NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

December 20, 2013

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 136

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket is the Public Staff's Proposed Order.

By copy of this letter, I am forwarding a copy to all parties of record.

Sincerely,

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

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	PUBLIC STAFF'S
Rates for Electric Utility Purchases from	)	PROPOSED ORDER
Qualifying Facilities – 2012	)	

HEARD: Tuesday, February 12, 2013, at 9:00 a.m., Tuesday, October 29, 2013, at 1:00 p.m., and Wednesday, October 30, 2013, at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

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

APPEARANCES:

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

Kendrick C. Fentress and Lawrence B. Somers, Duke Energy Corporation, NCRH 20, Post Office Box 1551, Raleigh, North Carolina 27602

Dwight Allen, Allen Law Offices, PLLC, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27608

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

Horace D. Payne, Jr., Dominion North Carolina Power, 120 Tredegar Street, Richmond, Virginia 23219

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For Renewable Energy Group:

Charlotte A. Mitchell, Styers, Kemerait & Mitchell, 1101 Haynes Street, Suite 101C, Raleigh, North Carolina 27604

For North Carolina Sustainable Energy Association:

Michael Youth, North Carolina Sustainable Energy Association, 1111 Haynes Street, Raleigh, North Carolina 27604

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Chapel Hill, North Carolina 27516

Katie Ottenweller, Southern Environmental Law Center, 129 Peachtree Street, Suite 605, Atlanta, Georgia 30303

For the Using and Consuming Public:

Gisele L. Rankin and Tim R. Dodge, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

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 (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings also are held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of State regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain qualifying facility (QF) status under Section 210 of PURPA. 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 FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to the State regulatory authorities.

State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

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

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

On June 18, 2012, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing*. That Order made Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (New River) parties to the proceeding in order to establish the avoided cost rates each is to pay for power purchased from qualifying facilities pursuant to the provisions of Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. The Order also required each electric utility to file proposed rates and proposed standard form contracts. On June 25, 2012, DEP filed confidential avoided cost data, and on August 24, 2012, DNCP filed a comparison of avoided cost payments.

The Order also stated that the Commission would attempt to resolve all issues arising in the docket based on a record developed through public witness testimony, written statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules, rather than a full evidentiary hearing. DEC, DEP, DNCP, WCU, and New River were required to file their statements and exhibits by November 1, 2012. Other persons desiring to become parties were allowed to intervene and file their comments and exhibits by January 7, 2013, and all parties were required to file reply comments by February 13, 2013, and proposed orders by March 13, 2013. The Commission scheduled a public hearing for February 12, 2013, solely for the purpose of taking nonexpert public witness testimony. Finally, the Commission required DEC, DEP, DNCP, WCU, and New River to publish notice and submit Affidavits of Publication no later than the date of the hearing.

On November 1, 2012, DEC, DEP, DNCP, WCU, and New River made their initial filings setting forth their proposed avoided cost rates and proposed standard form contracts. Also on November 1, 2012, DEP filed a motion to suspend the availability of its Schedule CSP-27 long-term rates. On November 5, 2012, DNCP filed corrected comments, exhibits, and avoided cost schedules.

The following parties filed timely petitions to intervene: the North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville, North Carolina; the Carolina Utility Customers Association, Inc.; the Carolina Industrial Customers for Fair Utility Rates I, II, and III; and the North Carolina Electric Membership Corporation. Each of these petitions was granted. In addition, 15 renewable energy companies collectively referred to as the Renewable Energy Group (REG) also petitioned to intervene and their intervention was granted. This group consisted of the following: Argand Energy Solutions, LLC, Birdseye Renewable Energy, LLC, Carolina Solar Energy, LLC, Community Energy Solar, LLC, ENlight Solar, LLC, FLS Energy, Inc., Mid-Atlantic Renewable Energy Coalition, National Renewable Energy Corporation, 0_2 Energies, Inc., SfL+a Architects, PA, Solbridge Energy, LLC, Strata Solar, LLC, SunEdison, Sunpower Corporation, and Sustainable Energy Solutions. REG amended its Petition to Intervene on January 18, 2013, to include HelioSage Energy, North Carolina Hydro Group, and Sunlight Partners, LLC, and subsequently filed notice that the North Carolina Clean Energy Business Alliance had been added.

On November 6, 2012, NCSEA filed a brief in opposition to DEP's motion to suspend the availability of the currently approved rates. On November 8, 2012, the Commission issued an Order establishing due dates for the filing of comments and reply comments. On November 21, 2012, REG, NCSEA, EWP, LLC, and the Public Staff filed comments in opposition to DEP's motion. The Public Staff, REG, and DEC/DEP filed reply comments and NCSEA filed a reply brief on December 5, 2012. On December 21, 2012, the Commission issued its *Order on Motion to Suspend Avoided Cost Rates*, allowing the suspension and making the proposed long-term rates available subject to a true-up if the Commission approved rates higher than DEP's proposed long-term rates, except for QFs that had filed applications for certificates of public convenience and necessity (CPCN) or reports of proposed construction (RPC) on or before December 1, 2012, and that established a legally enforceable obligation (LEO) prior to the issuance of an Order approving new long-term rates. QFs meeting these conditions remained eligible for the Schedule CSP-27 long-term avoided cost rates.

Upon motion of the Public Staff, the Commission by Order issued December 28, 2012, established discovery deadlines and extended the deadlines for intervention and comments, reply comments, and proposed orders to February 7, March 15, and April 15, 2013, respectively.

On February 7, 2013, the Public Staff filed its Initial Statement, NCSEA filed its Comments and Exhibits, and REG filed its Initial Comments and the Affidavit of Don C. Reading.

The Commission held a hearing for the purpose of taking nonexpert public witness testimony as scheduled on February 12, 2013. The following witnesses appeared at this hearing: Michael D. Whitson, John Morrison, Michael Shore, Bruce Burcat, Beth Henry, Donna Robichaud, and Kevin Edwards.

On March 28, 2013, NCSEA filed a motion for an evidentiary hearing, and the Public Staff filed its Reply Comments stating that an evidentiary hearing would be appropriate. Also on March 28, 2013, DNCP filed reply comments, and DEC and DEP filed Joint Reply Comments. On April 1, 2013, the Commission issued an order allowing comments on the pending requests for an evidentiary hearing and suspending the due date for the filing of proposed orders.

On May 14, 2013, the Commission issued an Order requiring DEC and DNCP to offer, as of the date of the Order, their long-term fixed avoided cost rates proposed in this docket, subject to a true-up if the Commission approved rates higher than those proposed.

On June 6, 2013, the Commission issued an Order scheduling an evidentiary hearing to begin on September 10, 2013, and establishing due dates for intervention and the filing of testimony. On June 26, 2013, the Public Staff filed a motion for a revised procedural schedule, proposing the following: the evidentiary hearing begin on October 29, 2013; the utilities' direct testimony and exhibits be due on or before August 9, 2013; petitions to intervene and intervenor testimony and exhibits be due on or before September 27, 2013; and any utility rebuttal testimony and exhibits be due on or before October 18, 2013. By Order issued July 1, 2013, the Commission granted the motion and rescheduled the evidentiary hearing and extended the procedural schedule.

On August 9, 2013, DNCP filed both confidential and public versions of the testimony of Bruce E. Petrie and Robert J. Trexler. On August 13, 2013, DEC and DEP filed the testimony of Kendal C. Bowman and confidential and public versions of the testimony of Glen A. Snider and the testimony and exhibit of Theodore P. Pintcke.

On August 27, 2013, the Public Staff filed the testimony of Kennie D. Ellis and confidential and public versions of the testimony of John R. Hinton; REG filed confidential and public versions of the testimony of Don C. Reading, the testimony of John E.P. Morrison, and the affidavit of Erik Stuebe; and NCSEA filed the testimony and exhibits of Karl R. Rábago.

On October 18, 2013, DEC and DEP filed confidential and public versions of the rebuttal testimony and exhibits of Glen A. Snider and the rebuttal testimony of Kendal C. Bowman. On the same date, DNCP filed the rebuttal testimony of Bruce E. Petrie and Robert J. Trexler.

On September 9, 2013, Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which the Commission allowed by Order dated September 10, 2013.

On October 18, 2013, NCSEA filed a report titled "The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina" (Report) and a cover letter notifying the Commission and the parties to the proceeding of the report and its impact on NCSEA witness Rábago's testimony. On October 25, 2013, DEC, DEP, and DNCP filed a motion to strike the letter and report, and NCSEA filed a response stating that it could not have filed the letter and Report prior to the due date for pre-filed testimony as the Report was not completed until October 18, 2013. NCSEA further stated that it sought nothing more than to have witness Rábago correct and update his pre-filed testimony from the stand as has been traditionally allowed by the Commission for all witnesses. By Order dated October 28, 2013, the Commission denied the motion to strike, stating that, as the letter and accompanying Report were not testimony, exhibits, or other information to be relied upon at the hearing, the joint motion is not ripe for consideration.

On October 28, 2013, DEC and DEP notified the Commission that they had reached a settlement agreement with the Public Staff and requested that the Commission reschedule the start time of the evidentiary hearing until the afternoon of Tuesday, October 29, 2013, in order to allow time to file the settlement agreement with the Commission prior to the start of the hearing. The Presiding Commissioner granted DEC and DEP's request and rescheduled the evidentiary hearing to begin at 1:00 p.m. on October 29, 2013.

On the morning of October 29, 2013, DEC, DEP, and the Public Staff filed their Stipulation of Settlement. Also on October 29, 2013, DNCP and the Public

Staff filed their Stipulation of Settlement. The case came for hearing as scheduled. During opening statements at the hearing, counsel for DEC and DEP stated that DEC and DEP had reached agreement with REG and NCSEA on the installed cost of a combustion turbine (CT). On October 30, 2013, DNCP and REG filed their Stipulation of Settlement.

On November 14, 2014, in response to concerns expressed by the Public Staff regarding the impression that may have been left by DEC/DEP witness Snider's summary of his pre-filed rebuttal testimony, which did not reference the settlement among DEC, DEP, and the Public Staff, DEC and DEP filed a letter reiterating their support of the CT costs included in the settlement and clarifying that they believe the settlement agreement in its entirety is just and reasonable and should be approved.

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

Based on the entire record in this proceeding, the Commission makes the following:

FINDINGS

1. DEC, DEP, and DNCP should be required to offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane

derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DEC, DEP, and DNCP should offer their standard five-year levelized rate option to all other qualifying facilities contracting to sell three MW or less capacity.

2. For QFs that have a currently effective contract with DNCP under Schedule 19-DRR, it is appropriate that they be grandfathered and for DNCP to continue to maintain, update, and file Schedule 19-DRR until such time as no grandfathered QFs exist. It also is appropriate for DNCP to offer grandfathered QFs the opportunity to switch to Schedule 19-FP by entering into a new Schedule 19-FP contract with a term equal to the remaining duration of the grandfathered contract.

3. It is appropriate for DNCP to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in the 2006 biennial avoided cost proceeding in Docket No. E-100, Sub 106 (Sub 106

Order). It also is appropriate for DNCP to provide a comparison of the peaker method and the PJM market pricing method in the next biennial avoided cost proceeding.

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

5. The peaker method is generally accepted and used throughout the electric industry and is reasonable for use in this proceeding.

6. The input assumptions used by DEC, DEP, and DNCP for the purpose of determining their avoided energy rates are reasonable. The decrease in natural gas price forecasts over the next 15 years is the most significant cause of the much lower avoided energy rates proposed in this proceeding.

7. The installed CT cost per kW (in 2013 dollars) stipulated to by DEC, DEP, and the Public Staff in their Stipulation of Settlement filed October 29, 2013, is reasonable and appropriate for purposes of calculating both DEP's and DEP's avoided capacity rates in this proceeding.

8. The installed CT cost per kW, including AFUDC, stipulated to by DNCP and the Public Staff in their Stipulation of Settlement filed October 29, 2013, and by DNCP and REG in their Stipulation of Settlement filed October 30, 2013, is reasonable and appropriate for purposes of calculating DNCP's avoided capacity rates in this proceeding.

9. A performance adjustment factor (PAF) of 2.0 should continue to be utilized by DEC, DEP, and DNCP (for its Schedule 19-FP) in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation. A PAF of 1.2 should continue to be used for all other QFs.

10. DEP should calculate and include in its avoided cost rate schedule CSP-29 an Option B, with avoided capacity rates calculated using the same on-

peak hours (for both summer months and non-summer months) as used by DEC in its currently effective Option B rates, as provided for in the Stipulation of Settlement entered into among DEC, DEP, and the Public Staff. Its recalculated proposed avoided capacity rates should be offered as Option A under DEP's Schedule CSP-29, and both Option A and Option B capacity rates should be filed for approval by the Commission in this proceeding.

11. Subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of DEP's current review of its time-of-use rates, DEP should meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden should be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.

12. DNCP should calculate and include in Schedule 19-FP an Option B with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC, in its currently effective Option B rates, as provided for in DNCP and the Public Staff's Stipulation of Settlement. DNCP's currently proposed capacity rates should be offered as Option A under DNCP's Schedule 19-FP, and the Option B capacity rates should be filed for approval by the Commission in this proceeding.

13. The value of solar proposition proffered by NCSEA and its witness Rábago should not be adopted at this time. A separate docket should be opened to consider these issues in a broader context, including further consideration of the materials presented in the Crossborder Study, the system impact study that is being developed by DEC and DEP, and other resources that the Commission, Public Staff, and other parties may wish to consider.

14. The provisions in DEC's current tariff and DEP's proposed tariff that limit the availability of long-term avoided cost rates to QFs that are under contract with the utilities on or before November 1 in a year in which a biennial proceeding has been initiated are inconsistent with the Commission's recent arbitration orders and PURPA.

15. Each QF that (a) has obtained a CPCN or filed an RPC, as applicable, no later than November 1 of the year in which a biennial proceeding has been initiated (or the actual filing date of proposed rates if later) and (b) has indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output should be entitled to the fixed, long-term avoided costs rates approved in the immediately preceding biennial proceeding.

16. Because DEC and DEP have the ability to delay the execution of contracts with QFs, DEC's and DEP's tariffs and related documents should be changed so that the fixed long-term rates on DEC's and DEP's approved rate schedules, respectively, are available to all QFs (otherwise eligible) that have established an LEO by November 1, 2014. QFs should be given 30 months from

the date of the Commission's Order establishing avoided cost rates in the pending proceeding to begin delivering power in order to retain the fixed, long-term avoided cost rates in effect before November 1, 2014, and a QF should be allowed additional time if the project in question is making reasonable progress, and the QF is making a good faith effort to complete the project in a timely manner. Absent further order of the Commission, this structure should remain in place without change in the rate schedules and standard contracts except for the update of dates absent further order of the Commission.

17. It is appropriate to reconsider the Commission's prior approval of the limitation in DNCP's tariff that restricts the availability of the standard rates to QFs that enter a contract and begin deliveries within a very narrow window of time. DNCP's proposal in this proceeding that the availability be restricted to QFs that enter contracts and begin deliveries no earlier than January 1, 2013, and no later than December 31, 2014, should be rejected, and DNCP should be required to revise its tariff in accordance with Finding No. 16 above.

18. DEC and DEP, in their 2012 REPS Compliance Plans filed on September 4, 2012, in Docket No. E-100, Sub 137 (Sub 137), inappropriately reported no change in their avoided costs and showed their projected avoided cost rates in 2013 and 2014 to be the same as the avoided cost rates approved in the 2010 avoided cost proceeding in Docket No. E-100, Sub 127 (Sub 127). Because QFs rely on this information, DEC and DEP henceforth should include actual projected avoided costs rates as of the date of the compliance filing.

19. DEC's standard contracts signed between November 1, 2010, and November 1, 2012, should be deemed to include the "Note" in its standard contract filed in the Sub 127 proceeding to the effect that the ability to change the rates in the contract did not apply to the five-, ten-, and 15-year long term rates.

20. DEC's standard contract and rate schedules should be amended by the addition of the language proposed by DEC to cure the deletion of the "Note."

21. It is appropriate to require that all proposed changes to tariffs, terms and conditions, and standard contracts be blacklined in all of the utilities' filings in the biennial proceedings in order to be valid and approved.

22. The provisions in DEP's Terms and Conditions that allow DEP to charge QFs a Reduction in Contract Capacity and a Reduction in Contract Energy are inconsistent with previous rulings of the Commission and should be rejected. In lieu thereof, DEP should be allowed to propose a provision that more narrowly addresses the harm for which it asserts the penalty is designed, i.e., a reduction in production in later years because of the effect of levelized rates.

23. It is appropriate for DEP to amend its Terms and Conditions to reflect the Monthly Facilities Charge approved in DEP's recent general rate case in Docket No. E-2, Sub 1023, and to apply the new charge to all QF contracts that contain a Monthly Facilities Charge, regardless of when the contracts were executed. It is also appropriate for DEC to amend its Terms and Conditions to reflect the Extra Facilities Charge approved in DEC's recent general rate case in

Docket No. E-7, Sub 1026, and to apply the new charge to all QF contracts that contain an Extra Facilities Charge, regardless of when the contracts were executed.

24. DEP should make all other changes it agreed to make in the reply comments filed by DEC and DEP on March 28, 2013.

25. The provision in DNCP's avoided cost standard contract that provides for changes in the amount paid a QF prospectively and potentially requires a QF to repay any amounts disallowed for ratemaking purposes is inappropriate and should be removed from the standard contract.

26. The rate schedules and standard contract terms and conditions proposed in this proceeding by DEC, DEP, and DNCP should be approved, except as otherwise discussed herein. The utilities should be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

27. It is appropriate for DEC, DEP, and DNCP each to include with the new versions of their rate schedules to be filed in compliance with this Order, a public report showing their annualized avoided cost rates calculated in the manner presented in DEC's Exhibit 3 to its filing on November 1, 2012 in this docket. In future avoided cost initial filings and future filings related to approved

avoided cost rates, DEC, DEP, and DNCP each should include a public report showing their proposed annualized avoided cost rates calculated in the manner presented in DEC's Exhibit 3 to its filing on November 1, 2012, for the purpose of allowing QFs and other interested parties to readily discern the effect of the proposed changes to avoided energy and capacity rates.

28. WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution should be approved. The changes the Commission has approved herein to DEC's proposed five-, ten-, and 15-year avoided capacity rates should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 1

No party to this proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell five MW or less capacity or the availability of five-year levelized rate options to all other qualifying facilities contracting to sell three MW or less capacity. The Commission has consistently concluded in prior avoided cost proceedings that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next and that, in doing so, it must balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. The

Commission continues to believe that its decisions in past avoided cost proceedings strike an appropriate balance between these concerns.

In the last biennial proceeding, the Commission directed DNCP to file proposed fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts, as well as proposed rates based upon long-term levelized generation mixes with adjustable fuel prices for QFs larger than 100 kW. In this proceeding, DNCP proposed to establish a new rate schedule, Schedule 19-FP, calculated using the peaker method.

Based on the foregoing, the Commission concludes that DEC, DEP, and DNCP should each offer long-term levelized rate options of five-, ten-, and 15-year terms to hydro QFs contracting to sell five MW or less and to QFs contracting to sell five MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass. The Commission further concludes that DEC, DEP, and DNCP should offer their five-year levelized rate options to all other QFs contracting to sell three MW or less capacity. With these limitations, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments and should continue to be made available.

EVIDENCE AND CONCLUSIONS FOR FINDINGS NOS. 2-3

The evidence supporting these findings are contained in DNCP's Comments, Exhibits, and Avoided Cost Schedules filed (corrected) on November

5, 2012, and the Public Staff's Initial Statement, all of which were admitted into evidence at the outset of the evidentiary hearing.

DNCP proposed to close Schedule 19-DRR upon the approval of Schedule 19-FP except for those QFs that have a currently effective contract under Schedule 19-DRR ("grandfathered QFs"). With regard to such grandfathered QFs, DNCP proposed to continue to maintain, update, and file Schedule 19-DRR for approval until such time as no grandfathered QFs exist. In addition, DNCP proposed to offer grandfathered QFs the opportunity to switch to Schedule 19-FP by entering into a new Schedule 19-FP contract with a term equal to the remaining duration of the grandfathered QF's existing Schedule 19-DRR contract.

The new rate schedule 19-FP would be available to all QFs that qualify for the standard rates. Schedule 19-FP introduces seasonal on-peak and off-peak hours and offers levelized capacity payments for five, ten, and 15 years based upon DNCP's estimate of the installed cost of a CT. The capacity rates for hydroelectric QFs reflect a PAF of 2.0, and the capacity rates for all other eligible QFs reflect a PAF of 1.2.

DNCP also proposed to continue to offer QFs Schedule 19-LMP as an alternative. Under this methodology, DNCP would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kW would be the PJM Dominion

Zone Day-Ahead hourly LMPs divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs, who elect to supply energy only, would be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kWh rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DNCP used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per MW per day from PJM's Base Residual Auction for the Dom Zone. As proposed in the last proceeding, DNCP adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period June 1 through September 30). Depending on the QF's prior year's operations, the SPPF will be one of the following: 0, 0.2, 0.4, 0.6, 0.8, or 1.0.

In its Initial Statement, the Public Staff stated that the proposed Schedule 19-FP complies with the Commission's Order in the 2010 proceeding. However, the Public Staff also noted that DNCP's proposed Schedules 19-FP and 19-LMP do not include a two-year variable capacity rate. The Public Staff stated that such a rate should be included and made available to QFs otherwise eligible for standard rates.

Based upon the foregoing, the Commission concludes that DNCP's proposals to grandfather QFs that have currently effective contracts with DNCP under Schedule 19-DRR and to continue to maintain, update, and file Schedule

19-DRR until such time as no grandfathered QFs exist are reasonable and appropriate. The Commission concludes that it also is appropriate for DNCP to offer grandfathered QFs the opportunity to switch to Schedule 19-FP by entering into a new Schedule 19-FP contract with a term equal to the remaining duration of the grandfathered contract. Finally, the Commission concludes that it is appropriate for DNCP to offer, as an alternative to avoided cost rates derived using the DRR method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Sub 106 Order.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 4

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

The Commission concludes that DEC, DEP, and DNCP should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission Order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise.

The Commission has previously ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously available complaint process. The Commission concludes that the arbitration option should be preserved.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 5

The evidence supporting this finding is contained in the Public Staff's Initial Statement, which was admitted into evidence at the outset of the evidentiary hearing, the testimony of DEC/DEP witness Snider, the testimony of DNCP witness Petrie, and the testimony of Public Staff witness Hinton.

DEC and DEP have used the peaker methodology to develop their avoided costs in each of the past several avoided cost proceedings; DNCP has used the DRR methodology. In this proceeding, in response to the Commission's directive that DNCP file proposed fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts, DNCP employed the peaker method to calculate the avoided cost rates in its proposed Schedule 19-FP.

The Commission has long approved the use of the peaker methodology for the purpose of establishing avoided costs. The Commission has held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker. The Commission has held further that a

CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, avoided capacity costs should equal the cost of a hypothetical CT.

No party contested the appropriateness of using the peaker method to calculate avoided costs. Accordingly, the Commission concludes that the peaker method is generally accepted and used throughout the electric industry and, for purposes of this proceeding, its use is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 6

The evidence supporting this finding is contained in the initial filings of DEC, DEP, and DNCP (corrected) and the Public Staff's Initial Statement, all of which were admitted into evidence at the outset of the evidentiary hearing, and the testimony of Public Staff witness Hinton.

With regard to the proposed avoided cost of energy, the Public Staff stated that it had determined that DEC, DEP, and DNCP all employed many of the same assumptions as to the operating characteristics of their generation units and the same or nearly the same projected cost of fuels, chiefly with respect to their natural gas and coal price forecasts, as used to support their in their 2012 Integrated Resource Plans (IRPs) filed on September 4, 2012, in Sub 137.

DEP proposed to decrease its 15-year avoided on-peak energy rate by 29% and its 15-year avoided off-peak energy rate by 14%. DEC proposed to decrease its 15-year avoided on-peak energy rate by 14% and its off-peak energy rate by 3%. With respect to DEC and DEP, the Public Staff stated that it had reviewed the PROSYM inputs for both utilities as to the projected MWs of generation; variable O&M; outage rates of their generating units; price forecasts for delivered natural gas, coal, oil, and uranium; projected prices of SO_2 and NO_X emission allowances; projected MWh generation from renewable energy resources; projected energy purchases; and other inputs, such as the hourly activations of demand-side management (DSM) programs. The Public Staff's investigation found that the decrease in natural gas price forecasts over the next 15 years is the most significant explanation for the decrease in avoided energy rates. Based on its review, the Public Staff stated that the inputs used by both DEC and DEP in their PROSYM models are reasonable for the determination of both of their avoided energy costs.

DNCP proposed to decrease its 15-year on-peak avoided energy rates by 19% and its off-peak avoided energy rate by 15%. With respect to DNCP, the Public Staff stated that DNCP's method for calculating avoided energy costs for Schedule 19-DRR and its new Schedule 19-FP is consistent with the methods previously employed. DNCP's avoided energy rates were determined using PROMOD to estimate its marginal avoided energy costs for on-peak and off-peak periods over the next 15 years. DNCP incorporated a "base" case and "with" QF capacity case with the resulting output used to determine the avoided energy rates and energy mixes. The Public Staff stated that it had reviewed DNCP's PROMOD inputs as to projected MW generation; variable O&M; outage rates of generation units; price forecasts for delivered natural gas, coal, oil, and uranium;

projected prices of SO_2 and NO_X emission allowances; projected MWh generation from renewable energy resources; projected energy purchases; and other inputs, such as the hourly energy cost per MWh required before DSM is dispatched in the model. Based on its review, the Public Staff stated that DNCP's inputs into the model and the output data from the model are reasonable for the determination of DNCP's avoided energy costs.

While NCSEA argued in its Comments that the Commission should examine whether it was appropriate for DEC and DEP to exclude consideration of hedging costs from the development of their proposed avoided energy costs, it did not file testimony specifically addressing that issue. Otherwise, no party took issue with the proposed avoided energy rates filed by DEC, DEP, and DNCP. Accordingly, based upon the foregoing, the Commission concludes that the proposed avoided energy rates filed by DEC, DEP, and DNCP should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 7

The evidence supporting this finding is contained in the initial filings of DEC and DEP, the Public Staff's Initial Statement, NCSEA's Comments and Exhibits, REG's Initial Comments and the affidavit of REG witness Reading, and DEC and DEP's Reply Comments, all of which were admitted into evidence at the outset of the evidentiary hearing; the direct testimony of DEC/DEP witness Snider, Public Staff witness Hinton, REG witness Reading, the rebuttal testimony of DEC/DEP witness Snider, and the Stipulation of Settlement between DEC, DEP, and the Public Staff.

With respect to avoided capacity rates, for non-hydroelectric QFs, DEC proposed to decrease all of its Option A, on-peak, and off-peak rates by 29%, and its rates for hydroelectric QFs by somewhat different, but comparable amounts. DEP proposed to decrease its 15-year on-peak avoided capacity rates by 22% and its off-peak avoided capacity rates by 25%, and the variable, five-, and ten-year rates by slightly higher amounts. It proposed to decrease its capacity rates for hydroelectric QFs by virtually the same amounts. DNCP proposed to decrease its 15-year on-peak Schedule 19-DRR avoided capacity rates by 7%. Because DNCP previously did not offer its proposed Schedule 19-FP, no comparison can be made.

The evidence shows that, while DNCP used the same CT costs in this proceeding as those used in its 2012 IRP in Sub 137, which was filed two months earlier, DEC and DEP used different assumptions regarding the installed cost of a CT in calculating their proposed avoided capacity rates in this proceeding. These different assumptions account for a significant portion of the decrease in both DEC's and DEP's proposed avoided capacity rates.

The Public Staff, in its Initial Statement said that in both the 2010 and 2008 proceedings, DEP selected Burns and McDonnell Engineering Company, Inc. (B&M), to provide a cost estimate for a CT. For this proceeding, DEP hired the consulting firm of Sargent & Lundy (S&L) to perform a similar cost study, while DEC deviated from its usual practice of relying on in-house expertise and used B&M. The Public Staff further stated that DEC's and DEP's lower proposed avoided capacity rates result mainly from their assumptions with respect to the installed cost of a CT.

In its Reply Comments, the Public Staff emphasized the importance of consistency between the assumptions and the projected CT costs used in the utilities' respective IRPs and in their avoided cost calculations, noting that in the two months between the filing of their IRPs and the filing of their proposed avoided cost rates, DEC and DEP made fundamental changes to the assumptions and data, while DNCP's projected CT cost was consistent with its 2012 IRP. In addition to departing from the data they provided to Astrape Consulting for the reserve margin studies on which they relied in their IRPs, these changes included the following: an unsubstantiated increase in the output of the generic peaker used to develop the avoided capacity rates; an increase in the useful life of such a peaker; a reduction in contingency costs; the deletion of the transmission system upgrade costs that DEC normally includes; and the incorporation by DEC for the first time in its avoided cost calculations of significant economies of scale. In addition, despite the fact that DEC and DEP worked together in an attempt to align their assumptions, there are a number of differences that were not adequately been explained. Accordingly, the Public Staff requested that the Commission schedule an evidentiary hearing for the consideration of the identified issues.

NCSEA's Comments and Exhibits questioned whether DEC's and DEP's collaborative approach in proposing new avoided cost rates violated the "separation" requirement in their Code of Conduct and questioned a number of the assumptions used by DEC and DEP collaboratively to produce their proposed avoided cost capacity costs. NCSEA questioned DEC and DEP's joint assumption of a higher CT rating and a longer useful life and argued that their reduction in owner's contingency and DEC's adoption of DEP's practice of excluding transmission system upgrades were inappropriate.

In summary, NCSEA argued that substantial evidence, attached to the comments as exhibits, suggested DEC and DEP's jointly developed inputs and assumptions were not appropriate and that their avoided cost rates should instead be based on the following alternative inputs and assumptions: lower CT ratings that are consistent with their 2012 IRP assumptions should have been used; the assumed useful life of a CT should continue to be 25 years for DEP and 30 years for DEC; DEC should have used the full estimated owner's contingency costs that were included in the S&L engineering study; DEC should have included transmission system upgrade costs so as to be consistent with its 2012 IRP assumptions; DEC should have used a discount rate that is more comparable to DEP's and DNCP's discount rates; to the extent the contingency costs DEP used are different from those it was provided by its engineering firm, the Commission should scrutinize DEP's reduction as well; and the Commission should examine whether DEP's practice of excluding transmission system upgrade costs (which was adopted by DEC) is appropriate.

REG’s Initial Comments stated that the FERC adopted a full-avoided-cost-rule when it implemented PURPA, and the United States Supreme Court upheld the rule as "just and reasonable to the electric consumers of electric utilities and in the public interest." REG further noted that the members of REG – many of them QFs and others of them businesses that support QFs – reflect the companies that depend on the avoided cost rates established in this proceeding to finance projects in North Carolina that will (1) generate power using renewable energy resources, thereby achieving the objectives of PURPA and S.L. 2007-397 (Senate Bill 3 or SB 3) and facilitating the utilities' compliance with the mandates of SB 3; and (2) create jobs in North Carolina. If QFs in North Carolina are offered rates derived from less than the utilities' full avoided costs, existing in-state QFs will suffer financially, and investors will choose other states in which to deploy capital and develop new renewable energy facilities.

REG’s comments further stated that DEC and DEP, by their own admission, worked together in developing their proposed avoided cost rates, which not only resulted in lower proposed capacity rates for both utilities, but allowed the utilities to pick and choose the values of certain key drivers in their proposed capacity costs. The collaboration also occurred after DEC and DEP filed their 2012 IRPs and REPS Compliance Reports in early September and resulted in large reductions in the proposed costs of a CT during less than a two-month period. As a result, REG asserted that both DEC and DEP have proposed capacity rates that are not reflective of their full avoided costs.

REG witness Reading questioned the installed CT costs used by DEC and DEP in this proceeding, noting that they are significantly lower than the CT costs used in recent and other pending proceedings and lower than the CT costs used by DNCP, in both this docket and its 2012 IRP. He further noted that DNCP's avoided capacity rates are close to that the avoided capacity rates approved for DEC and DEP by the Commission in the 2010 avoided cost proceeding in Sub 127.

In their Reply Comments, DEC and DEP maintained that the following factors appropriately contributed to the decrease in their avoided capacity rates: (1) the increase in the generation output of the new GE 7FA.05 CTs; (2) the ability to combine the knowledge base of DEC and DEP with respect to building CTs as a result of the merger; (3) the use of a lower contingency factor for project risk; (4) the incorporation of economies of scale associated with building four CTs at one site; and (5) the increase in the useful life of the CTs used for modeling purposes. They further stated that differences between current CT cost information and historical CT cost information is not a relevant consideration in determining a utility's current actual avoided costs.

In his direct testimony, DEC/DEP witness Snider testified that the collaborative approach taken by DEC and DEP after the merger of Duke Energy and Progress Energy resulted in a sharing of data and processes that improved the avoided cost rate development process for both of the two utilities. He further testified that DEC's and DEP's proposed avoided capacity rates are based on CT cost estimates that are reasonable, well-developed and verified by multiple sources. He further testified that, contrary to the suggestions of other parties to this proceeding, the post-merger cooperation between DEC and DEP resulted in several decisions that actually increased their proposed avoided cost rates.

DEC/DEP witness Bowman testified that DEC'S and DEP's ability to share information, compare projects, and develop best practices was a significant benefit of the merger for the utilities' customers. Avoided cost rates depend heavily on a number of projections and estimates, including the cost of constructing generation and long-term gas prices. By pooling their data and sharing their individual analyses and projections, DEC and DEP were able to develop a more robust foundation for their avoided cost calculations. DEC and DEP collaborated in the development of their avoided costs to ensure their proposed avoided cost rates are as accurate as possible. The only goal of the collaboration between DEC and DEP was to share information and to compare prices in order to improve the processes by which DEC and DEP calculated their avoided cost rates. DEC and DEP have proposed avoided capacity rates based on CT costs that are supported by numerous industry sources, including two separate cost studies conducted by leading industry experts. All of that data is current and all of it supports the conclusions that DEC and DEP used a reasonable and appropriate estimate of the cost of constructing a new CT in determining their avoided capacity costs.

Public Staff witness Hinton addressed in detail the factual issues raised in the Public Staff's Initial Statement and in its Reply Comments, and discussed his disagreement with all of the assumptions underlying DEC's and DEP's proposed installed CT costs addressed in DEC/DEP witness Snider's direct testimony. He testified that historically DEP had assumed that it could build CTs at a significantly lower cost than DEC. He further testified that both DEC and DEP used substantially lower installed costs of a CT in this proceeding than in the 2010 avoided cost proceeding and that trade publications, producer price indices, and studies of the cost of new entry do not support the dramatic decrease in the installed CT cost proposed by DEC and DEP. Finally, he testified that it was more reasonable to reflect the economies of scale associated with a two-unit CT site, considering DEC's and DEP's expected annual load growth, the uncertainties inherent in long-range forecasts, and the economic advantages of higher capacity factors with combined cycle generation. Based on his opinion that DEC and DEP had failed to fully support their assumptions, his review of various studies related to the cost of new generation, and the significantly higher installed costs filed by DNCP, witness Hinton recommended a higher installed cost be used in this proceeding.

REG witness Reading testified that DEC's and DEP's avoided capacity rates are too low and noted that, even without land and other greenfield site costs, DNCP's proposed avoided capacity rates are closer to the rates previously approved by the Commission for DEC and DEP in the last avoided cost proceeding in Sub 127, as opposed to those proposed by DEC and DEP in this proceeding. He further testified that the cost of future generation plant stated in the 2012 IRPs filed by the utilities defines the long-run avoided capacity cost of the filing utility at the time the filing is made. The filing of the 2012 IRPs by the utilities preceded the filing of their proposed avoided cost rates by just two months. Therefore, the input assumptions used in this proceeding should match those used in the IRPs filed just two months earlier, which was not the case for DEC and DEP. The CT costs they used in their IRPs are significantly higher than those used in this proceeding to determine avoided capacity cost. In addition, the CT costs provided by DEC and DEP to Astrape Consulting for the preparation of reserve margin studies, which were filed with the 2012 IRPs, also produced much higher installed CT costs for both utilities.

In his rebuttal testimony, DEC/DEP witness Snider testified that (1) the intervenors either inappropriately applied or misread studies they relied upon for opposing the CT cost used by the utilities; (2) the five percent contingency figure used by the utilities is consistent with the utilities' actual experience, as well as external studies; (3) the CT cost estimate used by the utilities in calculating their avoided capacity rates are reasonable and well supported; (4) the utilities appropriately relied upon an average CT cost of a four-unit site for calculating avoided costs, given that the utilities typically construct CTs with at least four units at a site; (5) the use of a 35-year useful life in their CT cost estimates is appropriate; and (6) it is appropriate for the utilities to exclude transmission system upgrade costs from their CT cost estimates.

In the Stipulation of Settlement filed October 29, 2013, DEC, DEP, and the Public Staff stipulated as to the reasonable and appropriate installed CT cost per kW (in 2013 dollars) for use in this proceeding to calculate both DEC's and DEP's avoided capacity rates. The Stipulation expressly provided that it did not constitute an admission by any stipulating party as to any of the disputed assumptions used in the calculation of DEC's and DEP's installed CT costs.

During opening statements at the hearing, counsel for DEC and DEP stated that DEC and DEP had reached agreement with REG and NCSEA on the installed cost of a CT and had waived cross-examination on issues related thereto.

DEC/DEP witness Snider stated in his direct testimony that DEC and DEP believe that this settled CT cost is reasonable as a compromise of the parties' respective positions in the context of the resolution of the issues by the Stipulation and asked that the Commission approve the Stipulation in its entirety.

For purposes of this proceeding, the Commission concludes that the installed CT cost agreed to by DEC, DEP, and the Public Staff in their written stipulation and by REG and NCSEA in their oral stipulation, is reasonable and appropriate for use in this proceeding to calculate both DEC's and DEP's avoided capacity rates.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 8

The evidence supporting this finding is contained in the initial filing of DNCP (corrected), the Public Staff's Initial Statement, REG's Initial Comments and the affidavit of REG witness Reading, and DNCP's Reply Comments, all of which were admitted into evidence at the outset of the evidentiary hearing; the testimony of DNCP witness Petrie, Public Staff witness Hinton, REG witness Reading, the rebuttal testimony of DNCP witness Petrie, the Stipulation of

Settlement between DNCP and the Public Staff, and the Stipulation of Settlement between DNCP and REG.

With respect to DNCP's avoided capacity rates, the Public Staff, in its Initial Statement, maintained that the installed CT costs used by DNCP were used in both its IRP and this proceeding, but that such costs did not include land costs for purposes of calculating avoided capacity rates. The Public Staff further stated that this issue was litigated in Docket No. E-100, Sub 87 (Sub 87), and the Commission concluded that land costs must be included in avoided capacity costs. The Public Staff noted in its Reply Comments that DNCP's installed CT cost was in the range of the installed CT costs used in the reserve margin studies performed by Astrape for DEC and DEP and those used in DEC's and DEP's IRPs.

REG's Initial Comments and the testimony of REG witness Reading questioned whether DNCP had properly included financing costs and AFUDC and noted that their inclusion would result in a higher installed CT cost. In addition, DNCP proposed that land not be included as a cost component, which REG noted was inconsistent with the studies performed by third parties in estimating the total cost to construct a CT.

In its Reply Comments, DNCP stated that the suggestion of the Public Staff and REG that DNCP should use the capital cost of a greenfield site CT in its calculation of avoided capacity cost is not appropriate, as greenfield capital costs do not represent the Company's avoided capacity cost in this proceeding. The full cost of a greenfield CT comprises more expenses than simply the cost of land. It also includes, for example, the costs of equipment, construction, electrical interconnect and switchyard, all of which are higher for a greenfield CT than for a brownfield. DNCP agreed that in its Order in the 2000 Biennial Proceeding, as referenced by Public Staff, the Commission stated that it should adopt DNCP's agreement to include land costs in its capacity credits, and concluded that DNCP should be required to include the capital costs of land in its calculation of capacity credits, but noted that the ruling was only for purposes of that specific proceeding. DNCP believes that the correct CT capital cost for setting avoided capacity cost rates in this proceeding is the capital cost required to construct a CT on a brownfield site, rather than on a greenfield site.

In his direct testimony, DNCP witness Petrie testified that the inputs and assumptions on which DNCP based its CT cost calculations are consistent with those supporting the installed cost of a CT in its 2012 IRP. Consistent with the installation of such a CT on a Company-owned site, also as reflected in the IRP, DNCP did not include land or other "greenfield" costs in its CT cost calculation, because the avoided land costs for that CT are zero. In justification for the exclusion of land costs, witness Petrie stated that DNCP has multiple existing brownfield sites available where there is adequate land and where the site configuration would allow the addition and build-out of at least 800 MW of CT units. Because DNCP would not incur or avoid any land costs for the CT, DNCP's position is that the avoided land costs are zero. With respect to the Commission's ruling in Sub 87, that DNCP was required to include land costs in its calculation of capacity credits, he testified that this holding was only in the circumstances of that proceeding.

Public Staff witness Hinton testified that he was comfortable with the total amount of DNCP's projected CT costs, but that the Public Staff has a long-standing position favoring the inclusion of land cost because the peaker method uses a hypothetical CT and is designed to approximate the cost of a baseload plant. While utilities sometimes add capacity at existing sites, they also build capacity at greenfield sites, such as the Lee Nuclear plant that has been identified as a potential plant in DEC's IRP.

REG witness Reading testified that DNCP's estimate of the installed cost of a CT is the highest among the three utilities, and, in contrast to DEC's and DEP's filing, the CT costs used by DNCP in this proceeding are the same as those used in its 2012 IRP. However, REG witness Reading opined that the installed cost of a CT would be higher if financing costs and AFUDC were included, as would be proper. In addition, DNCP's proposal that land not be included as a cost component is inconsistent with the studies performed by third parties in estimating total cost to construct a CT.

Witness Petrie stated in his rebuttal testimony that he disagreed with Public Staff witness Hinton's position that DNCP's installed CT cost estimate should include "land cost" even though DNCP intended to install CTs at brownfield sites. DNCP has multiple existing brownfield sites available where there is adequate land and where the site configuration would allow the addition and build-out of at least 800 MW of CT units. As a result, DNCP witness Petrie stated that DNCP would install such CT capacity on such brownfield sites.

With respect to REG witness Reading's recommendation that a greenfield site be used, witness Petrie reiterated the arguments he had offered in response to Public Staff witness Hinton's similar recommendation. With respect to REG witness Reading's position that DNCP's installed CT cost did not include AFUDC and financing costs, witness Petrie stated that REG witness Reading was correct, but that such costs are accounted for separately by DNCP's calculations and are indeed included in the final proposed avoided capacity cost rates. Because financing and AFUDC costs are accounted for elsewhere in the Company's model, including them in the installed CT figure would result in double counting of those costs.

In the Stipulation of Settlement filed October 29, 2013, between DNCP and the Public Staff and in the Stipulation of Settlement filed October 30, 2013, between DNCP, REG, and NCSEA, the parties agreed that the installed CT cost per KW in 2013 dollars (excluding AFUDC and the cost of CWIP as allowed in Virginia and land and other greenfield costs) was the amount stated in DNCP's comments filed in November 2012 and in the direct and rebuttal testimony of DNCP witness Petrie. The parties further agreed that, under the avoided cost methodology used by DNCP, the cost of AFUDC is accounted for separately from the calculation of the CT installed cost, but the AFUDC and financing cost amounts were included in the final calculation of DNCP's avoided capacity cost rates. They also agreed that the installed CT cost on which DNCP's proposed avoided capacity rates were based, when adjusted to include AFUDC, was a reasonable and appropriate installed cost per kW for purposes of calculating DNCP's avoided capacity rates in this proceeding. The Stipulations expressly provided that they do not constitute an admission by any stipulating party that land or other greenfield related costs should or should not have been included in DNCP's calculation of installed CT cost.

For purposes of this proceeding, the Commission concludes that the installed CT cost stipulated to by DNCP, the Public Staff, and REG is reasonable and appropriate for use in this proceeding to calculate DNCP's avoided capacity rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS NOS. 9-12

The evidence supporting these findings is contained in REG's Initial Comments, NCSEA's Comments, and the Reply Comments of DEC and DEP, DNCP, and the Public Staff, all of which were admitted into evidence at the outset of the evidentiary hearing; the testimony of DEC/DEP witnesses Bowman and Snider, DNCP witness Petrie, Public Staff witness Ellis, NCSEA witness Rábago, and REG witness Reading; and the rebuttal testimony of DEC/DEP witness Bowman and DNCP witness Petrie.

In its Initial Comments, REG requested that the Commission approve a 2.0 PAF for solar and wind QFs, in addition to using such a PAF for run-of-the-river hydroelectric QFs. REG stated that the Commission has authorized the use of a PAF in calculating the capacity credit of avoided cost rates for those utilities that rely on the peaker methodology to determine avoided costs, in recognition of the fact that certain generating facilities cannot operate at all times. NCSEA indicated in its Comments that it supported REG's request that the Commission adjust the PAF for solar and wind.

REG stated that in the last six avoided cost proceedings, the Commission has ordered DEC and DEP to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation, most recently in the Sub 127 proceeding, and to utilize a PAF of 1.2 for all QFs that do not qualify for a PAF of 2.0.

REG noted that the Commission explained the reason for the 2.0 PAF for run-of-river hydro generating facilities in its Sub 106 Order, as follows:

> The actual reason for using a 2.0 PAF for run-of-river hydro QFs has been that doing so allows them to receive the full capacity payments to which they are entitled while operating under the constraints created by their stream flows. As the Public Staff witnesses pointed out, using a 2.0 PAF places run-of-river hydro QFs on an equal footing with run-of-river hydro generating facilities included in the rate base of the State's utilities, which are able to cover the full costs of these facilities. With respect to solar and wind QFs, however, this comparison has no relevance, because the State's utilities have no solar or wind facilities in rate base. On the other hand the Commission agrees that solar and wind QFs, like run-of-river facilities, have no control over their energy sources. This is a legitimate argument for treating them in the same manner as run-of-river hydro QFs.

Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 106, December 19, 2007, p. 20.

Also in the Sub 106 proceeding, the Commission declined to calculate avoided capacity rates using a PAF other than the 1.2 PAF for solar and wind, stating that its reasoning for using a 2.0 PAF for run-of-the-river hydro had no relevance to solar and wind because the utilities did not have any such facilities in their rate bases. On the other hand, the Commission agreed that solar and wind QFs, like run-of-the-river hydro, have no control over their energy source and found that to be a legitimate argument for treating them in the same manner. The Commission ultimately concluded that it should continue its existing practices with the understanding that the parties should further address PAF-related issues in the next biennial avoided cost proceeding. (Sub 106 Order, pp. 21-22) The issue was not litigated during the last two biennial proceedings.

REG stated that several factors justify the Commission reconsidering the PAF for solar and wind facilities, including those discussed in the 2006 proceeding. First, REG noted that solar and wind QFs, like run-of-river facilities, have no control over their energy sources and no storage capability. This creates a significant disadvantage for these facilities since none of the utilities proposes to offer capacity credit in the off-peak, which means that QFs that rely on intermittent resources will receive only the energy credit of the avoided cost rate for the power produced in the off-peak. However, utilities recover their full capacity costs regardless of when their facilities produce power. REG noted by way of illustration, that the capacity cost of a utility-owned peaker that sits idle 11 months out of the year is fully recovered in the utility's rate base. Second, REG noted that DEC has already added utility-owned solar to their resource mix and that both DEC and DNCP indicated in their 2012 IRPs that they plan to add solar capacity to their resource mix. REG stated that to the extent solar capacity additions are made through self-build programs, the utilities are entitled to recover the full cost of constructing these facilities. Similarly situated QFs, however, would be penalized under the avoided cost rates, as the rates do not include capacity credits for power produced during the off-peak.

REG also stated that FERC had recently ruled that it is permissible for states to differentiate among QFs using various technologies when establishing avoided cost rates.[1] "Because avoided cost rates are defined in terms of cost that an electric utility avoids by purchasing capacity from a QF, and because a state may determine what particular capacity is being avoided, the state may rely on the cost of such avoided capacity to determine the avoided cost rate. Thus, the avoided cost rate may take into account the cost of electric energy from the generators being avoided, e.g., generators with certain characteristics."[2] In their Joint Reply Comments, DEC and DEP stated that none of the rationales offered by REG warrant increasing the PAF paid to solar and wind QFs for the following reasons: (1) A facility should be considered only to have value as capacity if and to the extent it operates during peak periods, so off-peak power from a QF does not allow a utility to avoid any capacity costs; (2) a peaker is available to provide power even when it is idle, therefore satisfying a utility's need for capacity even when it is not operating; (3) the concept of parity between utility-owned facilities

[1] California Public Utilities Commission, Docket No. EL 10-64-002, Order Granting Clarification and Dismissing Rehearing, 133 FERC 61,059 (2010); 27; Order Denying Rehearing, 134 FERC 61,044 (2011), 32 and 33 (footnotes omitted) (*CPUC).*

[2] *Id*. at 15.

and QFs is not relevant in the context of determining the utilities' avoided cost rates; and (4) the FERC's decision in *CPUC*, that distinctions could be made in the avoided cost rates applicable to different technologies if those technologies satisfied different needs for a utility, is not relevant in North Carolina.

DEC and DEP further stated that as a result of PURPA and the State REPS requirements, North Carolina has seen a tremendous increase in the development of solar facilities, and that no further encouragement is needed for the development of such QFs. DEC and DEP further stated that they were concerned about the costs of the potential impact of REG's proposal. As an illustration, they estimated that for every 1,000 MW of new solar QFs that execute 15-year fixed rate contracts, a PAF of 2.0 would impose an incremental cost over the 15-year life of the contract of over $150 million on consumers based on the avoided cost rates proposed by the utilities.

DEC and DEP lastly stated that REG's proposal to establish a PAF based on the operating characteristics of each resource is not in alignment with the goals of PURPA to set rates based on the costs that a utility is avoiding. DEC and DEP acknowledged in their Reply Comments that the integration of intermittent resources, such as solar and wind, is an issue of growing importance and recommended that the Commission consider holding a separate workshop to address the integration of intermittent resources into the utilities' systems. In its Reply Comments, DNCP stated that it opposed REG's proposal to increase the PAF to 2.0 for solar and wind because wind and solar generation is intermittent in nature, does not produce energy dependably over the super-peak hours, and is not dispatchable and controllable like a CT unit. DNCP stated further:

> In the PJM capacity market, and in the electric industry in general, it is recognized that wind and solar generators have reduced capacity during the summer super-peak hours when the energy is most needed. Under PJM market rules, 100 MW (nameplate) of new wind capacity is given credit for 13 MW of effective capacity, and 100 MW (nameplate) of new solar capacity is given credit for 38 MW of effective capacity. Therefore, it is not reasonable to expand the use of a PAF of 2.0 to a solar or wind resource that is intermittent in nature and less valuable from a reliability perspective.

DNCP Reply Comments, p. 14.

DNCP stated that if the Commission decided to implement a PAF of 2.0 for wind and solar facilities, DNCP would propose to establish capacity rates based on 13% and 38% of the cost of a CT, specifically for wind and solar, respectively. These rates would better represent the avoided capacity costs related to these intermittent and less reliable renewable resources. Additionally, DNCP indicated that if the Commission implemented a PAF of 2.0 for wind and solar facilities, it would request a cap on its annual capacity payments in order to avoid paying a QF in excess of its allotted annual capacity payment.

In its Reply Comments, the Public Staff stated that it believes it would be appropriate for the Commission to address the need for a solar-related PAF, and, given the *CPUC* decision and the REPS requirements of SB 3, appropriate for the Commission take steps to evaluate the appropriate treatment of avoided costs in this context.

DEC/DEP witness Bowman testified that increasing the PAF to 2.0 for solar and wind QFs is inconsistent with the purpose and intent of SB 3 and that the increase in the PAF would result in a significant economic burden on the utilities' customers without a legitimate policy basis for doing so. Witness Bowman stated that SB 3 established a policy to allow for the recovery of costs that exceeded utility avoided costs, but was not designed to increase the avoided cost rates paid to renewable QFs. Further, witness Bowman indicated that the growing amount of solar and wind generation that are already in the utilities' interconnection queues demonstrates that the current avoided cost rate structures is adequate to satisfy the State's policy to encourage the development of new renewable energy projects.

DEC/DEP witness Snider reiterated DEC and DEP's opposition to increasing the PAF for wind and solar, as originally stated in their Joint Reply Comments. DNCP witness Petrie stated that, in compliance with long-standing Commission precedent, DNCP used a PAF of 2.0 for hydro projects with no storage capability and no other generation, and a PAF of 1.2 for all other QFs eligible for its newly proposed Schedule 19-FP. Witness Petrie reiterated DNCP's opposition to increasing the PAF for wind and solar. Witness Petrie elaborated further on the *CPUC* proceeding and asserted that the FERC's decisions in that case do not provide meaningful guidance on the PAF issue in North Carolina. He stated that the *CPUC* line of cases arose out of a specific legislative Californian mandate that required California utilities to enter into contracts with combined heat and power (CHP) facilities that met certain efficiency and emissions standards, at prices set by the CPUC. The question dealt with whether PURPA allowed the CPUC to create a multi-tiered avoided cost rate structure that calculated estimated avoided prices for purchases from CHP QFs separately from avoided costs for purchases from other QFs. Witness Petrie found that due to distinctions between the *CPUC* orders and how PURPA is implemented in this State, the *CPUC* orders did not provide meaningful guidance on the PAF issue in this proceeding.

Public Staff witness Ellis provided a brief history of the PAF and stated that in the early years of its implementation of PURPA, the Commission approved a capacity credit adjustment using a 20% reserve margin, which was subsequently renamed the PAF. The Commission consistently has recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive payments equal to the utility's avoided capacity costs. More specifically, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided cost without a PAF would require a QF to operate 100 percent of the on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled.[3] Using a 1.2 PAF allows QFs to receive payment of the utility's full avoided capacity costs if it operates 83 percent of the on-peak hours. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating

[3] Tr. Vol. 3, p. 25, referencing Sub 127 Order at pp. 11-12.

in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Witness Ellis stated that since 1997 the Commission has ordered that a PAF of 2.0 be utilized by both DEC and DEP in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation. The use of a 2.0 PAF requires a QF to operate 50 percent of the on-peak hours in order to collect the full capacity credit. He further stated that the Public Staff, in the Sub 106 proceeding, had opined that, in addition to considering the appropriateness of using a different PAF for solar QFs, the Commission should consider whether there are other ways by which capacity credits could be spread over fewer on-peak hours. Witness Ellis stated that the Public Staff believes DEC's Option B has some merit in this regard and that the Commission should consider requiring DEP and DNCP to offer a comparable Option B in addition to their traditionally-calculated avoided capacity rates.

REG witness Reading repeated REG's recommendation that the Commission increase the PAF applicable to avoided capacity calculations for wind and solar QFs to 2.0. He stated that the Commission has repeatedly ordered DEC and DEP to utilize a PAF of 2.0 in their respective avoided cost calculations for certain hydro facilities, and to use a PAF of 1.2 for other QFs. He noted that the Commission has explained that the use of a higher PAF for these hydro facilities does not exceed avoided costs; it simply changes the method by which the avoided costs are paid to the QF. In recognition of the fact that certain

QFs cannot control their energy source, a PAF is intended to allow such QFs to receive full capacity payment to which they are entitled.

NCSEA witness Rábago testified that, as a result of his review of past positions in this case and his review of valuation of solar (VOS) studies and analyses, he believes that an equitable basis exists for increasing the PAF for solar pending a more comprehensive and precise valuation. Mr. Rábago noted that the Commission's adoption of a 2.0 PAF for small hydroelectric was designed to serve as a kind of equitable relief for QFs that do not have control over their "fuel" source and therefore otherwise are denied the opportunity to recover full capacity payments. He stated that a 2.0 PAF for solar could similarly serve to address the same issue hydroelectric QFs had faced and that solar QFs currently face.

Witness Rábago added that he believes application of a PAF of 2.0 for solar is the least disruptive way to address the discrimination in this proceeding. Witness Rábago further testified:

> A PAF adjustment could serve as a near-term and longer-term "fix," but I recognize that, with the advent of VOS analysis, such an adjustment may prove to be too imprecise for the longer-term. For the foregoing reasons, I recommend that the Commission (1) increase the PAF for solar electric generation in this proceeding to 2.0 to make the electric utilities' offerings to distributed solar facilities better approximate full avoided costs, and (2) indicate that the increased PAF is intended as an interim measure and will be re-examined in the 2014 biennial avoided cost proceeding (which will be opened less than a year after the final order is issued in this proceeding), at which time the Commission will determine whether to make permanent any PAF adjustment or to establish a solar-specific avoided cost rate or take other action in light of any North Carolina-specific VOS studies.

Tr. Vol. 2, p. 179.

In her rebuttal testimony, witness Bowman stated that the Commission should reject the proposed increase in the PAF for solar and wind QFs proposed by REG and NCSEA, for the reasons DEC and DEP had originally laid out in their Reply Comments and testimony. Further, with regard to NCSEA witness Rábago's VOS analysis, witness Bowman stated that this type of analysis is inappropriate for setting avoided cost rates and is irrelevant to the present proceeding.

In his rebuttal testimony, DNCP witness Petrie repeated DNCP's opposition to the increase in the PAF for solar and wind QFs proposed by REG and NCSEA. Witness Petrie stated that using the VOS analysis as proposed by NCSEA witness Rábago was not in line with the requirements of PURPA to compensate QFs for the costs that are avoided by utilities.

Turning now to the Option B issues, Public Staff witness Ellis explained that, in its reply comments in Sub 106, the Public Staff had recommended that the Commission, in addition to considering the appropriateness of using a different PAF for solar QFs, consider whether there are other ways by which capacity credits could be spread over fewer on-peak hours. He further stated that the Public Staff believes that DEC's Option B has some merit in this regard and that the Commission should consider requiring DEP and DNCP to offer a comparable Option B in addition to their traditionally-calculated avoided capacity rates.

DEC/DEP witness Bowman testified in rebuttal that conceptually, DEP's current avoided cost rate schedule is equivalent to DEC's Option B. Like DEC's Option B, DEP's avoided cost rates uses a definition of on-peak hours that is based on the on-peak hours reflected in DEP's non-residential Time-of-Use (TOU) rate schedules (Schedules LGS-TOU and SGS-TOU). Thus, DEP's avoided cost rates and DEC's Option B both use a TOU based definition of on-peak hours to focus avoided capacity rate payments on the times when the need for capacity is highest, which is the best measure of when power purchased from a QF provides meaningful capacity value. Although DEP's avoided cost rates and DEC's Option B share a common conceptual basis, however, they are not identical. The definition of on-peak hours applied in DEP's non-residential TOU rate schedule and its avoided cost rate schedule is more expansive than the definition of on-peak hours reflected in DEC's non-residential TOU rates and in DEC's Option B. She added that DEP's avoided cost rate schedule (and its non-residential TOU rates) uses a definition of on-peak hours that encompasses 3,132 hours, as opposed to the 1,860 on-peak hours reflected in DEC's Option B (and DEC's non-residential TOU rate schedules). She further testified that it is unnecessary for DEP to amend its avoided cost rate schedule as proposed by Public Staff witness Ellis.

In addition, witness Bowman testified that DEP is currently assessing the design of its TOU rates, as it committed to do in its recent rate case, and is to propose new TOU schedules within two years. After this assessment is complete, DEP intends to continue its practice of using a consistent definition on-peak hours for its TOU rates and its avoided cost rates. It is possible, although not certain, that such assessment will result in DEP proposing changes to its TOU rates, including a redefinition of on-peak hours that is more similar to the definition reflected in DEC's Option B. In any event, these assessments should be completed before any premature changes are made. Further, she testified that, as a practical matter, DEP would find it difficult to adopt a significant change in the definition of on-peak hours now before the assessment of DEP's TOU rates is completed. Consequently, it would be problematic for DEP to implement Public Staff witness Ellis' recommendation before it is made moot by DEP's reassessment of its TOU rates.

DNCP witness Petrie testified on rebuttal that DNCP is not opposed to adding an Option B type rate offering, in addition to its existing rate offerings, so long as the PAF used in the Option B rate offering is 1.2. He noted that the definition of on-peak hours in Option B is consistent with customers' current demand patterns, and covers those hours when the system is most likely to experience its peak load. He noted, however, that as customer demand patterns change (for example, with increasing penetration of distributed solar generation), adjustments to the on-peak hours definition may be appropriate. If DNCP adds an Option B type rate offering, and subsequently concludes that such a change is required, it would bring the issue to the Commission's attention in its biennial filings.

The Stipulation between DEC, DEP, and the Public Staff and the Stipulation between DNCP and the Public Staff resolved the Option B/PAF issue.

The parties to those two stipulations agreed that DEP and DNCP will calculate and include in their Schedule CSP-29 and Schedule 19-FP, respectively, an Option B with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC in its currently effective Option B rates. DEP and DNCP will file such Option B, using the on-peak hours set out in their Stipulations with the Public Staff, for approval by the Commission in this proceeding. The Stipulation further provided that DEP's and DNCP's proposed capacity rates, as ultimately approved by the Commission, would be offered as Option A under DEP's Schedule CSP-29 and as Option A under DNCP's Schedule 19-FP.

With respect to DEP, the Stipulation provided further that, subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of the current review of its time-of-use rates, DEP will meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden will be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.

At the hearing, DEC/DEP witness Bowman provided a statement of support for the Stipulation and a brief overview of the provision relating to DEP's adoption of a rate schedule comparable to Option B. Pursuant to the Stipulation, DEP will file an additional avoided cost rate schedule that applies a definition of on-peak hours that is consistent with the definition of on-peak hours contained in DEC's Option B. This definition of on-peak hours is narrower than the definition in DEP's proposed avoided cost rate schedule. As a result, the new DEP rate schedule will have higher avoided capacity rates than DEP's currently filed avoided cost rate schedule. Witness Bowman further stated that DEC and DEP believe that DEP's adoption of the new rate schedule comparable to DEC's Option B is a reasonable compromise of the parties' respective positions in the context of the resolution of the issues by the Stipulation. DEC and DEP asked that the Commission approve the Stipulation in its entirety.

DNCP witness Petrie reiterated DNCP’s support for the Public Staff's suggestion that DNCP offer avoided cost rates similar to the Option B rates offered by DEC, so long as the PAF used in the Option B-type rate offering is 1.2 for non-hydro QFs.

Based upon the foregoing, the Commission concludes that a PAF of 2.0 should be utilized by DEC and DEP in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation and that a PAF of 1.2 should be used for all other QFs. Further, the Commission concludes that DEP and DNCP should calculate and include in their respective Schedules CSP-29 and 19-FP, an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC in its currently effective Option B rates, as provided for in the Stipulations of Settlement entered into among DEC, DEP, and the Public Staff and between DNCP and the Public Staff. DEP's and DNCP's avoided capacity rates, as approved herein, should be offered as Option A under DEP's Schedule CSP-29, and both Option A and Option B capacity rates should be filed for approval by the Commission in this proceeding. Finally, the Commission concludes that DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's as specifically provided for in the DEC/DEP and Public Staff Stipulation, subject to approval by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 13

The evidence supporting this finding is contained in the testimony of Public Staff witness Ellis and NCSEA Witness Rábago and the rebuttal testimony of DEC/DEP witness Bowman and DNCP witness Petrie.

Public Staff witness Ellis described some of the ways that QFs, under properly established avoided cost rates, can potentially provide positive benefits to ratepayers in the State, including the following: price stability and cost reductions; reduced construction and financing costs; better matching of resource additions to load growth; enhanced system reliability through the distributed nature of the resource; and compliance with State renewable energy policies. Witness Ellis also noted that DEC, DEP, and DNCP are all summer peaking systems, and that it is appropriate to consider the value of the power provided by generating systems that operate during these times of higher customer demand and to encourage production during periods of time when the value of the electricity is greater to the purchasing utility and to ratepayers. He further stated that, to a limited extent, this is one of the particular advantages that solar photovoltaic generation offers. As a result, the Public Staff recommended that the Commission direct DEP and DNCP to offer an Option B rate schedule comparable to DEC's Option B, in addition to their traditionally-calculated avoided capacity rates.

NCSEA witness Rábago stated that valuation techniques for distributed solar energy have significantly improved over time, providing better information about how distributed solar can maximize benefits to the utility and to ratepayers. He noted that information is available to address biases against renewable energy resources, such as undervaluation of risk reduction, especially fuel price risk, and similar risks relating to water, carbon regulation, and other factors, that may arise using traditional avoided cost methodologies.

Witness Rábago further testified that numerous published VOS studies are now available that confirm distributed solar resources cumulatively "offer energy, capacity, line loss savings, financial, and security benefits that exceed retail rates for electricity and, therefore, these resources should be paid their full avoided costs." Witness Rábago noted that integration costs must also be considered.

Witness Rábago updated his testimony to include as an exhibit the October 18, 2013, report titled “The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina,” prepared by Crossborder Energy (Crossborder Study), and indicated that the report provided North Carolina-specific confirmation of his assertion that the value of solar in North Carolina and, hence, the appropriate avoided cost, is higher than that proposed by the utilities.

DEC/DEP witness Bowman testified that the VOS analysis proposed by witness Rábago is inappropriate for setting avoided cost rates and is not relevant to the present proceeding. On cross-examination, she agreed that DEC and DEP had previously reported to the Commission that they were “initiating a comprehensive study seeking to identify and, where possible, quantify potential benefits and costs of solar generation across the entire generation, transmission and distribution systems" and that “[t]hese study results would be incorporated into the resource planning and avoided cost processes in order to reach the optimal economic solution when building or procuring solar resources."[4]

DNCP witness Petrie stated that using the VOS analysis as proposed by NCSEA witness Rábago was not in line with the requirements of PURPA to compensate QFs for the costs that are avoided by utilities. He noted that the VOS as described by witness Rábago provides compensation to QFs not only for the costs that are avoided by utilities but also for perceived benefits of solar QFs, such as “‘reputational community participation,’ recognition of financial risks

[4] Tr. Vol. 3, p. 186, quoting from NCSEA Bowman Rebuttal Cross Examination Exhibit Number 1.

associated with ‘future control regimes’ and ‘societal benefits’ such as job growth, and increased local tax revenues.” Witness Petrie stated that while DNCP believes that a VOS analysis may be a way to ascertain the value of solar facilities to society generally, it is not a methodology for determining avoided costs as defined by PURPA. In addition, he noted that “other avenues exist for local, state and federal entities, if they choose, to compensate QFs for these types of intangible or unquantifiable benefits, as currently evidenced by the various tax benefits, renewable energy credits and other incentives for QFs that produce these sorts of benefits.”

The Commission recognizes the potential magnitude of the impacts 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 than was provided during this proceeding, and have relevance to multiple other proceedings before the Commission, including resource planning, REPS compliance, future avoided cost determinations, and others.

As a result, the Commission declines to adopt the value of solar proposition proffered by NCSEA and its witness Rábago, but instead will open a separate docket to consider these issues in a broader context. This separate docket will allow for further consideration of the materials presented in the Crossborder Study, the system impact study that is being developed by DEC and DEP, and other resources that the Commission, Public Staff, and other parties may wish to consider.

EVIDENCE AND CONCLUSIONS FOR FINDINGS NOS. 14-17

The evidence supporting these findings is contained in the Public Staff's Initial Statement and Reply Comments, REG's Initial Comments, NCSEA's Comments, the DEC/DEP Reply Comments, and DNCP's Reply Comments, all of which were admitted into evidence at the outset of the evidentiary hearing, and the testimony of DNCP witness Petrie.

DEP proposed in initial filing to incorporate into its tariff the limitation contained in DEC's tariff making the long-term avoided cost rates in the approved tariff available only to QFs that are under contract on or before November 1 of the year proposed avoided cost rates are filed with the Commission. Contemporaneously with its initial avoided cost filing, DEP filed a motion to suspend the availability of its Schedule CSP-27 long-term rate. In its Reply Comments to DEP's suspension motion, that Public Staff stated that it believes that the Commission's *Arbitration Orders*[5], PURPA, and the FERC's implementing regulations all require that the standard for eligibility be based upon when a QF filed its application for a CPCN and that the date should be no later than November 1, 2012. For QFs that met that filing date, the Public Staff opined that they are entitled to any of the avoided cost rate options in the currently approved Schedule CSP-27, including the long-term options (assuming they are otherwise eligible in terms of size and such factors). For QFs that did not reach the filing date, the Public Staff took the position that DEP should be required to

[5] Order dated June 18, 2010, in Docket No. SP-467, Sub 1, involving Economic Power and Steam, LLC; and Order dated January 26, 2011, in Docket No. E-22, Sub 966, involving EPCOR USA North Carolina, LLC (referred hereafter collectively as the *Arbitration Orders*).

sign contracts at whichever of its new, proposed rates the QF chooses, subject to an upward adjustment if the Commission ultimately approves avoided cost rates that are higher.

The Public Staff further stated that the foregoing is consistent with the Commission’s treatment of a comparable motion to suspend filed by Duke Power Company (Duke) in the 1994 PURPA proceeding in Docket No. E-100, Sub 74. In that case, as in this one, the proposed avoided cost rates were substantially lower than those approved in the prior proceeding, and Duke proposed that it be allowed to sign contracts at the new, proposed avoided cost rates. The Commission, citing Section 292.304(d) of the FERC’s regulations, ruled that Duke must sign contracts at the 1992 rates with any QF that wanted those rates and already had a CPCN by the date of the Commission’s Order so ruling. The Order was issued on February 13, 1995, approximately four and a half months from the filing of the new, proposed avoided cost rates and two and a half months from the filing of Duke’s motion to suspend the currently approved rates. For QFs that did not meet the cut off, the Commission allowed the signing of contracts at the proposed rates, subject to adjustment upward if the Commission ultimately approved avoided cost rates that were higher.

Noting that QFs under two megawatts (MW) in size are now exempted from the certification requirement in G.S. 62-110.1, the Public Staff recommended that the appropriate standard to be applied to these QFs is whether or not they filed their reports of proposed construction by November 1, 2012. The Public Staff stated QFs that meet this deadline should be entitled to any of the avoided cost rate options in the currently approved Schedule CSP-27, including the long-term options (assuming they are otherwise eligible). For otherwise eligible QFs that do not meet this deadline, DEP should be required to sign contracts at whichever of its new, proposed rates the QF chooses, subject to an upward adjustment if the Commission ultimately approves avoided cost rates that are higher.

The Commission, by Order dated December 21, 2012, ruled that QFs that had filed applications for CPCNs or RPCs on or before December 1, 2012, and that established an LEO prior to the issuance of an order approving new long-term rates, remained eligible for the Schedule CSP-27 long-term avoided cost rates. The Commission allowed the suspension for other QFs and made the proposed long-term rates available subject to a true-up if the Commission approved rates higher than DEP's proposed long-term rates.

In its Initial Statement, the Public Staff stated that it believes that the provisions in DEC's and DNCP's current tariffs, along with DEP's proposed provision, limiting the availability of long-term avoided cost rates to QFs that are under contract with the utilities on or before November 1, are inconsistent with the Commission's recent *Arbitration Orders* and PURPA. At the time the provisions were approved for DEC and DNCP, the Commission had not yet established the parameters of the LEO concept based upon the FERC's decisions in *J.D. Wind 1, LLC*.[6] Citing the FERC's regulations, the Commission,

[6] 129 FERC ¶ 61,148 (2009) (November 19 *J.D. Wind* Order), *reconsideration denied*, 130 FERC ¶ 61,127 (2010) (February 19 *J.D. Wind* Order) (collectively referred to as the *J.D. Wind* Orders).

in its *Arbitration Orders*, stated that a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from it. Thus, the Commission held that a QF has the option of either selling energy on an "as available" basis or selling energy and capacity pursuant to a LEO over a specified term. If it chooses the latter, it has the further option of choosing a rate based on avoided costs calculated at the time the obligation is incurred.

In addition, the Commission cited the FERC's statement in its *J.D. Wind* Orders that a QF has a right to long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.

The utilities all propose that the determining factor be whether or not a QF has signed a purchased power agreement (PPA). While it has been the FERC's long-standing practice to leave to state commissions the issue of when and how an LEO is created, the Public Staff asserted that this does not mean that a state commission is free to ignore the requirements of PURPA or the FERC's regulations. PURPA requires that the FERC's rules encourage QF development, and Section 210(f) of PURPA, 16 U.S.C. § 824a-3(f), requires the states to implement the rules adopted by the FERC.

The *Arbitration Orders* were the first time the Commission had had to address the prerequisites for an LEO to have occurred or to have been created. The Commission had previously used the issuance of a CPCN as a standard for determining the availability of approved rates after the filing of proposed rates and continued that practice in this context. The Commission also added that the QF needed to have made it clear to clear to the utility that it wanted to commit itself to sell its output pursuant to an LEO over a specified term. Thus, the Public Staff argued, a tariff provision that limits the availability of the currently approved long-term avoided cost rates to QFs that have signed PPAs by November 1 of the year new proposed avoided cost rates are filed is inconsistent with this standard and prior Commission Orders. In any event, the Public Staff opined that using the signing of a PPA as the determining factor is unlawful because it is totally inconsistent with the purpose of the LEO concept and leaves a QF's options entirely in the hands of the utility.

In its reply to DEP's motion to suspend and in its Initial Comments, REG argued that in the past, when the Commission has entered suspension orders when new, lower avoided cost rates were proposed, the Commission has always allowed exemptions from the suspensions. *See, e.g., Order on Motion of Consolidated Hydro*, Docket No. E-100, Sub 79, issued June 19, 1997. These exemptions are ultimately based on PURPA regulations that give QFs the right to rates calculated at the time their obligation is incurred. Therefore, those QFs deemed ready, willing, and able to enter into an LEO were entitled to the old rates and were exempted. REG noted that in contrast with the DEC motion filed in 1996, DEP's motion did not include a CPCN-related exception, and it provided negligible advance notice to QFs already in project development, particularly those with pending applications for CPCNs. REG argued that allowing this type of last minute downward adjustment to avoided cost rates jeopardizes many QFs that are in project development, citing as an example that there was at least one member of REG that has multiple projects in development for which a CPCN has been issued, an interconnection agreement has been executed, interconnection fees paid to DEP, but for which DEP has yet to execute a PPA. Allowing the relief requested by DEP, and in effect allowing DEP unilaterally to control whether a QF receives a PPA at the currently approved rates, REG argued is fundamentally unfair.

REG further noted that, as had been previously argued by Public Staff, the FERC explicitly concluded in its order implementing PURPA that, under PURPA, QFs are entitled to be protected from future changes in avoided cost projections and not deprived of the benefits of fixed rates established at the time the QF made its commitment. In addition, the Public Staff has pointed out that to the extent FERC's regulations and orders are not clear, the fact that the overriding purpose of PURPA is to encourage the development of QFs dictates that the regulations be interpreted so as to provide that encouragement.

Thus, given PURPA's requirements and the FERC's statements that: (a) a QF is entitled to fixed rates; (b) fixed rates enable the investor to determine the expected return on a project and thus, ultimately, whether to finance the project; and (c) the overriding purpose of PURPA is to encourage the development of QFs, a tariff provision that allows only variable rates to be available to the QF during the pendency of the avoided cost proceeding is inconsistent with the FERC's rulings.

PURPA conditions a QF's right to rates derived from avoided costs on QF status and not on a utility's willingness to contract. Specifically, PURPA and its regulations establish the right of a QF to rates derived from avoided costs at the time the LEO arises, which is based on the status of the QF and not based on any date or deadline established by the utility. See 18 C.F.R. § 292.304(d)(2)(ii). In interpreting PURPA, the Commission has determined that a LEO arises when the QF: (a) commits itself to sell its output to a utility (which concomitantly commits the utility to purchase the output from the QF); and (b) has a CPCN.

NCSEA's stated in its Comments that, while the availability of proposed fixed avoided cost rates instead of variable rates might satisfy North Carolina statutory language, the absence of an option for solar and other renewable developers to select a Commission-vetted and Commission-approved fixed five-, ten-, or 15-year avoided cost rate does not comply with PURPA. NCSEA further stated that PURPA and North Carolina law are violated when only a take-it-or-leave-it variable rate is made available until new rates are established. PURPA is still violated (even if State law is not) by the mere added availability of proposed, but unvetted, fixed five-, ten-, and 15-year avoided cost rates that are subject to upward true-up when new rates are established by Commission order.

In its Reply Comments, the Public Staff stated that for the same reasons the Commission concluded that DEP must offer approved rates to QFs that had timely filed applications for CPCNs or RPCs, the Commission must change DEC's and DNCP's tariffs so that fixed long-term rates remain available to QF.

In their Reply Comments, DEC and DEP argued that approval of DEC's, and now DEP's, interim suspension of their respective standard long-term, fixed avoided cost rates as of the date of their next biennial filing (November 1, 2014) continues to be reasonable. Consistent with the explanation previously provided by DEC and relied upon by the Commission in past proceedings, the intent of this contractual language is to allow long-term avoided costs rates offered to QFs to more closely align to the utilities' actual avoided costs. As explained in the past, suspending the long-term rates after the utilities file proposed new rates also avoids the potential for QFs to attempt to-"lock in" at the utilities' currently authorized long-term avoided cost rates if a utility's avoided costs have declined compared to its current long-term rates. Consistent with past practice for DEC, QFs will have the option under both DEC's and DEP's avoided cost rates to convert from the variable contract rate to the long-term fixed rates once the Commission's order approving new avoided cost rates is issued or, if the QF elects to remain on variable rates, the previously existing variable rates will be superseded by the newly approved variable rates. Thus, as noted by the Commission in prior proceedings, the import of this provision is simply to ensure that QFs are receiving the utility's actual avoided costs and to "prevent QFs from gaming the system" to take advantage of outdated calculations of avoided cost rates. Finally, DEC and DEP argued that the requests of intervenors to disallow this practice has not raised any arguments not already considered by the Commission in its Sub 127 Order.

DNCP, in its reply comments, argued that December 31, 2014, is the appropriate cut-off for the availability of DNCP's proposed Schedule 19-FP and Schedule 19-LMP because that is the end of the two-year period forming the basis for the estimated avoided cost rates contained in the schedules proposed in this proceeding. During the interval between January 1, 2013, and the Commission's final order in this proceeding, DNCP will enter into contracts with QFs that can meet the deadline at the rates and terms and conditions in the proposed Schedule 19. DNCP explained further that a QF that will not begin delivery of power between January 1, 2013, and December 31, 2014, will not be eligible for the avoided cost rates and contracts approved during this proceeding. Instead, DNCP will enter into contracts with such at rates, terms and conditions contained in the then proposed or approved Schedule 19 that covers the period in which the QF will begin deliveries of power.

DNCP further noted that this provision was reflected in DNCP's Schedule 19 rates filed as part of the Sub 127 proceeding, in which the Commission found that the Company's limitation of availability of Schedule 19 to QFs that can begin delivery of power to DNCP during the specified period to be "reasonable, consistent with PURPA and Commission orders implementing PURPA." DNCP also argued that the Sub 127 Order was issued after the issuance of the *JD Wind* Orders and Arbitration Orders, which indicates that the Commission found this provision and policy to be consistent with the intervening precedent.

DNCP asserted that avoided costs determined in the Commission's biennial proceedings are necessarily based on the assumption that QFs will begin power deliveries during the proposed two-year period. For example, in this proceeding, DNCP argued that its Schedule 19-FP rates are all based on the assumption that a QF will start delivering power to the utility in either 2013 or 2014, and DNCP does not believe that any avoided cost rate estimates will be developed or approved in this proceeding for QFs that begin operating in 2015, 2016, or beyond. DNCP asserted that a different conclusion would require the calculation of avoided cost rates for years not covered by the Schedule 19 rates approved in this proceeding, using different data and assumptions.

The Commission has previously concluded, in the context of arbitration proceedings involving QFs not entitled to standard contracts, that the FERC's regulations provide that a QF has a right to choose fixed long-term avoided cost rates calculated at the time an LEO is created even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.

That right is in no way limited to small QFs or QFs not eligible for standard contracts, as argued by DNCP. All QFs are entitled to fixed avoided costs at the outset of the creation of the obligation in the QF to sell energy and capacity, which the Commission has ruled occurs when the QF has its CPCN or has filed an RPC and indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output.

The effect of DNCP's narrow window is that a small QF requiring a construction time of more than a few months could not know the avoided cost rates to which it would be entitled before beginning construction. Given the time it takes to complete the interconnection process, as well as any applicable permitting requirements, very few QFs would be able to complete development, acquire financing, and finish construction in the narrow period of time allowed by DNCP's current provision. This renders the availability of the long-term rates illusory and it is inconsistent with the stated purpose behind the FERC's requirement in its Order No. 69 that a QF be able to establish a fixed contract price for its energy and capacity at the outset of its obligation. The FERC's stated purpose was to make it possible for an investor to be able to evaluate the financial feasibility of a QF by providing reasonable certainty as to the expected return on a potential investment before construction on a facility is begun. *Order Denying Reconsideration*, 130 FERC ¶ 61,127 (2010).

With respect to DNCP's argument that its Schedule 19-FP rates are based on the assumption that a QF will start delivering power to the utility in either 2013 or 2014, such an assumption has not been the practice in avoided cost proceedings before the Commission. DEC's tariff explicitly applies to a QF that begins delivery of power within 30 months from the earlier of the date of the contract or six months after the filing date of new proposed avoided cost rates, thus extending beyond DNCP's cut-off. Of greater significance is the Commission's Order dated December 22, 1993, in Docket No. SP-65, Sub 1. This case began on August 26, 1993, when a QF, Enerco Systems, Inc. (Enerco), filed a letter asking to renew its CPCN for a 4.95 MW project that was under construction at that time. DEP (then CP&L) filed a complaint stating that six years had passed since the contract was signed, and the rates established by the initial contract no longer represent DEP's current avoided costs. DEP requested that the Commission rule the existing contract to be null and void and require Enerco to enter into a new contract. The Commission required DEP to honor the contract and concluded that the FERC's regulations allowed Enerco the option of avoided cost rates calculated at the time the legal obligation was incurred. The Commission, therefore, ruled that Enerco was entitled to the 15-year rate option that was in effect at the time the contract was signed (five or six years earlier).

By their very nature, the 15-year rates are based upon projections of costs out into the future using forward looking data. A QF that establishes a LEO is explicitly entitled to such 15-year rates whether or not it begins to deliver power within a year or two of establishing the LEO. Given the FERC's regulations and this Commission's interpretation of them, DNCP's argument that the standard avoided cost rates approved in this proceeding were calculated using data and assumptions applicable to the commencement of delivery of power in 2013 and 2014 and not beyond must be rejected.

Based upon the foregoing, the Commission concludes that the provision in DEC's current tariff and DEP's proposed tariff that limit the availability of long-term avoided cost rates to QFs that are under contract with the utilities on or before November 1 in a year in which a biennial proceeding has been initiated, are inconsistent with the Commission's recent arbitration orders and PURPA. Further, the Commission concludes that each QF that (a) has obtained a CPCN or filed an RPC, as applicable, no later than November 1 of the year in which a biennial proceeding has been initiated (or the actual filing date of proposed rates if later) and (b) has indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output should be entitled to the fixed, long-term avoided costs rates approved in the immediately preceding biennial proceeding.

Because DEC and DEP have the ability to delay the execution of contracts with QFs, the Commission believes that DEC's and DEP's tariffs and related documents should be changed so that they provide that the fixed long-term rates on DEC's and DEP's approved rate schedules, respectively, are available to all QFs (otherwise eligible) that have established a legally enforceable obligation by November 1, 2014. QFs should be given 30 months from the date of the Commission's Order establishing avoided cost rates in the pending proceeding to begin delivering power in order to retain the fixed, long-term avoided cost rates in effect before November 1, 2014, and should be allowed additional time if the projects in question are nearly complete and the QF is making a good faith effort to complete the project in a timely manner. Absent further order of the Commission, this structure is to remain in place without any change in the rate schedules or standard contracts except for the relevant dates.

It is similarly appropriate for DNCP to be required to amend the availability section of its avoided cost tariffs to remove the requirement that a QF must enter into a contract and begin deliveries within a very narrow window of time. DNCP's proposal in this proceeding that the availability be restricted to QFs that enter contracts and begin deliveries no earlier than January 1, 2013, and no later than

December 31, 2014, should be rejected and DNCP should be required to revise its tariff in accordance with the above discussion.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 18

The evidence supporting this finding is contained in the Comments of REG and the testimony of REG witness Reading and the Reply Comments of the Public Staff and is essentially uncontroverted. The affidavit of REG witness Reading and the various replies that were filed in response to DEP's motion to suspend the availability of its approved avoided cost rates discussed Commission Rule R8-67(b)(l)(v), which requires electric power suppliers to include "the current and projected avoided cost rates for each year" in their REPS compliance plans. On September 4, 2012, DEC and DEP filed their 2012 REPS compliance plans in Sub 137, and neither of them projected any decrease in avoided costs rates in its filing. Instead, both companies projected avoided cost rates to remain at their currently approved levels through the 2013-2014 biennium. DNCP's 2012 REPS compliance plan, in contrast, showed a projected decline in rates.

In its Reply Comments, the Public Staff stated that it had come to its attention that a number of QFs relied on the avoided cost projections filed in DEP's and DEP's 2012 REPS compliance filings and that QFs had invested time and money in preparing CPCN applications without any awareness that a November 1, 2012, deadline would be requested.

The Commission concludes that DEC and DEP, in their 2012 REPS Compliance Plans filed in Sub 137, inappropriately reported no change in their avoided costs, showing their avoided cost rates in 2013 and 2014 to be projected to be the same as the avoided cost rates approved in Sub 127. Because QFs rely on this information, DEC and DEP henceforth should include actual projected avoided costs rates, as of the date of compliance filing.

EVIDENCE AND CONCLUSIONS FOR FINDINGS NOS. 18-21

The evidence supporting these findings is contained in the Public Staff's Initial Statement, REG's Initial Comments, and DEC and DEP's Reply Comments, all of which were admitted into evidence at the outset of the evidentiary hearing.

In its Initial Statement, the Public Staff noted that the last sentence of Section 2 of DEC's standard contract states the following:

> Said [Rate Schedule and] Service Regulations are subject to change, revision, alteration or substitution, whether in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction, and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict herewith.

The Public Staff further stated that, prior to the 2010 proceeding, the following language appeared immediately thereafter: "Note: "Rate Schedule and" included in the above sentence for variable rates only." In the Sub 127 proceeding, this "Note" was omitted and it was not blacklined as a proposed change. The Public Staff opined that this may have been inadvertent given that the Commission has consistently ruled that the rates and essential terms of signed standard contracts cannot be changed by subsequent regulatory action. The Public Staff recommended that the Commission require that the "Note" be added back into DEC's standard contract and that standard contracts signed between November 1, 2010, and November 1, 2012, be deemed to include the "Note."

REG's Initial Comments also raised this issue, stating that the proposed DEC standard contract in this proceeding does not contain the limitation that had previously been included, thereby subjecting both the variable rates and fixed rates to change. The removal of this limitation undermines the availability of fixed long-term rates "calculated at the time the obligation is incurred" as required by PURPA, 18 C.F.R. § 292.304(d)(2)(ii), and, moreover, undermines the confidence of potential investors. REG requested that the final sentence of this section be modified, consistent with previously approved standard contacts, to exclude fixed rates.

In their Reply Comments, DEC and DEP stated that the only issue raised concerning DEC's Terms and Conditions relates to Section 2 and that the Public Staff and REG both noted that certain language that had been included in previous versions of Section 2 had been omitted. The language in question pertains to the effect of changes made by the Commission to DEC's rate schedules and service regulations. Section 2 of DEC's Terms and Conditions provides those rate schedules and service regulations are subject to change by the Commission and any such changes "shall immediately be made a part [of the

QF contract], and shall nullify any prior provision in conflict therewith." Previously, DEC's Terms and Conditions also included language that limited the reference to changes in rate schedules to "variable rates only." The Public Staff and REG questioned the omission of that language.

DEC and DEP further stated that DEC removed the language in question because it was over-broad and appeared to suggest that long-term fixed rate contracts would not be subject to changes in non-rate terms and provisions. The Reply Comments stated that, in removing this language, DEC did not intend to imply that the long-term fixed avoided cost rates themselves were subject to change during the term of a contract. In light of Public Staff's and REG's Comments, DEC proposed to amend Section 2 of its Terms and Conditions to include the following language:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges), and all non-rate provisions.

The Reply Comments further stated that DEC believes that the foregoing language addresses the concerns raised by the Public Staff and REG.

This issue was not addressed in testimony at the hearing, and the Public Staff and REG indicated their agreement with this solution in their post-hearing filings. Therefore, the Commission concludes that it is appropriate for DEC's standard contract to be amended by the addition of the language proposed by DEC.

As a result of DEC's undisclosed deletion of the "Note," as discussed above, the Public Staff recommended in its Initial Statement that the Commission include in its order in this proceeding the requirement that all proposed changes to tariffs, terms and conditions, and standard contracts be blacklined. Asserting that the workload of the Commission and the Public Staff is such that reviewing all of these filings word by word should not be required, the Public Staff requested that the Commission's order explicitly state that only the proposed changes blacklined in the filings that are not otherwise discussed are being approved.

Based upon the foregoing, the Commission concludes that DEC's standard contracts signed between November 1, 2010, and November 1, 2012, should be deemed to include the "Note" in its standard contract filed in the Sub 127 proceeding to the effect that the ability to change rates in the contract did not apply to the five-, ten-, and 15-year long term rates. Further, the Commission concludes that DEC's standard contract should be amended by the addition of the language proposed by DEC. In the future, all proposed changes to tariffs, terms and conditions, and standard contracts must be blacklined in all of the utilities' filings in the biennial proceedings in order to be valid and approved.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 22

The evidence supporting this finding is contained in the REG's Initial Comments, the Public Staff's Reply Comments, and DEC and DEP's Reply Comments, all which were admitted into evidence at the outset of the evidentiary hearing, the testimony of DEC/DEP witness Bowman and the testimony of REG witness Morrison.

In its Initial Comments and the testimony of REG witness Reading, REG objected to the provisions of Section 6 of DEP's Standard Terms and Conditions, which provides for an adjustment in the event that a QF fails to provide the contracted-for energy specified in the agreement. The subsection on the reduction in contract energy contains a Reduction-In-Contract-Energy-Charge if the "Seller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak energy level." REG objected to the Reduction-in-Contract-Energy-Charge as unnecessary and unduly punitive for QFs that generate electricity using intermittent sources. Electric utilities do not pay QFs unless energy is generated by and received from the QF. Charging a small QF for failure to produce 20% of contract energy unfairly enriches the electric utility at the expense of the QF. This is particularly unfair when the QF relies on hydro, solar, or wind sources to run and has no control over its ability to produce energy. REG requested that the Reduction-In-Contract-Energy-Charge be removed from DEP's Terms and Conditions.

In its Reply Comments, the Public Staff stated that the Commission has previously held in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide, but the utility could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel, such as run-of-the-river hydro, solar, and wind, absent an explicit order from the Commission. QFs under the standard contracts are not paid unless they are generating, and therefore a penalty is unwarranted. The Public Staff, therefore, recommended that DEP be required to delete this charge from its Terms and Conditions.

In their Reply Comments, DEC and DEP stated that REG overstated the effect of Section 6 because the Reduction-in-Contract-Energy-Charge is not triggered by failure to meet hourly, daily, monthly or even seasonal production goals. It can only be invoked if the QF fails to meet its contracted-for energy targets over a 12-month period. Moreover, the calculation called for in Section 6 is based on a 12-month average, which gives the QF the benefit of any periods in which it produced energy in excess of the contracted-for amounts. Thus, Section 6 does not require a QF to predict precisely its hour-to-hour or day-to-day energy production; it merely requires that over the long term that the QF perform as represented (or at least at 80% of its represented capability). DEC and DEP also asserted that REG ignored the most important aspect of the Reduction-in-Contract-Energy-Charge – its purpose. As the Commission has observed, long-term levelized rate QF contracts create a tension between encouraging QF development, on the one hand, and the risk of overpayments to QFs, on the other. One source of that tension is that long-term levelized rates tend to overpay QFs in the early years and underpay QFs in later years. Consequently, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes, and could even disappear, over the life of a long-term levelized rate contract. DEC and DEP argued that it would be unfair to DEP and its customers for a QF to underperform during the latter part of its contract, having already reaped the excess benefits provided by levelized rates in the earlier years of the agreement. The Reduction-in-Contract-Energy-Charge prevents that situation by providing a mechanism to adjust the contract to restore the expected balance of the economic benefits to both parties in the event the QF's performance falls materially short of its contractual obligation.

REG witness Morrison testified that a subsection of Section 6 of DEP's Terms and Conditions for the Purchase of Electric Power contains a Reduction-In-Contract-Energy-Charge if the "[seller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak energy level." The Reduction-in-Contract-Energy-Charge is unnecessary and unduly punitive for QFs that generate electricity using variable resources. He noted that the utilities do not pay a QF unless electricity is generated by and received from the QF. Charging a small QF when production is off by 20% (or falls below 80%) unfairly enriches the electric utility at the expense of the QF, and it is particularly unfair when the QF relies on variable resources such as hydro, solar, or wind and causes hardship for the QF developer when attempting to access capital on reasonable, workable terms.

Therefore, the Reduction-In-Contract-Energy-Charge should be removed from the DEP Terms and Conditions. He added that it is worth noting that the DEC Standard Contract does not contain an identical provision, which is an improvement in process and practice that DEP should be required to adopt.

In her rebuttal testimony, DEC/DEP witness Bowman stated that the Reduction-in-Contract-Energy-Charge provides for a modification of the amounts paid to a QF in the event that the QF fails to provide the amount of energy called for in the contract. The purpose of the Reduction-in-Energy-Contract-Charge is to ensure the economic balance of levelized QF contracts is maintained throughout the life of the contract. She asserted that the Reduction-in-Energy-Contract-Charge is, therefore, neither punitive nor unfair. It merely restores the intended economic balance of the agreement in the event that a QF fails to deliver energy commensurate with the contract energy level. Moreover, DEP has never applied the Reduction-in-Contract-Energy-Charge in a punitive manner and has never had to resort to the Reduction-in-Contract-Energy-Charge to resolve a performance issue with a QF.

Witness Bowman also noted that the Reduction-in-Contract-Energy-Charge only comes into play after the QF has operated for two years, which allows the QF time to work out any initial startup issues. It also gives the QF two years to assess the actual operating capability of its facility and determine whether it can meet its contractual obligation.

The Commission concludes that the provisions in DEP's Terms and Conditions that allow DEP to charge QFs a Reduction-in-Contract-Capacity and a Reduction-in-Contract-Energy starting two years after a QF begins operations are inconsistent with previous rulings of the Commission and with DEP's stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts. Accordingly, such provisions should be removed from the DEP's Terms and Conditions. In lieu thereof, DEP may propose a provision that allows it to take action if the harm it alleges the penalty is designed to fix (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval.

EVIDENCE AND CONCLUSIONS FOR FINDINGS NOS. 23-24

The evidence supporting these findings is contained in the comments filed by REG and NCSEA and in the reply comments filed by DEC and DEP. They are essentially uncontroverted. REG and NCSEA raised concerns about whether the reductions from 2% to 1.3% in monthly facilities charge associated with additional facilities, and from 1.0% to 0.5% under the contributory option, that were requested in DEP's rate case in Docket No. E-2, Sub 1023, which was pending at the time of the initial filings in this proceeding, would be reflected in the monthly facilities charge applicable to QF interconnection facilities.

In their Reply Comments, DEC and DEP stated that this change will be effective upon approval by the Commission, at which time DEP will apply the new rates to all contracts that contain the Monthly Facilities Charge, regardless of when the contracts were executed. DEP stated that it believes that this process resolves any issues REG may have regarding these charges.

The Commission concludes that it is appropriate for DEP to amend its Terms and Conditions to reflect the Monthly Facilities Charge approved in Docket No. E-2, Sub 1023, and to apply the new charge to all QF contracts that contain a Monthly Facilities Charge, regardless of when the contracts were executed.

The Commission notes that DEC similarly reduced its Extra Facilities Charge in its recent general rate case in Docket No. E-7, Sub 1026 from 1.7% to 1.1% in monthly facilities charge associated with additional facilities. The Commission concludes that it is also appropriate for DEC to amend its Terms and Conditions to reflect the Extra Facilities Charge approved in Docket No. E-7, Sub 1026, and to apply the new charge to all QF contracts that contain and Extra Facilities Charge, regardless of when the contracts were executed.

With respect to the other issues related to DEP's Terms and Conditions, the Commission concludes that DEP should make all other changes it agreed to make in the Reply Comments filed by DEC and DEP on March 28, 2013.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 25

The evidence supporting this finding is contained in the testimony of DNCP witness Trexler and the testimony of REG witnesses Morrison and Stuebe.

Article 6 of DNCP's proposed standard contract covers the situation where a regulatory commission issues an order that prohibits DNCP from recovering in rates the payments it has made to a QF and/or requires DNCP to refund to ratepayers the payments it has already made to a QF (the Regulatory Disallowance Clause). This clause provides that in the event of an order from a regulatory commission that is found to be lawful, the rates provided under the standard contract will be reset on a prospective basis at levels that DNCP is allowed to recover in rates. It also provides that if the regulatory commission requires DNCP to refund previous QF payments to its ratepayers, the QF must refund those amounts to DNCP.

The Public Staff took issue with this provision in the Sub 127 proceeding, arguing that since a standard agreement for renewable QFs contracting to sell 5 MW or less is all that is involved, such a provision seemed unwarranted and likely to discourage QF development. In addition, the Public Staff argued that this requirement has the effect of changing the rate paid to the QF because of subsequent regulatory action, which was rejected in 1983 in Docket No. E-100, Sub 41, when language was proposed that would have allowed existing standard contracts to be amended as the result of subsequent governmental or judicial action. (Commission Sub 127 Order, p. 21)

DNCP argued in the Sub 127 proceeding that the Regulatory Disallowance Clause is warranted and that there is no evidence that the clause has discouraged QF development. DNCP also noted, citing, for example, *Freehold Cogeneration Assocs. v. Board of Regulatory Comm'rs of New Jersey*, 44 F.3d 1178 (3d. Cir. 1995), that QFs and their lenders know, as does DNCP, that a regulatory disallowance is a remote possibility under existing law and precedent.

Based on the record in that proceeding, the Commission found that DNCP's inclusion of a regulatory disallowance clause in its Schedule 19-DRR was reasonable and should be allowed. (Sub 127 Order, p. 22)

In this proceeding, REG witness Stuebe testified that the company with which he is associated, Ecoplexus, currently has multiple 5 MW solar QFs under development in DNCP's service territory and that he has been involved in attempting to secure financing for these projects. Ecoplexus has sought financing for these projects from two lenders, both of which have financed more than $100 million of solar generation projects. One of the lenders has previously financed Ecoplexus solar generation projects in other states. Both lenders declined to finance these North Carolina projects because of Article 6 in DNCP's standard agreement, which requires a QF to accept payments that are reset at new rate levels or to repay certain sums to DNCP in the event a regulatory body with jurisdiction, such as the Commission or FERC, issues an order that (1) disallows payments of energy or capacity to non-utility generators; (2) prohibits DNCP from recovering through rates any sums previously paid to non-utility generators; or (3) requires DNCP to repay to ratepayers sums already paid to non-utility generators. Based on his experience in attempting to develop solar QFs in DNCP's service territory, witness Stuebe testified that this provision constitutes a barrier to finance.

REG witness Morrison testified that the uncertainty created by Article 6 of DNCP's proposed standard contract is a barrier to financing a QF project, as investors are unwilling to overlook the asserted right of DNCP to modify rates and collect a refund. This contract provision is one of the primary reasons why QF development in DNCP's service territory is minimal, relative to the service territories of DEC and DEP. Furthermore, as explained by the FERC in its Order No. 69, in order to be able to evaluate the financial feasibility of a QF, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before the construction of a facility. Witness Morrison further testified that the unnecessary uncertainty created by the provision regarding an investor's expected return on a potential investment appears to be a violation of Order No. 69. Additionally, the contract provision is inconsistent with the clear and unambiguous right of the QF set forth in 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of the power purchase agreement. He further stated that in his own experience, Strata has not developed solar facilities in DNCP service territory because of this provision. Thus, he concluded, the contract provision discourages QF development.

In his rebuttal testimony, DNCP witness Trexler explained that DNCP has had this provision or one similar to it in its Schedule 19 PPAs since at least 1997 and that those PPAs have been accepted by this Commission as reasonable. In the previous biennial proceeding, the Commission specifically held that the Regulatory Disallowance Clause was reasonable and should be allowed. While unlikely, the risk of a disallowance order is real. DNCP has twice been disallowed recovery of such costs, once by this Commission and another time by the Virginia State Corporation Commission. Due to these experiences, he stated that DNCP believes that it is necessary to include Article 6 in the PPA in the case where a disallowance order is issued and is found to be lawful. In the event of such a disallowance, DNCP does not believe that there is a principle or reason that the burden of the disallowance should be borne by the Company and its shareholders. The Company has a legal obligation to purchase energy and capacity from QFs. Because these purchases are required by law, without Article 6, in the event of a disallowance order, DNCP would be required to continue making full payments to the QF, but would not be able to recover the portion of those payments that exceeded the amount permitted by the order. In that event, the Company and its shareholders would bear the full burden of these unrecoverable costs, an inequitable result, given that the purchases themselves are mandated by law.

With regard to REG witness Stuebe's statements, DNCP witness Trexler stated that two lenders do not constitute the universe of potential lenders or sources of financing to Ecoplexus' proposed facilities. DNCP has entered into a number of QF contracts containing Article 6 and those QFs have seemingly managed to finance their facilities. Finally, he stated that he is aware of no requirement under PURPA that the Company or this Commission modify their respective avoided cost policies based on the demands of a QF's lenders.

With regard to witness Morrison's testimony, witness Trexler testified that the Regulatory Disallowance Clause does not give the Company, or the

Commission, the right to modify PPA rates. The clause simply recognizes that neither DNCP nor a QF can control the actions of a regulatory body and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful. In addition, he testified that a QF investor, like any other investor needs to be able to estimate, with reasonable certainty, the expected return on potential investment before the construction of a facility. However, he stated that he is unaware of any provision in PURPA that requires that QF investors, unlike other investors, be entitled to absolute certainty of a return on their investment. He further stated that he believes that an investor in Schedule 19-FP QF has a "reasonable certainty" with respect to its investment, because under existing law and precedent, the possibility of a Regulatory Disallowance Order is remote. Finally, he questioned why the entire risk should be shifted to the Company and its ratepayers, if the QF and its lenders will not accept the remote but real risk of a disallowance order.

Witness Trexler further testified that he disagreed that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA. Because under the Schedule 19 PPA, a QF is entitled to receive fixed rates over the term of the PPA, absent the occurrence of a breach of the PPA by the QF, the QF's entitlement to those rates would be affected only if there is a Disallowance Order that is found to be lawful after appeal by the Company. To be found lawful, a court would almost certainly have to find that a disallowance was not barred by 18 C.F.R. § 292.304(d)(2).

The Commission notes that standard contracts are available only to certain specified types of QFs contracting to sell 5 MW or less. The FERC has released DNCP from the obligation to purchase from QFs having a net capacity in excess of 20 MW, pursuant to section 210(m), 16 U.S.C. § 824a-3(m). While a Regulatory Disallowance Clause might be appropriate in a negotiated contract with a larger QF, standard contracts with small QFs create a much lower risk to DNCP of a disallowance that DNCP itself describes as remote. As noted in DNCP’s initial comments [p. 3, footnote 3], there are five North Carolina QFs that are currently on Schedule 19-DRR, three of which are operational and two of which have contracts under existing Schedule 19-DRR but have not achieved commercial operations as of the date of the filing. Whether this lack of QF development is because of the previous lack of fixed, long-term rates or the Regulatory Disallowance Clause, it does not appear that small QFs in the past have been encouraged to locate in DNCP’s territory.

Further, unlike in the Sub 127 proceeding in which no evidence was offered that the Regulatory Disallowance Clause actually interfered with financing, two developers have provide uncontroverted testimony that such interference has occurred, with one of those witnesses testifying that the uncertainty created by the Clause is the reason his company has not pursued projects in DNCP’s territory.

Accordingly, the Commission concludes that the provision in DNCP's standard contract that allows DNCP to change the amount paid to the QF and provides a mechanism for the repayment by the QF any amounts disallowed for ratemaking purposes is inappropriate and should be removed from the standard contract.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 26

This finding is essentially uncontroverted. The Commission concludes that the rate schedules and standard contract terms and conditions proposed in this proceeding by DEC, DEP, and DNCP should be approved, except as otherwise discussed herein. The utilities should be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. They should be allowed to go into effect 15 days after they have been filed. The utilities' filings should stand unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 27

The evidence supporting this finding is found in the Public Staff’s Initial Statement, which was admitted into evidence at the outset of the evidentiary hearing.

The Commission concludes that, with the new versions of their rate schedules required to be filed in compliance with this Order, DEC, DEP, and DNCP should each include a public report showing its annualized avoided cost rates calculated in the manner presented in DEC’s Exhibit 3 to its filing on November 1, 2012 in this docket. In future avoided cost initial filings and future filings related to approved avoided cost rates, DEC, DEP, and DNCP should each include a public report showing their proposed annualized avoided cost rates calculated in the manner presented in DEC's Exhibit 3 to its filing on November 1, 2012, for the purpose of allowing QFs and other interested parties to readily discern the effect of the proposed changes to avoided energy and capacity rates.

EVIDENCE AND CONCLUSIONS FOR FINDING NO. 28

The evidence supporting this finding is contained in the Joint Comments and Proposed Rates of WCU and New River, which were verified by a person who would otherwise be qualified to present expert testimony in a formal hearing, and in the Public Staff's Initial Statement, which was admitted into evidence at the outset of the evidentiary hearing.

In their jointly filed comments, WCU and New River recounted the procedural history of their avoided cost rates. WCU, since 1984, has offered formula avoided cost rates and no long-term rate options. New River filed avoided cost rates for the first time in 2010 and proposed formula rates similar to those filed by WCU. The Public Staff indicated in the Sub 127 proceeding that the lack of long-term fixed rates presented difficult issues and that it would continue to work with WCU and New River on these issues. The Commission then granted the rates proposed by WCU and New River but only on an interim basis. WCU and New River further recounted that, since the approval of these interim rates, they have been in discussion with the Public Staff in regard to the appropriate rates for this proceeding.

Based on their discussions with the Public Staff, WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved five-, ten-, and 15-year long-term avoided cost rates for QFs interconnected at distribution. As proposed, WCU and New River would offer Schedules WCU PP-N and NRLP PP-N, respectively, for non-hydroelectric QFs and WCU-H and NRLP-H, respectively, for hydroelectric QFs.

In its Initial Statement in this proceeding, the Public Staff indicated that it did not object to WCU's and New River's proposal. DEC is WCU's requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation. The purchased power agreement between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis à vis Blue Ridge. The Public Staff noted that, to the extent the Commission changes DEC's proposed five-, ten-, and 15-year avoided cost rates, such changes will need to be reflected in the long-term avoided cost rates of WCU and New River.

The Commission concludes, based upon the foregoing, that WCU and New River's rate proposal should be accepted and that the changes approved herein with respect to DEC's installed CT costs for purposes of calculating avoided capacity rates should be reflected in WCU's and New River's long-term avoided cost rates.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DNCP shall offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DEC, DEP, and DNCP shall offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell three MW or less capacity.

2. That for QFs that have a currently effective contract with DNCP under Schedule 19-DRR, they shall be grandfathered and DNCP shall continue to maintain, update, and file Schedule 19-DRR until such time as no grandfathered QFs exist. DNCP shall offer grandfathered QFs the opportunity to switch to Schedule 19-FP by entering into a new Schedule 19-FP contract with a term equal to the remaining duration of the grandfathered contract.

3. That DNCP shall offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Sub 106 Order.

4. That DNCP shall provide a comparison of the peaker method and the PJM market pricing method in the next biennial avoided cost proceeding. As part of this comparison, DNCP shall (a) file PJM prices during each relevant summer season; (b) identify the five peak hours that were used in the SPPF; (c) file the PJM input data for each of the five coincident peak hours; and (d) file a comparison of the payments a QF would have received for one year, including the first full summer following the date of this Order, under the peaker method and under the PJM market pricing method, assuming various levels of hypothetical outages during the five coincident peak hours during preceding summer.

5. That DEC, DEP, and DNCP shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as

appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates shall have the option of selling into the wholesale market. The exact points at which an active solicitation is regarded as beginning and ending for these purposes shall be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

6. That a PAF of 2.0 shall be utilized by both DEC and DEP in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation.

7. That a PAF of 1.2 shall be utilized by both DEC and DEP for all QFs that do not qualify for a PAF of 2.0 as set forth above.

8. That DEP shall calculate and include in its avoided cost rate schedule CSP-29 an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC in its currently effective Option B rates, as provided for in the Settlement Agreement entered into among DEC, DEP, and the Public Staff. Its recalculated proposed avoided capacity rates shall be offered as Option A under

DEP's Schedule CSP-29, and both Option A and Option B capacity rates shall be filed for approval by the Commission in this proceeding.

9. That, subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of the current review of its time-of-use rates, DEP shall meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden will be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.

10. That DNCP shall calculate and include in Schedule 19-FP an Option B with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC, in its currently effective Option B rates, as provided for in the DNCP and Public Staff Settlement Agreement. DNCP's currently proposed capacity rates shall be offered as Option A under DNCP's Schedule 19-FP, and the Option B capacity rates shall be filed for approval by the Commission in this proceeding.

11. That value of solar proposition proffered by NCSEA and its witness Rábago is not adopted at this time. The Commission will open a separate proceeding to consider these issues in a broader context, including further

consideration of the materials presented in the Crossborder Study, the system impact study that is being developed by DEC and DEP, and other resources that the Commission, Public Staff, and other parties may wish to consider.

12. That the provision in DEC's current tariff and DEP's proposed tariff that limits the availability of long-term avoided cost rates to QFs that are under contract with the utilities on or before November 1 in a year in which a biennial proceeding has been initiated shall be modified in accordance with the findings and conclusion with respect thereto in this Order.

13. That the availability provision in DNCP's avoided cost tariff shall be revised in accordance with the findings and conclusion with respect thereto in this Order.

14. That DEC and DEP, in their 2013 REPS Compliance Plan and thereafter, shall include actual projected avoided costs rates as of the date of the compliance filing.

15. That DEC's standard contracts signed between November 1, 2010, and November 1, 2012, shall be deemed to include the "Note" in its standard contracts filed in the Sub 127 proceeding, as discussed in more detail herein.

16. That DEC's standard contract and rate schedules shall be amended by the addition of the language proposed by DEC to cure the deletion of the "Note."

17. That all proposed changes to tariffs, terms and conditions, and standard contracts shall be blacklined in all of the utilities' filings in the biennial proceedings in order to be valid and approved.

18. That the provisions in DEP's Terms and Conditions that allow DEP to impose a Reduction-in-Contract-Capacity charge and a Reduction-in-Contract-Energy charge shall be stricken from DEP's Terms and Conditions; in lieu thereof, DEP may propose a provision that more narrowly addresses the harm for which it alleges the penalty is designed and file it for approval.

19. That DEP's Terms and Conditions shall reflect the Monthly Facilities Charge approved in DEP's recent rate case in Docket No. E-2, Sub 1023, and DEP shall apply the new charge to all QF contracts that contain a Monthly Facilities Charge, regardless of when the contracts were executed.

20. That DEC's Terms and Conditions shall reflect the Extra Facilities Charge approved in DEC's recent rate case in Docket No. E-7, Sub 1026, and DEC shall apply the new charge to all QF contracts that contain an Extra Facilities Charge, regardless of when the contracts were executed.

21. That DEP shall make all other changes it agreed to make in the Reply Comments filed by DEC and DEP on March 28, 2013.

22. That the provision in DNCP's avoided cost standard contract that provides for changes in the amount paid a QF prospectively and potentially requires a QF to repay any amounts disallowed for ratemaking purposes shall be removed.

23. That the rate schedules and standard contract terms and conditions proposed in this proceeding by DEC, DEP, and DNCP are approved, except as otherwise discussed herein. The utilities shall file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

24. That DEC, DEP, and DNCP shall each include with the new versions of their rate schedules filed in compliance with this Order, a public report showing their annualized avoided cost rates calculated in the manner presented in DEC's Exhibit 3 to its filing on November 1, 2012 in this docket; in future avoided cost initial filings and future filings related to approved avoided cost rates, DEC, DEP, and DNCP shall each include a public report showing their proposed annualized avoided cost rates calculated in the same manner.

25. That WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five-, ten-, and 15-year long-term avoided cost rates for QFs interconnected at distribution is approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed five-, ten-, and 15-year avoided capacity rates.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of ____________, 2013.

NORTH CAROLINA UTILITIES COMMISSION

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Gail L. Mount, Chief Clerk