id.)* Finally, witness Beach suggested that inclusion of carbon costs in avoided cost calculation might be justified as a means of compensating QFs for the general environmental benefits they provide, over and above the actual costs they allow a purchasing utility to avoid. (Tr. Vol. 5 at 211-12)

NC WARN witness LaPlaca testified that the value of avoided carbon emissions should be included in avoided cost calculations, along with a host of other societal, health and environmental benefits of renewable energy. (Tr. Vol. 5 at 287)

In his rebuttal testimony, SACE witness Rabago argued for the inclusion of carbon costs in DEC's, DEP's and DNCP's avoided cost calculation. (Tr. Vol. 6 at 177) Witness Rabago based his argument on the fact that EPA had issued its proposed CO_2 Regulations and, therefore, it was likely that some carbon costs would be incurred by the utilities within the term of many QF contracts entered into now. (*Id.*) Witness Rabago did not offer an opinion as to how such potential carbon costs should be calculated for avoided cost purposes.

Upon careful review of the evidence presented, the Commission concludes that carbon costs should not be included in the utilities' avoided cost calculations at this time. Despite EPA's issuance of its proposed CO_2 Regulations, the Commission finds that

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potential future carbon costs are not sufficiently known or quantifiable to justify their inclusion in avoided cost calculations. The purpose and limits of avoided cost rate making under PURPA is an important factor in reaching this conclusion. It is an absolute requirement that the rates set in this proceeding be no more than the energy and capacity costs avoided by the utilities by virtue of their purchases of power from QFs. To that end, the utilities' avoided cost calculations must include known and measurable costs actually avoided by such QF purchases. For several reasons, the Commission finds that possible future carbon costs do not satisfy those criteria.

First, as Public Staff witness Kirsch rightly points out, North Carolina utilities currently bear no carbon regulation costs at all. The EPA's proposed CO_2 Regulations may change that fact in the future, but there is no guarantee that those regulations will be implemented. Legal challenges, changes in political leadership and other factors could serve to derail the proposed regulations. Utility customers should not be required to bear the cost of potential regulations over the life of long-term QF contracts when the regulations may never come to fruition.

Second, even if one assumes that the carbon regulations will eventually come to pass, there is no certainty as to the timing of such regulations. EPA's proposed CO_2 Regulations are scheduled to take effect in 2016 with the first carbon targets not taking effect until 2020. Any number of factors could result in a change in those schedules. Absent more certainty as to the timing of the regulations and the underlying mandates, there is no reasonable way to accurately project a utility's compliance costs.

Third, putting aside any other issues, EPA's proposed CO2 Regulations are not a straight-forward carbon tax or other $/ton of carbon charge. Rather, EPA has opted for a

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regulatory approach based on state-by-state carbon intensity targets. By its very nature, such an approach makes predicting the cost impact on any particular utility difficult. If some version of EPA's proposed CO_2 Regulations is put into effect, a number of possible compliance alternatives will be available for each state and each utility. In fact, EPA's own publications tout the "flexibility" that its proposed regulations provide to states in developing their compliance plans. EPA has stated that its proposed CO2 Regulations are designed to "offer states broad flexibility" in developing compliance plans, allowing for the use of a wide range of compliance strategies and measures based on the state's particular circumstances and policy goals.[5] Thus, if the proposed CO_2 Regulations are implemented, state compliance plans may include DSM and EE programs, renewable resources, re-firing or fuel switching, new or expanded nuclear capacity, improving efficiency of existing generation, infrastructure investments or other compliance measures. Furthermore, such plans may be developed on a single state or multi-state basis. Under these circumstances, it is not possible with any degree of accuracy to determine the timing or magnitude of compliance costs that a utility might incur if the proposed carbon regulations become effective.

Notwithstanding the numerous uncertainties associated with future carbon regulation, witnesses for NCSEA, SACE and TASC argue that carbon costs should be included in the utilities' avoided costs because the utilities' IRPs include assumptions regarding future carbon costs. This argument fails to take into account the clear distinction between the IRP process and avoided cost ratemaking. As DEC/DEP witness Snider, and Public Staff witness Hinton explained, the IRP is a long-term resource planning exercise. As such, the utilities must consider a number of possible future

[5] http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-flexibility

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scenarios to ensure that their resource plans are robust enough to allow them to fulfill their service obligations. In the case of future carbon regulations, the utilities consider various scenarios of potential carbon costs. This is not done because the utilities believe they can accurately predict the future of such regulation, but rather because they view such regulation as possible. Thus, considering potential carbon costs as part of their IRPs allows the utilities to develop resource plans consistent with their obligation to ensure that they are providing reliable, least cost service to their customers, despite the uncertainties inherent in such long-term planning. The use of potential carbon costs in such scenario planning, therefore, cannot be equated with the level of certainty needed to include those costs in avoided cost rates.

Finally, the Commission declines to adopt the Public Staff's proposal that utilities must calculate their avoided energy costs based on an expansion plan that assumes only known and quantifiable costs. The most obvious effect of the Public Staff's proposal would be to require the utilities to calculate avoided energy based on a zero carbon cost assumption, as opposed to using the base case expansion plan reflected in their IRPs. Public Staff suggests that this approach is necessary for the sake of consistency, but this approach ignores a significant distinction between the inclusion of costs in avoided cost calculations and the long-term projection of a utility's resource plans.

PURPA dictates that costs that are not currently known and measurable should not be included in avoided cost calculations. This is necessary to prevent customers from being burdened by the inclusion of such speculative and unverifiable costs based on guess work as to the cost's timing and magnitude. This is the basis of the Commission's conclusion that assumed future carbon compliance costs should not be included in

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avoided cost rate calculations at this time. Conversely, in developing long term resource plans, public utilities have an affirmative obligation to develop a robust, least-cost plan that accounts for a number of factors. Thus, in the case of future carbon costs, a utility's resource planning should account for the possibility that such costs may be imposed in the future, even if these costs cannot yet be accurately predicted or quantified.

IS IT, THEREFORE, ORDERED as follows:

1. That DEC and DEP shall continue to use the peaker methodology to calculate avoided costs for the purpose of compensating QFs under PURPA.

2. That DEC and DEP shall offer long-term levelized capacity payments and energy payments for five-year, ten-year, and fifteen-year periods as standard options to hydroelectric QFs owned or operated by small power producers as defined in N.C. Gen. Stat. § 62-3(27a) contracting to sell 5 MW or less capacity.

3. That DEC and DEP shall offer long-term levelized capacity payments and energy payments for five-year and ten-year periods as standard options to non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 100 kW or less capacity.

4. That DEC and DEP shall calculate capacity payments to be paid on a per-kilowatt hour (kWh) basis.

5. That DEC and DEP shall calculate capacity credits for purposes of establishing long-term levelized capacity payments that shall take into account the utility's relative need for generating capacity.

6. That, to the extent practical, appropriate and consistent with PURPA,

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DEC's and DEP's filings in their biennial avoided cost rate dockets shall be consistent with their filings in their most recent IRP dockets. DEC and DEP may update information and assumptions from the IRP dockets before they make their biennial avoided cost filings if necessitated by changing market conditions or new or revised cost studies.

7. That DEC and DEP shall base their avoided capacity cost on the average cost of building four CT units at a greenfield site and that avoided capacity cost shall incorporate appropriate economies of scale.

8. That, in calculating their avoided capacity costs, DEC and DEP shall include avoided CT interconnection costs, but shall exclude any estimated T&D system upgrade costs.

9. That, in calculating their avoided capacity costs, DEC and DEP shall use a 5% contingency factor in calculating their respective CT construction cost in this docket.

10. That, in calculating their avoided capacity costs, DEC and DEP shall calculate the annual capacity value of a CT incorporating a 35-year book life.

11. That DEC and DEP shall continue to utilize a 2.0 PAF in their respective avoided cost calculations for hydroelectric facilities with no storage capability.

12. That DEC and DEP shall utilize a 1.05 PAF in their respective avoided cost calculations for all QFs that do not qualify for a PAF of 2.0 as set forth above.

13. That, in calculating their avoided capacity rates, DEC and DEP shall apply the definition of on-peak hours they have proposed in this proceeding.

14. That the avoided cost rates set for DEC and DEP in this docket shall

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include a charge to solar QFs to account for solar integration costs, set at the lowest end of the identified range of integration costs in the compliance scenario within the Duke PV Study or DEC and DEP shall adopt an alternative mechanism to incorporate such integration costs into the avoided cost rates paid to solar QFs.

15. That, except as set forth in ordering paragraph 14, DEC and DEP shall not incorporate the costs or benefits associated with solar integration in its avoided cost rates in this docket. However, DEC and DEP shall undertake an analysis of the costs and benefits of solar integration into their T&D systems with the goal of presenting that analysis in the next biennial avoided cost proceeding.

16. That DEC and DEP shall not maintain avoided cost rate schedules with definitions of on-peak and off-peak hours other than the definitions authorized in ordering paragraphs 13 and 18.

17. That, in calculating their avoided energy rates, DEC and DEP shall incorporate the lost energy value of future CTs deemed to be avoided by virtue of QF purchases.

18. That, in calculating their avoided energy rates, DEC and DEP shall continue to use the definition of on-peak hours currently reflected in their respective Options B.

19. That the future costs of compliance with EPA regulations on requiring reductions in CO_2 emissions are not sufficiently known or quantifiable to justify their inclusion in avoided cost calculations.

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ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ________, 2014.

NORTH CAROLINA UTILITIES COMMISSION

Gail S. Mount, Chief Clerk

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