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September 18, 2015

VIA ELECTRONIC FILING

Mrs. Gail L. Mount, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: Docket No. E-100, Sub 140

Dear Mrs. Mount:

On behalf of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power ("DNCP"), enclosed for filing in the above-referenced docket is the *Proposed Order of Dominion North Carolina Power*.

Thank you for your assistance with this matter. Please do not hesitate to contact me if you have any questions.

Very truly yours,

s/Andrea R. Kells

ARK:asm

Enclosures

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014	)	**PROPOSED ORDER OF DOMINION NORTH CAROLINA POWER**

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

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

APPEARANCES:

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

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of 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 FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards 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.

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

This Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with which they interconnect. The Commission has also 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 N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in 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 N.C. G.S. § 62-156 is more restrictive than the PURPA definition of that term, in that N.C.G.S. § 62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding other types of renewable resources.

On February 25, 2014, the Commission issued in the above-captioned docket an *Order Establishing Biennial Proceeding and Scheduling Hearing*, which, for the purpose of considering certain issues that were raised in the 2012 biennial avoided cost proceeding in Docket No. E-100, Sub 136 (2012 Biennial Proceeding), initiated the 2014 biennial avoided cost proceeding in advance of the filing of new rates and contracts (Phase 1 Scheduling Order). The Commission scheduled an evidentiary hearing to consider changes to the methodology used to calculate avoided cost payments.

The Phase 1 Scheduling Order also directed persons desiring to become formal participants and parties of record to file verified petitions to intervene in accordance with the applicable Commission rules. The North Carolina Sustainable Energy Association (NCSEA), Carolina Utility Customers Association, Inc. (CUCA), the Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR), NC Hydro Group (NC Hydro Group), the North Carolina Waste Awareness and Reduction Network (NC WARN), the Alliance for Solar Choice (TASC), the Environmental Defense Fund (EDF), the Public Works Commission of the City of Fayetteville (FPWC), the North Carolina Chapter of the Sierra Club (Sierra Club), the Natural Resources Defense Council (NRDC), Southern Alliance for Clean Energy (SACE) and Google, Inc. (Google) filed petitions to intervene, all of which were granted.

Following the submission of testimony and exchange of discovery by the parties, and the evidentiary hearing held July 7-10, 2014, the Commission issued an *Order Setting Avoided Cost Parameters* on December 31, 2014 (Phase 1 Order). The Phase 1 Order, among other things, established certain parameters by which avoided cost rates should be calculated, and directed the utilities to file proposed avoided cost rates within sixty days of that order.

On January 8, 2015, the Commission issued the *Order Establishing Procedural Schedule and Scheduling Public Hearing* in the above captioned docket, thereby commencing Phase 2 of its 2014 biennial determination of avoided cost rates for electric utility purchases from QFs pursuant to Section 210 of PURPA and G.S. 62-156 (Phase 2 Scheduling Order). The Phase 2 Scheduling Order stated that, with the issuance of the Phase 1 Order, it was now time to proceed with the filing of proposed avoided cost rates by the utilities in the usual manner of biennial avoided cost proceedings before the Commission. The Commission therefore directed each of the major North Carolina electric utilities (the Utilities) to file a set of proposed rates for purchases from QFs, showing all calculations for determining the proposed rates, including inflation rates and discount rates used, and proposed standard form(s) of contract between QFs and the utility, and a description of any differences between the proposed standard form(s) of contract and the currently approved standard form(s) of contract, including the reasons for such differences. The Phase 2 Scheduling Order also directed that the Utilities file their proposed rates and standard form contracts in accordance with the determinations and guidance set forth in the Phase 1 Order.

On January 28, 2015, Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) filed a Joint Petition for Clarification and Request for Expedited Treatment. NCSEA filed a response to this Petition on February 2, 2015.

On February 27, 2015, Western Carolina University (WCU) and New River Light and Power (NRLP) filed proposed avoided cost rates and proposed standard form contracts in compliance with the Phase 2 Scheduling Order.

On March 2, 2015, DEC, DEP and Dominion North Carolina Power (DNCP) filed Comments, Exhibits and Avoided Cost Schedules (with respect to each, the Initial Filing). Also on March 2, 2015, DNCP filed the biennial avoided cost information required by Section 292.302(b)(1)-(3) of FERC's rules and regulations.[1]

On March 6, 2015, the Commission issued an Order of Clarification in this proceeding, in which it discussed further certain findings of fact contained in the Phase 1 Order pertaining to the application of the peaker methodology for determining avoided capacity costs.

A hearing was held at the Commission on May 19, 2015 for the purpose of receiving public testimony on the Utilities' proposed avoided cost rates and contracts. Following an extension of time for the procedural schedule granted by the Commission on April 15, 2015, on May 29, 2015, the Commission issued an Order Granting Motion for Extension of Time, setting the remaining procedural schedule.

On June 22, 2015, the Public Staff filed its Initial Statement responding to the electric Utilities' statements and exhibits filed in the proceeding (Public Staff Initial Statement). Also on June 22, 2015, NCSEA filed Initial Comments (NCSEA Initial Comments) and associated exhibits, and SACE filed Initial Comments (SACE Initial Comments), in response to the Utilities' filings.

[1] 18 C.F.R. § 292.302(b)(1)-(3) (2015).

On July 22, 2015, DEC and DEP filed a joint motion for extension of time to file Reply Comments which was allowed by Commission order on July 24, 2015. Reply Comments were filed by the parties on August 7, 2015.

On August 31, 2015, the Public Staff filed a motion for extension of time to file Proposed Orders which was allowed by Commission order issued on September 1, 2015.

On September 10, 2015, the Public Staff filed a letter stating that DEC, DEP, DNCP, NCSEA and the Public Staff had engaged in discussions regarding the Notice of Commitment form proposed by DNCP in this proceeding.

On September 17, 2015, DEC, DEP and DNCP filed a joint letter explaining that they had had additional discussions regarding the Notice of Commitment form and had agreed to certain additional revisions to the form.

On September 18, 2015, the parties filed Proposed Orders with the Commission.

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

FINDINGS OF FACT

1. DNCP should continue to offer long-term levelized capacity rates and energy rates 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 megawatts (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. DNCP should offer its standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity.

2. It is appropriate for DNCP to offer, as an alternative to avoided cost rates under Schedule 19-FP derived using the peaker method, avoided cost rates under Schedule 19-LMP based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the 2006 biennial avoided cost proceeding in Docket No. E-100, Sub 106 (Sub 106 Order). It also is appropriate for DNCP to continue to provide a comparison of the peaker methodology and the PJM market pricing methodology in the next biennial avoided cost proceeding.

3. DNCP should continue to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an

arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable 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. The input assumptions used by DNCP for the purpose of determining its proposed avoided energy rates, including the avoided costs related to fuel hedging activities as modified by the Company's Reply Comments, are reasonable and appropriate for use in this proceeding.

5. DNCP's estimated installed cost per kW of a hypothetical CT was derived from reasonable and publicly available industry sources, and the publicly available industry source data used by DNCP to estimate the hypothetical CT installed cost per kW was appropriately modified to adapt such information to the Carolinas and Virginia. The resulting estimated installed CT costs used by DNCP to calculate its avoided capacity costs and proposed avoided cost rates for this proceeding are reasonable and appropriate for use in this proceeding, and DNCP's proposed avoided capacity cost rates are also reasonable and appropriate.

6. DNCP has complied with the Commission's directives regarding economies of scale and scope in its calculation of avoided capacity costs.

7. The contingency factor and expected useful life of the hypothetical CT used by DNCP to determine its estimated avoided capacity cost are reasonable and appropriate for use in this proceeding.

8. DNCP's proposed Option A and Option B hours and seasonal allocations are reasonable and appropriate for use in this proceeding and comply with the directives of the Phase 1 Order.

9. DNCP's proposed modifications to its standard rate schedules to clarify the geographical limitations applicable to QFs eligible for standard rates and terms, and to amend the provisions related to line losses and site-specific line loss determinations, are reasonable and appropriate.

10. DNCP's proposed modifications to the provision of its standard contract terms and conditions related to assignment of the contract are reasonable and appropriate.

11. DNCP's proposed modifications to the provisions of its standard contracts pertaining to opportunities to cure and termination rights are reasonable and appropriate.

12. The Notice of Commitment form (LEO Form) proposed by DNCP, as revised by DNCP's Reply Comments and the September 17, 2015 letter filed by DEC, DEP and DNCP (Utilities LEO Letter), is reasonable and appropriate for use in determining when a QF has met the commitment to sell requirement of the Commission's LEO test and in clarifying when the LEO for a QF arises. It is also reasonable and appropriate that the Utilities post their respective LEO Forms to their websites and that they comply with the other directives pertaining to the LEO Form discussed further herein. The LEO Form(s) will become the only and mandatory method for a QF to make a commitment to sell its output to a utility on and after the date of this order. A QF

wishing to commit to sell to DEC/DEP shall use the LEO Form contained at Exhibit A to the Utilities LEO Letter; a QF wishing to commit to sell to DNCP shall use the LEO Form contained at Exhibit B to that letter. The foregoing rulings shall not apply to cases currently pending before the Commission, which shall be decided based on the facts and circumstances of each case in light of existing Commission precedent on the establishment of an LEO.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding is contained in the Initial Filing of DNCP and in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued on February 21, 2014 in Docket No. E-100, Sub 136 (2012 Biennial Order) and the Phase 1 Order.

No party to this Phase 2 of this proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell five MW or less capacity or the availability of five-year levelized rate options to all other QFs contracting to sell three MW or less capacity. In prior avoided cost proceedings, most recently in the 2012 Biennial Order, the Commission has consistently concluded that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next, and, that, in doing so, it must balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. In the 2012 Biennial Order, the Commission concluded that its decisions in past avoided cost proceedings strike an appropriate balance between these concerns. In the Phase 1 Order, the Commission noted as well its obligation to balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers.[2] Given those considerations, and based on the record established during Phase 1 of this proceeding, the Commission found it appropriate to retain the previously approved parameters for QF payments in North Carolina for purposes of this 2014 Biennial Proceeding.[3]

Based on the foregoing, the Commission concludes that DNCP should offer long-term levelized capacity rates and energy rates for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The Commission further concludes that DNCP should offer five-year levelized rate options to all other QFs contracting to sell three MW or less capacity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

In its Initial Filing, DNCP explained that, except with respect to certain specific provisions discussed further herein, the Schedule 19-LMP that it proposed in this

[2] *See* Phase 1 Order at 21.
[3] *See id.* at 21-22.

proceeding was substantially the same as that approved in the 2012 Biennial Proceeding. Pursuant to the directive of the 2012 Biennial Order, Exhibit DNCP-7 to the Company's Initial Filing provided a comparison of the Company's rates under Schedule 19-FP and Schedule 19-LMP. No party to this proceeding raised any issue with the Company's proposed Schedule 19-LMP or the comparison of rates under that rate schedule to rates offered under Schedule 19-FP.

Based on the record in this proceeding, and consistent with our determination in the 2012 Biennial Order, the Commission concludes that it is appropriate for DNCP to continue to offer, as an alternative to avoided cost rates derived using the peaker methodology, 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. We also conclude that DNCP should continue to file a comparison of the Company's rates under Schedule 19-FP and Schedule 19-LMP in the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

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

The Commission concludes that DNCP should continue 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.

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. In the 2012

Biennial Order, the Commission determined that such arbitration would be less time consuming and expensive for the QF than the previously available complaint process, and that the arbitration option should be preserved. We continue to believe that the arbitration option should be preserved as an alternative to the complaint process for the reasons expressed in the 2012 Biennial Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding is contained in the Initial Filing and Reply Comments of DNCP, the Initial Statement and Reply Comments of the Public Staff, the Initial and Reply Comments of NCSEA and SACE, the Phase 1 Order, and the FERC precedent cited herein.

Fuel price forecasting

In its Initial Filing, DNCP explained that it used the PROMOD utility production costing model to calculate the avoided energy costs contained in its Schedule 19-FP. DNCP explained further that the difference in annual system production costs between the base case, based on the generation expansion plan contained in the Company's most recent integrated resource plan (IRP) (the "without QF" case), and the "with QF" case, which is run with an additional QF resource, represents the Company's forecasted avoided energy costs. The resulting PROMOD output is then used to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP. Pursuant to the Phase 1 Order determination that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation, DNCP stated that it calculated and included the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates over the hedging terms actually used by the Company. DNCP also stated that avoided energy rates under its Schedule 19-LMP are based on the hourly PJM DOM Zone Day-ahead Locational Marginal Price (DA LMP) expressed as $/MWh.

In its Initial Statement, Public Staff stated that it had reviewed the PROMOD inputs used by the Company to calculate avoided energy rates and that it believed that the inputs into the model and the output data from the model are reasonable for the determination of DNCP's avoided energy costs.

In its Reply Comments, Public Staff asserted that DNCP changed the weightings of the fundamental forecast and futures market data between the 2014 IRP proceeding and the Company's Initial Filing to place greater weight on futures market data, which resulted in different avoided energy cost rates than would otherwise have been achieved. Public Staff stated that, to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question, some use of futures market data may be appropriate for the short-term, but took issue with the use of forward prices for natural gas and coal in developing long-term price forecasts. Public Staff contended that there is limited liquidity in the markets for coal futures and long-term natural gas futures contracts, and that forward market prices do not represent the same level of analysis and consideration given to the development of long-term forecasts performed by the US Dept. of Energy – EIA, Moody's Investor Services, Inc., and other firms with forecasting expertise. Public Staff also argued that use of forward prices is not consistent with the Utilities' fuel procurement practices and therefore does not provide an accurate representation of their future fuel costs. Public Staff contended that the Utilities typically acquire natural gas for less than 50% of their projected gas needs with contracts that span over 12 and 24 months, and that they use a mix of long-term contracts and spot purchases for their coal purchases. Public Staff recommended that the Commission direct the Utilities to recalculate their avoided energy costs using the same fuel forecast weightings utilized in their 2014 IRPs, and also recommended that, to the extent that the Utilities wish to adjust the way they utilize forward prices and long-term forecasts in Commission proceedings, they make those proposals in the biennial IRP proceedings, which Public Staff contended provide the basis for support for CPCNs and avoided costs over the subsequent year.

In its Initial Comments, NCSEA disputed the Utilities' methods of calculating future fuel prices, alleging that they have overemphasized futures market data and underestimated long term prices, thereby understating their respective avoided energy costs. NCSEA noted the volatility of natural gas prices over both short and long periods of time, and asserted that the Utilities ignored the "high probability" of increased gas prices and "disregarded the possibility these spot prices may be a temporary aberration." NCSEA opined that, as a result, there is more risk that the actual costs that the Utilities will incur when producing electricity using their own generating units will be substantially higher than their avoided energy cost estimates.

Specifically with regard to DNCP, NCSEA suggested that DNCP's projected natural gas prices are understated because they do not reach the long term trend line of gas prices. NCSEA stated that DNCP used a different method in the 2014 IRP proceeding, in which it gave less weight to futures market data. NCSEA contended that approval of the proposed cost estimates would discourage QF development and make ratepayers bear the risk and burden of paying for electricity at prices far exceeding the prices estimated by the Utilities in this proceeding.

In its Reply Comments,[4] NCSEA reiterated its earlier arguments, and contended that in this proceeding, avoided energy costs should be calculated using each utility's future resource expansion plans as set forth in its IRP in order to most accurately approximate generation to be avoided by the utility. NCSEA contended further that, as a result, the fuel price forecasts used in this proceeding should not differ from those used in the IRP. NCSEA argued that the Commission must reject the Utilities' fuel price estimates in order to achieve PURPA's objective of ratepayer indifference.

In its Reply Comments, DNCP stated that it used current price estimates, an appropriate price-blending period, and long term commodity price inputs in calculating its proposed avoided energy rates. The Company explained that it is not appropriate to use the natural gas prices from its 2014 IRP to calculate avoided energy costs in this proceeding. The Company explained further that, when forecasting energy prices in its IRPs, it uses 18 months of forward market prices, with an additional 18 months of blended prices to transition to the long-term fundamental prices from ICF International. DNCP noted 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. The Company also stated, however, that for avoided cost pricing purposes, using forward market prices for a longer time period (in this case, four years, with three years of

[4] Appended to NCSEA's Reply Comments was an affidavit of Dr. Ben Johnson. As Mr. Johnson's affidavit is in substance expert testimony, and no expert evidentiary hearing was held in this Phase 2 of the proceeding, the affidavit was not entered into the record and Dr. Johnson was not subject to cross-examination. Given these circumstances, as well as the late stage in the proceeding at which the affidavit was filed, which did not permit a response by the Utilities, the Commission declines to address in this Order the affidavit or the arguments made therein.

blended prices) is appropriate because the Company is determining actual contract rates to be paid to a counterparty in a 15-year power supply contract. DNCP stated that, because the market forward prices are current, relevant, transactable, and a more accurate representation of its avoided energy costs at the time of filing, a longer price blending period is appropriate as it will result in a more accurate forecast of long-term avoided costs than prices derived from long-term fundamental forecasts. DNCP noted that in its Initial Statement the Public Staff agreed (with respect to DEC and DEP) that market forward prices are appropriate up to five years prior to using the fundamental long term forecast.

In addition, DNCP explained that, because the commodity price assumptions used in the 2014 IRP were developed in May 2014, those prices were nearly a year out of date (and therefore inappropriate for use) by the time of the Company's March 2, 2015 Initial Filing, so DNCP used the best available (i.e., more current) data when calculating the proposed avoided energy cost rates for this proceeding. Moreover, DNCP noted that the gas prices shown in Figure 4 of NCSEA's Initial Comments included the effect of CO2 regulations, which would not be appropriate for use in this case because in the Phase 1 Order the Commission ruled it inappropriate for ratepayers to shoulder the costs of such regulations until they become known and verifiable. Therefore, DNCP observed, using these prices would result in electric customers paying too much for these power purchases from QFs.

In response to NCSEA's comparison of DNCP's projected gas prices to historical trends, DNCP stated that historical gas prices are not relevant in the avoided energy cost context, since avoided energy costs are based on forward-looking estimates, not on historical trend lines that bear little relation to either the current or future natural gas market. DNCP noted that while the gas price history presented by NCSEA shows an upward sloping price curve with long term prices above those used by DNCP in this case, a similar analysis could simply select fewer years of historical data and show a flat or downward sloping price curve. DNCP noted further that NCSEA provided no evidence to support its suggestions with regard to future gas prices. The Company contended that ratepayers will be indifferent when the avoided energy rates truly reflect DNCP's expected avoided energy costs, and that DNCP's proposals best meet that goal, since its fuel price estimates are as accurate as possible and appropriate for inclusion in its proposed avoided energy costs.

Hedging

With regard to hedging costs, Public Staff asserted in its Initial Statement that the Utilities' proposed avoided energy costs do not fully reflect the fuel price hedging benefits that result from the substitution of renewable generation for fossil-fueled generation. Specifically with regard to DNCP, Public Staff stated that the Company's avoided energy costs include the hedging fees that it expects to incur related to the purchase of natural gas, but that these fees are transaction costs that DNCP will pay to purchase natural gas. Public Staff said 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. Public Staff stated that it evaluated the prices of "at the money" Henry Hub natural gas options using the Black-Scholes Option Pricing Model, and recommended that the Utilities be directed to recalculate the value of their current hedging programs using Black-Scholes 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.

In its Initial Comments, NCSEA disputed DNCP's approach to calculating hedging benefits of renewable energy. In its Reply Comments, NCSEA supported Public Staff's alternative proposal for calculating hedging benefits, though it contended that the 1% interest rate used by Public Staff in its Black-Scholes options calculator should be replaced with a 3.10% rate, based on its assertion that that 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 asked the Commission to direct the Utilities to recalculate the avoided energy component of avoided cost rates, using a hedge value of at least 0.09 cents/kWh (based on the 3.10% interest rate) in each year of the term of the power purchase agreement (PPA). NCSEA agreed with the Public Staff and SACE that the value of hedging benefit should be included in each year of the entire term of the QF PPA.

In its Initial Comments, SACE argued with respect to the duration of the fuel hedge savings in avoided energy rates that fuel hedging savings should be included in all years of the forecast rather than just the first year. SACE also requested clarification regarding the $3.2 million high-end estimate of gas broker transaction and financing costs noted in discovery responses provided by DNCP. In its Reply Comments, SACE supported the use of the Black-Scholes method for calculating avoided hedging costs, but noted that a critical parameter for this method is the assumed annual volatility rate. SACE explained that this parameter is critical because small changes in the volatility value have significant effects on the calculated Black-Scholes value, and because it is impossible know what the volatility of the spot price of natural gas over the future time period will be.

DNCP argued in its Reply Comments that the best way to estimate the fuel hedging benefits of renewable energy purchases is to use the cost of avoided brokerage fees related to natural gas hedges, since, to the extent that DNCP buys energy from QFs, it would need to buy less fuel, and could reduce its payments to brokers for financial hedges on fuel. DNCP explained that it calculated hedging benefits by dividing $1 million in avoided broker charges by the total amount of non-nuclear energy supply, which the Company argued was an appropriate method because it spreads the avoided costs over the entire amount of energy supply that could potentially be displaced by renewable QFs. DNCP stated that this method results in a 2015 rate of approximately $0.02/MWh. DNCP also offered an alternative method for calculating hedging benefits that is more similar to the method suggested by Public Staff, which results in an avoided gas hedging cost of $0.01/MWh.

Specifically with regard to Public Staff's suggestion of an option pricing model, DNCP noted that it was unaware of any jurisdiction that employed this method for calculating avoided cost pricing. DNCP also observed that the model is not supported by model back testing or validation, and that it would require difficult modeling and numerous debatable assumptions to implement. In particular, DNCP explained, the Black-Scholes model results are heavily driven by the volatility assumption (noting that in an answer to a discovery request, Public Staff showed an assumed 20% volatility of natural gas prices without any basis for that assumption), and can produce vastly different answers if, for instance, 10% volatility is assumed as opposed to 20%. DNCP noted that if Public Staff's proposal were adopted, then the calculation of the value of hedging benefits would be driven by the fuel price volatility assumption, which is not transparent or verifiable. With respect to Public Staff's suggested method of subtracting the "at the money" put option price from the "at the money" call option price, DNCP noted that settlement data provided by Public Staff showed that the nearest "to the money" put option price is actually higher than the corresponding call option price, indicating a negative hedge value. DNCP noted that this result demonstrates the unreliability of Public Staff's suggestion to use a theoretical value to represent a real cost. In contrast, DNCP stated that its proposed method for estimating fuel hedging costs is a quantifiable approach that achieves the same result, since buying swaps through an exchange and paying the related brokerage fee is equivalent to buying a call option and selling a put option.

DNCP agreed with SACE that it is reasonable to include fuel hedging savings in all years of the forecast, and clarified with respect to its original estimate of gas broker costs that the $3.2 million estimate was later revised to be less than $1 million, which amount represents the avoidable broker fees related to the entire DNCP system (both North Carolina and Virginia).

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the proposed avoided energy rates filed by DNCP should be approved. In the Phase 1 Order, we determined that "[t]he 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."[5] This directive did not, however, require that DNCP use the same fuel price forecast method in this proceeding that it used in the 2014 IRP proceeding. First, that directive was made with the purpose of addressing the issue of whether to reflect carbon regulation costs in forecasted energy costs, and our discussion of this conclusion did not involve fuel price forecasts.

We note that the IRP and the avoided cost dockets serve fundamentally different purposes. We agree with DNCP that, while the use of forward market prices for a shorter time period is acceptable for IRP modeling, where new resource options are economically compared to each other, it may not be appropriate to use the natural gas prices from its 2014 IRP to calculate avoided energy costs. Market prices for fuel and power, to the extent available and liquid, are a more accurate reflection of future costs than prices calculated from long term modeling of supply and demand fundamentals. We believe the Company's forward fuel price assumptions struck a reasonable balance of market-based forward prices and forecasted prices derived from long term fundamental modeling. We also agree, under the current fuel market conditions, that using forward market prices for a longer time period is appropriate in an avoided cost proceeding where the Company is determining actual contract rates to be paid over the course of a 15-year power supply contract. In addition, notably, while the Phase 1 Order directive quoted above was made to clarify that ratepayers should not bear the burden of carbon costs until they are known and verifiable, the fuel prices used by DNCP in the 2014 IRP (base case) and presented by NCSEA in its Initial Comments included the effect of carbon regulations and therefore would not be consistent with that Order for purposes of this proceeding. Given these conclusions, we find that DNCP has calculated avoided cost

[5] Phase 1 Order at 8; *see also id.* at Ordering Paragraph 8.

rates that achieve the proper balance between consistency with the prior IRP and accuracy of the avoided costs, given the best available current information.

Finally, we also agree with DNCP that we have not seen any evidence to support NCSEA's projections as to the future direction of gas prices, and that historical gas trends are of little value in the avoided cost context, which relies on forward-looking estimates. FERC's Order No. 69 establishes the principle that customers should be indifferent as to whether a utility purchases energy and capacity from a QF, buys those products from others or produces them itself. Ratepayers will be indifferent when the avoided energy rates most closely reflect expected avoided energy costs. We find that DNCP's proposed fuel price estimates best meet that goal, since those estimates are as accurate as possible.

In the Phase 1 Order, the Commission also concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. The Commission directed that the Utilities should calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of their avoided cost rates to be filed in this Phase 2, and noted that hedging benefits should be valued only over the hedging terms (time period) actually used by the Utilities.[6]

Based on the record in this proceeding, the Commission concludes that DNCP's proposed methodology for calculating the hedging costs avoided due to energy purchases from renewable QFs is reasonable and appropriate. We agree with the Company that its proposed method of dividing the cost of avoided brokerage fees related to natural gas hedges by the total amount of non-nuclear energy supply appropriately spreads the

[6] *See* Phase 1 Order at 8, 42.

avoided costs over the entire amount of energy supply that could potentially be displaced by renewable QFs. Therefore we accept DNCP's proposed 2015 avoided hedging cost rate of $0.02/MWh.

We decline to accept the Public Staff's suggestion that the Black-Scholes or a similar method be used to calculate fuel hedging benefits. As DNCP explained, the calculation of the value of hedging benefits under this method would be heavily driven by the fuel price volatility assumption, which is not transparent or verifiable. In contrast, as we have determined, DNCP's proposed method is verifiable and not reliant on assumptions, particularly volatility assumptions, that could result in unreliable cost estimates. As we decline to direct that the Black-Scholes or a similar method be used to calculate avoided hedging costs, we also decline to address NCSEA's arguments with regard to the interest rate used under that method. Finally, because we are accepting DNCP's proposed hedging cost calculation method and rejecting the method proposed by the Public Staff, it is not necessary to address DNCP's alternative proposed method.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding is contained in the Initial Filing and Reply Comments of DNCP and in the Initial Statement and Reply Comments of the Public Staff and the Initial and Reply Comments of NCSEA, as well as the Phase 1 Order.

In its Initial Filing as supplemented by its Reply Comments, DNCP stated that, consistent with its 2013 and 2014 IRPs, it used a Siemens SGT6-5000F turbine-generator set (Siemens-5000) as the generating equipment for the hypothetical CT in this proceeding. DNCP explained that to calculate the installed cost of a hypothetical CT using a Siemens-5000 turbine, it used data from two publicly available industry sources.

For the cost of the turbines, DNCP used simple-cycle plant prices published in the 2013 Gas Turbine World Handbook (2013 GTW Handbook). For the other construction and owner-related costs for the CT, DNCP used the 2014 Brattle Group study "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM" (Brattle Report). DNCP explained that the equipment cost of the Siemens-5000 turbine from the GTW Handbook did not require any adjustments, but that it did make adjustments to the other construction and owner-related cost data for the hypothetical CT from the Brattle Report that were clearly needed to adapt that data to the Carolinas and Virginia. Those adjustments included: eliminating the Selective Catalytic Reduction (SCR), which would not be included in a CT built by the Company in Virginia or North Carolina; correcting the construction labor costs to reflect the CT costs adopted by PJM in its cost of new entry modifications and approved by FERC; adjusting the sales tax to reflect rates applicable for Virginia; adjusting electric and gas interconnection costs to reflect those costs expected for a CT constructed by the Company in Virginia or North Carolina and to reflect economies of scale; adjusting fuel costs for startup and inventories to be consistent with fuel cost projections reflected in avoided fuel costs; and eliminating financing fees since such costs are already included as part of the CT cost in the economic carrying charge (ECC) calculations. DNCP's resulting installed cost per kW was $485/kW.

In its Initial Comments, NCSEA asked the Commission to direct DNCP to use the GE-7FA turbine for its determination of avoided capacity costs of a hypothetical CT, rather than the Siemens-5000 selected by the Company. In addition, while supportive of DNCP's use of the Brattle Report in calculating its CT cost estimate, NCSEA also offered a general objection to the adjustments that DNCP made to the Brattle Report data in estimating the Company's avoided capacity costs, contending that each of the adjustments reduced DNCP's cost per kW below the Brattle Report estimate. NCSEA contested DNCP's use of the cost estimate for the Siemens-5000 contained in the 2013 GTW Handbook, instead of the cost of the GE-7FA turbine contained in the Brattle Report, based on NCSEA's contentions that the GE-7FA is "representative" of DNCP's generation fleet and that the Company has not installed any Siemens-5000 turbines.

In its Reply Comments, NCSEA again recommended that the Commission direct DNCP to recalculate its avoided capacity cost using the GE-7FA. In the alternative, NCSEA asked the Commission to reject the cost estimate provided by DNCP for the Siemens-5000 based on its contention that the industry source for the estimate (the 2013 GTW Handbook) is out of date and its speculation that, because the GTW cost estimate decreased significantly between 2012 and 2013, DNCP relied on the GTW Handbook for its CT cost data simply because it provided a low cost estimate.

NCSEA also stated its support for Public Staff's position that additional related adjustments, including the applicable contingency factor, capital spare parts, and O&M, to the cost estimate are needed to reflect what Public Staff considered to be DNCP's limited experience with the Siemens turbine.

In its Initial Statement, Public Staff stated that after reviewing the adjustments to the Brattle Report data made by DNCP that it found DNCP's adjustments to be reasonable. Public Staff also recommended that DNCP use either the GE-7FA turbine or a comparable unit for determining the avoided capacity costs of a hypothetical CT instead of the Siemens-5000. Public Staff contended that DNCP should use the GE-7FA because that is the CT technology used in the Brattle Report. Public Staff asserted that the Brattle

Report utilized the GE-7FA "in part because it is the predominant turbine type built in PJM," and argued that this justifies requiring DNCP to use the GE-7FA. Public Staff also based its comments on what it characterized as the Company's lack of experience with the Siemens model turbines, and contended that due to such limited experience, additional adjustments would be needed if the Siemens-5000 turbine were used. Public Staff also suggested that the GE-7FA has a higher capacity factor than the Siemens-5000. Public Staff noted in its opposition to DNCP's proposed avoided capacity cost estimate that the estimate is lower on a per unit output basis than the Company's 2012 cost estimate, and contended that turbine prices have been relatively stable in recent years. Finally, Public Staff expressed doubt that DNCP would actually select a Siemens-5000 for construction.

In its Reply Comments, Public Staff stated that the Utilities should strive to use data from publicly available sources and provide clear justifications for any adjustments made to that data. Based on its reading of the 2011 and 2014 Brattle Reports, Public Staff reiterated its objection to DNCP's selection of the Siemens-5000.

In their Reply Comments, DEC and DEP discussed their choice of EPRI data for purposes of complying with the Phase 1 Order. They noted that, to some degree, use of the most robust data available and data that is also publicly available are mutually inconsistent concepts, and that the more public the data is, the more generalized it tends to be. DEC/DEP observed that accurate information of the type required by the Phase 1 Order is not available from "off the shelf" resources that completely eliminate the need for reasoned analysis and judgment.

In its Reply Comments, DNCP argued that the turbine used for avoided capacity cost calculations should be the turbine that is selected as the least cost option in the Company's IRP. The Company explained that during its IRP process, it evaluates future resource alternatives in order to provide safe and reliable service to its customers at the lowest reasonable cost and that the IRP evaluation conducted in 2012 concluded that the GE-7FA turbine was the appropriate least cost CT option. Accordingly, the Company used the GE-7FA turbine as the basis for its hypothetical CT cost determination in the 2012 biennial proceeding in Docket No. E-100, Sub 136. DNCP explained further that, during 2013, based on its reassessment of the cost and performance of the available turbine models – the GE-7FA, Siemens-5000 and Mitsubishi Heavy Industries (MHI) – for future simple cycle CT installations, it selected the Siemens-5000 for IRP modeling that year. DNCP noted that, while the total capital cost (in dollars) and other performance factors of the Siemens-5000 and the GE-7FA were roughly equivalent, the Siemens-5000 turbines have approximately 57 MW greater capacity than the GE-7FA for an assumed two-unit facility. DNCP explained that this makes the Siemens-5000 a far more economical turbine on a per-unit basis (lower cost per kW) than the GE-7FA. DNCP explained further that, while the MHI turbine was also superior to the GE-7FA on a cost per kW basis, due to lower MW output on the MHI turbine while using fuel oil, DNCP selected the Siemens-5000, which produces virtually the same output whether running on natural gas or fuel oil. DNCP also noted that the Siemens-5000 was found during the 2013 reassessment to have a better heat rate than the GE turbine. Based on the 2013 reassessment, DNCP incorporated the Siemens-5000 into its 2013 and 2014 IRPs, which as DNCP noted were subsequently approved by the Commission, as well as the

Company's 2015 IRP update filed with the Commission on July 1, 2015. DNCP noted that no party to those IRP proceedings contested the Company's use of the Siemens-5000. DNCP stated that, consistent with its past practice, because it selected the Siemens-5000 as the least cost CT option in the 2014 IRP, the Company also used that turbine as the CT technology in this proceeding.

DNCP argued that Public Staff's and NCSEA's comments on DNCP's selection of the Siemens-5000 ignore the Company's selection of the Siemens-5000 as the least cost option in the IRP process. DNCP also argued that requiring the Company to use the GE-7FA would force it to use the turbine that it has determined is not the least cost option on a per unit output basis. DNCP noted Public Staff's statement in its Initial Statement, quoting the Phase 1 Order, that a "utility's projected CT costs must be reasonable so as to comply with PURPA" and that "FERC's order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF." DNCP pointed out that forcing the Company to calculate avoided costs based on the high cost CT option would impose avoided cost payments on ratepayers well in excess of the Company's actual avoided costs, in contravention of this principle. Moreover, DNCP argued, forcing the GE-7FA on DNCP would contradict the Commission's policy that avoided cost rates should be based on the best information available at the time the estimate is made.

DNCP also argued that, contrary to Public Staff's assertions, the Brattle Report's use of the GE turbine model does not dictate that the GE-7FA be used in this proceeding. The Company stated that the purpose of this proceeding, as it relates to DNCP, is to determine the Company's avoided cost based on the resource and expansion plans for the

Company's system, not the cost of new entry of a merchant generator to PJM. DNCP noted that, unlike the Company's selection of the Siemens-5000, the Brattle Report's use of the GE-7FA did not appear to have been made on the basis of least cost planning considerations and was instead used because the PJM OATT mandates use of the GE-7FA as the "Reference Resource" for the cost of new entry study. DNCP noted that, while the Brattle Report authors stated that they did not find a basis to change the turbine model from the tariff-specified model, the fact remained that use of the GE-7FA in the Brattle Study was a PJM requirement. DNCP argued that the Commission has imposed no such technology mandate on DNCP or any other utilities, and given the Company's selection of the Siemens-5000 as the least-cost option through its IRP process, the Company's decision to use the Siemens-5000 was an adjustment clearly needed to adapt the Brattle Report to the Carolinas and Virginia as permitted by the Phase 1 Order. Finally, in response to Public Staff's statements regarding the GE-7FA being the predominant turbine type built in PJM, DNCP noted that the only large CT facility constructed in either North Carolina or Virginia during the past five years was constructed with Siemens-5000 turbines at Southern Company's Plant Cleveland located in Cleveland County, North Carolina.

DNCP argued further that Public Staff's suggestion that the GE-7FA has a better capacity factor than the Siemens-5000 is incorrect. DNCP noted that, while Public Staff's statements appeared to be based on the Company's initial response to a Public Staff data request, the Company subsequently corrected that response to show that the GE-7FA would operate with capacity factors within the same range as that of the Siemens-5000. The Company argued that, therefore, the capacity factors of the two turbine models are equivalent and that, given the lower cost per kW of the Siemens-5000 as compared to the GE-7FA, the Siemens-5000 is the best option for the hypothetical CT.

DNCP acknowledged that its proposed 2015 avoided capacity cost estimate is lower than the Company's 2012 estimate, but argued that the fact that the estimate decreased from the 2012 biennial case to the 2015 biennial filing does not mean that the 2015 estimate is too low or that it is otherwise inaccurate. DNCP also stated that Public Staff's comments reflected a comparison of apples to oranges. First, according to DNCP, comparing the 2012 cost estimate, which was based on the GE-7FA turbine, to the 2015 estimate, which is based on a Siemens-5000, ignores the distinctions between those turbines in terms of price per kW and time period. In addition, DNCP argued that, because the Producer Price Index (PPI) that Public Staff used to measure installed CT costs simply shows the percentage change in turbine prices from year to year, it has a limited bearing on the dollars per kW price metric used in the avoided cost calculations the Company makes in these biennial proceedings, and is not an appropriate comparison to the complex peaker methodology of cost estimation used in these proceedings.

DNCP noted in addition that, while Public Staff's observation that absolute turbine prices themselves have been relatively stable over the past five years, the prices per kW for Siemens turbines as well as GE and MHI models have in fact decreased. The Company noted that the Siemens turbines have experienced the largest reduction in price per kW of the three models, due to improvements in turbine performance, resulting in higher capacity output and higher efficiency and therefore lower cost per kW of output. Specifically, DNCP stated that the prices per kW for the Siemens turbines dropped 15% from 2012 to 2013, primarily because the turbine output increased from 208 MW to 232

MW. DNCP explained that, more than the absolute cost of the turbine, it is the price per kW (the ratio of the turbine's absolute cost to the turbine's output) that is important to the Company's and the Commission's evaluation of hypothetical CT costs.

With regard to Public Staff's suggestion that DNCP would not select the Siemens turbine for construction, DNCP noted first that no evidence was offered to support this suggestion. DNCP explained further that it has not constructed a new simple-cycle CT facility—GE model or otherwise—since completing the fifth turbine at the Company's Ladysmith facility in 2009. The Company also stated that, when the initial development at Ladysmith was completed in 2001, the GE-7FA was the predominant turbine in the market, and that since 2009 the Company has not purchased a single GE-7FA. DNCP also noted that, for its three most recent combined-cycle facilities, it selected MHI turbines due to the better overall cost and performance of those turbines than either the GE or the Siemens-5000. The Company noted further that, based on this recent history alone, it could reasonably have based a hypothetical CT's cost on the MHI turbine, and the cost per kW of capacity would have been even lower than proposed in this case. Because, however, the MHI turbines did not have extensive demonstrated operating history on dual fuel in a CT facility, the Company selected the Siemens-5000 as the turbine option for its 2013-2015 IRPs and, as a result, for this avoided cost proceeding. The Company stated that while it cannot guarantee that it will choose the Siemens-5000 when the time comes to install another CT facility, since the turbine selection will result from a competitive bidding process, given the current cost advantage of the Siemens-5000 and the MHI turbines over the GE-7FA, it is highly unlikely that the Company would select the GE-7FA for its next CT facility.

With regard to NCSEA's generalized critique of the adjustments that DNCP made to the Brattle Report data, the Company noted that NCSEA did not specifically object to any particular adjustment other than DNCP's selection of the Siemens-5000 turbine, and did not provide evidence supporting its general claim that these adjustments were inappropriate. The Company argued that the fact that the adjustments that it made result in a reduction to the avoided cost does not by itself make those adjustments inappropriate or inaccurate. DNCP stated that it had presented considerable evidence in its Initial Filing, through discovery, and in its Reply Comments supporting those adjustments as being appropriate to tailor the estimated CT costs contained in the publicly available industry sources that DNCP consulted to the Company's own service territory as permitted by the Phase 1 Order. DNCP noted as an example that NCSEA's citation of the Brattle Report's estimation of the installed CT cost for the Company's service area quoted a number that is unrealistically high given the Company's ability to construct an entire 3x1 combined cycle plant, which requires considerably more capital expense than a CT, for less than this quoted cost.

DNCP also noted that, other than the selection of the Siemens-5000, Public Staff stated in its Initial Statement that it generally found the adjustments that the Company made to be reasonable. In addition, DNCP explained that no adjustments to its estimated avoided capacity costs are needed to account for what Public Staff terms the Company's limited experience with Siemens turbines. DNCP stated that it has very experienced equipment procurement and construction management departments, and a long history of planning, designing, constructing, operating and maintaining CT facilities, as well as completing generation construction projects on-time and in line with budget estimates.

DNCP argued that this experience and recent procurement activity supports its conclusion that the Siemens-5000 represents the most likely equipment that it would procure for a new CT facility based on the relative cost and performance of alternatives. DNCP also noted that, especially when it is compared to other, more complicated, supply options like the Virginia City coal plant and its three recent gas combined cycle plants, a CT facility is simple to plan, design, and build.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that, for purposes of this proceeding, the installed CT cost proposed by DNCP is reasonable and appropriate for use in calculating DNCP's avoided capacity rates. We also conclude that DNCP has complied with the directives of the Phase 1 Order to use publicly available data to determine installed CT cost and to only make those adjustments to that data that are clearly needed to tailor the information to the Carolinas and Virginia.

In the Phase 1 Order, the Commission concluded that the peaker methodology for calculating avoided capacity costs should be maintained. In order to implement that methodology going forward, and as all of the parties in this Phase 2 have noted, the Phase 1 Order stated that, "because the focus on 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."[7] As the parties have also noted, the Commission also stated that the Utilities could make adjustments to the publicly

[7] Phase 1 Order at 48.

available information “only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.”[8]

As an initial matter, we recognize the comments offered by DEC/DEP regarding the difficulty in complying with the Phase 1 Order’s directives to use publicly available data and to limit adjustments to that data. We conclude that, while they each relied on different data sources, the Utilities have made reasonable and appropriate selections of publicly available data as well as reasonable adjustments to tailor that data to their own service area expertise and circumstances.

With regard to DNCP, we conclude that the Company’s selection of the Siemens-5000 turbine model for its determination of hypothetical CT costs, its use of turbine costs from the 2013 GTW Handbook and other costs from the Brattle Report, and the adjustments that it made to the Brattle Report data, are all reasonable and appropriate decisions. Public Staff’s reliance on the fact that DNCP chose the GE-7FA model in the 2012 biennial proceeding is misplaced. The more appropriate rationale is that relied on by DNCP—that the turbine used for avoided capacity cost calculations should be the turbine that is selected as the least cost option in the Company’s IRP. As that turbine for DNCP has been in the Siemens-5000 in its last three IRPs and IRP updates, it is reasonable and appropriate that the Company rely on the Siemens-5000 for use in this proceeding as well. We note in addition, as did DNCP and the Public Staff, that a utility’s projected CT costs must be reasonable so as to comply with PURPA and that, in the Phase 1 Order, we said that “FERC’s order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or

[8] *Id.* at 48, Ordering Paragraph 6.

alternative purchase and a purchase from a QF."[9] We agree with the Company that forcing DNCP to use the GE-7FA turbine to calculate its avoided capacity costs would be inconsistent with the ratepayer indifference principle of PURPA that has been upheld by the Commission.

We disagree with the Public Staff that the Brattle Report's use of the GE turbine model dictates that DNCP use the GE-7FA in this proceeding. As DNCP observed, PJM required that the GE-7FA be used in that analysis. Moreover, given the Company's selection of the Siemens-5000 as the least-cost option through its IRP process, DNCP's decision to use the Siemens-5000 was an adjustment clearly needed to adapt the Brattle Report to the Carolinas and Virginia as permitted by the Phase 1 Order. Finally, given the decreasing cost of the Siemens-5000 turbine on a dollars per kW basis, and the value of that metric as demonstrated by DNCP, the Company's selection of the Siemens-5000 turbine was reasonable.

With regard to Public Staff's suggestion that DNCP would not actually select the Siemens-5000 for construction, we agree with DNCP that the Public Staff has offered no evidence to support this suggestion. Indeed, the evidence in the record demonstrates that DNCP's three most recent generating facilities have incorporated turbine technology other than GE-7FA. Further, the only CT constructed in the Carolinas in the last five years in fact uses Siemens turbines. Under these circumstances, and given the experience and recent activity of DNCP's procurement and construction groups, we accept that, while the Company cannot guarantee that it will use a Siemens 5000 for its next CT, it appears more likely than not that the next unit will not be the GE-7FA.

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[9] *Id.* at 20.

With respect to arguments advanced by NCSEA in its Reply Comments, first, NCSEA offers no evidence to support its assertion that the 2013 GTW Handbook data relied upon by DNCP in its Initial Filing was not current at the time that the Company made its Initial Filing or filed its Reply Comments in this proceeding. Moreover, we reject NCSEA's suggestion that DNCP selected the GTW data simply because it provided what NCSEA terms a low estimate of CT costs. DNCP has explained its rationale for using the GTW information for turbine cost data and using the Brattle Report for other cost data and we see no reason to discount those statements. We agree with DNCP that the fact that CT costs have declined between 2012 and 2015 does not itself mean that 2015 cost estimates are too low or inaccurate; as the Company has explained, there are reasons for the price decline, including improved efficiency. NCSEA's citation to the rebuttal testimony of DEC/DEP witness Glen Snider in the 2012 Biennial Proceeding actually supports this conclusion. In that case, Mr. Snider argued that the decline in CT costs between 2012 and 2013, which was not predicted in 2012 but nonetheless occurred due to decreased demand for CTs, demonstrated the point that past CT costs should not be used to measure the reasonableness of current CT cost estimates. The same argument applies here. Finally, we cannot accept or rely upon NCSEA's statement that DNCP does not plan to use a Siemens-5000 in constructing its next CT; as the Company has explained, given all of the information known at this time, the Siemens-5000 is the least cost option for the Company were it to construct a new CT facility today.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding is found in the Initial Filing and Reply Comments of DNCP, the Initial Comments of NCSEA, the Reply Comments of Public Staff, the Reply Comments of DEC/DEP, and the Phase 1 Order.

In its Initial Filing, DNCP stated that it adjusted its installed CT cost estimate to account for economies of scale as permitted by the Commission in the Phase 1 Order. This adjustment reflected the cost benefits associated with building multiple CTs at a single site, up to four units.

In its Initial Comments, NCSEA contended that the Utilities have not complied with the Commission's directives from the Phase 1 Order regarding the inclusion of economies of scale and scope when calculating the installed cost of a CT. With regard to DNCP, NCSEA asserted that DNCP did not propose any adjustments to the Brattle data to remove the impact of economies of scope. NCSEA also contested DNCP's adjustment to the Brattle data to reflect additional economies of scale corresponding to a four-unit site with regard to electrical and gas interconnection costs, contending that by doing so the Company cut the cost estimate for each of these cost categories in half without offering evidence to support that adjustment.

In its Reply Comments, Public Staff also asserted that the Utilities did not exclude economies of scope from the installed CT cost estimate, and recommended that the Commission direct the Utilities to recalculate their avoided capacity costs to ensure that all economies of scope are excluded.

In their Reply Comments, DEC/DEP observed that the type of data publicly available to estimate CT costs makes it impossible to isolate economies of scale from economies of scope to an empirical certainty.

In its Reply Comments, DNCP explained that, since it relied on the Brattle Report to estimate a hypothetical CT's construction costs, without knowing the underlying assumptions and derivation of the numbers contained in the Report, it was not possible to ascertain whether those numbers included cost savings from economies of scope. DNCP stated that, as a result, NCSEA's comment that the Company did not propose any adjustment to the data to remove the impacts of economies of scope is correct, because the Company did not have any basis for doing so. DNCP argued that it would not be appropriate to adjust the Company's estimated costs for economies of scope without knowing whether such economies were included in the first place. The Company stated that, if the Commission determines an adjustment to remove economy of scope is required, that the adjustment be limited to the mobilization and start-up category of the Company's cost sheet, since that would be the only cost incurred based on the (Commission required) assumption of installing the turbines one at a time. DNCP noted that any such costs would be minimal.

DNCP also explained that its adjustment to the Brattle Report data to reflect additional economies of scale for a four-unit site (rather than a two-unit site as contemplated by the Brattle Report), was expressly contemplated by the Phase 1 Order. In response to NCSEA's assertions regarding the impact of DNCP's assumption of a four-unit site, the Company explained that the reductions in the estimated costs associated with electric and gas interconnection reflected in its Initial Filing are the result of not only the adjustment for a four-unit site, but also of specific adjustments made to the electric and gas interconnection costs reflected in the Brattle Report. These adjustments included the removal of the cost of electric transmission network upgrades as required by the Phase 1 Order, and the reduction of the assumed length of the natural gas lateral from five miles (assumed in the Brattle Report) to one mile, which approximates the actual expected gas lateral length.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that DNCP has complied with the Commission's directives regarding economies of scale and scope. In the Phase 1 Order, the Commission explained that economies of scale include the cost benefits associated with building multiple CTs at a single site, and that economies of scope include the cost benefits associated with building multiple CTs at the same time. The Commission agreed with the Utilities that it is appropriate to incorporate economies of scale for the construction of up to four CTs at one site in the calculation of estimated CT costs, and concluded that the Utilities had demonstrated that this practice is historically supported and reflects the most likely proxy of future hypothetical CT construction, but decided that economies of scope were not appropriate to include.[10]

Consistent with our determination in the Phase 1 Order, we accept DNCP's reflection of economies of scale associated with a four-unit site in its CT cost estimate, including the adjustments made by the Company to electric transmission and gas lateral interconnection costs. As DNCP explained, these adjustments are justified by the Commission's own determination in the Phase 1 Order that network upgrade costs should

[10] *See* Phase 1 Order at 48.

not be included in the calculation of CT installed cost,[11] and by the Company's actual experience in constructing natural gas laterals. With regard to economies of scope, we agree with the Utilities that the public sources of data that were relied upon to estimate installed CT costs—which as discussed elsewhere in this Order were reasonable and appropriate—do not permit the quantification of a specific amount for economies of scope. Under these circumstances, we conclude that DNCP has complied with the Commission's Phase 1 Order directives to the extent reasonable and feasible for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding is found in the Initial Filing and Reply Comments of DNCP, the Initial and Reply Comments of NCSEA, the Reply Comments of Public Staff, the Reply Comments of DEC/DEP, and the Phase 1 Order.

In its Initial Filing, DNCP explained that, for purposes of determining avoided capacity costs for this proceeding pursuant to the peaker methodology maintained by the Phase 1 Order, the Company used the construction and operating cost of a combustion turbine (CT). DNCP described the CT that it used for its avoided cost determination as part of a four-unit greenfield installation, assumed to be operational in 2014, 232 MW capacity rating, with an installed cost of $485 per kW plus annual costs related to fixed O&M, with a book life of 36 years. DNCP's Initial Filing also included a 10% contingency rate for the engineering, procurement and construction (EPC) related costs, and a 9% contingency rate for the owner's related costs.

In its Initial Comments, NCSEA argued that DNCP should be required to use a contingency factor for its estimated avoided capacity costs of at least 15-20%. NCSEA

[11] *See id.* at 9, Ordering Paragraph 7.

also contended that, if the Commission approves DNCP's use of the Siemens turbine for its avoided CT costs, an even higher contingency factor – 30% – would reflect what NCSEA termed DNCP's lack of experience and corresponding lack of ability to forecast construction and other risks with accuracy. In its Reply Comments, NCSEA argued that a contingency factor of 5 or 10% might be adequate for internal purposes at the late stages of the planning process, after completion of final site selection, site-specific design document preparation, and once final bid documents are ready to be issued, but would not be adequate even for internal purposes during earlier stages of planning. NCSEA contended that in the context of this proceeding, where the goal is to compensate for the risks bore by ratepayers throughout the entire planning, design and construction process, a higher contingency is necessary, and argued that this would be consistent with the Commission's directive that the contingency factor reflect "a hypothetical plant in relatively early stages of planning." NCSEA asserted that if the Commission approves DNCP's use of the Siemens-5000, it must direct the Company to recalculate its avoided capacity cost using a higher contingency factor that reflects what NCSEA termed the Company's inexperience with that technology. NCSEA contended that a contingency factor of 30%, which is the high end of the industry sources discussed in its Initial Comments, would be needed to appropriately reflect this "lack of experience and the corresponding lack of ability to forecast construction and other risks with accuracy."

NCSEA also disagreed with the Company's use of a 36-year life span for the Siemens turbine, noting that the Brattle Report assumes a 20-year life span. NCSEA asserted that "even if DNCP were to produce evidence concerning the lives of its existing GE model fleet, this would provide no basis for approximating the useful life of a CT model with which DNCP has no actual experience. Therefore, if the Commission permits DNCP to 'swap' in a Siemens model CT in spite of the Public Staff's and NCSEA's recommendation otherwise, DNCP should be ordered to use the 20 year useful life assumed in the Brattle Report." NCSEA asked the Commission to direct DNCP to recalculate its avoided capacity cost using a shorter useful life, and contended that the Company should use a useful life of 20 years.

In its Reply Comments, Public Staff also contended that the contingency factor used by DNCP is unreasonably low, relying on the Company's proposed use of what it termed a new model CT with which the Company has no construction or operational experience. Public Staff recommended that the Commission direct DNCP to increase its contingency factor to reflect a hypothetical plant in the early stages of development.

In their Reply Comments, DEC/DEP addressed NCSEA's criticism of those utilities' proposed contingency adders, and noted that NCSEA's proposed increased contingency adder more than triples the contingency adders that DEC/DEP had proposed and that they have experienced in their Carolinas operations. DEC/DEP argued that NCSEA's proposed contingency adder was overly high and utterly unrelated to the companies' experience. DEC/DEP also stated that their contingency adder is reasonable for use in the relatively early stages of planning because it is based on real-world experience in constructing CTs and consistent with the use of contingency adders. The companies explained that the equipment for constructing a CT is generally uncomplicated and standardized, and that the CT construction process is relatively quick and straightforward. DEC/DEP explained further that, because of their uncomplicated nature, CT projects are not prone to the unforeseen risks and circumstances that a contingency adder is intended to cover. As a consequence, they argued, higher contingency adders are not required or justified in their experience in constructing CTs in the Carolinas. DEC/DEP argued that using NCSEA's suggested higher contingency adder would result in an avoided capacity cost rate in excess of their actual avoided costs and produce an unreasonable result.

With regard to useful life, DEC/DEP also addressed NCSEA's arguments that those companies should use a shorter useful life estimate than they have proposed. They noted that avoided capacity rates should reflect the capital costs that the purchasing utility actually avoids if it purchases power from a QF rather than generating power itself, and that the rates paid by customers for QF power should not exceed the purchasing utility's avoided cost. DEC/DEP argued that the best reference points for determining a CT's useful life for these purposes are the actual operating lives of the utility's CT fleet and the CT useful life assumptions used in setting the utility's base rates.

In its Reply Comments, DNCP explained that, contrary to NCSEA's implication, constructing a simple cycle CT plant is not a new or risky endeavor, but rather is a well-known and documented construction process. DNCP explained further than switching from GE to Siemens turbines does not change the overall risk profile of the potential project and, therefore, the same percentage level of contingency is adequate.

With regard to turbine life span, DNCP explained that it uses a 36-year life because that is the assumed life expectancy of a new utility-owned CT facility, as supported by an asset depreciation study that was filed with both the Commission and the VSCC in 2013. That study, DNCP explained, stated that a life span of 35-40 years was estimated for the majority of CTs, and noted that such a life estimate is typical for CTs that are used primarily as peaking units and for CC units used as base load. The Company also noted that its use of a 36-year life here is supported by its use of a 36-year expected life to recover the costs of its existing CT plants, and that this life span represents what customers actually pay.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the contingency factors and useful life estimates used by DNCP in its estimation of installed CT costs are reasonable and appropriate for purposes of this proceeding. In the Phase 1 Order we concluded that "transmission system impacts, a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, and a reasonable estimate of useful life of a CT are appropriate to include in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs."[12] We also stated that the Utilities should use "a reasonable estimate of a useful life of a CT" in calculating avoided capacity costs.[13]

With regard to contingency, Public Staff and NCSEA have provided no evidence to justify cost contingency factors in the range of 15 to 30%. Given the fact that CT construction is as the Utilities have explained a well-understood and generally low-risk and standardized process, and that DNCP's recent procurement and construction experience as described in the Company's Reply Comments demonstrates extensive knowledge of this market and ability to construct new facilities on time and within budget, we conclude that it would not be reasonable to impose a higher contingency factor on DNCP based on the fact that it has not yet constructed any Siemens-5000

[12] Phase 1 Order at 48.
[13] *Id*. at 9.

turbines. For the same reason we find that DNCP's proposed contingency factors are reasonable for use with regard to the early stages of planning.

With regard to useful life, it is clear to the Commission that the metric by which to determine a hypothetical CT's useful life is derived from the experience of the utility with respect to CTs in its generation fleet. Based in particular on the asset depreciation study prepared for DNCP, the Company's proposed useful life estimate is reasonable and appropriate for use in determining avoided capacity costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding is contained in the Initial Filing and Reply Comments of DNCP, the Initial Statement of the Public Staff, the Initial and Reply Comments of NCSEA, and the Phase 1 Order.

In its Initial Filing, DNCP stated that Section III of its Schedule 19-FP defines the on- and off-peak hours, which vary both by season, and depending on whether the QF has chosen to receive rates specified under Option A or Option B, as those options are offered pursuant to the Phase 1 Order. DNCP explained that the Option A summer season runs from midnight on March 31 to midnight on September 30 of each year, with the hours between 10:00 a.m. and 10:00 p.m., Monday through Friday except holidays, being on-peak hours, and the remaining twelve hours being off-peak. DNCP's Option A non-summer season runs from midnight on September 30 to midnight on March 31 of each year, with the hours between 6:00 a.m. and 1:00 p.m. and between 4:00 p.m. and 9:00 p.m., Monday through Friday except holidays, being on-peak hours, and the other hours off-peak. DNCP's Option B summer season runs from midnight on May 31 to midnight on September 30 of each year, with the hours between 1:00 p.m. and 9:00 p.m., Monday through Friday except holidays, being on-peak hours, and the remaining 16 hours off-peak. Finally, DNCP's Option B non-summer season runs from midnight on September 30 through midnight on May 31 of each year, with the hours between 6:00 a.m. and 1:00 p.m. Monday through Friday except holidays being on-peak hours, and the other hours off-peak.

In its Initial Statement, Public Staff stated that the Utilities use an allocation process to weight their avoided capacity costs between summer (on-peak) and non-summer (off-peak) months, and noted that DNCP applied a 60/40 summer/non-summer allocation to its avoided capacity costs. The Public Staff did not take issue with the seasonal cost allocation methodologies used by the Utilities to weight avoided capacity costs in this proceeding, but noted its interest in reviewing the seasonal allocation of avoided capacity costs in the future. To that end, 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. Public Staff stated that it will continue to work with the Utilities to determine the exact data needed to inform this evaluation.

In its Initial Comments, NCSEA took issue with the changes proposed by DEC and DEP to those utilities' seasonal weightings of capacity rates and argued that any such changes should be deferred until a future proceeding. In its Reply Comments, NCSEA included DNCP in repeating its request that the Commission reject the seasonal allocations proposed by the Utilities. NCSEA contended that the Utilities' proposed seasonal weighting based on CT production data is inconsistent with the peaker method.

In its Reply Comments, DNCP stated that it did not object to Public Staff's suggestion that the parties work together to review the seasonal allocations in the next avoided cost proceeding.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the seasonal allocation of avoided capacity costs proposed by DNCP in this proceeding is reasonable and appropriate. In the Phase 1 Order, we directed the Utilities to continue to calculate and include in their avoided cost rate schedules both an Option A and an Option B, "with the avoided capacity rates in Option B calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP and the Public Staff."[14] While NCSEA offered a general critique of the Utilities' proposed allocations, it did not offer any specific counter proposal, and we do not agree with NCSEA that DNCP's proposed seasonal allocations are inconsistent with the peaker methodology. Moreover, DNCP did not change its proposed 60/40 summer/non-summer seasonal allocation from that which we approved in the 2012 Biennial Order.

With regard to the Public Staff's suggestion that it work with the Utilities to review seasonal allocations for the next avoided cost proceeding, we acknowledge that the parties are free to work on this matter going forward to the extent they agree to do so.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding is in DNCP's Initial Filing, the Initial Comments of SACE and NCSEA, the Reply Comments of Public Staff, and the FERC regulations cited therein and below.

[14] Phase 1 Order at 53-54.

Geographical Proximity Limitation

In its Initial Filing, DNCP stated that it proposed to modify Section I of Schedules 19-FP and 19-LMP to add the following availability restriction:

> This schedule is not available or applicable to a QF that utilizes a renewable resource, such as hydroelectric, solar, or wind power facilities, which is owned by a developer, or affiliate of a developer, who is selling or will sell power to the Company from another renewable resource QF located within one mile if the combined output of such renewable resource QFs will exceed 5,000 kW (ac).

DNCP explained that the purpose of the new provision is to restrict the availability of Schedule 19 prices to those QFs for which it is intended (those with a net capacity no greater than 5,000 kW), and that the criteria provide clarity to developers as to what is deemed a single facility. DNCP noted that facilities that fail to meet the applicability criteria for standard contracts may still meet the applicability for a non-standard contract.

In its Initial Comments, SACE commented that the one-mile rule and the 5000 kW restriction in Schedule 19 should apply only when the two proposed facilities are under common ownership and use the same energy resource. SACE also stated that, for purposes of the one-mile rule, the distance between facilities is measured from the electrical generating equipment of each facility. In its Reply Comments, Public Staff supported SACE's comments.

In its Initial Comments, NCSEA recommended that the Commission make the geographical limitation for renewable resource QFs the same as it is for non-renewable resource QFs (i.e., one-half mile), and noted that DEC has historically included a one-half mile availability limit, which DEP in this proceeding has proposed to include as well. In its Reply Comments, Public Staff recommended that the Commission adopt a consistent availability limitation for all of the Utilities, limited to 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.

In its Reply Comments, DNCP agreed with SACE's comments, and proposed to modify the relevant section of its proposed Schedule 19-FP and Schedule 19-LMP accordingly.

DNCP disagreed with NCSEA's recommendation. DNCP explained that the purpose of the proximity or single-facility limitation, which DNCP noted has long been contained in Schedule 19, is to ensure that the standard rate schedule is available only to the small QFs for which it is intended (i.e., QFs with a net capacity not greater than 5,000 kW). DNCP explained further that Schedule 19 has long applied different proximity limitations to non-renewable resource QFs and renewable resource QFs. As an illustration, DNCP noted that Section I of the currently effective Schedule 19-FP (as approved in the 2012 Biennial Proceeding) provides that the Schedule is not available to a QF owned by a developer, or affiliate of a developer, who sells power to the Company from another facility located within one-half mile unless, among other things, each facility "utilizes a renewable resource which may be subject to geographic siting limitations, such as hydroelectric, solar, or wind power facilities." DNCP stated that, in its proposed addition to Schedule 19, the Company simply made clear what "geographic siting limitations" apply to renewable resource QFs. Specifically, for the purpose of determining the size of renewable resource QFs under Schedule 19, that limitation is the same one-mile test used by FERC at 18 C.F.R. § 292.204(a) to determine the size of a small power production QF such as a solar QF. DNCP noted that Section 292.204(a) implements Section 201 of PURPA, which defines a small power producer, inter alia, as a solar facility that "has a power production capacity which, together with any other facilities located at the same site (as determined by [FERC]) is not greater than 80 megawatts." 16 U.S.C. § 796(17)(A) (2010).

Line Loss

In its Initial Filing, DNCP also proposed to revise Section V of its standard rate schedules to establish that all energy purchase rates will be increased by 3.0% to account for line losses, and remove the former provisions allowing adjustments to the line loss percentage based on the percentage approved by the Commission in each biennial proceeding or use of an alternative line loss percentage for a QF that requests it, at the QF's expense.

NCSEA contested the Company's proposal to establish the 3.0% line loss allowance and its proposal to eliminate the QF's option to request a site-specific line loss allowance based on a study conducted at the QF's cost, and alleged that DNCP did not offer justification for these changes.

In its Reply Comments, DNCP explained that in 2010 it evaluated whether 3.0% percent, the line loss allowance it had historically applied to standard QFs, was still a valid allowance amount. The Company stated that internal discussions with its subject experts indicated that the calculations that determine line loss involve certain assumptions, including an assumption of the level of generation used as input kW. The Company performed example calculations of line loss that resulted in a range of line loss levels between approximately 1.83% and 3.08%. The Company also learned that losses can actually be negative, depending on the QF's position on the Company's distribution system, which would reduce payments to the QF. Due to the uncertainty involved with calculating line loss, and given the desire to avoid disputes over these results, DNCP concluded that 3.0% continued to be a fair number for line loss allowance, and so concluded that the option of site-specific line loss calculations was no longer necessary. DNCP noted that, if the Commission determined that DNCP should accept requests for site-specific calculations, then the QF requesting the calculation should reimburse the Company's actual costs in performing the calculation and be bound by the results of the calculation regardless of the outcome, including if the resulting number is a negative one.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the modifications to its standard rate schedules proposed by DNCP in its Initial Filing, as amended by its Reply Comments, to clarify the availability of the standard rate schedules are reasonable. We agree with DNCP that the modifications simply clarify what was already stated in the currently effective Schedule 19 and are also consistent with FERC's regulations. We see no reason to force DNCP to have exactly the same availability provision as DEC/DEP does in their standard rate schedules, especially when DNCP's modification simply clarifies a requirement that was already included in DNCP's standard tariffs.

The Commission also concludes that DNCP's proposal to maintain 3.0% as the line loss allowance applicable to standard QFs is reasonable and appropriate for use in this proceeding. In addition, based on the detailed and exhaustive analysis that DNCP conducted to determine that 3.0% is a valid line loss allowance, we agree with DNCP that the provision for site-specific calculation of line losses is no longer necessary.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding is in the Initial Filing and Reply Comments of DNCP, the Initial Comments of NCSEA, and the Reply Comments of the Public Staff.

In its Initial Filing, DNCP proposed to increase the maximum amount of the charge related to assignment of an avoided cost PPA from $10,000 per assignment to $12,000 per assignment.

In its Initial Comments, NCSEA proposed that Section I of the Schedule 19 Terms and Conditions, which pertains to assignment of a QF PPA, be revised to require that DNCP not unreasonably withhold consent to a proposed assignment. NCSEA also opposed the Company's proposal to increase the maximum cap on the fee related to assignment of a PPA. NCSEA noted DNCP's explanation in a response to a discovery request on this matter that the increase is considered a reasonable additional ceiling of internal and external legal and other resource costs to reflect the significant increase in solar projects in North Carolina since 2012, which in turn may be translated to an increase in the number and complexity of assignments of projects between developers and ultimate owners. NCSEA contended that DNCP acknowledged that the increase in projects since 2012 has not translated to an increase in the number or complexity of assignments, argued that an increase in the number of assignments would not in any case justify an increase in the per-assignment fee, and noted DNCP's response that there has been only one assessment under this provision, for which the fees totaled $750.

In its Reply Comments, the Public Staff contended that the Utilities' proposed assignment provisions could unreasonably burden QF development and should be revised accordingly.

In its Reply Comments, DNCP agreed to revise Section I of the Schedule 19-FP and Schedule 19-LMP Terms and Conditions such 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. With regard to the increased maximum assignment charge, DNCP noted that the $10,000/$12,000 amount is not a fee imposed on every assignment, but rather is a maximum cap on the cost for which a QF is liable even if the actual cost incurred by the Company in connection with an assignment exceeds that amount. DNCP stated that, because the amount of the reimbursement cap will be locked in for a period of up to 15 years under the standard contract options available to QFs, a $2,000 increase in the cap is conservative and reasonable.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that DNCP's proposed modifications to Section I of the standard Terms and Conditions with regard to assignment are reasonable and should be approved. DNCP's modification such 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, addresses NCSEA's and the Public Staff's concern with that provision. Regarding the assignment fee cap, we find NCSEA's complaints to be unfounded, and decline to judge the reasonableness of DNCP's fee cap on the basis of historical assignment numbers, complexity, or amounts. Given the fact that the increased amount is a maximum cap placed on the potential reimbursement of costs associated with an assignment that the Company will require, and recent experience indicates that it is unlikely that any such assignment cost reimbursement will even approach this cap, we find it reasonable to permit DNCP to increase the cap, especially in light of the fact that, as DNCP notes, the amount will be locked in for a period of up to 15 years for standard QF contracts.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding is in the Initial Filing and Reply Comments of DNCP, the Initial Comments of NCSEA, and the Reply Comments of the Public Staff.

In its Initial Comments, NCSEA objected to Article 7(a)(ii) of DNCP's proposed standard PPAs, which made a QF's failure to provide consecutive status reports a non-curable default. NCSEA also asserted a lack of certainty regarding the deadline for commencement of construction, and argued that a QF should be entitled to cure its failure to commence construction by the commencement deadline. NCSEA also contended that failure to maintain an interconnection agreement is not a default that cannot be cured. Finally, NCSEA stated that a termination of the PPA due to a FERC grant of a PURPA Section 210(m) petition should not be considered a termination for default.

In its Reply Comments, Public Staff also recommended that the provision of DNCP's proposed PPAs pertaining to a PURPA Section 210(m) application be removed or included as a stand-alone clause rather than included in the section of the PPA pertaining to defaults with no cure period.

In its Reply Comments, DNCP modified Article 7 to provide a QF an opportunity to cure its failure to provide a status report within 30 days of receiving notice of default from the Company. The Company also revised Article 6(b) of the PPA to clarify the criteria for commencement of construction for a solar QF, and to clarify the earliest date at which it must accept a declaration of Commercial Operations, in order to provide the Company with sufficient time to plan for the injection of the QF's power on its system. In addition, the Company modified Article 7(a)(i) of the standard contracts to clarify that the deadline for construction commencement (as defined in Section 6(b)), is the later of 14 months from the Effective Date of the agreement or 30 days after the Company tenders an interconnection agreement for execution by the QF. The Company explained that, given these lengthy timeframes, a cure period is inappropriate for these instances of default. DNCP also proposed to make failure to maintain an interconnection agreement a curable default and to modify the description of the default to reflect that a failure that is due to the breach of the interconnection agreement by a party other than the QF will not be considered a default. Finally, DNCP proposed to move the PURPA Section 210(m) provision from the default article in the standard contracts to the end of Article 2 (Term and Commercial Operations Date) to those agreements.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the modifications proposed by DNCP in its Initial Filing, as adjusted by its Reply Comments, are reasonable and appropriate for purposes of this proceeding. The Company's proposed modifications to its proposed standard contracts and terms and conditions reflected in its Reply Comments reasonably address all of the concerns raised by NCSEA and the Public Staff. With regard to Articles 6(b) and 7(a)(i), we agree with the Company that, given the lengthy timeframes proposed for a facility to commence construction, it is reasonable to include this as a non-curable event of default.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding is found in the Initial Filing and Reply Comments of DNCP, DEC and DEP, the Initial Statement and Reply Comments of the Public Staff, the Initial and Reply Comments of NCSEA, the Public Staff's September 10, 2015 letter, and the September 17, 2015 Utilities LEO Letter.

In its Initial Filing, DNCP included as an exhibit to its proposed standard rate schedules a legally enforceable obligation (LEO) Form, as discussed in Phase 1 of this proceeding and pursuant to the Phase 1 Order. DNCP explained that the purpose of the LEO Form is to determine the date of a QF's commitment to sell its output to the Company.

In its Initial and Reply Comments, NCSEA argued that a QF's use of the form must be permissive and not mandatory. NCSEA asserted that requiring use of the form to establish a commitment to sell would lead to further complaint proceedings with the Commission, raising uncertainty as to the LEO date of a project that is under development but does not yet have a PPA. NCSEA proposed instead that the Commission hold that on a prospective basis, a QF's use of the form will give rise to a rebuttable presumption that the QF has committed to sell its output to the utility on the date the QF submits the form to the utility, and that a QF's failure to use the form will give rise to a rebuttable presumption that the QF has not committed itself to sell. NCSEA also contended that the form proposed by DNCP was too complex and offered several suggestions for eliminating certain provisions of it. In its Reply Comments, NCSEA stated that the parties had been working together to attempt to achieve consensus on the LEO Form and noted its general support for the form presented by DNCP in its

Reply Comments, with the exception of the section of the form pertaining to termination of the commitment to sell. NCSEA objected to inclusion of this provision, arguing that, since neither FERC nor the Commission has provided guidance on termination of a commitment and therefore of a LEO, it would be premature and invite dispute to include this provision in the form.

In its Initial Statement, Public Staff stated its support for the creation of a simple form by which QFs and Utilities can clearly establish the date of an LEO, and that such a form could help clarify the rights and obligations of each party and avoid disputes that may otherwise be brought before the Commission or to the Public Staff for informal resolution. Public Staff stated that the form should be publicly available on each Utility's website in sections dealing with interconnection agreements and PPAs. Public Staff also recommended that all Utilities be required to make clear to developers on their websites how to establish an LEO and which departments must be contacted to negotiate interconnection agreements and PPAs. Public Staff also proposed that each utility, in the notification that it sends out to an interconnection customer confirming receipt of an interconnection request, include a statement that "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)." Public Staff also made several specific suggestions for modifications to the form proposed by DNCP.

In its Reply Comments, the Public Staff also noted the ongoing discussions among the parties regarding the form, and stated that the modifications made by DNCP to the revised form submitted with the Company's Reply Comments resolve the specific issues raised by the Public Staff's Initial Statement. Public Staff agreed that, with the modifications contained in the revised form, the form was simpler, should be less onerous to complete, with less likelihood of error. Public Staff contended that the Commission should make submission of the LEO form mandatory, provided that QFs are given a reasonable opportunity to cure any errors.

In their March 2 Initial Filings, DEC and DEP did not propose a particular form for approval, but generally supported DNCP's proposal of the LEO form. DEC and DEP suggested a few additions to the information required by the form, and noted that after initial Commission approval of the form, no further approval would be required unless the utility makes material changes to the form or ceases to use it. In their Reply Comments, DEC and DEP stated their agreement with Public Staff's proposal in its Reply Comments on the LEO form.

In its Reply Comments, DNCP argued that, if approved by the Commission, the LEO Form should be the exclusive means by which a QF can satisfy the commitment to sell prong of the Commission's LEO test. DNCP explained that the entire point of the form is to increase the transparency and simplicity of the process of establishing an LEO and that, if a QF is not required to use the form but can instead make a commitment to sell by some other means, or were the Commission to adopt NCSEA's proposed rebuttable presumption, the door is left open to the same types of disputes regarding the establishment of an LEO that have recently often faced the Commission. DNCP stated that the clear language that it proposed and that was suggested by the Public Staff to publicize the requirement to use the form, where to find the form, and where and how to submit the form, should make it clear to any developer seeking to establish an LEO what it must do, and there is no reason to allow LEOs to be established by some other means.

DNCP disagreed that its proposed form was too complex, particularly in light of the modifications that it agreed to make in its Reply Comments, and argued that the alternative form offered by NCSEA's Initial Comments did not contain the information needed to communicate exactly how and when the LEO will arise and to provide for LEO termination rules. As a result, DNCP argued, adoption of NCSEA's proposed form would lead to continued disputes between developers and Utilities.

DNCP proposed several modifications to the LEO Form in response to the Initial Comments offered by the intervenors, including: removing the form from the Company's standard rate schedules and simply providing it on the Company website; including in its notice confirming receipt of interconnection requests the language proposed by the Public Staff clarifying that the submission of an interconnection request does not constitute an indication of a customer's commitment to sell the output of the facility to the utility, as well as including the same statement on the Company's interconnection website; revising the form title to be a "Notice of Commitment;" removing the requirement to provide a copy of the certificate of public convenience and necessity (CPCN) or report of proposed construction (RPC) and inserting a space for the QF to note its size in kW (ac) net; removing the requirement to list names and locations of any QFs owned or under development by the developer or its affiliates located within one mile of the facility; and revising section 4 of the LEO form to indicate that the Notice of Commitment takes effect on the "Submittal Date" and making corresponding changes as needed. DNCP also proposed to remove the acknowledgement that it cannot enter into a PPA with a QF that has not received a CPCN or filed a RPC, but stated that it would continue to follow this requirement consistent with Commission policy, to modify the form to more accurately reflect the requirements of FERC's LEO rule, Section 292.304(d), and Commission policy implementing that rule, to remove section 5(e) from the form as well as references to that section, to remove the survival clause, and to indicate that the person who signs the form on behalf of the seller is duly authorized to do so. DNCP also proposed to revise section 6(c) such that the LEO would terminate if the QF did not execute a PPA within thirty (30) days of the Company's delivery of an executable PPA to the QF, and to modify this section with respect to QFs not eligible for standard rates and contracts to clarify the length of the potential extension of time allowed to execute a PPA related to tendering of an interconnection agreement, and to clarify that, for PPAs that are the subject to complaint or arbitration proceedings, the Commission will set the deadline for execution of a PPA.

The Public Staff's September 10, 2015 letter stated that DEC, DEP, DNCP, NCSEA and the Public Staff had, after engaging in discussions regarding the LEO Form, agreed to the first four sections of the form as contained in Exhibit E to DNCP's Reply Comments, but had not reached agreement with regard to Section 5 of the form, which addresses the date on which an LEO is established, or Section 6 of the form, which sets forth circumstances under which the notice of commitment to sell communicated via the form will terminate. Public Staff stated that these parties would address those unresolved issues in their proposed orders.

The September 17, 2015 Utilities LEO Letter stated that DEC/DEP and DNCP had engaged in additional discussions regarding the LEO Form and had come to agreement regarding Section 5 of the form. The Utilities agreed to maintain the provisions of Section 5 included in the form filed with DNCP's Reply Comments, which specify the date that an LEO is established based on the interaction of the LEO Form with the requirement that a QF obtain a CPCN (or file a RPC). The Utilities also agreed to include additional provisions in this Section 5 to clarify that the QF must make a new commitment to sell if the relevant PPA terminates or expires, and to clarify that the commitment to sell pertains only to the facility that is the subject of the relevant CPCN (or RPC), and not to the owner or developer of the facility. In addition, the Utilities proposed that, while Sections 1 through 5 of their respective LEO Forms would be consistent, Section 6 of their respective LEO Forms would differ, due to the different internal procedures established by DNCP as opposed to DEC/DEP for interacting with QFs. Section 6 of both of the Utilities' forms provides the circumstances under which the Notice of Commitment automatically terminates. Section 6 of DNCP's LEO Form would contain the same provisions as reflected in the form submitted with DNCP's Reply Comments, while Section 6 of DEC/DEP's LEO Form would contain different provisions that correspond to these Companies' procedures.

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the LEO Form as proposed by DNCP, modified as shown in Exhibit E to the Company's Reply Comments, and subsequently modified as shown in Exhibits A and B to the Utilities LEO Letter is reasonable and appropriate for use in determining when a QF has made a commitment to sell its output to a utility.

As an initial matter, the Commission determines it to be appropriate to make the LEO Form as approved in this order mandatory for all QFs seeking to establish an LEO. Commencing with the date of this order, completion and submittal of the LEO Form is the only way in which a QF can demonstrate a commitment to sell. We agree with DNCP that to conclude otherwise, or to adopt NCSEA's rebuttable presumption proposal, would simply leave the door open to additional disputes over the satisfaction of this requirement. The purpose of the form is to provide clarity and simplicity; to allow this requirement to be met by other means would only complicate matters further.

We also conclude that, as modified in DNCP's Reply Comments and the Utilities LEO Letter, the LEO Form is a simple and straightforward means of determining a date certain upon which a QF meets the requirement to commit to sell to the utility, and that the provisions contained in the forms submitted with the Utilities LEO Letter are necessary in order to ensure that the form meets this objective. In contrast, adoption of the alternative form offered by NCSEA would leave unanswered too many questions that need to be answered in order to set the date of the commitment to sell. In particular, we find that the provisions of Section 5 of the proposed form are necessary in order to determine the exact date upon which an LEO was established, in order to ensure that the relevant utility can offer the most appropriate and accurate rates to the QF.

We also conclude that the LEO Form should contain provisions for the termination of a QF's commitment to sell, in order to strike an appropriate balance between the QF's interest in relying on certain rates for its facility and the Utilities' interest in not being forced to pay rates based on stale estimates of avoided costs. Section 6 of the LEO Form, as contained in the exhibits to the Utilities LEO Letter, meets this goal. We also recognize that there are differences between the procedures for interacting with QFs that have been developed over time by DEC/DEP and DNCP, and therefore find it reasonable that Section 6 of the LEO Form used by QFs selling to DNCP differ from Section 6 of the LEO Form used by QFs selling to DEC/DEP, as reflected in Exhibits A and B to the Utilities LEO Letter.

Finally, we agree with Public Staff's proposals regarding communication of the requirement and location of the LEO Form to developers and regarding clarification of the distinction between interconnection requests and PPA discussions, as these suggestions should further clarify this process for QFs and avoid potential future disputes. We emphasize in particular that the Utilities should include in their notices confirming receipt of interconnection requests the language proposed by Public Staff that would clarify that submission of an interconnection request does not constitute an indication of a customer's commitment to sell. We also conclude that DNCP's proposal to include this language on its interconnection website would further clarify this distinction.

Based on these conclusions, we direct DEC/DEP and DNCP to post their LEO Forms as contained in Exhibits A and B to the Utilities LEO Letter, respectively, to their websites, at web pages contained on those sites that are dedicated to informing developers about the process for obtaining a PPA, as soon as practicable following the date of this Order. We also direct the Utilities to include the language suggested by Public Staff in the confirmation of notice provided to sellers that have submitted interconnection requests as well as on their respective interconnection websites.

Commencing with the date of this order, a QF may only demonstrate a commitment to sell by completing and submitting the LEO Form to the relevant utility.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

IT IS, THEREFORE, ORDERED AS FOLLOWS:

1. That DNCP shall offer long-term levelized capacity rates and energy rates 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. DNCP shall offer its standard five-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity.

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

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

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

5. That the Utilities shall post the LEO Form(s) as approved herein to the sections of their respective websites dedicated to informing developers about the process for obtaining a PPA as soon as practicable after the date of this Order, and that the LEO Form(s) as approved herein are, commencing with the date of this Order, the only method that a QF may use to make a commitment to sell to a utility. We also direct that the Utilities implement the suggestions made by the Public Staff with regard to informing parties seeking interconnection of the distinction between that process and the QF commitment process by including the language proposed by the Public Staff in their notices of confirmation of interconnection request receipt and on their respective interconnection websites.

6. That the rate schedules and standard contract terms and conditions proposed in this proceeding by DNCP are approved, except as otherwise discussed herein. The Utilities shall file new versions of their rate schedules and standard contracts,

in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

7. That DNCP shall include with the new versions of its rate schedules filed in compliance with this Order a public report showing its annualized avoided cost rates calculated in the manner presented in DEC's Exhibit 3 to its November 1, 2012 filing in Sub 136; in future avoided cost initial filings and future filings related to approved avoided cost rates, the Utilities shall each continue to include a public report showing their proposed annualized avoided cost rates calculated in the same manner.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of September, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Chief Clerk

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Proposed Order of Dominion North Carolina Power*, filed in Docket No. E-100, Sub 140 was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 18th day of September, 2015.

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