

**STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH**

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of  
Biennial Determination of Avoided Cost ) ORDER ESTABLISHING STANDARD  
Rates for Electric Utility Purchases from ) RATES AND CONTRACT TERMS FOR  
Qualifying Facilities – 2014 ) QUALIFYING FACILITIES

HEARD: Tuesday, May 19, 2015, at 9:30 a.m., in the Commission Hearing Room,  
Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

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

APPEARANCES:

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

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For North Carolina Sustainable Energy Association:

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For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, Attorney at Law, 2121 Damascus Church Road, Chapel Hill,  
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For the Using and Consuming Public:

Tim R. Dodge and Lucy E. Edmondson, Public Staff-North Carolina Utilities  
Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

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

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

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates 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.

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<sup>1</sup> Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30,128 (1980). See also 45 Fed. Reg. 12,214 (1980).

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

The Commission 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 utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and approved other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

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

### **Phase One of the 2014 Proceedings**

On February 25, 2014, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing. For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (Sub 136 proceeding), the Commission initiated the first phase of the 2014 avoided cost proceeding in advance of the filing of new proposed rates, stating that such rates would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments. Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP),<sup>2</sup> Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (New River) were made parties to the proceeding.

The following parties filed timely petitions to intervene, which were granted by the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Waste Awareness and Reduction

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<sup>2</sup> DEP converted from a corporation to a limited liability company on August 1, 2015.

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

Following the evidentiary hearing held July 7-10, 2014, the Commission issued an Order Setting Avoided Cost Input Parameters on December 31, 2014 (Order on Inputs). On January 8, 2015, the Commission issued an Order directing the parties to proceed with the second phase of the E-100, Sub 140 proceedings, focusing on the proposed rates to be filed by DEC, DEP, and DNCP (the Utilities). The Commission indicated its goal was to resolve all remaining issues in the docket based on the evidentiary record and written comments without conducting another full evidentiary hearing for the purpose of receiving expert testimony. Order on Inputs, among other things, established certain parameters by which avoided cost rates should be calculated and required that DEC, DEP, DNCP, WCU, and New River file proposed avoided cost rates 60 days from the issuance of the Order. The Commission established May 4, 2015, as the deadline for both interventions by interested persons and the filing of initial comments and statements with the Commission; scheduled a public hearing solely for the purpose of taking non-expert public witness testimony for Tuesday, May 19, 2015, at 9:30 a.m.; established deadlines for the filing of reply comments on or before June 8, 2015; and proposed orders on or before July 6, 2015.

### **Phase Two of the 2014 Proceedings**

In accordance with the Commission's January 8, 2015 Order, WCU and New River filed their proposed avoided cost rates on February 27, 2015. On March 2, 2015, DEC and DEP filed their respective Initial Comments and Exhibits (DEC and DEP Initial Comments and Exhibits). Also on March 2, 2015, DNCP filed its Comments, Exhibits, and Avoided Cost Schedules (DNCP Initial Comments and Exhibits).

On April 8, 2015, the Public Staff filed a motion requesting that the Commission: (1) extend the deadline for intervenors to file initial comments from May 4, 2015, to June 8, 2015; (2) extend the reply comment deadline from June 8, 2015, to July 13, 2015; and (3) extend the proposed order deadline from July 6, 2015 to August 10, 2015. By Order dated April 15, 2015, the Presiding Commissioner allowed the motion and extended the deadlines as requested.

On May 19, 2015, the Commission held a hearing to take non-expert public witness testimony. Two public witnesses, Heath McLaughlin and Carson Harkrader, testified.

On May 21, 2015, NCSEA filed a motion requesting that the Commission extend the current deadlines as follows: (1) intervenor initial comments from June 8, 2015, to June 22, 2015; (2) electric utility and intervenor reply comments from July 13, 2015, to July 27, 2015; and (3) proposed orders from August 10, 2015, to August 24, 2015.

By Order dated May 29, 2015, the Presiding Commissioner allowed the motion and extended the deadlines as requested.

On June 22, 2015, the Public Staff filed its Initial Statement, NCSEA filed its Initial Comments and Exhibits and the Affidavit of Ben Johnson, and SACE filed its Initial Comments.

On July 22, 2015, DEC and DEP filed a joint motion requesting that the Commission extend the current deadlines as follows: (1) electric utility and intervenor reply comments from July 27, 2015, to August 7, 2015; and (2) proposed orders from August 24, 2015, to September 4, 2015. By Order dated July 24, 2015, the Presiding Commissioner granted the motion and extended the deadlines as requested.

On August 31, 2015, the Public Staff filed a motion requesting that the Commission extend the deadline for proposed orders from September 4, 2015, to September 18, 2015. By Order dated September 1, 2015, the Presiding Commissioner granted the motion and extended the deadline as requested.

On September 9, 2015, the Public Staff filed a letter describing its discussions with DEC, DEP, DNCP, and NCSEA to resolve or narrow differences regarding the development of a form that would establish that a qualified facility had made a commitment to sell its output to a utility, the second prong of the Commission's test for establishment of a legally enforceable obligation (LEO). The Public Staff indicated that these parties had reached agreement on Sections 1-4 of DNCP's proposed Notice of Commitment Form filed with its Reply Comments, but had not reached resolution on Sections 5 and 6. The Public Staff stated that the parties named in the letter would address the unresolved issues regarding the LEO form in their proposed orders.

On September 17, 2015, DEC and DEP filed a letter advising the Commission of their settlement of several issues with NCSEA involving termination rights, the deadline for achieving commercial operation and commencement of term, and the inclusion of interconnection terms in the Terms and Conditions. DEC and DEP also filed a second letter on September 17, 2015, indicating that they and DNCP had discussed proposed language to be contained in Sections 5 and 6 of the Notice of Commitment Forms and had determined that these sections would necessitate DNCP's using a form separate and distinct from the one to be used by DEC and DEP. In its letter, DEC and DEP included a proposed Notice of Commitment Form which they would use, as well as a revised proposed Notice of Commitment Form which DNCP would use.

On October 8, 2015, NCSEA filed a Memorandum of Additional Authority with the Commission. On October 13, 2015, DNCP, DEC, and DEP collectively filed a response to NCSEA's memorandum. In their response, DNCP, DEC, and DEP requested that the Commission reject NCSEA's memorandum as it is inappropriately filed, untimely, and irrelevant. The Commission is well aware of its recent decisions and finds that NCSEA's memorandum is unnecessary to reaching its determination, and, therefore, grants the Utilities' motion to strike.

Between January 1, 2015, and September 9, 2015, 18 consumer statements of position were filed with the Commission. Various other filings and orders in the docket not discussed in this Order remain part of the record of this proceeding.

Based on the entire record of this proceeding, the Commission makes the following

## FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DNCP to 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 QFs contracting to sell three MW or less capacity. DNCP should continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM 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).

2. It is appropriate that DEC, DEP, and DNCP 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, it is appropriate that any unresolved issues arising during such negotiations be subject to arbitration by the Commission at the request of either the utility, the QF or both for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, only if the QF is prepared to commit its capacity to the utility for a period of at least two years. Whether there is an active solicitation underway or not, it is appropriate that QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. It is appropriate that the exact beginning and ending points of an active solicitation be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in

by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

3. As determined in the Commission's Order on Inputs, it is appropriate to require that the Utilities rely on publicly available data sources when calculating the installed cost of a combustion turbine (CT) for avoided capacity purposes and provide clear justifications for any adjustments made to the publicly available data. DEC and DEP have not submitted calculations of the installed cost of a CT for avoided capacity purposes that rely on publicly available data sources.

4. The hypothetical CT utilized by a utility for the purposes of determining avoided capacity rates should be based on the past operational history of the utility, as well as a reasonable expectation of the units the utility anticipates it will construct in the future. DNCP's selection of a CT model with which it has no prior construction or operational experience is inappropriate for use in calculating avoided capacity costs.

5. The useful lives selected by the Utilities for the purposes of this proceeding are reasonable.

6. The methodology utilized by DEC and DEP to apply a contingency factor for the purposes of this proceeding is reasonable and the contingency factor relied on by DNCP from the 2014 Brattle Report is reasonable as applied to DNCP's utilization of the GE 7FA unit for determining avoided capacity costs.

7. As determined by the Commission's Order on Inputs, it is inappropriate to include any economies of scope associated with the construction of more than one CT at the same time in calculating the installed cost of a CT. The Utilities inappropriately included economies of scope when calculating the installed cost of a CT.

8. DEC's and DEP's calculations of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of carbon dioxide (CO<sub>2</sub>) costs is inconsistent with the Commission's directives from the Order on Inputs.

9. To the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts, it is appropriate to require that these changes should be made in the Utilities' biennial integrated resource plans (IRPs), and the same approach should be used in their biennial avoided cost filings for that same year.

10. It is appropriate to require that the Utilities recalculate their avoided energy rates using natural gas and coal price forecasts that are developed in a manner consistent with those utilized in their 2014 IRPs.

11. It is appropriate to require that the Utilities recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement (PPA).

12. The seasonal allocation factors utilized by the Utilities in this proceeding are reasonable. It is appropriate to direct the Utilities, in the next biennial proceeding, to assemble their hourly CT operational data and marginal cost data on a season-specific basis in order to determine whether the allocation factors utilized in this proceeding remain reasonable.

13. It is appropriate to require that DEC and DEP amend the language regarding reporting of production data in Paragraph 5 of their standard PPAs to be consistent with the language agreed to with the Public Staff.

14. The Reduction in Contract Capacity and Reduction in Contract Energy provisions in DEC's and DEP's Terms and Conditions are inconsistent with previous rulings of the Commission and should be rejected.

15. It is appropriate to require that the Utilities not unreasonably withhold consent to a proposed assignment of a standard PPA.

16. The provision in Article 7(a)(vii) of DNCP's proposed Standard Contract granting it a right to terminate a contract where the FERC grants a petition by the utility under PURPA § 210(m) is unnecessary and should be deleted.

17. The language proposed by DEC and DEP in their September 17, 2015, letter providing a reasonable opportunity to cure of 30 days prior to termination of the contract except for fraudulent or unauthorized use of the utility's meter is appropriate and should be included in DEC's and DEP's Terms and Conditions.

18. The proposal by each utility to limit the availability of standard rates to facilities within one-half mile is reasonable, subject to the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms as long as the combined capacity of those facilities does not exceed five MW. The one-half mile restriction should only apply to facilities that use the same energy resource, and the Utilities should include language stating that the distance between facilities will be measured from the electrical generating equipment of a facility.

19. DEC's and DEP's respective standard contracts should provide that a utility may terminate a contract after 30 months if a QF has failed to achieve commercial operation at any level by that date, provided that the 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.

20. It is appropriate to require that DEC and DEP amend their standard contracts to clarify that the term begins upon the first date when electrical output is generated by a QF and delivered to the utility.



21. It is appropriate to require that DEC and DEP update Section 1(i) of their Terms and Conditions to allow termination for nonperformance only if the Seller fails to deliver energy to the utility for more than six months.

22. It is appropriate to require that DEC and DEP include a statement that in the event of a conflict between the Terms and Conditions and the interconnection agreement, the interconnection agreement will control.

23. It is appropriate to require that the Utilities update their applicable rate schedules to reflect the utility's payment associated with reactive power for interconnection customers if the power is requested by the utility.

24. It is appropriate to require the Utilities to adopt a form substantially similar to the Notice of Commitment Form submitted by DNCP with its Reply Comments and to require all QFs to utilize such form to establish a LEO.

25. It is appropriate to require that the Utilities place information on their websites clearly showing how to establish a LEO and which departments to contact to negotiate interconnection agreements and PPAs.

26. It is appropriate to require that DEC and DEP revise Paragraph 5 of their respective PPAs to limit their right to request planned operational information from QFs of three MW or larger.

27. 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 OF FACT NO. 1

The evidence supporting this finding of fact is contained in DEC, DEP, and DNCP's Initial Comments and Exhibits and the Initial Statement of the Public Staff.

The Commission found in the Order on Inputs that "DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options." No party in this phase of the 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 QFs contracting to sell three MW or less capacity. In addition to the Order on Inputs, 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, balancing 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 have struck an appropriate balance between these concerns, and that the same approach continues to be appropriate

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 to both encourage QF development and reduce the Utilities' exposure to overpayments and stranded costs, and should continue to be made available.

DNCP proposed to continue to offer QFs Schedule 19-LMP as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at avoided cost rates, as determined by the Commission. Under Schedule 19-LMP, 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 locational marginal prices (LMP) 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 kilowatt-hour (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 in prior proceedings, DNCP also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations.

In its Initial Statement, the Public Staff stated that the proposed Schedule 19-FP and Schedule 19-LMP are consistent with the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, issued on February 21, 2014, in Docket No. E-100, Sub 136 (Sub 136 Order). The Public Staff also stated that the proposed Schedule 19-FP complies with the Commission's Order in the 2010 proceeding.<sup>3</sup> However, the Public Staff noted that DNCP's proposed Schedules 19-FP and 19-LMP do not include a two-year variable capacity rate. The Public Staff recommended that

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<sup>3</sup> See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127 (2010 proceeding), July 27, 2011.

such a rate should be included and made available to QFs otherwise eligible for standard rates.

In the Sub 136 Order, the Commission concluded that, as provided in the stipulations entered into between DNCP and the Public Staff in that proceeding, the parties would further discuss the need for, and structure of, two-year variable capacity rates to be offered by DNCP. No parties in this proceeding raised this issue in their initial statements or reply comments. Nonetheless, the Commission finds that it is appropriate that such a rate should be included and made available to QFs otherwise eligible for standard rates. Therefore, DNCP and the Public Staff shall discuss the structure of two-year variable capacity rates to be offered by DNCP prior to the next biennial proceeding, and DNCP shall include such rates in its next biennial filing.

Based upon the foregoing, the Commission concludes that it is appropriate for DNCP to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Sub 106 Order.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP.

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, the Commission has ruled that any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility, the QF or both 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. Whether there is an active solicitation underway or not, the Commission has held that 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 would 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. The Commission has determined that if the variable energy rate option is chosen, such rate may not be locked in by a contract term, but instead shall change as determined by the Commission in the next biennial proceeding.

No party proposed that the Commission alter its prior position on this issue. Therefore, 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 as entitled to full avoided costs as is 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 utilized complaint process. The Commission concludes that the arbitration option should be preserved.

### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff, the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In the Order on Inputs, the Commission found that:

Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of a CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

In their Initial Comments and Exhibits, DEC and DEP relied on subscription-based data from the Electric Power Research Institute (EPRI) to derive the installed cost estimate for avoided capacity purposes based on the use of a GE Model 7FA unit. This is the same model previously utilized by DEC and DEP in their IRPs and avoided cost proceedings for both simple and combined cycle configurations. DNCP based its underlying installed cost on the cost estimates for the Siemens Model SGT6-5000F (Siemens-5000) CT provided in the 2013 edition of Gas Turbine World Handbook (GTW). For the construction costs and other capital costs, DNCP relied on data from the

Brattle Group's May 15, 2014 report, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," (2014 Brattle Report), which utilized the GE Model 7FA unit as the basis for its costs. DNCP noted that it utilized the Siemens unit in its 2013 and 2014 IRPs, as compared to its use of the GE Model 7FA units in Docket No. E-100, Sub 136 (the 2012 proceeding).

In their Initial Comments, NCSEA and SACE both commented that the Utilities used data from sources that are not publicly available and did not provide adequate justifications for their adjustments to the installed cost of a CT. NCSEA stated that DNCP made an effort to use data from publicly available sources and filed for public inspection the data underlying its avoided capacity cost calculation, with a narrative explanation that identifies the publicly available industry sources on which DNCP relied. NCSEA further stated that on the other hand, DEC and DEP did not initially disclose the data underlying their avoided capacity cost calculations or the sources on which they relied. NCSEA had to obtain this information through the discovery process, which delayed its ability to analyze the avoided cost filings. As such, NCSEA recommended that the Commission require that the Utilities, in future biennial avoided cost proceedings, file as part of their initial filings, the source and data underlying the capacity cost calculations.

The Public Staff did not take exception to the installed costs of a CT proposed by DEC and DEP, based on its assessment that that the projected installed costs were in line with other publicly available estimates of the installed costs for a CT in North Carolina, and were comparable to DEC's and DEP's projected installed CT costs approved by the Commission in the 2012 proceeding, after taking into account adjustments for inflation and the annual increases in CT costs indicated by the U.S. Bureau of Labor Statistics (BLS) Producer Price Index (PPI) for Combustion Turbines and Turbine Generator Sets. The Public Staff did note, however, that DEC and DEP's use of subscription-based data from EPRI, as opposed to the public reports, limits the public availability of the cost information and reduces the transparency of the avoided cost proceeding.

With regard to DNCP's reliance on GTW and adjustments based on the 2014 Brattle Report, the Public Staff noted that DNCP made additional cost adjustments, highlighted in DNCP's Exhibit 1, to the data from the 2014 Brattle Report as follows: (1) removed the equipment cost of selective catalytic reduction; (2) reduced the labor costs, principally with the use of non-union labor; (3) reduced the sales tax rate applicable to Virginia; (4) reduced the gas interconnection costs by assuming a shorter pipeline lateral of one mile, as opposed to the five miles assumed in the Brattle Report; (5) reduced electrical interconnection costs associated with the economies of scale with a four-unit site, as opposed to a two-unit site; (6) adjusted the fuel costs for start-up and inventories to be consistent with the assumptions in the PROMOD model for avoided fuel costs; and (7) removed financing fees that are already included in the economic carrying charge rate calculations. The Public Staff stated that it generally believes the 2014 Brattle Report provides an appropriate basis for a cost estimate and did not take

exception to DNCP's adjustments, with the exception of its selection of the Siemens Model CT as opposed to the GE Model 7FA CT.

In its Reply Comments, NCSEA repeated its position that the Utilities did not comply with the Commission's general directive that adjustments to estimates provided in publicly available industry sources be "clearly needed." NCSEA also generally agreed with the Public Staff's appraisal of DNCP's CT adjustments, as well as the Public Staff's position that DNCP had not adequately justified its decision to switch from the GE to the Siemens unit. As such, NCSEA recommended that the Commission direct DNCP to recalculate its avoided capacity cost using the GE Model 7FA CT.

DEC and DEP in their Joint Reply Comments stated that "[t]o some degree, the use of the most robust data available and data that is 'publicly available' are mutually inconsistent steps" and defended their reliance on the EPRI data as providing more robust, specific, and accurate data so that fewer adjustments are necessary. DEC and DEP further indicated that their agreement with EPRI specifically permits them to share the information with parties to regulatory proceedings, as they have done in this proceeding and will continue to do. They further noted that "accurate information of the type required for this proceeding is simply not available from 'off the shelf' resources that completely eliminate the need for reasoned analysis and judgment." With regard to NCSEA's comments that DEC and DEP did not make the underlying data publicly available, DEC and DEP contended that they consider some of the data used to calculate avoided costs to be a trade secret, and, as such, they redacted the information as allowed by the Commission pursuant to G.S. 132-1.2. DEC and DEP stated that they are willing to discuss this issue further with NCSEA to determine if some resolution of NCSEA's concerns can be found, and are willing to make a supplemental filing to report on these discussions.

DNCP in its Reply Comments noted that both the Brattle Report and GTW are "widely recognized, respected, and publicly available industry source[s]" and that it has appropriately tailored the hypothetical CT costs from publicly available industry data consistent with the Commission's Order on Inputs.

The Public Staff in its Reply Comments repeated its concern with DNCP's substitution of the lower costs associated with the Siemens unit from GTW in place of the GE 7FA turbine prices used in the 2014 Brattle Report. The Public Staff noted that the authors of the Brattle Report surveyed the CTs built around the country and concluded that the GE 7FA model is the predominant CT model built and best turbine on which to base its cost of new entry.

## DISCUSSION AND CONCLUSIONS

The Commission notes that the installed cost of a CT is a critical input in the calculations of avoided capacity costs using the peaker methodology, and recognizes the importance of an accurate, but also transparent source of information on which to base this value. As such, in the Order on Inputs, the Commission stated "[b]ecause the

focus of the peaker method is on a 'hypothetical CT,' for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data." Ordering Paragraph 6 of the Order on Inputs further stated that "in the calculation of the installed cost a CT, [DEC and DEP] shall use data from publicly available industry sources and tailor it only to the extent clearly needed to adapt any such information to the Carolinas." DEC and DEP have not followed this directive.

In this proceeding, the Public Staff found that DEC and DEP's reliance on EPRI data, despite its limited public availability, resulted in avoided capacity costs that were reasonable, and as such, did not take exception with the resulting values. The Public Staff based its recommendation in part on its assessment that the filed projected installed costs were in line with other publicly available estimates of the installed costs for a CT in North Carolina. If the Public Staff can justify the installed costs of a CT that were filed by DEC and DEP in this proceeding based on publicly available data, it would follow suit that DEC and DEP should be able to calculate installed costs based on publicly available data, as DNCP has clearly displayed is possible. DEC and DEP must already recalculate their avoided capacity costs excluding economies of scope pursuant to Finding of Fact No. 7 below. In doing so, the Commission will continue to require the Utilities to utilize data from publicly available sources when calculating the installed cost of a CT for avoided capacity purposes and to provide clear justifications for any adjustments made to the publicly available data.

With regard to DNCP's use of both GTW and the 2014 Brattle Report, the Commission finds that both of these sources meet the criterion of being publicly available, and concludes that DNCP's continued reliance on them for providing both an installed CT cost, as well as a basis to appropriately tailor the costs for construction of a CT to be constructed in North Carolina or Virginia, is appropriate. The Commission does not, however, support DNCP's ultimate selection of the Siemens unit, as discussed in Finding of Fact No. 4 below or its inclusion of economies of scope as discussed in Finding of Fact No. 7 below.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in DNCP's Initial Comments and Exhibits; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DNCP, NCSEA, the Public Staff, and SACE.

In its Initial Statement, the Public Staff stated that it had reviewed the adjustments made by DNCP to the installed costs of a CT from the 2014 Brattle Report and generally found them to be reasonable. However, the Public Staff took exception with DNCP's decision to utilize the cost data for the Siemens Model CT from GTW in place of the GE Model 7FA CT originally utilized by Brattle. For a number of reasons, the Public Staff questioned the likelihood that the Siemens model CT would actually be selected by DNCP for construction and, therefore, recommended that the Commission

direct DNCP to recalculate its avoided capacity costs based on a GE Model 7FA CT or a comparable unit from a publicly available industry source. In support of its position, the Public Staff noted that: (1) DNCP utilized a GE Model 7FA CT when calculating its avoided capacity cost in the 2012 biennial proceeding; (2) DNCP does not have a Siemens model CT in its fleet; (3) DNCP does not have experience with the construction and operation of a Siemens model CT; (4) relative to the GE units, a very small number of Siemens CTs have been installed by other utilities over the last five years; and (5) the combined cycle facilities recently placed into service or under construction by DNCP utilize Mitsubishi model CTs.

The Public Staff noted that the 2011<sup>4</sup> and 2014 Brattle Reports prepared for PJM utilized the same GE Model 7FA relied on by DNCP in the 2012 proceeding, in part because it is the predominant turbine type built in PJM. The Public Staff further noted that relatively few Siemens-5000 CTs have come online in a stand-alone configuration as compared to the number of GE-7FA units and cited the 2014 Brattle Report's discussion of its selection process, which did not yield a basis for changing its turbine selection from the GE-7FA.

The Public Staff further noted that DNCP's installed costs decreased by 35%, despite DEC and DEP indicating a small increase in their capacity prices over the same period, and the BLS PPI for Turbine and Turbine Generator Sets indicating an average cost increase of 1.9% per year in the prices of turbines since 2012. As previously noted, DEC and DEP increased their projected CT costs at a rate similar to that reported by the BLS. As such, the Public Staff found DNCP's projected installed cost to be overly conservative and recommended that the Commission direct DNCP to refile its avoided capacity costs based on a GE Model 7FA unit or a comparable unit from one of the publicly available sources, with appropriate cost adjustments.

DNCP in its Reply Comments noted that the turbine utilized for avoided capacity cost calculations should be the same turbine selected as the least cost option in its IRP. Since DNCP selected the Siemens-5000 as the least cost CT option in the 2014 IRP, it was appropriate for it to use the Siemens-5000 as the hypothetical CT for this proceeding. DNCP also indicated that the Public Staff's reliance on the "fairly simplistic" PPI as a measuring stick was not appropriate, since the PPI simply shows the percentage change in turbine prices from year to year and has limited bearing on the dollars per kW price metric used in avoided cost calculations.

## DISCUSSION AND CONCLUSIONS

The Commission recognizes the least cost nature of the IRP planning process and agrees that it is important that the inputs and assumptions utilized in the IRP proceeding carry forward through the following biennial avoided cost proceeding. To the

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<sup>4</sup> Spees, Kathleen, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, August 24, 2011 (2011 Brattle Report).



extent DNCP found the Siemens-5000 to be the least cost unit and anticipates constructing those units in the future as part of its current expansion plan, the Commission does not take issue with the selection of the unit. Nonetheless, the values used in avoided costs should be based not only on a reasonable expectation of what actually may be constructed or utilized in the future, but also on the past operational history of the utility.

With regard to the Public Staff's reference to the PPI as an indicator of the reasonableness of the utility's change in avoided capacity costs, the Commission disagrees with DNCP that the use of general indices such as the PPI is inappropriate. In fact, the Commission believes one of the key issues that recur in these biennial proceedings is a utility's reliance on capacity costs based on the specific circumstances that it prescribes, as opposed to reliance on market price indicators that are more widely available. Such public indices are helpful to both the Commission and general public by providing a check as to the reasonableness of the prices and adjustments being proposed by the Utilities. Further, combining data sources or making adjustments to the publicly available data in a piecemeal fashion from multiple data sources calls into question the reliability and integrity of the remaining value. As such, the Commission holds that DNCP should recalculate its avoided capacity costs as shown in Figure 1 of its March 2, 2015 Initial Comments, with the adjustments as shown, but using the turbine costs and capacity rating for a GE Model 7FA CT as originally utilized by the 2014 Brattle Report. This should not only provide DNCP with an internally consistent source for its avoided capacity cost values, but should also recognize the appropriate adjustments that it proposed to make to those values.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Order on Inputs, the Commission specified that "a reasonable estimate of useful life of a CT ... should be included in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs."

In their Initial Comments and Exhibits, DEC, DEP, and DNCP proposed estimates of the useful life of a CT. In its Initial Comments, NCSEA noted that all three Utilities assumed a useful life for a CT that is longer than both the 2014 Brattle Report estimate of 20 years and the confidential EPRI assumption. SACE in its Reply Comments noted that the 2014 Brattle Report "calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System of 20 years for a [combined cycle] plant and 15 years for a CT plant." SACE further noted the discussions in ISO-New England regarding the appropriate useful life to assume in calculating the cost of new entry for its forward capacity market. Specifically, SACE noted that while power generation plants may physically last for more than 30 years, in financial modeling it is appropriate to use

a shorter economic life due to “market risks, including lower cost capacity resources entering market,” and the risk of “market interventions that depress prices.”<sup>5</sup>

DEC and DEP in their Joint Reply Comments stated that the best reference points to use in determining the useful life of a CT in setting avoided cost rates are: “(1) the actual operating lives of the utility’s CT fleet, and (2) the CT useful life assumptions used in setting the utility’s base rates.” In its Reply Comments, DNCP noted that it used a 36-year useful life because that is the assumed life expectancy of a new utility-owned CT facility based on its most recent asset depreciation studies. In addition, DNCP noted that it used a 36-year expected life to recover the costs of its existing CT plants, and this represents what customers actually pay.

The Commission agrees with DEC and DEP that it is appropriate to consider the costs that North Carolina customers actually bear for a CT and the reasonable expectation of how long a CT should operate in the Carolinas when estimating the useful life for the calculation of the avoided capacity rates. While the consideration of market risk as proposed by SACE is relevant, particularly in RTOs and other restructured regulatory environments, it is less applicable in North Carolina. As such, the Commission finds the useful lives selected by the Utilities to be reasonable for the purposes of this proceeding.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Order on Inputs, the Commission directed the Utilities to include in the calculation of the installed cost of a CT “a reasonable contingency adder for a hypothetical plant in relatively early stages of planning.” DNCP applied a 10% contingency factor to engineering, procurement, and construction (EPC) costs and a 9% contingency factor to non-EPC costs. DEC and DEP applied a contingency factor that was filed as confidential. DNCP’s value was consistent with the contingency factor utilized in the 2014 Brattle Report, while DEC’s and DEP’s was originally provided in the EPRI data.

In its Initial Comments, NCSEA discussed the concept of a contingency factor, stating that its purpose is to cover “unforeseen costs that are likely to arise during construction.” NCSEA cited the discussion of the contingency factors in the following public reports: (1) The 2014 Brattle Report utilized by DNCP; (2) the Cost Report

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<sup>5</sup> Citing Newell, Samuel, and Chris Ungate, Net CONE for the ISO-NE Demand Curve, 3rd Response to Stakeholder Comments and Draft Proposal, Presented to the NEPOOL Markets Committee, February 27, 2014, slides 15-16.

prepared by Black and Veatch for the National Renewable Energy Laboratory (NREL),<sup>6</sup> which provided a range of contingency factors based on the design stage of a facility; and (3) the 2013 EIA report entitled Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, which included a 10% contingency factor on EPC costs as well as an additional 20% allowance for owner's costs and contingency, excluding financing.<sup>7</sup>

NCSEA stated that the reasonableness of a particular contingency factor would vary depending upon the specific context in which the factor will be used. It noted that while a 5% to 10% contingency factor might be adequate for internal purposes at the late stages of the planning process, a higher contingency is necessary for the purposes of avoided cost calculations "consistent with the Commission's directive that the contingency factor reflect 'a hypothetical plant in relatively early stages of planning.'" NCSEA stated that an understated contingency factor reduces an electric utility's avoided cost, which may discourage QF development and, therefore, fail to meet PURPA's objective of ratepayer indifference. As such, NCSEA recommended that the Commission direct the Utilities to include a contingency factor in the range of the industry sources it discussed – 15% to 20%, or 30% if the Commission approves DNCP's use of the Siemens CT.

In its Initial Statement, the Public Staff did not take exception to the contingency factor utilized by DEC and DEP, due in part to its general acceptance of the reasonableness of the overall installed costs of capacity proposed by the utility. The Public Staff did, however, state that if the Commission approves DNCP's selection of the Siemens CT, a number of other adjustments such as the applicable contingency factor associated with the facility, capital spare parts, and O&M would need to be adjusted to reflect DNCP's limited experience with the unit.

In its Reply Comments, NCSEA recommended that the Commission direct DEC and DEP to adjust the contingency factor upward to 15-20%, which it believed is more appropriate for a plant in relatively early stages of planning. SACE stated in its Reply Comments that it concurred with the Public Staff that the combination of DNCP's limited experience with the Siemens unit and "the very rough nature of the cost estimate" supports the use of a higher contingency factor in determining avoided capacity costs.

In its Reply Comments, DNCP stated that "constructing a simple cycle CT plant is not a new and risky endeavor, but a well-known and documented construction process. DNCP contended that switching from GE to Siemens turbines does not change the overall risk profile of the potential project; thus, the same percentage level of contingency is adequate." As such, DNCP argued that no adjustments to its estimated

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<sup>6</sup> Cost Report: Cost and Performance Data for Power Generation Technologies, prepared by Black & Veatch, prepared for NREL, February 2012, p. 8, available at: <http://bv.com/docs/reports-studies/nrel-cost-report.pdf>. Included as Exhibit 3 to NCSEA's Initial Statement.

<sup>7</sup> Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, prepared by United States Energy Information Administration (EIA), April 2013, Sections 8 and 9, available at: <http://www.eia.gov/forecasts/capitalcost/>.

avoided capacity costs are needed, including its use of a Siemens as the hypothetical CT. DNCP stated that its procurement group is active and experienced in the power plant equipment market and maintains regular dialogue with key manufacturers and vendors of equipment. DNCP also explained that it has an experienced construction management department and has historically been able to plan, design, construct, operate, and maintain CT facilities on-time and in-line with its budget estimates.

DEC and DEP stated in their Joint Reply Comments that the contingency adder they utilized is reasonable because it is based on their actual experience in constructing CTs in both simple cycle and combined cycle configurations in the Carolinas and is consistent with industry standards for how contingency adders are defined and utilized.

### DISCUSSION AND CONCLUSIONS

The Commission believes that it is appropriate to continue to require the inclusion of a reasonable contingency adder for a hypothetical plant in the relatively early stages of planning. The amount of this adder should be adjusted based on a utility's experience in the construction and operation of a specific unit, current market conditions for skilled labor and materials, and other relevant factors. As such, the Commission accepts the methodology utilized by DEC and DEP to calculate its contingency adder as reasonable for this proceeding, and finds that the contingency factor relied on by DNCP from the 2014 Brattle Report is acceptable as applied to DNCP's utilization of the GE 7FA unit for determining avoided capacity costs. To the extent necessary, DEC and DEP shall adjust its contingency adder to reflect its use of publicly available data when recalculating its avoided capacity costs, rather than relying upon EPRI data.

### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, and NCSEA.

In its Order on Inputs, the Commission provided that when calculating the installed cost of a CT, the Utilities may include economies of scale for up to four CTs constructed on the same site; but not any economies of scope associated with constructing more than one CT at a time. Further, the Commission specified that "to the extent a utility applies economies of scale related to the installed cost of multiple CTs at a single location, the utility should provide detail as to the economies being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied."

In their initial filings, the Utilities utilized economies of scale for the construction of four CTs on the same site. DEC and DEP stated that the EPRI data they utilized included both economies of scale and scope for a four-unit site. They further stated that they excluded economies of scope by eliminating the assumption that four CTs were

contracted under a single EPC contract simultaneously at the same site. Instead, they assumed that they could purchase at least two turbines at the same time to be placed at different locations within their various service territories. The Brattle Report on which DNCP relied assumed “two turbines at one site to capture savings from economies of scale.”<sup>8</sup> DNCP also made further adjustments to the data to reflect additional economies of scale related to its electrical and gas interconnection costs to correspond to a four-unit rather than a two-unit site.

NCSEA and SACE both filed comments stating that the Utilities misapplied the Commission’s directive with regard to economies of scope. NCSEA noted that DEC’s and DEP’s calculation assumes the construction of four units at two sites, relying on the EPRI 2 x 2-unit site data. NCSEA stated:

Rather than starting with the 2-unit data or the 4-unit data, ... DEC and DEP could have started with the EPRI and B&M 1-unit data and adjusted those cost estimates downward to reflect the estimated impact of economies of scale within the categories for which DEC and DEP assert that such economies are realized – the cost of land, site preparation work, roads, buildings and structures, as well as general plant facilities.

Further, in his affidavit submitted on behalf of NCSEA, Dr. Ben Johnson noted that adjustments to include economies of scale should be computed “net of the additional carrying costs (capital costs and property taxes) that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when these are needed for the additional units.” With regard to DNCP, NCSEA stated that since the Brattle Report assumed that both turbines were to be constructed at the same time, the cost estimates in the Brattle Report also included cost savings from economies of scope that should have been excluded. It also challenged the other adjustments made by DNCP as being unjustified.

In their Joint Reply Comments, DEC and DEP stated that the type of data available publicly makes it impossible to isolate economies of scale from economies of scope to an empirical certainty, and that sound judgment is required. They contended that “[t]he question for the Commission [should not be what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF.”

DNCP in its Reply Comments stated that it since it relied on the 2014 Brattle Report in its estimation of a hypothetical CT’s construction costs, without knowing the underlying assumptions and derivation of the Brattle Report numbers, it was impossible to know whether the estimates included cost savings from economies of scope. Therefore, DNCP did not propose any adjustment to this data to remove the impacts of

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<sup>8</sup> 2014 Brattle Report at 8.

economies of scope. DNCP noted that “if the Commission determines that an adjustment is required, then the adjustment should be limited to the ‘mobilization and start-up category’ of its detailed cost sheet because that would be the only cost incurred based on the (Commission- required) assumption of installing the turbines one at a time (and such costs would in fact be minimal).” DNCP further noted that with respect to its further adjustment of the electric and gas interconnection costs to assume a four-unit site, it did not simply cut the estimate in half, but instead made specific adjustments to the electrical interconnection costs to remove electric transmission network upgrade costs and reduced the assumed length of the natural gas lateral from five miles to one mile to better approximate the actual expected interconnection costs.

## DISCUSSION AND CONCLUSIONS

DEC and DEP have submitted data that includes economies of scope for purchase of at least two turbines at the same time in contravention of the Commission’s Order on Inputs. Likewise, DNCP also failed to follow the Commission’s Order when it relied upon data that assumed two turbines were to be constructed at the same time. The Commission clearly stated in Ordering Paragraph 7 of its Order on Inputs that “DEC, DEP and DNCP shall not include any economies of scope associated with the construction of more than one CT at the same time.” DEC and DEP state as justification for their non-compliance that “the question for the Commission should not be what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF.” The Commission ruled on this issue in its Order on Inputs and determined that the inclusion of economies of scope in the installed cost of a CT is inappropriate when determining avoided capacity costs under PURPA. Therefore, it follows from the Commission’s Order that such an inclusion does not comply with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF.

The Utilities shall be required to recalculate the installed costs of a CT excluding economies of scope. The Utilities have stated that it is difficult to separate the permitted adjustments for economies of scale from adjustments made for economies of scope. The Commission notes that, in addition to stating that the calculation of the installed cost of a CT “shall not include any economies of scope”, Ordering Paragraph 7 of the Order on Inputs also states that the calculation shall include “economies of scale for up to four CTs constructed on the same site.” Thus, if the Utilities are unable to establish a proper methodology to include economies of scale without including economies of scope in their calculations, they are permitted, pursuant to the Order on Inputs, to submit an installed CT cost based on the installation of one CT at a single site without adjustments for economies of scale or scope.

With regard to economies of scale, when recalculating the installed costs of a CT, the Utilities shall take note of the affidavit of Ben Johnson, filed on behalf of NCSEA, stating that adjustments to include economies of scale should be computed net of the additional carrying costs (capital costs, property taxes, etc.) that would be

incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when they are needed for the additional units. The Commission finds merit in this argument. The Utilities should continue to provide detail as to the economies of scale being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied, while also taking into account any carrying costs associated with the economies of scale.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA; and the Joint Reply Comments of DEC and DEP.

In the Order on Inputs, the Commission held that for the purpose of calculating avoided energy rates, the generation expansion plans used in the avoided production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs. The Commission further found that CO<sub>2</sub> costs “are not sufficiently certain to be included in avoided costs at this time.”

The Public Staff in its Initial Statement noted that DNCP utilized a generation expansion plan to calculate avoided energy costs that did not include carbon costs. However, DEC and DEP in their avoided energy cost calculations utilized generation expansion plans that were selected based on inclusion of a CO<sub>2</sub> emissions price, as reflected in certain scenarios in their 2014 IRPs, while at the same time, the cost of CO<sub>2</sub> abatement was excluded from the avoided energy calculations. The Public Staff stated that this mismatch of generation expansion plans and avoided energy inputs could distort the avoided energy calculations and result in a miscalculation of avoided energy costs. For example, the inclusion of carbon prices in IRP modeling may result in the selection of new nuclear units in the generation expansion plan, as it did with DEC’s base case in its 2014 IRP.<sup>9</sup> Since the capital costs associated with new nuclear units are not included in the avoided energy calculations, the relatively low cost energy provided from the new nuclear results in an underestimation of avoided fuel costs. The Public Staff therefore recommended that the Commission direct DEC and DEP to recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO<sub>2</sub>. NCSEA raised similar concerns, noting that under DEC and DEP’s approach “the QF has the potential to be penalized by the cost of carbon in the avoided energy calculation, without being credited with the avoidance of such cost by the utility.”

In their Joint Reply Comments, DEC and DEP stressed the distinction between their “development of a long-term resource plan that is robust and accounts for the possibility that carbon costs may be imposed in the future with the intent of PURPA,

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<sup>9</sup> DEC Integrated Resource Plan (Annual Report) filed on September 1, 2014, in Docket No. E-100, Sub 141.

which is to calculate avoided costs based on currently known and measureable costs that are avoided because of the purchase of power from the QF.” They stated that to the extent carbon costs actually have been incurred, these costs are included in their avoided costs calculations.

## DISCUSSION AND CONCLUSIONS

The Commission notes the extended discussion on this issue in the Order on Inputs and reiterates its determination that the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs. DEC’s and DEP’s calculation of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of the CO<sub>2</sub> costs is inconsistent with the Commission’s directives from the Order on Inputs. Therefore, DEC and DEP shall recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO<sub>2</sub>. In their 2014 IRPs, DEC and DEP evaluated the portfolios identified as part of their screening analysis under a No Carbon Scenario, and found that under the base case sensitivity for fuel prices, Portfolio 1 had the lowest present value revenue requirement of the portfolios considered.<sup>10</sup> The Commission concludes that DEC and DEP should recalculate their avoided energy rates utilizing the generation expansion plans resulting from Portfolio 1 under the No Carbon Scenario.

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

The evidence supporting these findings of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Initial Statement, the Public Staff stated that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations that they used in their 2014 IRPs. In this proceeding, DEC and DEP incorporated ten years of future spot prices combined with their traditional fundamental forecast for the years eleven through fifteen, while in their 2014 IRPs, they relied on five years of forward price data. The Public Staff stated that the change results in a significant difference in the slope of the natural gas price forecasts between 2020 and 2025 in the IRPs and the avoided cost filing, respectively. The Public Staff further noted that in the 2012 IRP<sup>11</sup> and 2012 avoided cost proceeding, DEC used two years of forward price data combined with 24 months of transitional data that it merged with its long-term fundamental natural gas price forecast.

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<sup>10</sup> DEC and DEP IRP (Annual Report) filed on September 1, 2014, in Docket No. E-100, Sub 141, at pp. 54-55.

<sup>11</sup> DEC Integrated Resource Plan (Annual Report), filed September 1, 2012, in Docket No. E-100, Sub 137.



The Public Staff noted that in the Order on Inputs, the Commission emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. The Public Staff contended that the use of five years of forward prices is acceptable, but the market for ten-year futures is much smaller and relatively illiquid. Further, the Public Staff discussed the differences between spot price forecasts and forward prices and the different roles they serve. The Public Staff stated its view that an overreliance on forward price data can call into question the reliability of the long-term forecasts. The Public Staff also expressed similar concerns over DEP and DEC's use of longer-term forward prices for coal, considering the non-fungible nature of the fuel and the lack of transparency in the coal markets, resulting in decreased confidence in the forecast over time. As such, the Public Staff recommended that the Commission direct DEC and DEP to reconstruct their natural gas and coal price forecasts using only five years of forward price data, consistent with the approach utilized in their 2014 IRPs, and to recalculate their avoided energy costs using the updated fuel price forecasts.

NCSEA had similar concerns regarding the changes in future fuel prices. In its Initial Comments, NCSEA discussed the history of fuel prices for both coal and natural gas and noted that each of the Utilities developed its fuel price forecasts by using a different method from that used in its 2014 IRPs. In addition, NCSEA noted that DEP relied on the same fuel price forecasting method used in its 2014 IRP in its application for a certificate of public convenience and necessity (CPCN) to construct the 84 MW Sutton blackstart CT, which was filed on April 25, 2015, in Docket No. E-2, Sub 1066. NCSEA also stated that DNCP relied more heavily on futures market data during the first seven years of the planning period. NCSEA concluded that by changing the methodologies from those used in their 2014 IRPs and placing greater emphasis on futures market data, the Utilities developed much lower avoided energy cost estimates than they would have if they had used the same assumptions and methodology used in their 2014 IRPs. NCSEA therefore requested that the Commission direct the Utilities to recalculate their avoided energy costs using the future fuel prices developed for their 2014 IRPs.

In its Reply Comments, the Public Staff noted that DNCP made changes in its weightings of the fundamental forecast and futures market data, resulting in different avoided energy cost rates than its approach utilized for developing fuel forecasts in its 2014 IRP. The Public Staff repeated its concerns about the appropriateness of utilizing forward prices for natural gas and coal in developing long-term price forecasts, stating that "some use of futures market data might be appropriate for the short-term, but only to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question." The Public Staff noted that "while forward market prices may provide a snapshot of current future prices, they do not represent the same level of analysis and consideration given to the development of long-term forecasts, as performed by the EIA, Moody's Investor Services, Inc., Global Insight, Inc., and other firms whose expertise is in forecasting." Further, the Public Staff

noted that the utilization of forward prices is not consistent with the fuel procurement practices of the Utilities and thus does not provide an accurate representation of the Utilities' future fuel costs.

NCSEA in its Reply Comments noted that the Utilities did not propose to change their fuel forecasting methods in the first phase of the proceeding, despite the purpose of that phase of the proceeding being to determine appropriate input parameters for avoided cost calculations. NCSEA agreed with the Public Staff that DEC and DEP should use no more than five years of futures market data when constructing their fuel price forecasts, noting that this approach is not only consistent with DEC's and DEP's IRP forecasts but is also more consistent with DEC's and DEP's fuel procurement practices, citing to the Fuel Procurement Practices Report filed by DEC in December 2014. NCSEA disagreed, however, with the Public Staff's recommendation that DEC and DEP update their 2014 IRP forecasts; NCSEA instead recommended that DEC and DEP's actual 2014 IRP fuel forecasts be used to recalculate their avoided energy costs.

In its Reply Comments, SACE agreed with the Public Staff's and NCSEA's criticisms of the fuel price forecasts proposed by DEC and DEP and recommended that DEC and DEP use only three years of NYMEX Henry Hub natural gas futures prices and then transition to long-term forecasts when calculating avoided energy.

DEC and DEP in their Joint Reply Comments indicated that they have employed the same methodology in this proceeding that they have employed historically to calculate their avoided energy costs, contrary to the assertions by NCSEA and the Public Staff. DEC and DEP agreed that in their 2014 IRP filings, they relied on market data for the first five years and then used the fundamental forecast for the longer-term fuel prices. In the current proceeding, however, DEC and DEP found that improved liquidity in the market supported the use of market data over ten years instead of five. They indicated that their ability to acquire transactable price quotes for a ten-year period from four separate market participants demonstrates that sufficient market liquidity exists in the market to justify this approach. DEC and DEP stated that NCSEA's statement that DEP relied on fuel prices to justify the Sutton Blackstart CT Project is incorrect, stating that the project was justified exclusively for operation requirements, with no reliance on fuel costs.

DEC and DEP further stated that they have used and will continue to use market pricing to the extent reliably available, and will use forecasted fuel information for periods where market data is not available or is unreliable. They added: "The markets, not DEP or DEC, establish whether price transparency and liquidity exist, determined by the simple market-based test of whether there are willing sellers and buyers and whether there is a reasonable 'spread' between the bid and ask price action." DEC and DEP disagreed with the Public Staff's argument that "futures" prices are determinative of long-term "forward" supply prices. They stated that futures are valued to account for or insure against price movement of the underlying asset, and therefore serve as a risk mitigation, or hedging, mechanism. Further, they stated that "futures prices are traded as financial instruments that value the anticipated volatility of the underlying asset

class – not the forward transactional value of the asset class.” They stated that their price forecasts have always been based on the value of forward sale and purchase commitments, not futures contracts. They also challenged the Public Staff’s statement that the market for ten-year futures is relatively illiquid, noting that they do not obtain gas for ten-year deliveries using a ten-year futures contract; and that fewer market participants does not mean a market has become illiquid. Instead, DEC and DEP argued that at this time, fewer market participants are using long-dated futures contracts because there are better risk mitigation alternatives, such as the over-the-counter financial “swaps.”

In its Reply Comments, DNCP discussed the different approaches it utilized in forecasting energy prices in its IRPs as compared to avoided cost calculations. DNCP stated that using forward market prices for a shorter time period is acceptable for IRP modeling, where new resource options are economically compared to each other, in the development of a resource expansion plan. However, for avoided cost pricing purposes, using forward market prices for a longer time period is appropriate because DNCP is determining actual contract rates that may be paid to a contracting QF, and this approach provides a more accurate representation of its avoided energy costs at the time of the filing, as compared to the prices derived from long-term fundamental forecasts. In addition, DNCP noted that it disagreed with NCSEA’s recommendation that it use the same fuel price forecasts used in the 2014 IRP, since those rates would have been nearly a year out of date at the time of filing.

## DISCUSSION AND CONCLUSIONS

The Commission recognizes the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates. In addition, the Commission notes that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and that changes in the liquidity and trading prices in the natural gas markets over the long-term are being incorporated into long-term forecasts. In the context of both the avoided cost and IRP proceedings, recognition of these changing markets is appropriate. The Commission acknowledges that forecasting natural gas and coal prices over the next fifteen years is challenging and that forward market prices may provide a better snapshot of prices over the near and short-term future. However, forward market prices do not reflect the same level of analysis and consideration given to the development of long-term forecasts, as performed by firms whose expertise is in long-term forecasting. The Commission finds that the increased reliance on forward prices for natural gas by the Utilities in their 2014 IRPs, and on coal prices by DEC and DEP, adequately captures some of these changing market conditions at this time. This determination also reflects the important relationship that exists between the biennial avoided cost proceeding and the IRP, and helps to maintain internal consistency between these proceedings. As such, the Commission agrees with the Public Staff that DEC, DEP, and DNCP should recalculate their avoided energy rates using natural gas and coal price forecasts that are constructed in a consistent manner with those utilized in their 2014 IRPs.

Furthermore, as noted by the Public Staff, the Utilities have increasingly placed greater emphasis on futures market data in both of the last two biennial IRP and avoided cost proceedings. However, rather than utilizing the same approach in both of the 2012 proceedings, DEC and DEP changed their approach between the 2012 IRPs filed in September 2012 and the avoided cost filings in November 2012. Similarly, in 2014, DEC and DEP changed their approach between their September 2014 IRP filings and the filing of their 2014 avoided cost rates in March 2015. In the Order on Inputs in this Docket, the Commission emphasized the relationship between the IRP and avoided costs and the need for their inputs and assumptions to be consistent. As such, the Commission finds that to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes should first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In the Order on Inputs, the Commission found that:

[T]here are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation.

The Commission then concluded that the Utilities should value hedging benefits only over the term hedging is actually used, and that the Utilities should include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates.

In their Initial Statements and Exhibits, DEC and DEP used forward market indices for the years 2015 through 2025 to determine their respective avoided energy costs. They then accounted for hedging costs by using the “ask” price, rather than the mid-point in developing their fuel price forecasts. DNCP indicated that it included in its avoided energy costs the gas broker transaction costs and financing costs fees it expected to avoid as a result of purchases from renewable energy suppliers.

The Public Staff in its Initial Statement indicated that it does not believe that the avoided energy costs of the Utilities fully reflected the fuel price hedging benefits that result from the substitution of renewable generation for fossil-fueled generation. It further stated that “avoided energy costs should reflect both projected fuel costs and the

fuel price hedging benefits of renewable generation for each year of the contract.” As an illustration of this approach, the Public Staff utilized the Black-Scholes Option Pricing Model to evaluate Henry Hub natural gas options, stating that these financial instruments over terms of less than three years are publicly traded in a robust marketplace with transparent prices. Using this evaluation, the Public Staff determined that a net option price, the price of a call option minus the price of a put option, for “at-the-money” Henry Hub natural gas options, is approximately \$0.04 per dekatherm for the 12- and 24-month hedge terms used by the Utilities. The Public Staff then converted the \$0.04 per dekatherm net option price to a hedge value of 0.028 cents per kWh. The Public Staff recommended that the Commission direct the Utilities to recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation.

NCSEA in its Initial Comments found that the Utilities’ hedging calculations substantially understated the hedging benefits of renewable generation and did not comply with the Order on Inputs. NCSEA stated that a different methodology must be used in order to provide a reasonable allowance for hedging consistent with the Commission’s directive, and contended that the allowance must be provided in each year of the contract term to reflect the fuel price hedging benefit year to year. It further noted that “a valid analysis of hedging benefits must consider the full level of risk that can be avoided by customers over the appropriate time horizon not simply the portion of that risk against which the utility is actually hedging.” SACE noted several similar issues with the hedging calculations proposed by the Utilities, including that the hedge value should be accounted for each year of a QF contract.

In its Reply Comments, SACE evaluated the Public Staff’s recommendation that the Utilities use the Black-Scholes Option Pricing Model or a similar method to calculate the hedge value of renewable energy purchases. SACE stated that the input parameters and calculation assumptions for the Black-Scholes Model must be carefully considered. SACE also stated that while some inputs can be easily obtained, the assumed annual volatility rate is a critical parameter for two reasons: (1) small changes in this value have significant effects on the calculated value, and (2) it is impossible to know what the volatility of the spot price of natural gas will be over a future time period. With these parameters in mind, SACE indicated its support of the Public Staff’s proposal to use the Black-Scholes Model to determine the hedging value of renewable generation.

NCSEA in its Reply Comments stated that it reviewed the alternative method proposed by the Public Staff, and while it did not take issue with the approach, it did take issue with the “risk-free interest rate” used by the Public Staff in calculating the hedge value. The Public Staff in its hypothetical example used 1% as the rate; and NCSEA proposed that a rate of at least 3.10% be used in the calculation, which it stated is consistent with the range of risk-free interest rates used by the Utilities in developing cost of equity estimates in their respective most recent rate case proceedings. NCSEA

agreed with the Public Staff and SACE that the hedge value should be included in each year of the entire term of the QF PPA. In addition, NCSEA noted that the calculation of the fuel price hedging benefit provided by QF generation is a topic being discussed across the country. As such, NCSEA requested that, in addition to approving the Public Staff's proposed methodology (corrected to incorporate NCSEA's recommendation regarding interest rate and hedge value), the Commission indicate its willingness to revisit this issue in future proceeding as further methodologies emerge.

In their Joint Reply Comments, DEC and DEP stated that rather than using a forecasted approach, they "utilized a 10-year liquid market approach, which uses actual, quoted transaction costs rather than forecasted, speculative information." DEC and DEP noted that establishing a hedge value is a difficult exercise, and while many approaches exist, they are the only parties in the proceeding to offer a concrete method using actual prices received from actual market participants, as opposed to the "use of selective input variables inserted into computer models, such as the Black-Scholes."

DNCP in its Reply Comments raised questions regarding the Public Staff's proposed use of an option pricing model such as the Black-Scholes Model, contending that it was a very nebulous and theoretical concept that would require difficult modeling and numerous debatable assumptions. DNCP further stated that it is not aware of any jurisdiction that has employed this methodology for the calculation of avoided costs. DNCP instead proposed an alternative method that estimated the fuel hedging costs, which it described as brokerage charges related to gas financial transactions that could be avoided with increasing amounts of renewable energy purchases. Lastly, DNCP agreed that it is reasonable to include the fuel hedging savings in all years of the forecast, not just the first year.

## DISCUSSION AND CONCLUSIONS

The hedging value of renewables was discussed at length in the first phase of this proceeding, and while the Order on Inputs directed the Utilities to include a value for hedging, it did not specify a particular method to be used. The proposals made by the Utilities have merit in that they recognize actual prices in the market for long-term gas prices or the estimated transaction fees that could be avoided, but they fail to capture the full hedging benefits that renewable energy purchases can provide by reducing ratepayers' exposure to fuel price volatility and providing price stability. Furthermore, the Commission is not persuaded that DEC and DEP's use of "ask" prices in forward markets provides a reasonable estimate of the value from hedging. Likewise, the Commission is not persuaded that DNCP's use of transaction fees is the appropriate method to estimate the hedge value of stable fuel prices with solar and renewable generation.

As such, the Commission finds that it is appropriate for the Utilities to utilize the Black-Scholes Model or a similar model to determine the hedging value of renewable generation. The Commission notes that during the late 1990s, DEC and DEP each conducted a request for proposals (RFP) that resulted in various option-based power

bids that necessitated the Utilities to incorporate a Black-Scholes Model. These models relied on price volatility estimates, risk-free discounts, and strike prices. DEC incorporated such models in its RFP evaluation in the application of Rockingham Power, LLC, for a CPCN in Docket No. SP-132, Sub 0<sup>12</sup> and in DEP's application to build CT generation capacity in Wayne County in Docket No. E-2, Sub 669.<sup>13</sup> The Commission further finds that the fuel hedge value should be included for each year of the entire term of the QF PPA. With regard to NCSEA's concern over the appropriate risk-free interest rate utilized in the calculation, the Commission does not take a position with regard to a specific percentage, but notes that the appropriate risk-free rate selected for use by the Utilities should reflect the time-value of money related to buying the hedge position, which in turn should be tied to their current natural gas hedging practices.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Initial Statement of the Public Staff, the Initial Comments of NCSEA, and the Reply Comments of NCSEA and DEC and DEP.

In its Initial Statement, the Public Staff noted that DEC, DEP, and DNCP used an allocation process to weight their avoided capacity costs between summer (on-peak) and non-summer (off-peak) months. DEC and DEP have historically included such an allocation in weighting their avoided capacity costs to determine their avoided capacity rates and have designed the allocation to reflect the historical percentage breakdown of annual CT production between the on-peak and off-peak seasons. In response to the Public Staff's data requests, both DEC and DEP provided information indicating that their CT fleets were used more during summer months than winter months. The data supported the 60%/40% weighting for summer and non-summer months for the proposed avoided capacity rates under DEC Option B and DEP Options A and B, and the 80%/20% (summer/non-summer) weighting for DEC Option A.

The Public Staff noted that DNCP also applied a 60%/40% summer/non-summer allocation to its avoided capacity costs for similar reasons to those stated by DEC and DEP. In response to the Public Staff's data request, DNCP further stated that the capacity "value" was more critical during the summer peak load times. However, DNCP also acknowledged the occurrence of winter peak loads and indicated that they tended to be more volatile. DNCP further indicated that PJM has proposed to revise its capacity market rules to address the winter peak loads and fuel issues, recognizing the importance of system reliability during both winter and summer peak seasons. DNCP indicated that the FERC was reviewing PJM's proposal, and that DNCP anticipates

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<sup>12</sup> Public Staff Confidential Report on Duke Energy's Corporation's Bidding Process, pp. 8-11, filed May 19, 1999.

<sup>13</sup> Public Staff Confidential Report on Carolina Power and Light Company's Bidding Process, pp. 5-11, filed October 30, 1998.

reviewing the summer/winter allocation going forward as the PJM capacity market proposal is finalized and approved.

The Public Staff indicated its interest in further evaluating the differences in the winter and summer peak loads, how the Utilities meet their peak load obligations for each season, and the cost impacts associated with the distinct differences in the need for, and character of system capacity. It further noted that given the peak load conditions that have been observed in North Carolina in both the winter and summer seasons, the continued use of a seasonal allocation of avoided capacity costs in the manner proposed by the Utilities may need further review. Therefore, the Public Staff recommended that in the next avoided cost proceeding, the Utilities assemble their hourly CT operational data and marginal cost data on a season-specific basis to determine whether the allocation factors proposed in this proceeding remain reasonable.

NCSEA in its Initial Comments stated that DEP and DEC's proposed changes to the seasonal weighting of capacity rates are closely related to the issues that were presented relating to the modification of Option B in Phase One, noting that the Commission declined to adopt the proposed modifications to Option B at that time. NCSEA stated that to the extent the Commission is willing to consider modifications to the hours and seasonal weighting, it should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner.

In its Reply Comments, NCSEA disagreed with the Public Staff's acceptance of the changed seasonal weightings. It noted that in both the Sub 136 proceeding and Phase One of this proceeding, parties proposed to adjust the hours offered under Option B, but the Commission ultimately concluded that DEC, DEP, and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with the avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP, and the Public Staff in the 2012 biennial proceeding. NCSEA asserted that the Utilities' proposed seasonal weighting based on CT production data is inconsistent with the peaker method, and stated that, to the extent the Commission is willing to consider modifications to the definitions of on-peak and off-peak hours and allocation of capacity cost based on the Utilities' demand, consideration should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner to better tailor rates to the Utilities' needs.

DEC and DEP in their Joint Reply Comments stated that the changes in their seasonal allocation factors were adopted to create a more standardized and uniform methodology to use in their calculation of avoided costs, and to send more consistent price signals across their North Carolina service territories. They stated, however, that individual analyses for DEC Option B and DEP Options A and B based on CT production support the use of the 60% summer and 40% non-summer allocation. As such, DEC and DEP recommended that the Commission find their proposed seasonal allocations to be appropriate and justified.



## DISCUSSION AND CONCLUSIONS

With regard to NCSEA's argument that DEC's and DEP's adjustments to the seasonal allocation factor would not comport with the peaker method, the Commission disagrees. The theory underlying the peaker method, as recognized by the Commission in Phase One of this proceeding and in prior proceedings, is that the capacity cost of the peaker plus the marginal system running costs equals the cost of any generating plant, including a baseload plant. Once that initial determination of capacity cost is made, the calculation then leaves the framework of the peaker methodology and becomes a ratemaking question. The actual hours during which that capacity value is allocated may vary based on production data, seasonality, and other factors. The Commission finds that it is appropriate to base the number of hours over which capacity value is allocated on the peak hours when the utility typically operates its fleet of CTs. Second, it is reasonable that similar production costs for the on-peak and off-peak hours be grouped together, and thus the Commission has historically allowed the Utilities to allocate such costs on a seasonal and hourly basis.

For the current proceeding, the Commission finds that the Utilities' proposed seasonal allocations are reasonable, but that it is appropriate to continue to evaluate the seasonal allocation factors used by the Utilities for avoided costs in light of changing seasonal peak load conditions experienced in North Carolina. Therefore, the Commission directs the Utilities in the next biennial proceeding to assemble their hourly CT operational data and marginal cost data on a season-specific basis in order to determine whether the allocation factors utilized in this proceeding remain reasonable.

### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Joint Reply Comments of DEC and DEP, the Reply Comments of NCSEA, and the Initial Statement of the Public Staff.

In their standard contracts filed with their Initial Statements (Exhibit 4), DEP and DEC included language in their PPAs requiring a QF larger than 100 kW to provide notice of annual, monthly, and day-ahead forecasted hourly production. In its Initial Statement, the Public Staff indicated that it had discussed the difficulty and ambiguity of this reporting requirement with DEC and DEP. Both utilities indicated that the requirement was intended to give system operations ample notice of QF operations to allow them to plan generation accordingly, particularly when a QF was experiencing an outage. The Public Staff stated that while it believed such reporting might be appropriate for certain facilities, the threshold for reporting and the detail required appeared onerous and did not provide clear direction to the QF when it was necessary to report such operations.

As a result of these the discussions, the Public Staff, DEC, and DEP agreed to the following language as a substitute for Paragraph 5 of DEC's and DEP's standard contracts:

Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. If the Seller is required to notify the Company of planned or unplanned outages, notification should be made as soon as known. Seller shall include the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage.

In their Joint Reply Comments, DEC and DEP noted that the information that would be provided by this revised reporting requirement would aid them in procuring alternative resources when a QF plans reduced operations. Further, as a request for planned operational information is unlikely to be necessary for QFs below three MW, exempting QFs below that threshold is deemed to be reasonable based upon current system operations.

In its Reply Comments, NCSEA noted the value of accurate production data for system operations and the purpose of the proposed provision. However, NCSEA expressed concerns regarding the production forecast requirements agreed to by the Public Staff and DEC and DEP. It noted that accurate hourly production forecasts for QFs often require sophisticated meteorological analysis, the cost of which is prohibitive at this time for most small QFs. NCSEA contended that the Utilities have superior forecasting resources and capabilities to those of QFs, and thus the likelihood of reliance by a utility on production forecasts provided by a QF is very low. Therefore, NCSEA recommended that the Commission reject the DEC/DEP/Public Staff proposal as it relates to production forecasting, but that the issue of production forecasting be revisited in a future proceeding when forecasting tools available to QFs have improved and become more cost effective. NCSEA requested that if the Commission is inclined to include the language agreed to by the Public Staff, DEC, and DEP related to production forecasts, that the Commission consider revising the language to make clear that a QF may rely on the production forecasts produced during the design/development process to fulfill its obligations under the contract provision, and that any inaccuracy in the forecasts shall not give rise to a right to terminate by the respective utility.

### DISCUSSION AND CONCLUSIONS

The Commission finds that the language agreed to by DEC, DEP, and the Public Staff should allow DEC and DEP to plan system operations without being unduly onerous to the QFs. While the Commission understands NCSEA's concerns regarding the production forecasting requirement, NCSEA's proposal that it be able to use the forecasts developed during its design and development may be sufficient to satisfy the requirement in some cases, and insufficient in others. Further, while the Commission is aware that the Utilities have developed sophisticated forecasting capabilities beyond

what should be expected of a small QF, a certain degree of accuracy in a QF's forecast should be expected. Whether repeated inaccuracies rise to the level and degree to merit contract termination would be a subjective determination that would depend on the circumstances. Therefore, the Commission concludes that it is appropriate for DEC's and DEP's Standard Contracts to include the language agreed to by DEC, DEP, and the Public Staff.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in Section 6 of DEC's and DEP's Terms and Conditions (Exhibit 5 to their Initial Statements), NCSEA's Initial Comments, the Reply Comments of the Public Staff, and the Joint Reply Comments of DEC and DEP.

Section 6 of DEC's and DEP's proposed Terms and Conditions states:

Reduction in Contract Capacity or Energy - If Seller's average energy generated in the on-peak or off-peak periods or capacity during any 12-month period falls significantly below the Contract annual kilowatt-hours or Contract Capacity, the Company may petition the North Carolina Utilities Commission to invoke a Reduction-In-Contract-Energy-Charge or Reduction in Contract Capacity Charge and establish a new Contract Energy and Capacity level. If approved by the Commission, the Reduction-In-Contract-Energy-Charge shall be equal to the total Energy Credits received for all prior years of the current Contract Period, less an amount computed at the new Contract Energy level using the on-peak or off-peak energy credit contained in the Purchase Agreement, less an amount equal to the energy supplied in all prior years of the current Contract Period which is in excess of the new Contract Energy level priced at the Variable Rate for energy which was in effect at the time the energy was delivered as specified in Company's applicable purchased power rate schedule, plus interest. The reduction in Contract Capacity Charge shall be a quantity equal to the amount as calculated under the Early Contract Termination clause multiplied by the ratio of the capacity reduction to existing Contract Capacity, plus interest. The interest rate shall be the same interest rate as computed in accordance with the Early Contract Termination provision.

In its Initial comments, NCSEA noted that prior to the Standard Contract approved pursuant to the Sub 136 Order, DEP's Standard Contract had included a similar provision. NCSEA pointed out that in Sub 136, the Commission concluded:

[T]he 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. Further, such charges are inconsistent

with DEP's stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts, as they may apply in both early (after two years) and later years of a contract. 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 occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval.

NCSEA also noted in that proceeding, the Commission invited DEP to propose an alternative provision to address the harm caused by lower production in the later years of a long-term levelized contract. NCSEA contended that DEC and DEP's current proposal, similar to the provision that was struck in Sub 136, is inconsistent with the purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts because it can apply in both early and later years of a contract. NCSEA opposes the proposal as being inconsistent with the 2012 Order, unnecessary, and unduly punitive. Additionally, NCSEA challenged the provision based on its being confusing. NCSEA stated that the provision "combines shortfalls in capacity and shortfalls in delivered energy into a single triggering condition" and does not define the phrase "significantly below." It also contended that the definition of the essential term "Contract Energy" is confusing as well, and that the basis for the calculated charge is obscure and does not bear any relation to the harm it is supposed to address. Thus, NCSEA recommended that the Commission reject DEC and DEP's proposal on the same basis that it rejected the provision in its 2012 Order.

In its Reply Comments, the Public Staff noted its initial comments in the Sub 136 proceeding that recognized the Commission's holding 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, or wind, absent an explicit order from the Commission.<sup>14</sup> The Public Staff further stated that QFs, under the standard contracts, are not paid unless they are generating, and, therefore, a penalty is unwarranted. The Public Staff also pointed out that in Phase One of this proceeding, the Commission had received evidence on this issue and concluded that "experience has shown that there is limited risk of nonperformance." The Public Staff recognized that while there may be some risk that a QF could underperform in the later years of a long-term levelized contract after receiving the benefits of a levelized contract in the early years, DEC and DEP's proposal does not address this concern. Thus, the Public Staff recommended that the Commission direct DEC and DEP to refile a proposal that more directly addresses underproduction in later years of a levelized contract, resulting in overpayment during the early years of the contract. The Public Staff also recommended that until such a proposal is approved by the Commission, DEC and DEP should remove the Reduction Contract Energy and Reduction in Contract Capacity

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<sup>14</sup> Initial Statement of the Public Staff filed on February 7, 2013, in Docket No. E-100, Sub 136, at p. 30.

charge provisions from their proposed Terms and Conditions. Finally, the Public Staff recommended that in the interim, DEC and DEP may apply to the Commission for approval to impose a charge on a case-by-case basis, at which time the Commission can determine the extent, if any, of the harm that the charge would address.

In their Joint Reply Comments, DEC and DEP maintained that their proposed Reduction in Contract Energy Charge and Reduction in Contract Capacity Charge are reasonable and should be retained. They noted that their filings in Docket No. E-100, Sub 136, contained similar, but not identical, language intended to protect their customers. DEC and DEP noted that long-term levelized rate QF contracts both encourage QF development and run the risk of producing overpayments to QFs. They contended that these rates tend to overpay the QF in the early years and underpay in later years. Thus, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes over the life of a long-term levelized contract. Therefore, DEC and DEP contended that they and their customers should not have to risk underperformance at the end of a contract with a QF having benefitted by the levelized rates in the early years. DEC and DEP stated that they believe their proposal provides a mechanism to address the situation should the QF's performance falls short of its contractual obligation. They contended that the provision proposed in this proceeding is more narrowly tailored to the harm it is intended to prevent than that proposed in previous proceedings. Further, they argue that their provision is not punitive because they cannot impose a charge without Commission approval.

### DISCUSSION AND CONCLUSIONS

The Commission has recognized the potential for levelized contracts to create the risk of underproduction in later years of a contract. Certainly, performance and maintenance issues as reported by Advanced Energy, if they go unaddressed, would increase the likelihood of this risk. However, the Commission found in Phase One that the potential for underperformance is minimal and that QFs' financing offers contain incentives for them to perform fully through the term of the contract. The language proposed by DEC and DEP would unnecessarily apply throughout the term of the contract, when the purpose is to address events only in the later years of the contract. Thus, again, the proposed language is overly broad. Further, the proposed language still requires adjudication by the Commission to determine whether a charge should be imposed, and if so, in what amount. The Commission has previously ruled that the Utilities have the right to apply to the Commission for imposition of a charge. Thus, the proposed language regarding adjudication only serves to note the existence of an action already permitted by the Commission, i.e., for DEC and DEP to file a complaint for Commission adjudication.

The Commission believes the approach recommended by the Public Staff has merit and therefore finds that DEC and DEP should remove the Reduction Contract Energy and Reduction in Contract Capacity Charge provisions from their proposed Terms and Conditions unless and until the Commission approves revised language that more directly addresses underproduction in later years of a levelized contract that

results in overpayment during the early years of the contract. Further, as is already permitted, the Utilities may apply to the Commission for approval to impose a charge on a case-by-case basis.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; the Reply Comments of the Public Staff and DNCP; and the Joint Reply Comments of DEC and DEP.

In its Initial Comments, NCSEA noted that DNCP's Terms and Conditions provide that a QF may assign its rights under DNCP's Standard Contract only with the prior written consent of DNCP, and that DNCP "may withhold such consent if it determines, in its sole discretion, that such assignment would not be in the best interests of DNCP or its customers." NCSEA contended that granting DNCP sole discretion to reject an assignment for any reason is commercially unreasonable, and proposed that DNCP amend this provision to require that it not unreasonably withhold consent to proposed assignment. Similarly, NCSEA pointed out that the assignment provisions in DEC's and DEP's Standard Contracts give them "undue discretion to disapprove or put onerous conditions on the assignment rights, such as the requirement of financial security, which ... have the potential to serve as an impediment to QF development." NCSEA recommended that the Commission direct DEC and DEP to revise their assignment provisions to require that they not unreasonably withhold consent to a proposed assignment, and not require commercially unreasonable measures, such as security.

In its Reply Comments, the Public Staff noted that in order to encourage QF development in compliance with PURPA, the Commission has, since Docket No. E-100, Sub 41A, included standard rates, terms, and conditions in its biennial avoided cost proceedings to reduce the transaction costs for smaller project developers who may not have the resources or expertise to negotiate with a utility. The Public Staff stated that the Utilities' proposed assignment provisions could constitute an unreasonable burden on QF development and recommended that the provisions be revised.

In their Joint Reply Comments, DEC and DEP contended that their standard contracts protect customers by providing that PPAs can only be assigned to a third party if the assignee is able to assume the QF's outstanding financial responsibilities. Thus, DEC's and DEP's proposed Standard Contracts provide that the PPA may be assigned to a third party if DEC or DEP is reasonably satisfied that the assignee will fulfill the financial obligations of the QF. DEC and DEP noted that this provision is similar to a provision currently in DEP's Terms and Conditions on file in Sub 136, except that they have added a sentence in reference to the regulatory approvals required by the Commission. DEC and DEP contended that this provision is intended to protect them, and ultimately, the ratepayers from assignment of a PPA to a QF that is unable to pay. DEC and DEP stated that a review of their records indicates that the only assignments they have declined were those that would have required that they accept a bank as a second counterparty.

In its Reply Comments, DNCP stated its agreement to revise Section I of the Schedule 19-FP and Schedule 19-LMP Terms and Conditions to state that it will not unreasonably withhold its consent to assignment of the PPA, provided that the assignment does not require any amendment of the Terms and Conditions of the PPA other than the notice provisions.

The Commission concludes that the Utilities should not unreasonably withhold consent to a proposed assignment of a standard PPA. This holding is consistent with prior Commission precedent keeping QFs' transaction costs to the minimum necessary, while allowing the Utilities to ensure that an assignee has the financial means to assume the obligations of the assignor. The Commission finds that the language DNCP has agreed to include in its Schedules is appropriate, and directs DEC and DEP to include similar language stating that they cannot unreasonably withhold consent to assignment in their standard contracts

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the Initial Statement and Exhibits of DNCP, the Initial Comments of NCSEA, the Reply Comments of the Public Staff, and the Reply Comments of DNCP.

In its proposed Standard Contract, DNCP included a provision in Article 7(a)(vii) that grants the utility a right to terminate the contract when the FERC grants a petition by the utility under PURPA Section 210(m), relieving the utility of its purchase obligation.

In its Initial Comments, NCSEA disagreed with DNCP's characterization of a grant by the FERC of a PURPA Section 210(m) application as constituting default by a QF, and stated that, to the extent the provision is permissible, it should not be included in Article 7(a), which is titled "Defaults with No Cure Period." NCSEA also noted that DEC's and DEP's proposed Terms and Conditions give the Utilities broad discretion to suspend or terminate contracts without an opportunity to cure. However, the current Terms and Conditions for both DEC and DEP require them to give advance notice to the QF of termination, except in circumstances where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter.

In its Reply Comments, the Public Staff noted that at the time of the filing of its Initial Statement, DNCP had a PURPA Section 210(m) application pending before the FERC,<sup>15</sup> but subsequently the FERC declined to grant that petition.<sup>16</sup> As no petitions were pending, the Public Staff found inclusion of this provision to be unnecessary and recommended that the Commission direct DNCP to remove the provision. If the

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<sup>15</sup> Virginia Electric and Power Company, Application to Terminate Purchase Obligation, Docket No. QM15-1-000 (Oct. 31, 2014).

<sup>16</sup> Virginia Electric and Power Co., Order Denying Application to Terminate Mandatory Purchase Obligation. Docket No. QM15-1-000, (April 16, 2015); 151 FERC ¶61,038 (2015).

Commission allowed this provision to remain, the Public Staff recommended that it be moved from the default section of the Standard Contract to a stand-alone clause.

In its Reply Comments, DNCP proposed to move the PURPA Section 210(m) provision from the default section in the 19-FP and 19-LMP PPAs to the end of Article 2 (Term and Commercial Operations Date) in those agreements.

The Commission concludes that DNCP's PURPA Section 210(m) provision is unnecessary. While it is clear that the provision should not be included in the section of DNCP's Standard Contract dealing with default, attempting to address any potential governmental actions that might affect the PPA, including the grant of a PURPA Section 210(m) petition, is unnecessary in a Standard Contract. If Commission intervention is necessary, the Commission will deal with such situations as they arise. As such, DNCP should remove this language from its Standard Contract.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Initial Comments of NCSEA, the Reply Comments of the Public Staff, and the Joint Reply Comments of DEC and DEP.

DEP's Terms and Conditions approved by the Commission in the Sub 136 proceeding included the following statement:

Company shall give Seller a minimum of 30 calendar days prior written notice before terminating or suspending the Agreement pursuant to provisions 1(h)(l)(default or breach of Agreement by Seller), 1(h)(3)(failure to pay any applicable bill when due and payable) or 1(h)(5)(Seller's inability to deliver to Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement), above: however, termination or suspension pursuant to provisions 1(h)(3)(fraudulent or unauthorized use of Company's meter) or 1(h)(4)(presence of dangerous condition) shall be immediate.<sup>17</sup>

In its Initial Comments, NCSEA noted that while DEC's and DEP's Standard Contracts provides a QF advance notice of termination (except where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter), it does not give a QF the opportunity to cure the condition giving rise to termination. NCSEA pointed out that DNCP provides a 30-day cure period for most defaults. NCSEA contended that many circumstances of default are temporary or curable, and that it would be commercially unreasonable if a cure provision were not included. NCSEA recommended that Section 1(i) of DEC's and DEP's Terms and

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<sup>17</sup> DEP, Terms And Conditions For The Purchase Of Electric Power, Sheet 2 of 9, Filed in Docket No. E-100, Sub 136, Effective April 1, 2014.



Conditions be modified to provide the QF notice and a reasonable opportunity to cure prior to authorizing termination by the utility.

In its Reply Comments, the Public Staff noted that it generally supports the inclusion of commercially reasonable opportunities to cure in QF PPAs in order to avoid impermissible burdens on QFs in violation of PURPA, and recommended that DEC and DEP amend their Terms and Conditions to provide QFs a reasonable opportunity to cure prior to termination of the contract. The Public Staff also recommended that DEC and DEP provide clearer guidance regarding the circumstances in which termination or suspension is warranted.

In their Joint Reply Comments, DEC and DEP agreed with NCSEA that QFs should be allowed an opportunity to cure before termination (except in dangerous conditions and in cases of fraud). While they acknowledged the 30-day period included in Sub 136 by DEP, they now argue that 30 days is in excess of what is required to cure, as the QF should already be aware of the situation except for dangerous conditions. They also pointed out that the new Interconnection Agreement approved by the Commission in Docket No. E-100, Sub 101 provides a five-day cure period, and proposed the same period for their Standard Contracts to be consistent and lessen confusion.

In their letter of September 17, 2015, indicating settlement of several issues with NCSEA, DEC and DEP noted that they had agreed that for termination issues that are included in both the interconnection agreements and the PPA, there will be a five-day cure period in Section (i) of its Terms and Conditions. For termination issues that are not covered by the interconnection agreement, the Terms and Conditions will contain a 30-day cure period, except for fraudulent or unauthorized use of Company's meter where termination is immediate. DEC and DEP provided language that they and NCSEA have agreed was appropriate.

The Commission concludes that QFs should have a commercially reasonable opportunity to cure prior to termination of a contract. The language proposed by DEC and DEP in their September 17, 2015 letter provides a reasonable opportunity to cure and should be included in DEC's and DEP's Terms and Conditions.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the Initial Statements of DEC, DEP, and DNCP, the Initial Comments of NCSEA and SACE, and the Reply Comments of DEC, DEP, DNCP, NCSEA, and the Public Staff.

In DNCP's Schedule 19, Section I filed with its Initial Statement, DNCP proposed that standard rates not be available to a QF owned by a developer or affiliate who sells or will sell power to DNCP from another QF located within one mile unless the combined capacity is equal to or less than five MW. DEC and DEP proposed a similar restriction in their Initial Statements, but proposed a one-half mile limitation, as opposed to the one mile proposed by DNCP.

In its Initial Comments, NCSEA pointed out that DEC included a similar provision in the past with a one-half mile limitation and included the same provision in this proceeding. DEP also proposes to include the same provision in this proceeding. NCSEA pointed out that DNCP provided no justification for increasing the limitation to one mile. NCSEA recommended that the Commission approve DEC and DEP's one-half mile proposal and limit DNCP to one-half mile, while maintaining the qualification that two QFs under the same or affiliated ownership are eligible for the standard offer so long as the combined capacity of those facilities does not exceed five MW.

In its Initial Comments, SACE pointed out that under PURPA, a facility is eligible for certification as a QF based on three criteria: the distance between the facilities (measured between the respective facilities' electric-generating equipment), ownership, and the type of energy resource. SACE noted that the requirement that two facilities be located more than one mile apart only applies to facilities under common ownership that use the same type of energy resource. SACE concluded that the one-mile radius restriction and the five MW restriction in DNCP's Schedule 19 should only apply when two proposed facilities under common ownership use the same energy resource. SACE further recommended that the distance between facilities should be measured from the electrical-generating equipment of a facility for purposes of making the one-mile determination.

In their Joint Reply Comments, DEC and DEP noted that their provisions in question are long established and consistent with the five MW threshold set by the Commission in 1997 in Docket No. E-100, Sub 41A. They explained that the intent of this provision was to ensure that larger QF developers could not avoid negotiating with the utility by breaking up larger facilities into multiple, closely-located five MW or less facilities. DEC and DEP argue that SACE's citation of the PURPA rules misses the point and pertains to the FERC requirements for certification of a facility as a QF under the "one mile rule", not to the availability of standardized rates, terms, and conditions to QFs. They maintain that their Terms and Conditions are entirely consistent with the FERC's one mile rule, as a Standard Contract is available to facilities that are certified as QFs as defined by the FERC in 18 C.F.R. §§ 292.203, 292.204, and 292.205. DEC and DEP state that the issue is not whether a facility meets the FERC criteria to be certified as a QF, but whether QFs owned by the same seller or an affiliate that sells power to the utility from another QF within one-half mile are eligible for the Standard Contract. DEC and DEP point out that like the five MW eligibility threshold, the limitation on eligibility for facilities owned by the same seller or an affiliate is a Commission determination, not a FERC determination. Finally, they note that neither the Public Staff nor NCSEA objected to this provision, and that SACE has not presented a compelling reason for the Commission to depart from its prior determination.

In its Reply Comments, DNCP agreed with SACE's comments that the one-mile rule and the five MW restriction in Schedule 19 should only apply when the two proposed facilities are under common ownership and use the same energy resource. DNCP also agreed with SACE that for purposes of the one-mile rule, the distance

between facilities is measured from the electrical-generating equipment of each facility. DNCP modified its proposed Schedule 19-FP and Schedule 19-LMP accordingly.

However, DNCP did not agree with NCSEA's recommendation that the Commission reduce the geographical limitation for renewable resource QFs to one-half mile. DNCP pointed out that its proximity limitation had long been contained in Schedule 19, and ensures that Schedule 19 is available only to small QFs with a net capacity not greater than five MW. DNCP noted that the geographic siting limitation for the purpose of determining the size of renewable resource QFs under Schedule 19 is the same one-mile test used by the FERC in 18 C.F.R. § 292.204(a) to determine the size of a small power production QF such as a solar QF.

In its Reply Comments, the Public Staff noted that DNCP has previously limited eligibility for its Schedule 19 tariffs to QFs owned by a seller or affiliate within one-half mile, but proposes increasing the limitation to one mile. The Public Staff also pointed out that DEC has historically included a similar one-half mile availability limitation, and that DEP has proposed to include the same limitation. The Public Staff recommended that the Commission adopt a consistent availability limitation for all three Utilities of one-half mile, while maintaining the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms so long as the combined capacity of those facilities does not exceed five MW. The Public Staff also agreed with SACE that the one-half mile restriction should only apply to facilities that use the same energy resource, and recommended that the Utilities include language stating that the distance between facilities would be measured from the electrical-generating equipment of a facility.

The Commission concludes that in the interests of consistency and clarity, it is appropriate for each utility to limit the availability of standard rates to facilities within one-half mile, provided two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms if the combined capacity of those facilities does not exceed five MW. DNCP has not provided adequate justification for increasing the one-half mile limitation to one mile. Further, there does not appear to be disagreement with SACE's proposal that the one-half mile restriction only to facilities that use the same energy resource, or the requirement to include language stating that the distance between facilities should be measured from the electrical-generating equipment of a facility. Therefore, the Commission finds it appropriate for the Utilities to include this language in their standard rates.

#### EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 – 20

The evidence supporting these findings of fact is contained in the Initial Statements of DEC, DEP, and DNCP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

In its Initial Comments, NCSEA pointed out that in the 2012 Order, the Commission approved a 30-month deadline for achieving commercial operation and

provided that the deadline could be extended if the project is progressing and the QF is making a good faith effort to complete the project. NCSEA noted that DNCP had included the deadline extension language in its proposed contract, but DEC and DEP had not. Additionally, NCSEA sought to clarify that the contract term commenced on the date the QF first delivers electricity rather than on the contract date. NCSEA recommended that DEC and DEP include the deadline extension language in their contracts as had been ordered by the Commission in 2012 and clarify that the term commenced upon delivery of electricity.

In its Reply Comments, the Public Staff addressed NCSEA's concern regarding extension of the 30-month deadline and recommended that the Commission direct DEC and DEP to amend their consent provisions to provide that consent to an extension of this initial delivery date shall not be withheld if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

In their Joint Reply Comments, DEC and DEP indicated that they had reached agreement with NCSEA to clarify in both Schedule PP and the Purchased Power Contract to indicate that the 30-month deadline can be extended. Further, DEC and DEP indicated that they and NCSEA had reached agreement that the term shall begin upon the first date when energy is generated by the QF and delivered to the utility.

In DEC and DEP's September 17, 2015 letter to Commission advising of their settlement of several issues with NCSEA, DEC and DEP provided language they and NCSEA had agreed upon allowing extension of the 30-month deadline if construction is nearly complete and the QF shows that it is making a good faith effort to complete its project. DEC, DEP, and NCSEA also agreed that the provision allowing termination if the QF does not deliver the quality or quantity of electricity provided in the PPA would not cover a situation where the QF was unable to deliver due to circumstances beyond its control, such as weather conditions, but rather situations within the QF's control such as unrepaired equipment.

It appears that NCSEA, DEC, and DEP have reached agreement that the 30-month deadline may be extended if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner. They have also agreed to clarify that the term begins upon delivery of electricity. The Commission concludes that the language agreed to by these parties is appropriate and should be included in DEC's and DEP's Standard Contracts.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

Section 1(i) of DEC's and DEP's respective proposed Terms and Conditions provides the right to terminate a contract "due to the Seller's inability to deliver to the Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement." NCSEA objected to this provision on several bases: (1) it does not clearly define the standard for quantity or quality; (2) it does not indicate what degree of deviation from the standard would be grounds for termination; (3) the utility has absolute discretion to terminate; (4) termination is an excessive remedy for under-delivery of energy or capacity; (5) the provision is duplicative of the "reduction-in-contract-energy" and "reduction-in-contract-capacity" charges discussed above; and (6) the provision is inconsistent with prior orders of the Commission. Thus, NCSEA recommended that the Commission direct DEC and DEP to remove this provision.

In its Reply Comments, the Public Staff again pointed out the Commission's holding in Docket No. E-100, Sub 59, that allowed a utility to require a QF to state the amount of capacity and energy it intended to provide, but also held that the utility could not use this statement to penalize the QF, without an explicit order from the Commission. The Public Staff concluded that since QFs under standard contracts are not paid unless they generate, the provision is unnecessary.

In their Joint Reply Comments, DEC and DEP indicated that they had discussed this matter with NCSEA and had agreed to add to Section 1(i) the following language: "Termination of the contract is at the Company's sole option and is only appropriate when the Seller either cannot or will not cure its default or if the Seller fails to deliver energy to the Company for more than six months."

The Commission concludes that the addition of this language to Section 1(i) of the Terms and Conditions for DEC and DEP addresses the concerns of DEC, DEP, NCSEA, and the Public Staff in that it provides DEC and DEP a remedy for non-performance and is clear as to the standard for such right to terminate to arise. Therefore, DEC and DEP are directed to include this language in section 1(i) of their Terms and Conditions.

## EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

In its Initial Comments, NCSEA noted that DEC and DEP have included various provisions in their standard offers related to the interconnection of QFs. NCSEA contended that some of these references to interconnection are unclear, have the potential to mislead, and are contradictory. It provided as examples Section 4 of DEC and DEP's respective Standard Contracts, Section 13 of their respective Terms and Conditions, and DEP's Rate Schedule. NCSEA recommended that the Commission require DEC and DEP to strike all provisions in the power sales documents related to interconnection, include a simple reference to the North Carolina Interconnection

Procedures, Forms, and Agreements, and state that an interconnection agreement is necessary in order to deliver output to the utility.

The Public Staff agreed with NCSEA that these provisions related to interconnection should not be included since the Commission has adopted separate procedures, forms, and agreements in Docket No. E-100, Sub 101, related to the interconnection of QFs, and inclusion could cause confusion and result in inconsistencies.

In their Reply Comments, DEC and DEP indicated that they had reached agreement with NCSEA on this issue. DEC, DEP, and NCSEA have agreed that inclusion of the terms regarding interconnection is intended to enhance clarity and transparency, and that if there is any conflict between interconnection terms, the interconnection agreement will control. In their letter of September 17, 2015, noting settlement of certain issues with NCSEA, DEC and DEP included specific language providing that the interconnection agreement controls if in conflict with the Terms and Conditions.

### DISCUSSION AND CONCLUSIONS

The Commission concludes that the interconnection agreement should control in the event that there is conflict between the terms of the standard contract and an interconnection agreement. Therefore, the provisions related to interconnection in DEC's and DEP's standard offers may remain, subject to the condition that the interconnection agreement controls if there is a conflict. The Commission finds the language agreed to by DEC, DEP, and NCSEA is appropriate and should be included in the Terms and Conditions.

### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

DEC's Rate Schedule includes the following provision:

#### POWER FACTOR CORRECTION

Unless the Seller is required by an Operating Agreement to adjust VAR production to support voltage control, when the Seller consumes VARs supplied by the Company or the Seller delivers VARs to Company, the Company may reduce the purchased energy measured in kilowatt-hours for that month by multiplying by the Average Consumed Power Factor. The Average Consumed Power Factor shall be the calculated on a monthly basis as the average kWh divided the average kVAh, where average kVAh shall be the square root of the sum of the average kWh

squared plus the average consumed and delivered kVARh squared. Company reserves the right to install facilities necessary for the measurement of power factor and to adjust the Interconnection Facilities Charge accordingly, solely at the option of Company.

Similarly, DEP proposed to bill a QF at a rate of \$0.34 multiplied by the number of kVARs consumed or supplied by the QF and stated that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control.

In its Initial Comments, NCSEA noted that DEC's provision would allow the utility to reduce the power factor without crediting a QF when it produces reactive power that benefits the utility. NCSEA contends that DEC's and DEP's provisions are unclear and, in effect, penalize QFs by not allowing them to benefit when they provide the Utilities reactive power. It requested that the Commission scrutinize these provisions.

The Public Staff noted that Section 1.8 of the Interconnection Agreement approved by the Commission in Docket No. E-100, Sub 111 provides that an interconnection customer, with the exception of wind generators, must operate within a power factor range of 0.95 leading to 0.95 lagging at continuous rated power output, and that a utility must pay the interconnection customer when the utility requests the customer to operate outside of that range. The Interconnection Agreement also requires a utility to pay an interconnection customer for reactive power to the extent it pays its own or affiliated generator. The Public Staff recommended that the Commission require DEC and DEP to update their rate schedules to reflect their obligation to pay for reactive power that the interconnection customer provides or absorbs at the Utilities' request.

In their Joint Reply Comments, DEC and DEP stated that they had revised the power factor provisions to clarify that a QF should operate its generation so that it will not adversely impact voltage. QFs without specific operating agreements are requested to operate at a unity or 100% power factor without either supplying or consuming VARs. DEC and DEP contend that this approach should prevent potential conflicts with normal system operations that could adversely impact service. DEC and DEP note that an operating agreement may be appropriate for larger QFs that can actively provide direct voltage support, and the agreement would specify the ancillary service requirements and compensation for the service. In regard to smaller QFs without an operating agreement, DEC and DEP indicate that as they must install capacitors if a smaller QF is not operating during a low voltage event, no costs are avoided. DEC and DEP propose to charge QFs not operating at a unity power factor for VAR consumption or supply similarly to their retail customers. DEC and DEP dispute NCSEA's assumption that the provision of VARs benefits the utility, arguing that this reactive power conflicts with their normal operations and may increase the cost of maintaining voltage in the area. They note that a unity power factor should also be desirable from the QF's perspective.

The Commission concludes that as to the issue of reactive power provided or absorbed at the utility's request, it appears that for larger generators with operating agreements, DEC's and DEP's operating agreements would specify the ancillary

services and the compensation for such services. To the extent that a smaller generator provides or absorbs reactive power at the utility's request, it is also appropriate for DEC and DEP to pay for such power to the extent they pay their own or affiliated generator. DEC and DEP should, therefore, revise their rate schedules accordingly.

#### EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 – 25

The evidence supporting these findings of fact is contained in the Initial Statements of DEC and DEP, the Initial Statement of DNCP and Exhibit A to Schedules 19-FP and 19-LMP, the Initial Statement of the Public Staff, the Initial Comments of NCSEA, the Joint Reply Comments of DEC and DEP, and the Reply Comments of DNCP.

In Phase One of this proceeding, DNCP witness Roger T. Williams explained that the Commission held in Sub 136 that an LEO is established when a QF has (1) obtained a CPCN (or filed a Report of Proposed Construction (ROPC), if applicable) and (2) indicated to the utility that it seeks to commit itself to sell its output to that utility. He further testified that DNCP believes that the standard is still too vague to be implemented in a fair manner, particularly with regard to the second prong of the LEO test, as there is not enough guidance regarding what it means for a QF to "commit itself to sell its output." DNCP proposed that the Commission adopt a form through which QFs could clearly show their intent to sell their output to a utility, thereby setting the date that a LEO is established (assuming that the first prong of the test has been met).

In its Order on Inputs, the Commission indicated that it was positively inclined towards this proposal. The Commission requested that parties address DNCP's proposal in more detail in Phase Two and listed certain questions that should be addressed:

How the QF would know it needed to obtain the form, how it would obtain the form (e.g., from a specified place on a utility's website), whether or how the form could be submitted electronically, and the extent to which the utility could change or withdraw the form without prior Commission approval.

In their Initial Statements, DEC and DEP supported DNCP's proposal that a QF complete a simple form stating that it offers to sell its output, thereby setting the date of the LEO, to increase clarity and to "prevent 'gaming' of the LEO date." If a QF has obtained a CPCN or filed an ROPC, DEC and DEP indicated that an LEO form should require the QF to provide the date and docket number in which it received a CPCN or filed an ROPC with the Commission. If the QF has not received a CPCN but has filed an application the form should indicate the date of filing of the CPCN application. Finally, if neither an ROPC nor an application for a CPCN has yet to be filed the form should be supplemented upon filing. DEC and DEP stated that the form should be signed and dated by a person authorized to make a commitment. They indicated that they would make the form available on their websites, and would not object to QFs submitting the forms electronically. Finally, DEC and DEP noted that after initial Commission approval of a form, no further approval would be necessary unless the utility makes material



changes to the form or ceases to use it. DEC and DEP did not propose a particular form for approval by the Commission.

In its Initial Statement, DNCP included comments responsive to the Commission's conclusions and questions and included a proposed LEO form as Exhibit A to Schedules 19-FP and 19-LMP (LEO Form). DNCP indicated that the proposed LEO Form should be used to determine the date of a QF's commitment to sell its output to the Company. DNCP's LEO Form contains: a formal request by the QF that DNCP enter into a PPA and purchase its electricity; contact information; certifications that it has received or applied for a CPCN or has filed or will file an ROPC with copies attached, the QF's intended rate schedule, termination provisions; and a survival clause. DNCP also included a section specifying how the LEO date will be determined for each QF. It stated that its LEO Form would be available on its web site as an exhibit to its applicable rate schedules. DNCP also indicated that upon completion of the form and submission by certified mail, courier, hand delivery, or e-mail to its Power Contracts Department, an LEO would be established and that any changes would be made only with Commission approval. Finally, DNCP proposed that use of the form to establish the second prong of the LEO test be mandatory.

In its Initial Comments, NCSEA submitted a proposed LEO form that it contended was much less complicated than the form submitted by DNCP, but contained the information necessary to establish a commitment to sell to the utility. NCSEA also recommended that the Commission make use of the form permissive instead of mandatory, allowing a QF to show it has committed to sell through other actions. However, NCSEA proposed that use of the form be encouraged on a prospective basis by creation of twin rebuttable presumptions regarding use of the form. NCSEA also advocated that the Commission make the establishment of the notice of commitment effective upon submission rather than upon receipt by the utility.

In its Initial Statement, the Public Staff indicated that it supported the creation of a simple form by which QFs and the Utilities could clearly establish the date of a LEO. The Public Staff stated that such a form could help clarify the rights and obligations of each party and avoid disputes that may ultimately have to be brought to the Commission for adjudication or to the Public Staff for informal resolution. The Public Staff recommended that the form be publicly available on each utility's website in sections dealing with interconnection agreements and PPAs, and that the Utilities should make clear to developers on their websites how to establish a LEO and which departments must be contacted to negotiate interconnection agreements and PPAs. Further, the Public Staff proposed that each utility, when confirming receipt of an interconnection request, include a statement as follows:

The submission of an interconnection request does not constitute an indication of a customer's commitment to sell the output of a facility to the utility. For information on submitting a legally enforceable obligation (LEO) form or requesting a power purchase agreement (PPA), please see the following website: (provide relevant website link).

The Public Staff agreed with DEC and DEP as to the items they indicated should be included on the form. It also reviewed the form submitted by DNCP and agreed that the form should include: (1) the date and docket number of the QF's CPCN, or ROPC, or an update if the CPCN is granted or the ROPC is filed thereafter; (2) the signature and title of an authorized representative for the QF; (3) the QF's contact information; (4) instructions on how the form should be submitted; (5) date of submission; and (6) provisions regarding the termination of the LEO.

In their Joint Reply Comments, DEC and DEP indicated that they agreed with the Initial Statement of the Public Staff regarding development of a LEO Form. In its Reply Comments, DNCP submitted a revised form entitled a "Notice of Commitment" that incorporated a number of the changes recommended by NCSEA and the Public Staff in their initial filings (Revised LEO Form). DNCP agreed to remove the form from its schedules and make it available on its website on the sections dealing with Interconnection Agreements and PPAs, as well as include the language recommended by the Public Staff on its website and in its confirmation of receipt of an interconnection request. In response to NCSEA's and the Public Staff's comments, DNCP agreed to change the title of the form to "Notice of Commitment" and to remove the requirement to provide documentation of the CPCN or ROPC and instead just require the docket number. DNCP also added a place for the QF to indicate the size of its facility. It removed the requirement that a QF list the names and locations of any QFs owned or under development by the developer or its affiliates within one mile of the facility. DNCP also made the form effective upon submission, as recommended by NCSEA. DNCP agreed to remove language acknowledging that a QF cannot enter into a PPA without a CPCN or filing an ROPC as acknowledgement of current Commission policy, on the grounds that it is not necessary for purposes of the LEO Form. DNCP also modified section 5(b) to reflect both FERC requirements and Commission policy. DNCP agreed to revise its termination section, including a definition of "executable PPA," clarifying the potential extension of time allowed to execute a PPA in relation to the tender of an interconnection agreement, and providing that the Commission will set the deadline for execution of a PPA that is the subject of complaint or arbitration proceedings. DNCP also removed the survival clause previously contained at Section 7 of the proposed LEO Form. Finally, the LEO Form was revised to indicate that the person signing is duly authorized to execute the form.

DNCP did not alter its position that use of the form should be mandatory. DNCP pointed out that the point of developing the form was to make the process of satisfying the second prong of the LEO test as clear and simple as possible, and that allowing use to be permissive would lead to further disputes as to the date a LEO was established. DNCP also did not agree with NCSEA's recommendation that its proposed acknowledgements or representations by the QF should be removed. In regard to NCSEA's proposed form, DNCP contended that it does not contain all the information needed in order to determine when a LEO is established or when a LEO is terminated. DNCP argued that NCSEA's form would lead to further disputes instead of clarifying the establishment of a LEO.

In its Reply Comments, the Public Staff stated that it had reviewed DNCP's revised form, and determined that it resolved the specific issues raised by the Public Staff's Initial Statement regarding DNCP's form. The Public Staff also noted that DNCP's revised form was much simpler and recommended that the Commission make its use mandatory, as long as QFs are allowed a reasonable opportunity to cure any errors.

In regard to DNCP's revised form, NCSEA stated in its Reply Comments that it supported the form with one exception, the section regarding termination or expiration of the commitment. NCSEA noted that neither the FERC nor the Commission has issued clear guidance on the issue of when a commitment to sell or an LEO terminates or is no longer valid, and so contended that the provision was premature. NCSEA also reiterated that use of the form should be permissive.

After the submission of Reply Comments, the Public Staff filed a letter indicating that DEC, DEP, DNCP, NCSEA, and the Public Staff had engaged in further discussions and had agreed on the contents of Sections 1 through 4 of DNCP's revised LEO Form, customized as appropriate for use by DEC and DEP. However, the Public Staff noted that these parties had not reached consensus on Sections 5 and 6 of DNCP's revised LEO Form, which involve certain acknowledgements by the QF and termination of the commitment to sell.

On September 17, 2015, DEC and DEP submitted a proposed LEO Form for use by DEC and DEP and a further revised LEO Form on behalf of DNCP.

### DISCUSSION AND CONCLUSIONS

The Commission concludes that use of a simple form clearly establishing a QF's commitment to sell its electric output to a utility to establish the notice of commitment to sell prong for creation of an LEO would provide clarity both to QFs and the Utilities and would, therefore, reduce the number of disputes between the parties and the number of complaints brought before the Commission for adjudication as to when an LEO was established. The revised form submitted by DNCP with its Reply Comments contains the information necessary to satisfy the second prong of the LEO test and should not be unduly burdensome for a QF to complete. As such, the Commission finds that use of the form should be mandatory.

In regard to the fifth section of DNCP's revised form, the Commission finds that while the acknowledgements contained therein are not necessary for establishment of a commitment to sell, they provide a QF notice of how the date of an LEO will be established, which should serve to reduce the potential for disagreements between QFs and DNCP. The provisions in Section 6 regarding termination of the Notice of Commitment are reasonable and similarly should serve to reduce the number of disputes. Once a QF and a utility enter into a PPA, the Notice of Commitment should terminate, as the purpose of a LEO, i.e., to ensure a utility enters into a PPA, will have been achieved. Further, the provision that the Notice of Commitment will be effective for up to 30 days after delivery of an "executable" PPA is reasonable. Likewise, the

provisions in Section 6.c. for termination of the notice if the QF and utility are negotiating a PPA appear reasonable, as they allow extension by mutual agreement after six months; extension until five days after execution of an interconnection agreement, if it has not been executed; and tolling of the six month deadline if an arbitration or complaint is filed.

In its September 22, 2015 Order Establishing Date of Legally Enforceable Obligation in Docket No. E-22, Sub 521, the Commission determined that the developer in that proceeding was “not required to have obtained QF status in order to satisfy the Commission’s two-prong LEO test.” The Commission has not previously required a developer to have obtained QF status in order to establish an LEO, however, given the increasing number of disputes over the date of an LEO and the new required use of the LEO Form, to provide a standardized and clearly stated method to establish an LEO the Commission finds good cause to require prospectively that a developer obtain QF status. Beginning concurrently with the mandatory use of the LEO Form (40 days from the issuance of this Order), a developer will be required to: (1) have self-certified with the FERC as a QF; (2) have made a commitment to sell the facility’s output to a utility pursuant to PURPA via the use of an approved LEO Form, and (3) have received a CPCN for the construction of the facility.

The September 17, 2015 forms submitted by the Utilities include added provisions and language that do not appear to be necessary to establish the second prong of the LEO test. Therefore, the Commission finds that the previously submitted revised LEO Form submitted as Exhibit E to DNCP’s Reply Comments should be approved for use by the Utilities effective 30 days after the date of this Order. DEC and DEP shall adapt the contents of this form for their use and submit its proposed form to the Commission for approval within 15 days of the issuance of this Order. Further, the Utilities shall place the forms and information on their websites that clearly shows how to establish a LEO, including the above stated change to the LEO test, and which departments must be contacted to negotiate interconnection agreements and PPAs, as well as the Public Staff’s proposed language from its initial comments on their websites and on communications acknowledging receipt of the LEO forms. The Utilities shall file within 30 days of the issuance of this Order with the Commission a description of the location of the forms and information on their respective websites and the Public Staff is requested to review this filing and recommend to the Commission if the information is clearly accessible and identifiable within 10 days of the Utilities’ filing. Finally, the Utilities should submit revisions to the forms, other than changes in contact information, to the Commission for approval.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding of fact is contained in the Initial Statement of the Public Staff and the Joint Reply Comments of DEC and DEP.

In their Joint Reply Comments, DEC and DEP indicated that they agreed with the Public Staff that Paragraph 5 of their PPAs should be revised to limit the requirement for

operational information to those QFs larger than three MW as it is unlikely that DEC and DEP would need planned operational information from QFs below three MW. The Commission finds this revision appropriate and directs DEC and DEP to revise Paragraph 5 of their PPAs as provided in their Joint Reply Comments.

#### EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact is contained in the Joint Comments and Proposed Rates of WCU and New River. 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. This is the same approach approved by the Commission in its February 21, 2014 Order in Docket No. E-100, Sub 136. No parties filed any comments or objections 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 PPA 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 Commission concludes, based upon the foregoing, that WCU's and New River's rate proposals should be accepted and that the changes approved herein with respect to DEC's avoided capacity and energy 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 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 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 their standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity.

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

3. 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 have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. That the Utilities shall rely on publicly available data sources when calculating the installed cost of a CT for avoided capacity purposes and provide clear justifications for any adjustments made to the publicly available data. DEC and DEP shall recalculate avoided costs utilizing data from publicly available sources. DNCP shall recalculate its avoided capacity costs as shown in Figure 1 of its March 2, 2015 Initial Comments, with the appropriate adjustments as shown, but retaining the turbine costs and capacity rating for a GE Model 7FA CT as originally utilized by the 2014 Brattle Report.

5. That the methodology utilized by DEC and DEP to determine its contingency factor is reasonable for this proceeding, and the contingency factor applied in the 2014 Brattle Report relied on by DNCP is acceptable as applied to its utilization of the GE 7FA unit for determining avoided capacity costs. DEC and DEP shall adjust their contingency factor as necessary to comply with the Commission's directive that they recalculate avoided costs utilizing data from publicly available sources.

6. That DEC, DEP, and DNCP shall recalculate the installed costs of a CT excluding economies of scope and taking into account any carrying costs associated with the economies of scale.

7. That DEC and DEP shall recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO<sub>2</sub>.

8. That DEC, DEP, and DNCP shall recalculate their avoided energy rates using natural gas and coal price forecasts that are constructed in a consistent manner with those utilized in their 2014 IRPs.

9. That to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

10. That DEC, DEP, and DNCP shall utilize the Black-Scholes Model or a similar model to determine the hedging value of renewable generation that is consistent with their current natural gas hedging practices. The hedging value shall be included for each year of the entire term of the QF PPA.

11. That the seasonal allocation factors utilized by the Utilities in this proceeding are reasonable. In the next biennial proceeding, the Utilities shall assemble their hourly CT operational data and marginal cost data on a season-specific basis to determine whether the allocation factors proposed in this proceeding remain reasonable.

12. That DEC and DEP shall amend the reporting language in Paragraph 5 of their standard PPAs to be consistent with the language agreed to with the Public Staff.

13. That the Reduction in Contract Capacity and Reduction in Contract Energy provisions in DEC's and DEP's Terms and Conditions are inconsistent with previous rulings of the Commission and are rejected. DEC and DEP shall be allowed to propose a provision that more narrowly addresses the harm for which they assert the penalty is designed, i.e., a reduction in production in later years because of the effect of levelized rates.

14. That the Utilities shall not unreasonably withhold consent to a proposed assignment of a standard PPA.

15. That the provision in Article 7(a)(vii) of DNCP's proposed Standard Contract that grants the utility a right to terminate a contract where the FERC grants a petition by the utility under PURPA 210(m) is unnecessary and shall be deleted.

16. That DEC and DEP shall amend their Terms and Conditions to include the language from their September 17, 2015, letter providing QFs with a reasonable opportunity to cure prior to termination of the contract.

17. That the proposal by each utility to limit the availability of standard rates to facilities within one-half mile is reasonable, with the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms as long as the combined capacity of those facilities does not exceed five MW. The one-half mile restriction shall only apply to facilities that use the same energy resource, and the Utilities shall include language stating that the distance between facilities will be measured from the electrical generating equipment of a facility.

18. That DEC and DEP shall amend their standard contracts to provide that a utility may terminate a contract after 30 months if a QF has failed to achieve commercial operation at any level by that date, provided that the QF shall 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.

19. That DEC and DEP shall clarify in their standard contracts that the term begins upon the first date when electrical output is generated by a QF and delivered to the respective utility.

20. That DEC and DEP shall strike provision 1(i)(5) in their proposed Terms and Conditions, since QFs under the standard contracts are not paid unless they are generating.

21. That DEC and DEP shall delete the provisions related to interconnection in their standard contracts, with the exception of a reference to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101, and a statement that an interconnection agreement is necessary in order to deliver output to the utility.

22. That the Utilities shall update their applicable rate schedules to reflect the utility's payment associated with reactive power for interconnection customers.

23. That the Notice of Commitment Form submitted by DNCP with its Reply Comments, shall be used, beginning 30 days after the date of this Order, by all QFs to show their compliance with the test to establish a LEO. DEC and DEP shall adapt DNCP's form their use and file their forms for approval within 15 days of the issuance of this Order.

24. That the Utilities shall place the LEO form and information on their websites that clearly shows how to establish a LEO, as clarified by this Order, and which departments must be contacted to negotiate interconnection agreements and PPAs. The Utilities shall file within 30 days of the issuance of this Order with the Commission a description of the location of the forms and information on their respective websites and the Public Staff is requested to review this filing and recommend to the Commission if the information is clearly accessible and identifiable within 10 days of the Utilities' filing.

25. That DEC and DEP shall revise Paragraph 5 of their respective PPAs to limit their right to request planned operational information to QFs of three MW or larger.

26. That WCU and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings



shall reflect the changes the Commission has approved herein to DEC's proposed five, ten, and 15-year avoided capacity rates.

27. The Utilities are required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 30 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.

ISSUED BY ORDER OF THE COMMISSION.

This the 17<sup>th</sup> day of December 2015.

NORTH CAROLINA UTILITIES COMMISSION

A handwritten signature in black ink, appearing to read "Jackie Cox", is written over the printed name.

Jackie Cox, Deputy Clerk