Reply Comments of the Public Staff

Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2014

Docket No. E-100, Sub 140

August 7, 2015

Table of Contents

INTRODUCTION

On March 2, 2015, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc.[1] (DEP), and Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP) (collectively, the Utilities) filed, in Docket No. E-100, Sub 140, their proposed avoided cost rates, standard power purchase agreements (PPAs), and terms and conditions (the March 2015 Filings). On June 22, 2015, the Public Staff, the North Carolina Sustainable Energy Association (NCSEA) and the Southern Alliance for Clean Energy (SACE) each filed initial comments on the March 2015 Filings. While there was some overlap in the comments of these three intervenors, each party raised separate issues or added additional points to the discussion. In these Reply Comments, the Public Staff responds to the following topics raised by NCSEA and SACE.

AVOIDED ENERGY COSTS

Reliance on Forward Prices in Developing Fuel Forecasts

NCSEA stated that DEC and DEP employed a different method to construct their natural gas price forecasts and coal price forecasts for their March 2015 avoided cost filings than they previously utilized in the 2014 Integrated Resource Planning (IRP) proceeding in Docket No. E-100, Sub 141 (2014 IRP).[2] This change in approach consisted of utilizing current forward prices for coal and natural

---

[1] DEP converted from a corporation to a limited liability company on August 1, 2015.
[2] Initial Comments by NCSEA filed on June 22, 2015 in Docket No. E-100, Sub 140, pp. 5-6.

gas over a larger portion of the planning period before shifting to long-term fundamental forecasts. This approach gives greater weight to the forward prices in developing the fuel forecasts, as compared to the fuel forecasts presented by the utilities in past avoided cost and IRP proceedings. The Public Staff made similar observations in its Initial Statement.[3]

NCSEA noted that similar to DEP and DEC, DNCP also changed its approach between the 2014 IRP proceeding and its March 2015 filing to place greater weight on futures market data.[4] The Public Staff agrees that DNCP's change in the weightings of the fundamental forecast and futures market data resulted in different avoided energy cost rates than its approach utilized for developing fuel forecasts in its 2014 IRP.

The Public Staff continues to have concerns about the appropriateness of utilizing forward prices for natural gas and coal in developing long-term price forecasts. Some use of futures market data might be appropriate for the short-term, but only to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question. For example, the relatively small number of contracts for coal futures reflect limited liquidity in the market and indicate that little confidence can be placed in the reasonableness of a particular forward price. A similar degree of illiquidity is observed with long-term natural gas futures contracts. While forward market

[3] Initial Statement of the Public Staff, filed June 22, 2015 in Docket No. E-100, Sub 140, pp. 28-34.

[4] NCSEA Initial Comments, pp.7-9.

prices may provide a snapshot of current future prices, they do not represent the same level of analysis and consideration given to the development of long-term forecasts, as performed by the U.S. Department of Energy - Energy Information Agency (EIA), Moody's Investor Services, Inc., Global Insight, Inc., and other firms whose expertise is in forecasting.

In addition, the utilization of forward prices is not consistent with the fuel procurement practices of the Utilities and thus does not provide an accurate representation of the Utilities' future fuel costs. The Utilities typically acquire natural gas for less than 50% of their projected gas needs with contracts that span over 12 and 24 months. For coal purchases, the Utilities use a mix of long-term contract and spot purchases. The expiration dates of the long-term contracts are staggered to expire at different times of up to three years in the future.

Furthermore, as noted in the Public Staff's initial statement on pages 29-31, the Utilities have increasingly placed greater emphasis on futures market data in both of the last two biennial IRP and avoided cost proceedings. However, rather than utilizing the same approach in both of the 2012 proceedings, DEC and DEP changed their approach between the 2012 IRPs filed in September 2012 and the avoided cost filings in November 2012. Similarly, in 2014, DEC and DEP changed their approach between their September 2014 IRP filings[5] and the filing of their 2014 avoided cost rates in March 2015. These changes were made despite the fact that the Commission emphasized the relationship between the IRP and

[5] In their 2014 IRPs, DEC and DEP used the same approach they used in their 2012 avoided cost filings.

avoided costs and the need for their inputs and assumptions to be consistent in its December 31, 2014, Order Setting Avoided Cost Input Parameters (Phase One Order) in this docket. As such, the Public Staff continues to recommend that the Commission direct the Utilities to recalculate their avoided energy costs using the same fuel forecast weightings utilized in their 2014 IRPs. In addition, the Public Staff recommends that, to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in proceedings before the Commission, they make those proposals in the biennial IRP proceedings, which provide the basis for support for certificates of public convenience and necessity (CPCNs) and avoided costs over the subsequent year.

AVOIDED CAPACITY COSTS

Public Availability of Information

Both NCSEA and SACE commented that the Utilities underestimated their avoided capacity costs through a number of methods, including using data from sources that are not publicly available, and not providing adequate justifications for the adjustments made when calculating the installed cost of a combustion turbine (CT).[6] While the Public Staff did not take exception to the installed costs of a CT proposed by DEC and DEP, the Public Staff did note that DEC and DEP's use of subscription-based data from the Electric Power Research Institute (EPRI), as opposed to the public reports prepared by the EIA and publications by PJM and

[6] NCSEA Initial Comments, pp. 19-24; SACE Initial Comments, p. 4, 9.

other Regional Transmission Organizations (RTOs), limits the public availability of the cost information and reduces the transparency of the avoided cost proceeding. In the Phase One Order, the Commission specifically directed the Utilities to "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 . . . tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."[7] The Public Staff agrees that the Utilities should strive to utilize data from publicly available sources and provide clear justifications for any adjustments made to the publicly available data.

The Public Staff's concern with such adjustments is illustrated by DNCP's substitution of the lower costs associated with the Siemens SGT6500F CT from Gas Turbine World in place of the GE 7FA turbine prices used in the 2014 Brattle Report,[8] despite the fact that the authors of the 2011[9] and 2014 Brattle Reports surveyed the CTs built around the country and concluded that the GE 7FA model is the predominant CT model built and best turbine on which to base its cost of new entry.

---

[7] Phase One Order, p. 48.

[8] Brattle, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, (2014 Brattle Report), May 15, 2014, at p. 8. Available at: http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx.

[9] Spees, K., S. Newell, R. Carlton, B. Zhou, and J. Pfeifenberger. (2011) Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM. August 24, 2011. Available from http://www.brattle.com/_documents/UploadLibrary/Upload971.pdf

Table 1: Turbine Model of CT Turbines Built and Under Construction in PJM and the U.S.[10]

Turbine Model	Turbine Class	Online After 2002				Online After 2008			
		PJM		U.S.		PJM		U.S.	
		(count)	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*
General Electric-7FA	Frame	31	4,807	105	16,132	3	481	16	2,518
General Electric-LM6000	Aeroderivative	11	1,615	27	4,088	7	317	80	3,669
General Electric-LMS100	Aeroderivative	15	1,165	135	10,057	3	273	28	2,606
Rolls Royce Corp-Trent 60	Aeroderivative	2	148	13	853	2	120	4	225
Siemens-501	Frame	22	949	198	8,784	0	0	0	0
Siemens-V84	Frame	3	273	29	2,688	0	0	0	0
General Electric-7EA	Small Frame	2	120	4	225	0	0	10	742
General Electric-MS6001	Small Frame	9	1,179	16	1,903	0	0	0	0

The publically available report goes on to state: "We find the frame-type GE 7FA turbine to be a reasonable choice for the PJM CT reference technology as it is the turbine model that has been built in most of PJM since 2008 and has a lower turbine cost per-kilowatt than the aeroderivative models."[11]

<u>Economies of Scale and Scope</u>

NCSEA also commented that DEC, DEP, and DNCP all included both economies of scale and scope when calculating the installed cost of a CT, despite the statement in the Phase One Order that the Utilities should not include any economies of scope associated with the construction of more than one CT at the same time.[12] SACE similarly commented that DEC and DEP erroneously included economies of scope.[13] The Public Staff did not take issue with these adjustments in its initial comments, but agrees that economies of scope were not properly

[10] 2014 Brattle Report, p. 8, excerpted from Table 6. According to the Brattle Report, the data was sourced from Ventyx's *Energy Velocity Suite* between November 2013 and March 2014.
[11] *Id.*
[12] NCSEA Initial Comments, pp. 25-29.
[13] SACE Initial Comments, filed June 22, 2015 in Docket No. E-100, Sub 140, p. 8.

excluded by the Utilities from the installed cost of a CT. The Public Staff recommends that the Commission direct the Utilities to recalculate their avoided capacity costs to ensure that all economies of scope are excluded.

Contingency Factors

NCSEA further commented that the Utilities used unreasonably low contingency factors,[14] despite the Commission's directive in the Phase One Order to "include a reasonable contingency adder for a hypothetical plant in relatively early stages of planning."[15] With regard to DEC and DEP, the Public Staff did not take issue with any of the specific adjustments, since the overall installed cost of the CT used for purposes of calculating avoided capacity rates seemed reasonable and the nominal increase in the projected CT cost from the 2012 proceeding was comparable to the price trends compiled by the Bureau of Labor Statistics[16]. The Public Staff agrees, however, that the contingency factor used by DNCP is unreasonably low, particularly in light of DNCP's proposed use of a new model CT with which it has no construction or operational experience. As such, the Public Staff recommends that the Commission direct DNCP to increase its contingency factor to reflect a hypothetical plant in the early stages of development.

[14] NCSEA Initial Comments, pp. 30-33.
[15] Phase One Order, p. 66.
[16] Initial Statement of the Public Staff, Figure 3, p. 41.

REVISIONS TO CONTRACT TERMS

As part of each of its biennial proceedings, the Commission has reviewed and approved other related matters involving the relationship between the Utilities and qualified facilities (QFs), such as terms and conditions of service, contractual arrangements and interconnection charges. NCSEA and SACE raised numerous issues with respect to the Utilities' proposed changes to the standard contract terms and conditions and expressed concerns that some of the proposed changes fail to adhere to prior Commission orders in Docket No. E-100, Sub 136 (the Sub 136 proceeding) and this docket, as well as unduly interfere with the ability of QFs to obtain financing, thus violating Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the regulations adopted by the Federal Energy Regulatory Commission (FERC). These issues are discussed below.

Limitation on Assignment Rights

NCSEA commented that DNCP's terms and conditions provide that a QF may assign its rights under DNCP's standard contract only with the prior written consent of DNCP and that DNCP "may withhold such consent if it determines, in its sole discretion, that such assignment would not be in the best interests of DNCP or its customers."[17] NCSEA stated that granting DNCP sole discretion to reject an assignment for any reason is commercially unreasonable and that this provision

[17] NCSEA Initial Comments, p. 38.

should be amended to require that DNCP not unreasonably withhold consent to proposed assignment.

Similarly, NCSEA stated that the assignment provisions in DEC and DEP's standard contract give the utilities "undue discretion to disapprove or put onerous conditions on the assignment rights, such as the requirement of financial security, which . . . have the potential to serve as an impediment to QF development."[18] NCSEA recommended that the Commission direct DEC and DEP to revise their assignment provisions to require that the utility not unreasonably withhold consent on a proposed assignment, and not require commercially unreasonable measures, such as security.

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

[18] NCSEA Initial Comments, p. 54.

Termination Rights and Opportunities to Cure

DNCP included a provision in Article 7(a)(vii) of its proposed Standard Contract that grants the utility a right to terminate a contract when the FERC grants a petition by the utility under PURPA Section 210(m). DNCP's Standard Contract notes that the provision would be included in the contract if the Company has a PURPA Section 210(m) application pending before the FERC on the effective date of the PPA. The Public Staff notes that at the time of the March 2, 2015, filing, DNCP did have a PURPA Section 210(m) application pending before the FERC.[19] However, the FERC declined to grant that petition.[20] As such, the Public Staff believes that inclusion of this provision seems unnecessary at this time, and recommends that the Commission direct DNCP to remove the provision from its standard contract.

NCSEA stated that the provision proposed by DNCP should not be characterized as an event of default by the QF, and to the extent the provision is permissible, it should not be included in Article 7(a), which is titled "Defaults with No Cure Period." The Public Staff agrees that the placement of this term is inappropriate and that to the extent the clause remains in DNCP's Standard Contract, it should be included as a stand-alone clause.

[19] Virginia Electric and Power Company, Application to Terminate Purchase Obligation, Docket No. QM15-1-000 (Oct. 31, 2014).

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

In addition, NCSEA noted that DEC and DEP's Terms and Conditions give the utilities broad discretion to suspend or terminate contracts without an opportunity to cure.[21] The Terms and Conditions for both utilities require the utility to give advance notice to the QF of termination, except in circumstances where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter.

The Public Staff notes that DEP's Terms and Conditions approved by the Commission in the Sub 136 proceeding included the following statement:

> Company shall give Seller a minimum of 30 calendar days prior written notice before terminating or suspending the Agreement pursuant to provisions 1(h)(l)(default or breach of Agreement by Seller), 1(h)(3)(failure to pay any applicable bill when due and payable) or 1(h)(5)(Seller's inability to deliver to Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement), above: however, termination or suspension pursuant to provisions 1(h)(3)(fraudulent or unauthorized use of Company's meter) or 1(h)(4)(presence of dangerous condition)- shall be immediate.[22]

In the current filing, this provision is stricken from the proposed Terms and Conditions without explanation. The Public Staff generally supports the inclusion of commercially reasonable opportunities to cure in QF PPAs in order to avoid impermissible burdens on QFs in violation of PURPA and therefore agrees that DEC and DEP should amend their terms and conditions to provide QFs with a reasonable opportunity to cure prior to termination of the contract, and that DEC

[21] *Id.* at 53.

[22] DEP, Terms And Conditions For The Purchase Of Electric Power, Sheet 2 of 9, Filed in Docket No. E-100, Sub 136, Effective April 1, 2014.

and DEP should provide clearer guidance regarding the circumstances in which termination or suspension is warranted.

Availability Limitation Based on Distance between Facilities under Common Ownership

NCSEA noted that DNCP proposes to amend its standard terms to provide that a QF owned by a developer or affiliate who sells or will sell power to DNCP from another QF located within one mile is not eligible for the standard rates unless the combined capacity is equal to or less than five megawatts.[23] DNCP previously had a similar provision in its Schedule 19 tariffs, but the distance between QFs was limited to one-half mile. NCSEA stated that DNCP provided no justification for the increase. DEC has historically included a similar one-half mile availability limitation, and in this proceeding DEP has also proposed to include the same limitation as DEC. NCSEA recommended that the Commission approve DEP's one-half mile proposal and limit DNCP's proposal to one-half mile, while maintaining the qualification that two QFs under the same or affiliated ownership are eligible for the standard offer so long as the combined capacity of the facilities does not exceed five megawatts. The Public Staff agrees that in the interests of fairness and clarity, the Commission should adopt a consistent availability limitation for all three utilities. As such, the Public Staff recommends that the Commission approve the availability limitations for each utility limited to one-half mile, while maintaining the qualification that two or more QFs under the same or

---

[23] *Id.* at 41.

affiliated ownership are eligible for the standard offer rates and terms so long as the combined capacity of those facilities does not exceed five megawatts.

SACE also took exception to DNCP's proposed distance requirement, noting that the restriction should only apply when the two proposed facilities under common ownership use the same energy resource. SACE also noted that it should be made clear that the distance between facilities is measured from the electrical generating equipment of a facility for purposes of making the one-mile determination.[24] The Public Staff notes that these requirements are analogous to the size and location criteria for QFs adopted by the FERC, which provide in part:

> (a) Size of the facility—(1) Maximum size. Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities *that use the same energy resource*, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.
>
> (2) Method of calculation. (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.
>
> (ii) *For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility*.[25]

The Public Staff agrees that the one-half mile restriction should only apply to facilities that use the same energy resource, and that the Utilities should include

[24] SACE Initial Comments, p. 7.

[25] 18 CFR § 292.204: Criteria for Qualifying Small Power Production Facilities (emphasis added).

language stating that the distance between facilities would be measured from the electrical generating equipment of a facility.

30-Month Deadline for Achieving Commercial Operation

NCSEA stated that DEC and DEP neglected to include the qualifying language approved by the Commission in its Sub 136 Order related to the 30-month deadline for achieving commercial operation, which provided that a "QF should be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner."[26] Instead, DEC and DEP included language in Section 3 of their standard contracts stating that the "Company, in its sole discretion may terminate this agreement . . . if Seller is unable to provide generation capacity and energy production consistent with the energy production levels specified in Provision No. 2 above. This date may be extended upon mutual agreement by both parties." NCSEA stated that a "utility's right to terminate at 30 months should be limited to the circumstances where the QF fails to achieve commercial operation at any level by that milestone – subject to the qualification that this deadline may be extended if the QF is making reasonable progress."[27] The Public Staff agrees that DEC and DEP's standard contract should be amended to provide that a utility may terminate a contract after 30 months if the QF has failed to achieve commercial operation at any level by that date, provided that the QF should be allowed additional time if the

[26] NCSEA Initial Statement at p. 45.
[27] *Id*. at 46.

project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

Commencement of Term under Utility's Control

NCSEA stated that DEC and DEP's proposed standard contract provides that the term of the contract begins on the earlier of a date certain (as specified in the contract) or the date the Company is first ready to accept electricity from the seller.[28] NCSEA further noted that DEC's contract historically has commenced on the initial delivery date, and that DNCP's standard contract provides that the term runs from the commercial operation date of the facility. The change to DEC's standard contract generally adopts the approach used by DEP in the contracts approved in the Sub 136 proceeding and in prior years. This proposed and existing language provides that this initial date of delivery may be extended upon mutual agreement by both parties. The Public Staff does not take issue with this proposed change to DEC's standard contract, but in order to provide assurance that the consent to extend this date will not be unreasonably withheld, recommends that the Commission direct DEC and DEP to amend their consent provisions to provide that consent to an extension of this initial delivery date shall not be withheld if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

[28] NCSEA Initial Statement at 46.

Reduction in Contract Energy and Contract Capacity Charge

NCSEA took issue with the proposed Reduction in Contract Energy and Reduction in Contract Capacity charge in DEC and DEP's terms and conditions, which would allow the Utilities to apply to the Commission on a case-by-case basis for approval to impose a charge in the event the QF's average energy generated or capacity falls significantly below the Contract energy and capacity levels.[29] NCSEA noted that DEP had previously included a similar provision in its standard contract, but the Commission in the Sub 136 proceeding directed DEP to remove the provision from its terms and conditions, finding it inconsistent with previous rulings of the Commission. The Commission, however, indicated that DEP could "propose a provision that allows it to take action if the harm it alleges the penalty is designed to fix occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval."[30]

In its initial comments in the Sub 136 proceeding, the Public Staff noted that the Commission previously held, in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide, but the utility could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel, such as run-of-the-river hydro, solar, or wind, absent an explicit order from the Commission.[31] The Public Staff further stated that QFs, under the standard contracts, are not paid unless they are generating, and,

[29] NCSEA Initial Statement at p. 47.
[30] Sub 136 Order at p. 42.
[31] Initial Statement of the Public Staff filed on February 7, 2013, in Docket No. E-100, Sub 136, at p. 30.

therefore, a penalty is unwarranted. In Phase One of this proceeding, the Commission received additional evidence from a number of parties on this issue and ultimately concluded that "experience has shown that there is limited risk of nonperformance."[32]

The Public Staff recognizes that there may be some risk that a QF could underperform in the later years of a long-term levelized contract after receiving the benefits of a levelized contract in the early years. However, the current proposal does not address this concern. As such, the Public Staff recommends that the Commission direct DEC and DEP to refile a proposal that more directly addresses underproduction in later years of a levelized contract that results in overpayment during the early years of the contract, and until such time as the proposal is approved by the Commission, remove the Reduction Contract Energy and Reduction in Contract Capacity charge provisions from their proposed terms and conditions. In the interim, the utilities may apply to the Commission for approval to impose a charge on a case-by-case basis, at which time the Commission can determine the extent, if any, of the harm that the charge would address.

Right to Terminate Based on Inability to Deliver Energy as Specified in Contract

NCSEA objected to provision 1(i)(5) in DEC and DEP's proposed terms and conditions, which authorizes the utility to terminate the contract "due to Seller's

[32] Phase One Order at 20.

inability to deliver to Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement." As discussed above, the Commission held, in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide, but the utility could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel, such as run-of-the-river hydro, solar, or wind, absent an explicit order from the Commission. Since QFs under the standard contracts are not paid unless they are generating, the proposed term is unnecessary.

Inclusion of Interconnection Terms

NCSEA took exception to DEC and DEP's proposed changes to their standard contracts, rate schedules, and terms and conditions to include additional provisions related to interconnection.[33] The Public Staff believes that since the Commission has adopted separate procedures, forms, and agreements in Docket No. E-100, Sub 101, related to the interconnection of QFs, there is no need for these additional terms to be added in the proposed standard offer documents, and doing so could result in confusion and inconsistencies. The Public Staff recommends that the Commission direct DEC and DEP to delete the provisions related to interconnection, with the exception of a reference to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-

[33] NCSEA Initial Comments, p. 56-57

100, Sub 101, and a statement that an interconnection agreement is necessary in order to deliver output to the utility.

Adjustments for Reactive Power

NCSEA stated that DEC and DEP's rate schedule provisions related to reactive power are unclear and have the potential to unfairly penalize a QF to the extent that the utility may benefit from reactive power.[34] NCSEA also stated that DEP's rate schedule contemplates that a QF may enter into an "Operating Agreement" with the utility to adjust VAR[35] production to support voltage control. DEP's North Carolina Terms and Conditions for the Purchase of Electricity require that the "Seller's facility shall be operated in such a manner as to generate reactive power as may be reasonably necessary to maintain voltage levels and reactive area support as specified by Company."[36]

Section 1.8 of the Commission approved North Carolina Interconnection Agreement specifies a that an interconnection customer, with the exception of wind generators, must operate within a power factor range of 0.95 leading to 0.95 lagging at continuous rated power output, and that a utility is obligated to pay the interconnection customer when the utility requests the interconnection customer to operate outside of that range.[37] The Interconnection Agreement further states

[34] *Id*. at pp. 57-58.
[35] Volt-ampere reactive.
[36] DEP Terms and Conditions, Sec.8, Sheet 6 of 10.
[37] North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections, approved on June 9, 2008, and May 15, 2015, in Docket No. E-100, Sub 101.

that "if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer."[38]

The Public Staff recommends that the Commission require DEC and DEP to update their applicable rate schedules to reflect the utilities' obligation to pay an interconnection customer for reactive power that the customer provides or absorbs at the utilities' request.

ESTABLISHING A LEGALLY ENFORCEABLE OBLIGATION

LEO Form

In its Initial Statement, the Public Staff discussed the initial statements of DEC and DEP and the initial comments of DNCP filed on March 2, 2015, regarding the creation of a simple form that would clearly establish that a QF had committed to sell all of its electrical output, thereby satisfying the second prong of the Commission's two-part test for establishing a legally enforceable obligation (LEO). DNCP submitted a proposed form with its initial comments, and NCSEA filed a proposed form as Exhibit 5 to its initial comments filed on June 22, 2015.

Following the filing of initial statements and comments, DNCP, NCSEA, DEC, DEP, and the Public Staff worked together to develop a simple form that

[38] Id. at Section 1.8.2

would provide sufficient guidance regarding what it means for a QF to "commit itself to sell its output", as discussed by DNCP witness Williams in Phase One of this proceeding,[39] and that addresses the comments of and issues raised by DEC, DEP, NCSEA, and the Public Staff regarding the contents of the form. While the discussions between these parties have been fruitful, several issues require further discussion. As such, the Public Staff intends to schedule further discussions in the next several weeks with these parties to attempt to resolve or narrow these differences, and to make a supplemental filing with the Commission regarding the outcome of these discussions.

With its reply comments, DNCP is submitting a revised form titled a "Notice of Commitment to Sell the Output of a Qualifying Facility to Dominion North Carolina Power." The Public Staff has reviewed this form, and it resolves the specific issues raised in the Public Staff's initial comments regarding DNCP's form. However, there appear to be a few remaining open issues among the other parties about several of the provisions, and as indicated previously, the Public Staff intends to hold discussions with these parties to resolve or narrow these open issues and make a supplemental filing prior to the filing of proposed orders.

In its initial comments, DNCP proposed use of the form as being mandatory, while NCSEA recommended that use of the form be permissive, subject to twin rebuttable presumptions. One argument both NCSEA and the Public Staff raised

[39] Phase One Order at 63.

in their initial comments was the complexity of DNCP's proposed form. This revised form is much simpler, requires no attachments, is a notice as opposed to a contract, and is effective upon transmission. As such, it should be much less onerous to complete and the likelihood of error should be more remote. Thus, the Public Staff believes that it is reasonable that the Commission require QFs to submit a notice of commitment form as approved by the Commission, as long as QFs are given a reasonable opportunity to cure any errors.

CONCLUSION

In summary, the Public Staff makes the following additional recommendations in its reply comments:

- That the Commission direct the Utilities to recalculate their avoided energy costs using the same weighting of futures market data and fundamental forecasts utilized in their 2014 IRPs.
- That the Commission direct the Utilities to make any proposed changes in the way they utilize forward prices and long-term forecasts in the biennial IRP proceeding, and to use that same approach in their biennial avoided cost filings for that same year.
- That the Commission direct the Utilities to utilize data from publicly available sources when calculating the installed cost of a combustion turbine for avoided capacity purposes and provide clear justifications for any adjustments made to the publicly available data.

- That the Commission direct the Utilities to recalculate their avoided capacity costs to ensure that all economies of scope are excluded.
- That the Commission direct DNCP to increase the contingency factor that it utilized to appropriately reflect a hypothetical plant in the early stages of development.
- That the Commission direct the Utilities to revise the assignment provisions in their standard contracts to provide that they will not unreasonably withhold consent to a proposed assignment.
- That the Commission direct DNCP to remove the provision in Article 7(a)(vii) of its proposed standard contract that grants the utility a right to terminate a contract where FERC grants a petition by the utility under PURPA § 210(m).
- That the Commission direct DEC and DEP to amend their terms and conditions to provide QFs with a reasonable opportunity to cure prior to termination of the contract, and to provide clearer guidance regarding the circumstances in which termination or suspension is warranted.
- That the Commission approve the availability limitations for each utility 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 megawatts. The one-half mile restriction should only apply to facilities that use the same

energy resource, and the Utilities should include language stating that the distance between facilities would be measured from the electrical generating equipment of a facility.

- That the Commission direct DEC and DEP to amend their standard contract to provide that a utility may terminate a contract after 30 months if a QF has failed to achieve commercial operation at any level by that date, provided that the QF should be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.
- That the Commission direct DEC and DEP to amend their consent provisions to provide that consent to an extension of the initial delivery date established in a PPA shall not be withheld if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.
- That the Commission direct DEC and DEP to remove the Reduction Contract Energy and Reduction in Contract Capacity Charge provisions from their proposed terms and conditions and refile a proposal that more directly addresses the harm that the charge is supposed to address (underproduction in later years of a levelized contract that results in overpayment during the early years of the contract).

- That the Commission direct DEC and DEP to strike provision 1(i)(5) in their proposed terms and conditions, since QFs under the standard contracts are not paid unless they are generating.
- That the Commission direct DEC and DEP to delete the provisions related to interconnection in their standard contracts, with the exception of a reference to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101, and a statement that an interconnection agreement is necessary in order to deliver output to the utility.
- That the Commission require the Utilities to update their applicable rate schedules to reflect the utility's payment associated with reactive power for interconnection customers.

WHEREFORE, the Public Staff respectfully requests that the Commission take the foregoing comments and recommendations into consideration in establishing the Utilities' avoided cost rates and approving their tariffs and standard agreements in this docket.