

LAW OFFICE OF CHARLOTTE MITCHELL

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PO BOX 26212  
RALEIGH, NORTH CAROLINA 27611  
919-260-9901  
www.lawofficecm.com

June 22, 2015

Gail Mount  
Chief Clerk  
North Carolina Utilities Commission  
430 N. Salisbury Street  
Raleigh, NC 27603 – 5918

**Re: Initial Comments by NCSEA - Public  
NCUC Docket No. E-100, Sub 140**

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket are the PUBLIC Initial Comments by NCSEA. There are five exhibits to the comments. Please ensure that these documents are posted on the Commission's website.

Should you have any questions or comments, please do not hesitate to call me. Thank you in advance for your assistance and cooperation.

Regards,

/s Charlotte Mitchell

4847-9065-5268, v. 1

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JUN 22 2015

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	)	<b>INITIAL COMMENTS</b>
Avoided Cost Rates for Electric	)	<b>BY NCSEA</b>
Utility Purchases from	)	
Qualifying Facilities - 2014	)	

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**STATE OF NORTH CAROLINA  
UTILITIES COMMISSION  
RALEIGH**

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided Cost	)	<b>INITIAL COMMENTS</b>
Rates for Electric Utility Purchases from	)	<b>BY NCSEA</b>
Qualifying Facilities - 2014	)	

On February 25, 2014, in the above-captioned docket, the North Carolina Utilities Commission (the “Commission”) issued its Order Establishing Biennial Proceeding and Scheduling Hearing held pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (“PURPA”), 18 U.S.C.A 824a-3, and the regulations of the Federal Energy Regulatory Commission (“FERC”), effectively initiating the 2014 biennial proceeding. For the purpose of considering various issues that had been raised in the 2012 biennial proceeding in N.C.U.C. Docket No. E-100, Sub 136, the Commission initiated the 2014 biennial proceeding in advance of the filing of new proposed rates by the electric utilities, conducting an evidentiary hearing to consider changes to the methodology used to calculate payments made to qualifying facilities (“QFs”). In addition to the five electric utilities subject to the jurisdiction of the Commission, eleven intervenors and the Public Staff participated as parties to the proceeding. In an evidentiary hearing that spanned four days, the Commission received into evidence testimony from twenty-four different expert witnesses on issues related to the calculation of avoided costs, as well as the components of the Commission-approved

standard offer to QFs. On December 31, 2014, the Commission entered its Order Setting Avoided Cost Input Parameters (“Order Setting Parameters”), making thirty-one separate findings of fact, carefully considering and weighing the evidence in the voluminous record, drawing conclusions from that evidence, and ordering the electric utilities to calculate their avoided costs and the associated rates paid to QFs in accordance with specific parameters based on its thorough examination.

On January 8, 2015, the Commission entered its Order Establishing Procedural Schedule and Scheduling Public Hearing, as subsequently amended by orders dated April 15, 2015 and May 29, 2015, directing all parties to the proceeding, other than the five electric utilities, to file with the Commission the comments and exhibits that they wish to present in this proceeding on or before Monday, June 22, 2015. In light of the foregoing, the North Carolina Sustainable Energy Association (“NCSEA”), having become a party to this proceeding pursuant to that Order Granting Petition to Intervene entered by the Commission on February 27, 2014, by and through undersigned counsel, respectfully submits these initial comments—focused on the proposed rates, power purchase agreements and terms and conditions of Duke Energy Carolinas, LLC (“DEC”), Duke Energy Progress, Inc. (“DEP”) and Virginia Electric and Power Company d/b/a Dominion North Carolina Power (“DNCP”) (collectively, the “Utilities”) filed in this docket on March 2, 2015 (the “March 2015 Filings”)—for consideration by the Commission.

For the purposes of this phase of the proceeding, NCSEA retained Ben Johnson Associates, Inc. to assist with the review of the March 2015 Filings, and Ben Johnson, Ph.D., served as consulting economist.

## INITIAL COMMENTS

### **I. Understatement of Avoided Energy Costs**

NCSEA's review of the March 2015 Filings revealed that the Utilities' methods of calculating future fuel prices overemphasize futures market data and underestimate long term prices, thereby understating their avoided energy costs.

The process used by the Utilities to calculate avoided energy costs was explained by the Public Staff in the 2012 biennial proceeding. As testified by Public Staff witness Hinton, each of the Utilities use a:

[P]roduction costing model to estimate their avoided energy costs over the next 15 years. The models provide a chronological estimate of the hourly fuel costs, variable O&M costs, and generation unit start-up costs associated with the production of energy. This estimate is performed by replicating the future costs of operating each utility's generating units combined with other supply-side resources, such as its demand side management programs and purchases from other generators. The model dispatches the generating units in a least cost manner subject to various constraints, such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times.<sup>1</sup>

Public Staff witness Hinton further explained that:

Fuel price forecasts are often the most influential factor on avoided energy costs and can cause significant changes between proceedings.<sup>2</sup>

Thus, the fuel price forecasts are critically important to the avoided energy cost calculations. Any discrepancy between estimated fuel prices and actual prices that are ultimately paid by the utilities translates into a corresponding discrepancy between the estimated avoided energy costs and the actual energy costs that would be avoided if electricity were instead obtained from a QF. The FERC's order implementing Section

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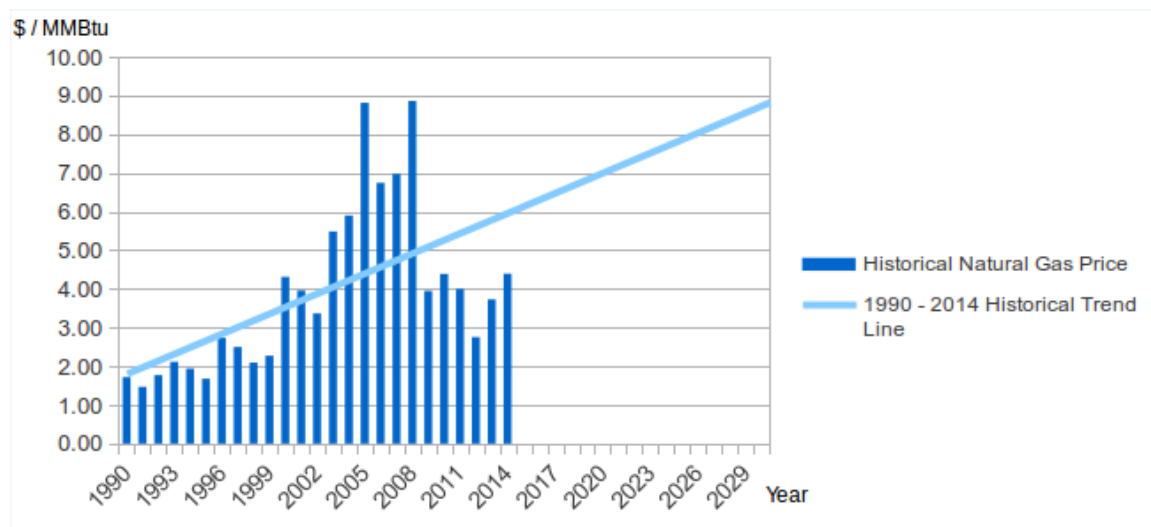
<sup>1</sup> Testimony of John R. Hinton on Behalf of the Public Staff North Carolina Utilities Commission, N.C.U.C. Docket No. E-100, Sub 136, September 27, 2013 ("Hinton Testimony"), p. 4, l. 14 – p. 5, l. 8.

<sup>2</sup> Hinton Testimony, p. 6, ll 8-12.



210 of PURPA provides that the objective of the “full avoided cost rule” is to leave ratepayers indifferent between utility self-built generation or the purchase of QF generation. Inaccurately calculated avoided energy costs will undermine this objective.

The following Figure 1 shows natural gas prices over the 25 year period from 1990 through 2014:



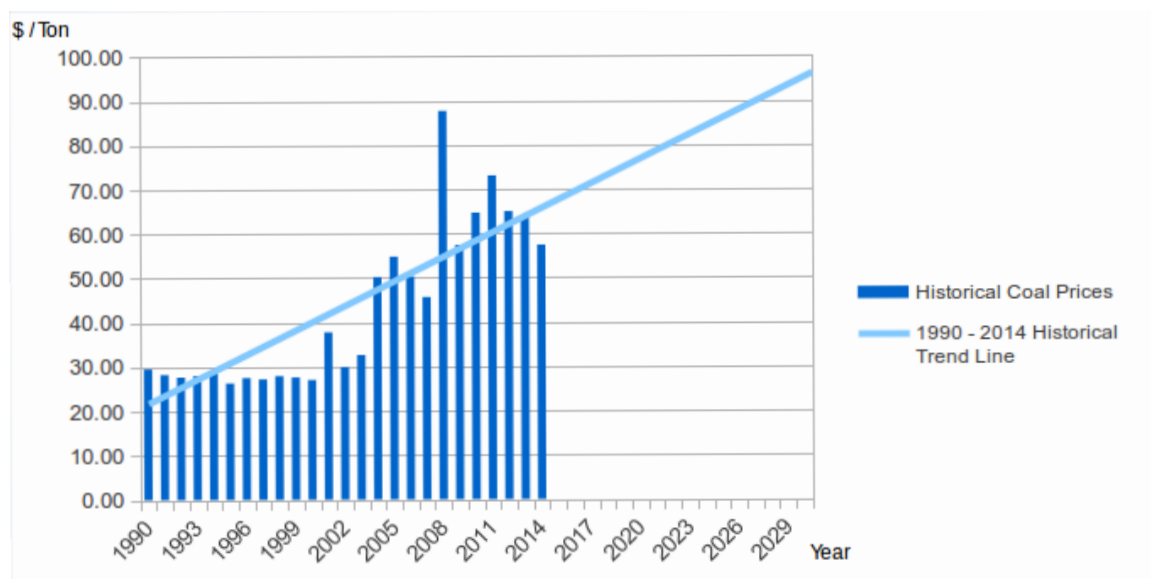
**Figure 1. Natural gas prices over the 25 year period from 1990 through 2014. Source: Reuters 1990-1996; EIA 1997-2014.**

Like many other commodities, natural gas prices exhibit great volatility over short periods of time, fluctuating sharply from month to month and year to year. Moreover, prices can also vary widely over much longer time periods, trending upward over multi-decade time intervals, and experiencing sharp movements that can temporarily bring prices close to, above, or back below, the long term trend line, due to the influence of many different political, economic and technical variables, as well as speculative impacts related to those variables.

These points are clearly demonstrated in the historical data shown in Figure 1. Natural gas prices stayed close to, or moderately below, the 25-year long term trend line throughout the 1990s. Suddenly, in 2003 prices moved well above the trend line, at

which point they resumed their upward pace at a similar rate of increase, but temporarily remaining well above the trend line. This pattern continued until the summer of 2008, when the market went into a tailspin at a time when many financial markets were in turmoil, the United States was moving into a recession, and stock market prices plunged. Additionally, around this same time, the shale gas revolution entered its full swing in the United States. In the midst of these external forces, natural gas prices suddenly collapsed to a level well below the 25-year trend line.

Coal prices exhibit some of these same characteristics, trending upward over long periods of time but occasionally experiencing sharp movements above or below the long term trend line. Coal prices have also exhibited some short term volatility, although to a lesser degree than natural gas. This is reflected in the following Figure 2, which shows an average of publicly reported coal prices for each of the 25 years from 1990 through 2014:



**Figure 2. Publicly reported coal prices over the 25 year period from 1990 through 2014. Source: BP 1990-2013; EIA 1990-2014.**

In their March 2015 Filings, each of the Utilities assumed very low prices for natural gas over the 15-year time horizon used in developing avoided energy cost

estimates. Troublingly, each of the Utilities developed its fuel price forecasts by using a method that is different from that which it used in the 2014 IRP proceeding. This is in contrast to the 2012 biennial avoided cost proceeding in which the Utilities used the actual fuel forecasts that had been used in their IRP proceedings. Specifically, in the 2012 biennial proceeding, the Commission noted as follows:

With regard to the proposed avoided cost of energy, the Public Staff stated its determination that DEC, DEP, and DNCP all employed many of the same assumptions as to the operating characteristics of their generation units and the same or nearly the same projected cost of fuels, chiefly with respect to their natural gas and coal price forecasts, as used to support their 2012 Integrated Resource Plans (IRPs) filed on September 4, 2012, in Sub 137.<sup>3</sup>

In addition, the Commission should note the following two points. First, in support of its application for a certificate of public convenience and necessity (“CPCN”) to construct the 84 MW Sutton blackstart CT (“Sutton Blackstart CT Project”), which was filed on April 25, 2015 – subsequent to the March 2015 Filings – DEP relied on the same fuel price forecasting method used in the 2014 IRP.<sup>4</sup> Thus, DEP: 1) developed and relied on a fuel price forecast for its 2014 IRP; 2) developed a new forecasting method and a new forecast for the purposes of the March 2015 Filing, in which the forecasted natural gas prices are suppressed over the 15 year term, relative to the IRP forecast; and then 3) reverted back to the 2014 IRP method and forecast to support its April 2015 CPCN application for the Sutton Blackstart CT Project.

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<sup>3</sup> Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 136, February 21, 2014, p. 15 (emphasis added).

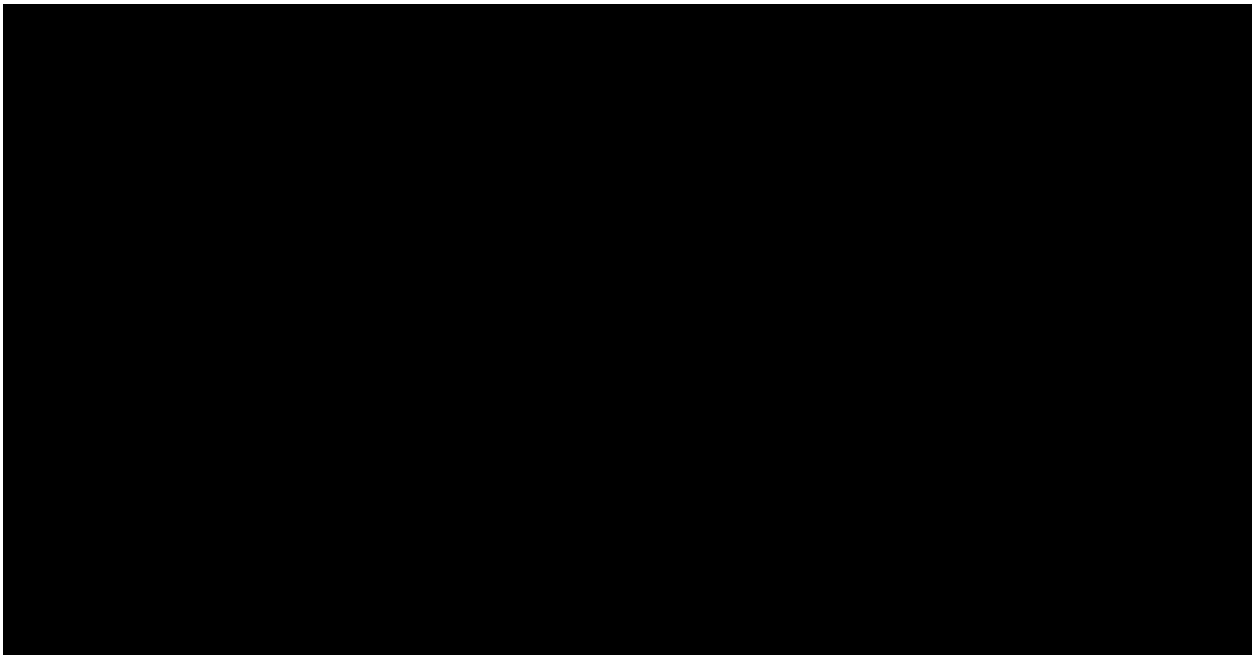
<sup>4</sup> See Direct Testimony of Glen A. Snider for Duke Energy Progress, N.C.U.C. Docket No. E-2, Sub 1066, April 25, 2015, p. 8, ll 6-12.

Second, in DEC's and DEP's Avoided Cost Informational Filing, filed in this docket on December 23, 2014 ("DEC/DEP Informational Filing") pursuant to their obligation under federal regulation, DEC and DEP used the same simulation run and input assumptions when calculating their avoided energy costs in that filing as had been used in their respective 2014 IRPs. All assumptions and input parameters are identical between those two filings. DEC and DEP confirmed this fact in response to a data request proposed by NCSEA.<sup>5</sup>

In this proceeding, the Commission must guard against the attempt by each of the Utilities to manipulate future fuel price estimates, as more fully explained below.

### 1. DNCP

DNCP's natural gas price inputs to its avoided energy cost calculation are shown in the following Figure 3: **BEGIN CONFIDENTIAL**



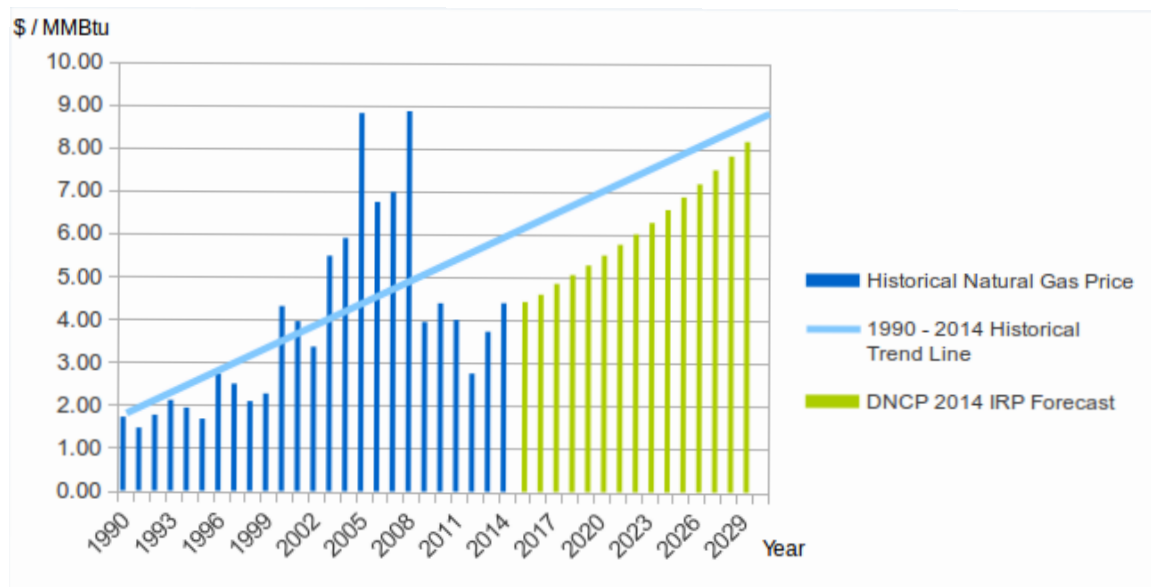
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<sup>5</sup>For ease of reference, responses to data requests which are cited in these Initial Comments have been assimilated into confidential Exhibit 1 hereto. Due to the sensitive, confidential information included in these responses, this exhibit is being filed confidentially. Each response within Exhibit 1 has a unique identification number, which is referenced in the footnote to guide you to the response. See DEP response to NCSEA Data Request ("NCSEADR") 4-1 and 4-2, Exhibit 1, 001-002.

## END CONFIDENTIAL

For its March 2015 Filing, DNCP's method of estimating natural gas prices was based on: 1) futures market data for the first four years; 2) a blend of these data and the fundamental commodity price forecast developed by ICF during the next three years; and 3) the ICF forecast for the remaining years.<sup>6</sup> The overall effect of DNCP's method is that the natural gas price inputs remain at very low levels during the first seven years of the 15-year horizon and never approach, much less reach, the long term historical trend line.

DNCP employed a different method in the 2014 IRP proceeding when estimating future natural gas prices. In the IRP proceeding, DNCP gave relatively little weight to futures market data, blending the market data with the ICF forecast during just three years (2015 – 2017) and relying entirely on the ICF forecast during all remaining years.<sup>7</sup> The following Figure 4 shows the natural gas prices used by DNCP in the 2014 IRP:



<sup>6</sup> DNCP response to Public Staff Data Request ("PSDR") 3-6, Exhibit 1, 003-004.

<sup>7</sup> Integrated Resource Plan of Dominion North Carolina Power, N.C.U.C. Docket No. E-100, Sub 141, August 29, 2014, Appendix 4A, p. AP-57.

**Figure 4. Natural gas prices used by DNCP in 2014 IRP. Source: Reuters 1990-1996; EIA 1997-2014; DNCP's Integrated Resource Plan, August 29, 2014, Appendix 4A, page AP-57.**

A comparison of Figure 3 and Figure 4 illustrates the significance of this difference in DNCP's methods.

## **2. DEC and DEP**

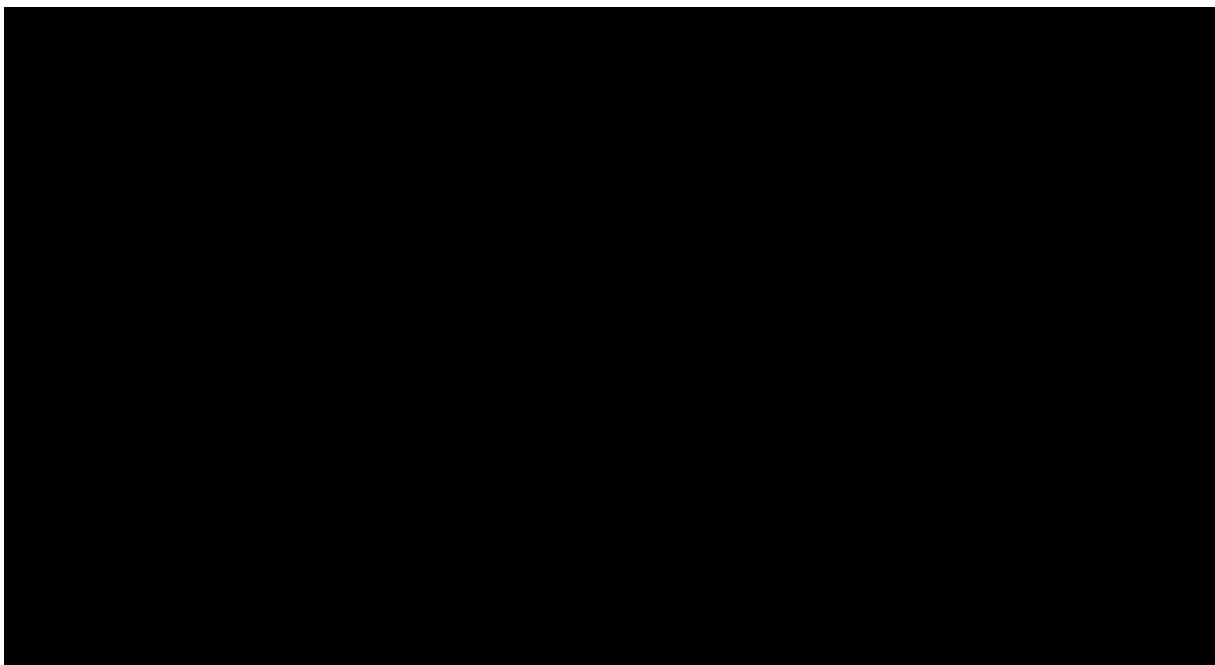
DEC and DEP employed a different method than DNCP for estimating natural gas prices, giving even greater emphasis to futures market prices throughout the **BEGIN CONFIDENTIAL [REDACTED] END CONFIDENTIAL** years of the 15-year time horizon. DEC/DEP's method effectively ignores the possibility that prices might be nearing the bottom of a cyclical downturn and might soon swing sharply higher to move back toward, or even above, the long term trend line. As well, the DEC/DEP method ignores the fact that futures market prices are at historically low levels, so there is currently more upside risk than downside risk – the probability that over the coming years prices are more likely to go up than go down. This is particularly troubling, in light of the fact that a DEC witness recently testified in another proceeding before the Commission that “there’s a much higher probability of an upswing in gas prices than downswing just because of where [futures market prices] are.”<sup>8</sup> Notwithstanding this evidence offered in DEC’s Fuel Rider Proceeding, DEC/DEP chose to ignore this probability when developing their estimates of future natural gas prices for the purposes of calculating its avoided energy costs in this proceeding.

As shown in the following Figure 5, which is specific to DEC, the DEC/DEP method emphasizes recent futures market data (as opposed to fundamental price

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<sup>8</sup>Application of Duke Energy Carolinas, LLC, Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities, N.C.U.C. Docket No. E-7, Sub 1051 (“Fuel Rider Proceeding”), Transcript of Testimony, June 3, 2014, pp 68-69.

forecasts) and, thus, assumes that prices will not approach the long term historical trend line until **BEGIN CONFIDENTIAL** [REDACTED]



**END CONFIDENTIAL**

Had DEC and DEP not given so much emphasis to futures market data, which are historically low, or if they had considered the possibility that prices are currently going through a cyclical swing and will eventually hit bottom and cycle back up to or beyond the long term trend line, their avoided energy cost estimates would have been higher.

As is the case with DNCP, DEC and DEP employed a different method in the 2014 IRP proceeding when estimating future natural gas prices. In the 2014 IRP proceeding, DEC and DEP used exclusively futures market data source during the first **BEGIN CONFIDENTIAL** [REDACTED]

[REDACTED] **END CONFIDENTIAL**<sup>9</sup> The effect of the different methods is striking, as illustrated by comparing Figure 5 with Figure 6 below, an analogous graph of data from the 2014 IRP proceeding: **BEGIN CONFIDENTIAL**

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<sup>9</sup> DEP response to NCSEADR4-1, Exhibit 1, 001.



**END CONFIDENTIAL**

### **3. Conclusion and Recommendation**

By changing methodologies from those used in their respective 2014 IRPs and placing much greater emphasis on futures market data, the Utilities developed substantially lower avoided energy cost estimates than if they had continued to use the same assumptions and methodology used in the 2014 IRPs. As previously stated, the estimated fuel prices are central to calculating the cost of avoided energy, so this change translates directly into substantially lower avoided cost estimates.

By emphasizing unusually low futures market prices, the Utilities have ignored the high probability of an upswing in gas prices, they have disregarded the possibility these spot prices may be a temporary aberration, and they have greatly increased the risk that the actual costs they will incur when producing electricity using their own generating units will be substantially higher than their avoided energy cost estimates. Succinctly stated, by abandoning the method used in the 2014 IRP proceeding and by ignoring the



possibility that fuel prices may soon revert to the long term trend line, the Utilities have reduced their avoided energy cost estimates to an unreasonably low level.

This change in method, and the resulting fuel price estimates, must be rejected by the Commission in order to achieve PURPA's objective of ratepayer indifference.<sup>10</sup>

Approval of the Utilities' fuel price estimates will discourage QF development and ratepayers will bear the risk and burden of paying for electricity generated by fossil fuels that cost far in excess of the prices estimated by the utilities in this proceeding. For this reason, NCSEA recommends that the Commission direct the Utilities to use the future fuel prices estimated for the purposes of their 2014 IRPs—and, for DEP, for the purpose of justifying the Sutton Blackstart CT Project—when calculating their avoided energy costs in this proceeding.

## **II. Non-Compliance with the Order Setting Parameters**

The Commission's Order Setting Parameters set forth specific parameters by which the electric utilities subject to the Commission's jurisdiction are to calculate their avoided costs. In calculating their avoided costs and the associated rates offered to QFs, DEC, DEP and DNCP have failed to comply with the Commission's Order Setting Parameters in the following instances.

### **A. Calculating Avoided Energy Costs**

#### **a. DEC and DEP use generation expansion plans that include carbon emissions control cost**

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<sup>10</sup> See 45 Fed. Reg. 12,214, 12,215 (February 25, 1980) ("Order No. 69") (providing explicitly that "electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting 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.")

As explained by Public Staff witness Hinton, the production costing models used to calculate avoided energy costs:

Dispatch[] the generating units in a least cost manner subject to various constraints, such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its Integrated Resource Plan (IRP).<sup>11</sup>

Thus, the resource expansion plan from the IRP, also referred to as the generation expansion plan, is involved in the calculation of avoided energy costs. In its Order Setting Parameters, the Commission limited the Utilities to using those generation expansion plans that take into account only known and quantifiable costs.<sup>12</sup> Although the subject of much debate in the evidentiary hearing, the Commission determined that the costs of carbon emissions control are not sufficiently known and verifiable at this time to be included in avoided cost calculations. The Commission concluded that "the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs."<sup>13</sup> Therefore, because costs of carbon emissions control are not sufficiently known and verifiable, IRP expansion plans that take into account costs of carbon emissions control may not be used in avoided energy cost calculations.

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<sup>11</sup> Hinton Testimony, p. 5, ll 4-10.

<sup>12</sup> Order Setting Parameters, Ordering Paragraph ("OP") 8.

<sup>13</sup> Order Setting Parameters, Finding of Fact ("FOF") 15.

In clear contravention of the Commission's order, DEC and DEP have used IRP expansion plans that take into account costs of carbon emissions control.<sup>14</sup> In response to a data request regarding how DEC's and DEP's proposed avoided rates would be affected by using an IRP generation plan that did not take into account costs of carbon emissions control (i.e., complying with the Commission's order), DEC and DEP responded that the "companies have not performed these calculations or additional substantial work."<sup>15</sup> As was discussed at length in the evidentiary hearing,<sup>16</sup> the inclusion of the cost of carbon emissions control is one of the primary reasons the least cost algorithms select new nuclear generation over alternative generation units. In turn, this expansion plan that includes nuclear generation allows the utility to assume that it can generate electricity using relatively little fuel, thereby suppressing avoided energy costs. In effect, the QF has the potential to be penalized by the cost of carbon in the avoided energy calculation, without being credited with the avoidance of such cost by the utility.

Much effort and analysis was devoted to the issue of whether the Utilities avoided cost calculations should reflect costs associated with the control of carbon emissions, as their IRPs do. Ultimately, the Commission determined to address the inconsistency by disallowing the use of expansion plans that include a carbon cost. DEC and DEP have not complied, and the inconsistency remains. The Commission must direct DEC and DEP to recalculate their avoided energy costs using the correct expansion plan.

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<sup>14</sup> DEP/DEC response to NCSEADR2-6, Exhibit 1, 005; DEC Response to PSDR6-3, Exhibit 1, 006-007; DEP Response to PSDR6-4, Exhibit 1, 008 (noting that "the expansion plan utilized for the [March 2015 Filing] is the same as the expansion plan developed in the base case of the 2014 IRP.").

<sup>15</sup> DEP/DEC response to NCSEADR2-6, Exhibit 1, 005.

<sup>16</sup> For a summary of the evidence presented on this issue, see Evidence and Conclusions for Findings of Fact No. 14-15, Order Setting Parameters, pp 42-44.

**b. The Utilities have not adequately allowed for fuel hedging benefits**

As the Commission found in its Order Setting Parameters, “renewable generation provides fuel price hedging benefits because a utility’s purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase.”<sup>17</sup> Noting that DEC and DEP have posited in separate proceedings that “a utility’s fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers[,]”<sup>18</sup> the Commission concluded:

[T]hat there are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation.<sup>19</sup>

In light of the foregoing, the Commission directed the Utilities “to calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates.”<sup>20</sup> NCSEA has concerns regarding the Utilities’ compliance with this directive for reasons set forth below.

**1. DNCP**

DNCP claims to have complied with the Commission’s directive by taking a “high-end estimate of \$3.2 million (based on 2012/13 cost data) for gas broker transaction costs and financing costs” and dividing that number by “the aggregate MWh amount of non-nuclear energy supply that could potentially be displaced by renewable

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<sup>17</sup> Order Setting Parameters, FOF 12.

<sup>18</sup> Order Setting Parameters, p. 42, fn 2.

<sup>19</sup> Order Setting Parameters, p. 42.

<sup>20</sup> Order Setting Parameters, OP 9.

generation.”<sup>21</sup> DNCP explains that “avoided hedging costs are shown for only 2015 because the Company’s financial hedges do not extend into 2016.”<sup>22</sup> However, DNCP’s approach does not accurately calculate and include the fuel hedging benefits as required by the Commission for several reasons.

First, DNCP’s approach involves a mismatch between the numerator and the denominator of the calculation. The numerator is limited to the portion of DNCP’s fuel costs which was hedged during 2012/13, whereas the denominator uses a much broader measure that includes energy that has not been hedged. No justification has been given for this inconsistency. It seems no more appropriate than calculating a price/earnings ratio by dividing a small firm’s stock price by a larger firm’s earnings.

Second, there is no reason to base the calculations on the extent to which DNCP has or has not been hedging against fuel volatility, except with respect to the appropriate hedging time horizon. The burden of volatility that is not being hedged within the relevant time horizon still imposes a cost on customers – a cost that can be avoided by acquiring electricity from a QF at a price that is fixed in advance. As testified by Public Staff witness Brown, “[i]f a utility chooses not to hedge its fuel costs, the financial benefit to the utility and its ratepayers of non-fuel-based generation like solar still corresponds to the net cost of the hedge.”<sup>23</sup> A valid analysis of hedging benefits must consider the full level of risk that can be avoided by customers over the appropriate time horizon not simply the portion of that risk against which the utility is actually hedging.

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<sup>21</sup>DNCP response to PS DR3-14, Exhibit 1, 009.

<sup>22</sup> Id.

<sup>23</sup> Transcript of Testimony Heard July 10, 2014, N.C.U.C. Docket No. E-100, Sub 140, Vol. 7, p. 344, ll 4-7.

## 2. DEC and DEP

With respect to the approach of DEC and DEP, DEC and DEP explain that they used 10 years of futures fuel price forecasts, based upon “ask” prices:

Hedging involves the agreement to purchase natural gas in the future at a price agreed upon in the present. Such prices are quoted as a “bid” price (the price for which a third party would purchase natural gas) and an “ask” price (the price for which a third party would sell it). For example, a quote expressed as a bid/ask might be bid at \$3.40 and ask at \$3.44. In such an instance, the transacting party would purchase gas for \$3.40 per MMBTU and sell gas for \$3.44 per MMBTU. Typically, when developing estimates of future gas prices, the mid-point between the bid and the ask is used as a reasonable estimate of future gas markets. In the example provided in this response, the mid-point would be the average of the \$3.40 (bid) and \$3.44 (ask) or \$3.42 per MMBTU. However, if the Company actually wanted to hedge the natural gas, it could possibly have to pay the full “ask” price (\$3.44) for the natural gas. As such, the Company accounted for this hedging cost by using the “ask” price, rather than the mid-point, from quotes obtained in the market.<sup>24</sup>

When asked to go beyond this hypothetical, DEC failed to provide documentation or any additional information concerning the actual prices paid for natural gas relative to “ask” prices. In response, DEC explained that “in order to isolate the actual hedge value the Company would have had to run a separate set of avoided cost model runs using the mid-point prices for gas as compared to the ask prices. This calculation would have resulted in using lower gas prices because the mid-point (or the average of the “bid” and the “ask”) is by definition lower than the ask price.”<sup>25</sup> Similarly, when asked to identify the allowance for hedging costs that was incorporated into its avoided energy cost estimates

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<sup>24</sup> DEC response to PSDR6-17, Exhibit 1, 010-011.

<sup>25</sup> DEC response to PSDR8-8, Exhibit 1, 012.

so that someone could remove the cost of hedging and replace it with a different estimate of the cost of hedging, DEC was unable to do so.<sup>26</sup>

Given the absence of any documentation containing actual (not just hypothetical) numbers, it is impossible to determine with any degree of certainty what allowance for avoided hedging costs has been provided by DEP and DEC. It is possible, however, to conclude that DEP/DEC's methodology is clearly and fatally flawed, since the spread between bid prices and ask prices associated with (up to) 10-year hedges cannot quantify the benefit of avoided future price volatility achieved via the use of ongoing 2-year hedges by DEP and DEC. As such, this methodology is inconsistent with the Commission's decision that hedging benefits should be valued using hedges "actually used by DEC, DEP and DNCP," which are currently 12 to 24 month hedges.<sup>27</sup>

### **3. Conclusion and Recommendation**

In sum, NCSEA has concerns regarding the extent to which an allowance for hedging has been provided in the Utilities' avoided energy calculations. Based on the explanations provided by the Utilities in response to data requests on this issue, NCSEA takes the positions that: i) the Utilities have not complied with the Commission's order; ii) they are substantially understating the benefits of hedging; iii) a different methodology must be used in order to provide a reasonable allowance for hedging consistent with the Order Setting Parameters; and iv) the allowance must be provided in each year of the contract term to reflect the fuel price hedging benefit year to year.

#### **B. Calculating Avoided Capacity Costs**

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<sup>26</sup> DEC response to NCSEADR4-1(d), Exhibit 1, 031-032.

<sup>27</sup> Order Setting Parameters, OP 13, p. 41.

When utilizing the peaker methodology, the calculation of avoided capacity cost relates largely to the installed cost of a natural gas fired combustion turbine (“CT”). The electric utility’s financial carrying cost for the CT, an estimate of fixed operating and maintenance costs, an adjustment for line losses, an estimate for working capital, and a performance adjustment factor are also used in calculating the avoided capacity cost.<sup>28</sup>

In its Order Setting Parameters, the Commission articulated as follows:

Because the focus of the peaker method is on a “hypothetical CT,” for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM’s cost of new entry studies or comparable data.<sup>29</sup>

To this end, the Commission identified a number of parameters to which the Utilities must adhere when calculating the cost of the “hypothetical CT”. As discussed below, the Utilities have failed to comply with several of those parameters.

**a. The Utilities have not used data from publicly available industry sources or have not justified adjustments to such sources when calculating the installed cost of a CT**

The Commission directed the Utilities, when applying the peaker methodology to calculate their avoided costs, to calculate the installed cost of a CT using “data from publicly available industry sources” and specified that the Utilities may adjust such data “only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.”<sup>30</sup> None of the Utilities complied with this directive.

**1. DNCP**

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<sup>28</sup> See Hinton Testimony, p. 8, ll 3-8.

<sup>29</sup> Order Setting Parameters, p. 48

<sup>30</sup> Order Setting Parameters, OP 6.



In calculating the installed cost of a CT, DNCP relied, primarily, on the report titled Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, prepared for PJM Interconnection, LLC, prepared by The Brattle Group and Sargent & Lundy, dated May 15, 2014 (the “Brattle Report”).<sup>31</sup> The Brattle Report is a publicly available industry source of the type contemplated by the Commission and provides a complete, robust estimate for the installed cost of a CT. Additionally, the Brattle Report provides a cost estimate that is geographically tailored for Dominion’s North Carolina and Virginia Service territories. In fact, the Brattle Report estimates that the installed cost of a CT in Dominion’s service area is \$977 per kW.<sup>32</sup>

Despite the fact that the Brattle Report provides an installed CT cost estimate that is geographically tailored for Dominion’s North Carolina and Virginia service territories, DNCP made more than a dozen different adjustments and modifications, each of which reduced DNCP’s cost per kW below the estimate provided in the Brattle Report.

The most significant of DNCP’s adjustments involves the equipment cost estimate for the combustion turbine. Notwithstanding the fact that the Brattle Report estimates the installed cost of a CT using the cost of GE 7FA model CT, which is representative of DNCP’s generating fleet, DNCP removed this cost from its estimate and instead relied on the 2013 Gas Turbine World Handbook (“GTW Handbook”) equipment cost estimate for the SGT6-5000F model CT manufactured by Siemens, which is significantly lower than the GE model CT.<sup>33</sup> This adjustment was made in spite of the fact that DNCP has not

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<sup>31</sup> DNCP March 2015 Filing, Section III, p. 3. The Brattle Report is attached hereto as Exhibit 2.

<sup>32</sup> Brattle Report, p. 26. This estimate, which includes AFUDC, is stated in 2018 dollars, and is equivalent to approximately \$900/kW in 2014 dollars.

<sup>33</sup> DNCP March 2015 Filing, Section III, p. 3.

installed any Siemens SGT6-5000F CTs or similar Siemens models and in spite of the fact that it does have GE model CTs in its generating fleet.<sup>34</sup> In its order, the Commission directed the Utilities to tailor cost estimates taken from publicly available industry sources only to the extent necessary to adapt such information to the Carolinas and Virginia. DNCP's tailoring of the Brattle Report estimate to include the cost associated with the Siemens SGT6-5000F CT does not comply with this directive. To the contrary, the adjustment moves away from a CT model that has been widely installed throughout Virginia and the Carolinas to a CT model that is not even used by DNCP.

In addition to adjusting the Brattle Report estimate for the Siemens CT, DNCP made other adjustments to the Brattle Report estimate, selectively relying on a critique of the Brattle Report developed by Pasteris Energy and Stantec Consulting Services, Inc. as well as its own internally developed cost estimates.<sup>35</sup> All told, DNCP made more than a dozen different adjustments to the \$977 per kW cost estimate provided in the Brattle Report, and each of these adjustments went in the same direction – cumulatively serving to reduce the cost estimate to \$485 per kW.<sup>36</sup>

## **2. DEC and DEP**

DEP and DEC relied primarily on the Electric Power Research Institute ("EPRI") Technical Assistance Guide ("TAG") Version 3.1 Database – 2014 to calculate their

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<sup>34</sup> See DNCP Response to PSDR4-7, Exhibit 1, 013 (noting that "the Company has not installed any Siemens SGT6-5000F combustion turbines ('CTs') or similar Siemens models"); DNCP Response to PSDR4-8, Exhibit 1, 014.

<sup>35</sup> DNCP March 2015 Filing, Section III, pp 3-5.

<sup>36</sup> DNCP March 2015 Filing, Section III, p. 4, 5, Figure 1.

respective avoided capacity costs.<sup>37</sup> The reliance of DEC and DEP on the EPRI TAG data is concerning for several reasons.

Even though the EPRI TAG is arguably an “industry source,” it is not developed for general public distribution. In fact, the TAG is “available at no cost to funding members only,” and while non-members have the option of purchasing the information, the asking price of \$75,000 or more precludes this from being a practical option.<sup>38</sup> Furthermore, the specific data relied upon by DEC and DEP was marked “CONFIDENTIAL” in their March 2015 Filings, which fundamentally contradicts the notion that this information be “publicly available.” Under the circumstances, the EPRI TAG does not appear to qualify as a “publicly available industry source.”

In addition, the TAG does not provide a complete installed cost estimate of a CT, rather it provides only some of the components of the installed cost. For this reason, DEC and DEP contracted with engineering firm Burns & McDonnell (“B&M”) to obtain “generic unit cost estimates” so that they could add “costs for evaporative coolers and dual fuel capability to the EPRI project cost” as well as for “transmission interconnection costs, gas supply interconnection costs and the addition of a gas metering and regulation (M&R) station.”<sup>39</sup> The B&M data were clearly not obtained from a “publicly available industry source,” further casting doubt on the appropriateness of the data sources relied on by DEC and DEP. As well, it is worth noting that combining cost estimates from two

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<sup>37</sup> DEP March 2015 Filing, paragraph 10; DEC March 2015 Filing, paragraph 10; DEC response to PSDR7-3, Exhibit 1, 015-018.

<sup>38</sup> See EPRI TAG website at: <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=00000000001021810> and <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002001434>.

<sup>39</sup> DEC response to PSDR7-3, Exhibit 1, 015-018.

different sources is not preferable, since this creates the potential for inconsistencies, double counting of items, omission of items, or the overstatement or understatement of costs due to differences in estimating methods or sources.

In fact, DEC and DEP have cherry picked numbers from these two sources in one important, illustrative instance, related to the average capacity of the CT unit used in the cost estimate. The EPRI TAG data assume an average capacity of **BEGIN CONFIDENTIAL [REDACTED] END CONFIDENTIAL**<sup>40</sup> Rather than using the EPRI data, DEC and DEP made an adjustment to increase this capacity to **BEGIN CONFIDENTIAL [REDACTED] END CONFIDENTIAL**<sup>41</sup> This adjustment was explained as follows:

The GE 7FA.05 capacity ratings were based on 2015 B&M data since the newer capacity rating information was available at the time the avoided capacity cost estimates were developed.<sup>42</sup>

In other words, DEC and DEP substituted a different capacity rating simply because it was available in early 2015, when the avoided capacity cost calculations were completed. However, this substitution introduces an inconsistency with the remainder of the capacity cost calculations, all of which were based upon data from late 2013 and early 2014.<sup>43</sup>

This picking and choosing of data points directly contravenes the Commission's order to use "data on the installed cost of CT per kW" tailoring only as "clearly

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<sup>40</sup> Id.

<sup>41</sup> Id.

<sup>42</sup> Id.

<sup>43</sup> The EPRI study was performed in the Fall of 2013 and published in the Spring of 2014, and DEC and DEP's adjustments to the EPRI data were based upon the 2014 B&M dataset, which was completed in the Spring of 2014. DEC response to PSDR7-5, Exhibit 1, 019.

needed[.]”<sup>44</sup> However, even if this type of adjustment to use a larger MW capacity were not precluded by the Commission’s order, the adjustment must be rejected because it has the potential to distort the calculations and introduce errors. For example, the installation of a larger generating unit might trigger the need for larger, more costly gas or electrical interconnection facilities than the ones that were assumed in the 2014 B&M data.

### 3. Conclusion and Recommendation

The Commission made clear in its Order Setting Parameters that the Utilities are authorized to tailor the cost estimates provided in publicly available industry sources, but the Commission was also clear that any such tailoring must be “clearly needed” to adapt the information provided in the publicly available industry sources to the Carolinas and Virginia. Thus, the Commission did not provide the Utilities with unfettered discretion to assemble their own cost estimates using bits and pieces of information taken from various different sources. Indeed, this sort of unfettered discretion would defeat the purpose of requiring use of a cost estimate from a publicly available industry source. In addition, it would create the opportunity to skew the cost estimate by cherry picking numbers from different sources or by selectively making adjustments that go in one direction, while ignoring offsetting adjustments that go in the opposite direction.

The Commission must reject the Utilities’ cost estimates for a hypothetical CT because they are unreasonably low, due to the use of downward adjustments that are inconsistent with the Order Setting Parameters. At a minimum, the Commission must reject DNCP’s substitution of a Siemen’s CT for the one included in the Brattle Report, and DEC’s and DEP’s substitution of the B&M estimate of total megawatts of generating capacity for the one included in the EPRI TAG.

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<sup>44</sup> Order Setting Parameters, p. 48.

**b. The Utilities include both economies of scale and scope when calculating installed cost of a CT**

The Commission provided that the Utilities, when calculating the installed cost of a CT, may include economies of scale for up to four CTs constructed on the same site, however the Commission specified that the Utilities “shall not include any economies of scope associated with the construction of more than one CT at the same time.”<sup>45</sup> None of the Utilities complied with this directive.

In addition, while the Commission allowed the utilities to consider the potential savings associated with economies of scale, it specified that “to the extent a utility applies economies of scale related to the installed cost of multiple CTs at a single location, the utility should provide detail as to the economies being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied.”<sup>46</sup>

**1. DNCP**

In calculating the installed cost of the CT, DNCP indicates that it adjusted the cost for economies of scale.<sup>47</sup> As has been previously stated, DNCP primarily relied upon the Brattle Report in calculating installed cost of the CT. The Brattle Report assumed “two turbines at one site (a “2x0”) to capture savings from economies of scale.”<sup>48</sup> Since both turbines were assumed to be constructed at the same time, the cost estimates in the Brattle Study also include cost savings from economies of scope. Despite making numerous

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<sup>45</sup> Order Setting Parameters, OP 7.

<sup>46</sup> Order Setting Parameters, p. 48.

<sup>47</sup> DNCP March 2015 Filing, Section III, p. 4.

<sup>48</sup> Brattle Report, p. 8.

other adjustments to the data included in the Brattle Report, DNCP did not propose any adjustments to the data to remove the impact of these economies of scope.

Moreover, DNCP adjusted the data significantly to reflect additional economies of scale (corresponding to a 4-unit site rather than a 2-unit site) in two categories: electrical interconnection and gas interconnection.<sup>49</sup> In making this adjustment, DNCP essentially cut the cost estimate for each of those categories in half, effectively assuming economies of scale are commensurate or one-to-one. DNCP has not offered any evidence to support this extreme assumption, which would not be reasonable even if all four units were being constructed at the same time and is even more obviously invalid in a context where additional equipment is being installed at a later time.

## **2. DEC/DEP**

Although DEC and DEP recognized the distinction between economies of scale and scope that was drawn by the Commission, they had difficulty complying with the corresponding requirements of the Commission's order. DEC explained that it was "difficult to differentiate precisely between economies of scale and economies of scope from public data sources as such data is not typically separated in that manner."<sup>50</sup> For instance, the EPRI TAG, the primary industry source relied by DEC and DEP does not distinguish between economies of scale and scope, but instead reports cost data that reflects the combined impact of both economies of scale and scope for projects of various sizes. As explained by DEC, "EPRI provides cost per kW data for a 4-Unit Site, 3-Unit Site, 2-Unit Site, and a 1-Unit Site. Thus, the cost to construct four units could be based

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<sup>49</sup> DNCP Response to NCSEADR1-2(e), Exhibit 1, 035.

<sup>50</sup> DEC response to PSDR7-3, Exhibit 1, 015-018.

on 1 x 4-unit site, 2 x 2-unit sites, 4 x 1-unit sites, etc.”<sup>51</sup> DEC and DEP used the B&M data, discussed above, to adjust the EPRI TAG cost estimate. NCSEA’s expert’s analysis revealed that the supplemental B&M data source had a similar limitation to the EPRI TAG data – providing information about economies of scale and scope on a composite basis, assuming simultaneous construction.<sup>52</sup>

DEC explains, persuasively, that it did not use the EPRI TAG data for the 4-unit site because “[u]se of the 1 x 4-unit site data would recognize total economies of scale and scope for building four units at the same site at the same time. Thus, use of this data would violate the Commission’s order.”<sup>53</sup>

However, DEC’s calculation assumes the construction of four units at two sites, relying on the EPRI 2 x 2-unit site data, for which it provides the following explanation:

[T]he Company utilized the EPRI 2 x 2-unit site \$/kW cost data as a proxy for incorporating economies of scale associated with constructing four CTs at a site, recognizing economies associated with the Company’s purchase of at least two CTs at a time that could be placed at various locations within its six regulated utilities’ service territories, while excluding economies associated with constructing multiple units simultaneously at the same site.<sup>54</sup>

The underlying premise seems to be that the economies of scope that are included in the data for a 2-unit site will be roughly equivalent to the additional economies of scale that could be achieved by eventually constructing two additional units at each of these two

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<sup>51</sup> Id.

<sup>52</sup> DEC response to PSDR7-3, Exhibit 1, 015-018; Attachment Rev1 CT Capital Cost\_PDSD\_CONFIDENTIAL.xlsx at Tab “B&M 2014”. Compare the magnitude of B67 to C67; also, note the cost of 4 units built simultaneously, shown in E67, exactly equals B67 plus 3 times C67.

<sup>53</sup> DEC response to PSDR7-3, Exhibit 1, 015-018.

<sup>54</sup> Id.



locations. However, there is no a priori reason to assume that economies of scale and scope are of equivalent magnitude.

DEC's explanation for why it did not focus on data for a 1-unit site is less persuasive. It explained that the "use of the 4 x 1-unit site data would recognize no economies related to scale or scope and thus would also violate the Commission's order to recognize economies of scale."<sup>55</sup> This reasoning is implicitly based on the premise the utilities are required to include economies of scale for a 4-unit site, when, in fact, the Commission deemed appropriate economies of scale for up to four units. In any event, DEC and DEP could have started with the EPRI 4 x 1-unit site data and adjusted the data, but only as clearly needed, to reflect the estimated impact of economies of scale within the categories for which DEC and DEP assert that such economies are realized: "the cost of land, site preparation work, roads, buildings and structures, as well as general plant facilities."<sup>56</sup>

For example, the B&M data indicates the land required for a single unit will cost **BEGIN CONFIDENTIAL [REDACTED] END CONFIDENTIAL**, while the land needed for 4 units will cost **BEGIN CONFIDENTIAL [REDACTED] END CONFIDENTIAL**.<sup>57</sup> The maximum potential cost savings in this category would therefore be the difference between the **BEGIN CONFIDENTIAL [REDACTED]**  
**[REDACTED] END CONFIDENTIAL** if all four units are simultaneously built on a single large parcel of land. In reality, the maximum

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<sup>55</sup> Id.

<sup>56</sup> Id.

<sup>57</sup> DEC response to PSDR7-3, Exhibit 1, 015-018; Attachment Rev1 CT Capital Cost\_PDSD\_CONFIDENTIAL.xlsx at Tab "B&M 2014" at Cell B70 and Cell E70.

potential savings from economies of scale (excluding economies of scope) is somewhat less than **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL** because of the impact of additional carrying costs (capital costs and property taxes) that would be incurred to acquire a larger parcel of land prior to the time when the additional units will be constructed.

Rather than starting with the 2-unit data or the 4-unit data, as this example illustrates, DEC and DEP could have started with the EPRI and B&M 1-unit data and adjusted those cost estimates downward to reflect the estimated impact of economies of scale within the categories for which DEC and DEP assert that such economies are realized – the cost of land, site preparation work, roads, buildings and structures, as well as general plant facilities. In other words, starting with the 1-unit data, appropriate downward adjustments for economies of scale could have been developed (net of the additional carrying costs required to achieve those economies) for each cost category, while taking care to exclude any benefits from economies of scope – precisely as required in the Order Setting Parameters. DEC and DEP inexplicably failed to do this.

### **3. Conclusion and Recommendation**

In sum, all three utilities failed to exclude economies of scope from their capacity cost estimates, as required by the Commission. The data sources selected by the Utilities assume multiple units are constructed at the same time in the same location, and the Utilities have not adequately compensated for this aspect of their source data, as they should have done, in order to comply with the Commission's order. Thus, NCSEA recommends that the Commission direct the Utilities to recalculate their avoided capacity costs ensuring that all economies of scope are excluded.

**c. The Utilities use contingency factors that do not reflect a hypothetical plant in the early planning stages**

In its Order Setting Parameters, the Commission directed the Utilities to include “a reasonable contingency adder for a hypothetical plant in relatively early stages of planning” in the calculation.<sup>58</sup> A contingency factor covers unforeseen costs that are likely to arise during construction. As explained in the Brattle Report, in the context of engineering, procurement and construction costs (“EPC”), “contingency covers undefined variables in both scope definition and pricing that are encountered during project implementation.”<sup>59</sup> In the context of owner’s costs, the Brattle Report explains that “contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, etc.”<sup>60</sup> The Brattle Report assumes an EPC contingency of 10% and an owner’s contingency of 9%.<sup>61</sup>

Black & Veatch, an international Engineering, Construction Management and Design-Build firm, has explained that:

There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both

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<sup>58</sup> Order Setting Parameters, OP 7.

<sup>59</sup> Brattle Report, p. 18.

<sup>60</sup> Brattle Report, p. 23.

<sup>61</sup> Brattle Report, p. 18, 23.

items not estimated and errors in the estimate as well as variability dealing with site-specific differences.<sup>62</sup>

Finally, in providing a cost estimate for a natural gas fired CT, the Energy Information Administration (“EIA”) includes a 10% contingency on EPC costs, as well as an additional 20% allowance for owner’s costs and contingency, excluding financing.<sup>63</sup>

The reasonableness of a particular contingency factor varies, depending upon the specific context in which the factor will be used. A 5% to 10% contingency factor might be adequate for internal purposes at the late stages of the planning process, after completion of the final site selection process, after site-specific design documents have been prepared and once the final bid documents are about to be issued. But that same 5% to 10% contingency factor would not be adequate, even for internal purposes, during the earlier stages of the planning process. In the context of this proceeding, where the goal is to compensate for the risks borne by ratepayers throughout the entire planning, design and construction process, a higher contingency is necessary, consistent with the Commission’s directive that the contingency factor reflect “a hypothetical plant in relatively early stages of planning.”

### **1. DNCP**

DNCP’s avoided cost calculation included a 10% contingency factor applied to owner-furnished equipment and engineering, procurement and construction (“EPC”)

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<sup>62</sup> Cost Report: Cost and Performance Data for Power Generation Technologies, prepared by Black & Veatch, prepared for National Renewable Energy Laboratory, February 2012, p.8, available at: <http://bv.com/docs/reports-studies/nrel-cost-report.pdf>. This report is attached hereto as Exhibit 3.

<sup>63</sup> Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, prepared by United States Energy Information Administration, April 2013, Sections 8 and 9, available at: <http://www.eia.gov/forecasts/capitalcost/>. This report is attached hereto as Exhibit 4.

costs and a 9% “owner’s contingency” applied to non-EPC costs, excluding financing fees.<sup>64</sup> While DNCP’s contingency factor is more reasonable than that which has been used by DEC and DEP, it still falls short of the Commission’s directive. Consistent with the industry sources discussed above, a contingency factor of at least 15-20% should be used. As discussed above in Section II.B.a., for the purpose of calculating the installed cost of a CT, DNCP used Siemens SGT6-5000F turbines, instead of the GE 7FA turbines that are used in the Brattle Report and that are representative of DNCP’s current generating fleet.<sup>65</sup> If the Commission approves DNCP’s use of the Siemens turbine, given that DNCP has no experience with this model of turbine, an even higher contingency factor—30%, which is the high end of the industry sources—would appropriately reflect this lack of experience and the corresponding lack of ability to forecast construction and other risks with accuracy.

## 2. DEC/DEP

DEC and DEP took the **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL** contingency factor provided in the EPRI TAG and slashed it **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL**<sup>66</sup> In the 2012 biennial proceeding, DEC and DEP proposed the same contingency factor as they propose in this proceeding. With respect to the 2012 proposal, Public Staff witness Hinton testified that in his view:

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<sup>64</sup> DNCP March 2015 Filing, Section III, p. 5.

<sup>65</sup> See DNCP Response to PSDR4-7 (noting that “the Company has not installed any Siemens SGT6-5000F combustion turbines (‘CTs’) or similar Siemens models”), Exhibit 1, 013; DNCP Response to PSDR4-8, Exhibit 1, 014.

<sup>66</sup> DEC Response to PSDR7-3, Exhibit 1 015-018; CT Capital Cost\_PDSD\_CONFIDENTIAL.xls.

[S]uch a contingency factor is more appropriate for a project fairly far down the road in terms of development. It is not appropriate for the calculation of the costs of a hypothetical plant for purposes of the peaker methodology.<sup>67</sup>

During the evidentiary hearing, DEC and DEP witness Snider testified that the equipment and construction costs estimated for the CT should represent an expected construction cost with neither a best case nor worst case contingency adder included. Snider specifically testified that a 5% contingency adder results in a reasonable expected construction cost.<sup>68</sup> Instead of specifically accepting Snider's recommendation, the Commission instead directed the Utilities to include a contingency factor that is consistent with a "hypothetical plant in relatively early stages of planning." As it did in its Order Setting Parameters, the Commission should again reject the DEP/DEC position as it is not consistent with a hypothetical plant in the early stages of planning. A contingency factor of 15% to 20% would be appropriate, consistent with the industry sources discussed above.

### **3. Conclusion and Recommendation**

Although the contingency factors proposed by the Utilities might be appropriate for internal purposes at the end of the planning process, or as Public Staff witness Hinton previously put it – a project fairly far down the road in terms of development – they are not sufficient to compensate ratepayers for the risks associated with planning and constructing a hypothetical CTs. Because an understated contingency factor understates an electric utility's avoided cost, it has the potential to discourage QF development and, therefore, fail to meet PURPA's objective of ratepayer indifference. To ensure that

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<sup>67</sup>Hinton Testimony, p. 24, ll 17-21.

<sup>68</sup> See Order Setting Parameters, p. 45.

ratepayers are indifferent between power obtained from a QF at contractually fixed prices and power obtained from the utility under conditions similar to a “cost plus” contract where the risks and uncertainties are borne by ratepayers, the Commission must direct the Utilities to include a contingency factor consistent with the industry sources discussed in this section—15% to 20%, or 30% if the Commission approves DNCP’s use of the Siemens CT.

**d. The Utilities’ useful life assumptions are unreasonable**

In its Order Setting Parameters, the Commission specified that “a reasonable estimate of useful life of a CT” should be used “in the calculation of the installed cost of a CT” to “be included in the calculation of avoided capacity costs.”<sup>69</sup> As has been previously explained by the Public Staff:

The second most influential assumption [in the avoided capacity cost calculation] is the carrying cost rate for the CT. The carrying cost calculation can be rather complex; however, it generally involves the application of factors such as the cost of capital, property and income tax rates, deferred taxes, insurance rates, and the projected inflation rate over the life of the CT. The carrying cost rate includes the cost of depreciation, which is dependent on the assumed useful life of the CT.<sup>70</sup>

Therefore, the assumed useful life influences the avoided capacity cost; the longer the assumed useful life, the lower the carrying cost and, therefore, the avoided capacity cost.

The industry sources used by the Utilities for the installed cost of the CT include information about the useful economic life of a newly constructed CT. The EPRI TAG

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<sup>69</sup> Order Setting Parameters, FOF 19, OP 7.

<sup>70</sup> Hinton Testimony, p. 8, ll 10-17.

assumes a useful life of **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL**<sup>71</sup>

The Brattle Report assumes a 20 year useful life.<sup>72</sup> However, the Utilities assumed longer useful lives in their avoided capacity cost calculations, which has the effect of reducing their avoided capacity cost estimates.

## 1. DNCP

DNCP assumed a **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL** useful life.<sup>73</sup> DNCP relied on the Brattle Report in calculating its avoided capacity cost.<sup>74</sup> As stated above, the Brattle Report assumes a 20 year useful life.

## 2. DEC/DEP

DEC and DEP assumed a **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL** useful life.<sup>75</sup> DEP and DEC relied on the EPRI TAG in calculating avoided capacity cost,<sup>76</sup> and, as stated above, the EPRI TAG assumes a useful life of **BEGIN CONFIDENTIAL** [REDACTED] **END CONFIDENTIAL** years. Prior to the 2012 biennial avoided cost proceeding,<sup>77</sup> DEC had assumed a **BEGIN CONFIDENTIAL** [REDACTED] **END**

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<sup>71</sup> DEC response to PSDR7-3, Exhibit 1, 015-018; Rev1 CT Capital Cost\_PDSD\_CONFIDENTIAL.xlsx at Tab “EPRI Tag” at Cells C14, D14, E14 and F14.

<sup>72</sup> Brattle Report, p. 39.

<sup>73</sup> DNCP response to NCSEADR1-2, Exhibit 1, 036.

<sup>74</sup> DNCP March 2015 Filing, Section III, p. 3.

<sup>75</sup> DEC response to PSDR7-1, Exhibit 1, 020-022; NCPS\_DEC\_DR\_7-1\_FCR\_Confidential.xlsx Tab “CTDual Fuel & Evap 7FA” at Cell G16; DEP response to PSDR7-1; DEP\_7-1 Fixed Charge Rate.xlsx Tab “CTDual Fuel & Evap 7FA” at Cell G16.

<sup>76</sup> DEP March 2015 Filing, paragraph 10; DEC March 2015 Filing, paragraph 10.

<sup>77</sup> NCSEA notes that DEC and DEP entered into a settlement agreement that addressed their respective avoided capacity costs as a single cost – the installed combustion turbine cost per kW – and specifically did not address any of the various components of that cost. See Public Version of Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress and the Public Staff, N.C.U.C. Docket No. E-100, Sub 136, October 29, 2013 (“2012 Settlement”), paragraph 1.



**CONFIDENTIAL** year useful life.<sup>78</sup> Prior to the 2012 biennial avoided cost proceeding, DEP had assumed a useful life of **BEGIN CONFIDENTIAL** ■ **END CONFIDENTIAL** years for the purpose of calculating its avoided costs.<sup>79</sup>

### 3. Conclusion and Recommendation

No explanation or justification was provided by the Utilities for assuming longer lives in this proceeding than the industry sources on which they relied. Given the Commission's directive to the Utilities to develop cost estimates for hypothetical CTs based on publicly available industry resources, NCSEA recommends that the Commission direct each electric utility to assume the useful life set forth in the industry publication on which that electric utility relied: 1) DNCP – 20 years; and 2) DEC and DEP – **BEGIN CONFIDENTIAL** ■ **END CONFIDENTIAL** years.

#### C. Calculating Rates

##### a. DEC and DEP have modified inappropriately the weighting given to summer and non-summer months in calculating their rates in this proceeding

In the 2012 biennial avoided cost proceeding, the Commission directed the Utilities to include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC at that time, in light of the settlement entered into

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<sup>78</sup>**BEGIN CONFIDENTIAL** ■

**END CONFIDENTIAL** Exhibit 1, 023.

<sup>79</sup> See **CONFIDENTIAL** - Initial Statement of the Public Staff in the Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities for 2012, N.C.U.C. Docket No. E-100, Sub 136, February 7, 2013, p. 7.

between DEC, DEP and the Public Staff.<sup>80</sup> With respect to DEP, the Commission found as follows:

Subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of DEP's current review of its time-of-use rates, DEP should meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden should be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.<sup>81</sup>

In the evidentiary portion of the instant proceeding, after considerable discussion and presentation of evidence by all parties on the issue of adjusting the hours offered under Option B to better reflect the Utilities' needs, the Commission declined the parties' various requests to modify Option B, ultimately concluding that DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with the avoided capacity rates 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.<sup>82</sup>

Both DEP and DEC have proposed changes to seasonal weighting of the capacity rates. While this proposal was not specifically presented in the evidentiary portion of the instant proceeding, it is closely related to the issues that were presented relating to the modification of Option B. In addition, upon information and belief, DEP did not meet

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<sup>80</sup> Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 136, February 21, 2014 (2012 Order), OP 8-10.

<sup>81</sup> 2012 Order, FOF 11.

<sup>82</sup> Order Setting Parameters, pp 53-54.

with the Public Staff to discuss these changes prior to proposing them, and the fact that DEP's Time of Use Rate Study was not filed until May 28, 2015 supports this position.<sup>83</sup> To the extent the Commission is willing to consider modifications to hours and seasonal weighting, consideration should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner to better tailor rates, and therefore induce QF generation, to the Utilities' needs.

### **III. Inappropriate Revisions to Contract Terms**

#### **A. DNCP's Proposed Revisions**

To QFs eligible for the Commission-approved rates and contract terms, DNCP offers an Agreement for the Sale of Electrical Output to Virginia Electric and Power Company (the "DNCP Standard Contract"). Exhibit B to the DNCP Standard Contract, which is titled General Terms and Conditions ("DNCP's Terms and Conditions"), as well as DNCP's rate schedule offered to QFs, Schedule 19, include general terms and conditions. DNCP's proposed revisions to the DNCP Standard Contract, including those proposed to DNCP's Terms and Conditions and Schedule 19, are discussed below in detail.<sup>84</sup>

##### **a. Limitations on assignment rights**

DNCP's Terms and Conditions provide that a QF may assign its rights under the DNCP Standard Contract only with the prior written consent of DNCP. DNCP "may withhold such consent if it determines, in its sole discretion, that such assignment would

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<sup>83</sup> Duke Energy Progress Time of Use Study, N.C.U.C. Docket No. E-2, Sub 1023, May 28, 2015.

<sup>84</sup> See DNCP March 2015 Filing, Section V, Exhibit DNCP-8, showing DNCP's proposed changes to its currently approved Schedule 19-FP DNCP Standard Contract, and Exhibit DNCP-10, showing DNCP's proposed changes to its currently approved Schedule 19-LMP DNCP Standard Contract.

not be in the best interests of [DNCP] or its customers.”<sup>85</sup> Providing DNCP with “sole discretion” to reject an assignment for any reason is commercially unreasonable and problematic for NCSEA’s business members. The ability to assign a contract under reasonable conditions is essential to the commercial viability of renewable generation projects and, therefore, is necessary to encourage QF development. NCSEA submits that Section I of DNCP’s Terms and Conditions should be amended to require that DNCP not unreasonably withhold consent to proposed assignment.

DNCP proposes to increase the maximum fee for an assignment from the currently-authorized \$10,000 to \$12,000.<sup>86</sup> There is no basis for this increase. In response to a data request propounded by NCSEA, DNCP maintains that the 20% 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 NC 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.”<sup>87</sup> First, DNCP acknowledges that the increase in the number of projects since 2012 has not actually resulted in an increase in the number or complexity assignments. Second, an increase in the number of assignments does not justify an increase in the per-assignment fee that may be charged. Moreover, DNCP reports that there has only been one event of an assessment under this provision of DNCP’s 2012 Schedule 19, for which fees amounted to only \$750.<sup>88</sup>

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<sup>85</sup> DNCP March 2015 Filing, Exhibit DNCP-8 and Exhibit DNCP-10, Exhibit B, Section I.

<sup>86</sup> Id.

<sup>87</sup> DNCP response to NCSEADR3-9, Exhibit 1, 024.

<sup>88</sup> Id.

**b. Inclusion of overreaching termination right for failure to commence construction**

Article 7(a)(i) of DNCP's Standard Contract gives DNCP the right to terminate—with no opportunity to cure—if a QF does not commence construction by a date certain. Although DNCP's Standard Contract does not specify what this date is based on, DNCP has stated in (in response to data requests from NCSEA) that “[t]he date is based on the expected construction schedule for the Facility after consultation between Company and the Operator.”<sup>89</sup> While not entirely clear, DNCP's response suggests that the date will be negotiated between the utility and QF. One of the primary purposes of a standard contract is to avoid the negotiation process. This is especially important with regard to a term such as this one, where failure to achieve the date could result in termination of the agreement. Furthermore, to the extent a QF's financing, and therefore ability to commence construction, is dependent on the receipt of an interconnection agreement, the QF's ability to commence construction as of a date certain is not entirely within its control. Accordingly, the Commission should direct DNCP to revise the contract to make clear that the QF specifies the date and has a 30-day opportunity to cure.

**c. Use of unclear terminology**

The terms “net capacity” and “net electrical capacity” are used throughout the DNCP's Standard Contract and rate schedules and are not defined in any of the various documents. According to DNCP's response to a data request propounded by NCSEA,

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<sup>89</sup> DNCP response to NCSEADR3-6, Exhibit 1, 025.

DNCP intends that these terms mean the same thing.<sup>90</sup> In the interest of clarity, the Commission should direct DNCP to use the same term throughout and define the term.

**d. Increase of availability limitation to one mile**

DNCP proposes that the Commission-approved rates and contract terms not be available to a QF owned by a developer or affiliate who sells or will sell power to DNCP from another QF located within one mile unless the combined capacity is equal to or less than five (5) megawatts.<sup>91</sup> DNCP has provided no justification for this increase. As discussed below, DEC's rate schedule has historically included an analogous limitation, but with the distance of one-half mile. In this proceeding, DEP proposes to include the eligibility provision, but using one-half mile, consistent with DEC. DEP also proposes to qualify this limitation with the provision that QFs under the same or affiliated ownership that are located within one-half mile of each other are eligible for the standard offer, so long as the combined capacity of the two facilities does not exceed five (5) megawatts. NCSEA does not oppose DEP's proposal. In the interest of fairness, consistency and ease of administration, NCSEA recommends that the Commission approve DEP's one-half mile proposal and limit DNCP to one-half mile, while maintaining the qualification that two QFs under the same or affiliated ownership are eligible for the standard offer so long as the combined capacity of those facilities does not exceed five (5) megawatts.

**e. Elimination of site-specific line loss allowance**

Line loss was an issue of significant discussion the first phase of this proceeding, and, ultimately, the Commission concluded that:

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<sup>90</sup> DNCP Response to NCSEADR3-5, Exhibit 1, 026.

<sup>91</sup> DNCP Schedule 19, Section I.

[I]t is appropriate for the utilities to continue to apply their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.<sup>92</sup>

In this proceeding, DNCP proposes to continue using a 3% line loss allowance for all QF projects but also proposes to eliminate the QF's option to request a site-specific line loss allowance that is based on a study conducted at the QF's cost.

DNCP's 3% line loss allowance is not based on any recently-conducted line loss study, but is merely consistent with past practice, previously approved by the Commission.<sup>93</sup> However, "past practice" also incorporated the ability to seek a site-specific allowance in situations where the 3% allowance would be insufficient. Eliminating this option would be inequitable to QFs whose avoided line losses exceed 3% and would result in their rates reflecting less than DNCP's full avoided cost. DNCP has offered no justification for eliminating this option and would suffer no prejudice from retaining it (the existing provision requires the QF to bear the cost of the line loss study). Therefore, NCSEA recommends that the Commission reject this proposal.

**f. Elimination of opportunities to cure and increased termination rights**

DNCP proposes several revisions to Schedule 19 related to DNCP's right to terminate based on events of default by the QF. Specifically, DNCP clarifies which defaults by the QF are subject to the QF's opportunity to cure and which defaults give DNCP the right to terminate without any opportunity to cure. NCSEA generally supports additional clarity regarding QFs' obligations and the consequences of failing to fulfill them. However, NCSEA objects to the inclusion of certain events of default in Article

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<sup>92</sup> Order Setting Parameters, p. 61.

<sup>93</sup> DNCP response to NCSEADR3-3, Exhibit 1, 033-034.

7(a) of DNCP's Standard Contract, which governs defaults with no cure period. Specifically:

i. Article 7(a)(ii): Failure to provide two consecutive status reports in accordance with Article 6. Article 6 of DNCP's Standard Contract requires the QF to submit quarterly construction status reports (by specified dates) prior to achieving commercial operation. Termination with no opportunity to cure is an exceedingly draconian remedy for a curable default on this administrative provision. NCSEA opposes the classification of this event of default as incurable.

ii. Article 7(a)(v): Failure to maintain an Interconnection Agreement in full force and effect unless such failure is due to DNCP's breach of the Interconnection Agreement. There are three problems with classifying this situation as an incurable default. First, the phrase "in full force and effect" is ambiguous and should be defined. Second, the proposed language should specify that the right of termination does not exist where a QF has an interconnection agreement with a party other than DNCP (i.e., with PJM Interconnection, LLC) and the interconnection agreement is terminated or suspended based on that party's default. And third, there is no reason why this event of default should be considered incurable, if the QF's interconnection agreement can be brought back into "full force and effect" within a reasonable cure period.

iii. Article 7(a)(vii): Granting of a PURPA 210(m) petition. Although DNCP may have the right to terminate where FERC grants a petition by the utility under PURPA Section 210(m), it is inappropriate to characterize this as an event of default by the QF. To the extent this provision is permissible, it should not be included in this section.



## **B. DEC's and DEP's Proposed Revisions**

DEC and DEP have worked to increase the consistency in rate schedules and contracts offered to QFs eligible for the Commission-approved rates and contract terms between the two utilities.<sup>94</sup> To this end, in this proceeding, DEC and DEP propose to offer QFs eligible for the Commission-approved rates and contract terms a Purchase Power Agreement (the “DEC Standard Contract” and the “DEP Standard Contract”). In addition, to accompany the Purchase Power Agreement, both utilities propose Terms and Conditions for the Purchase of Electric Power (the “DEC Terms and Conditions” and the “DEP Terms and Conditions”). Finally, DEC offers Schedule PP(NC) and DEP offers Purchased Power Schedule PP-1 (“Rate Schedules”). The standard contract, the terms and conditions and the rate schedules include general contract terms, and DEC's and DEP's proposed revisions thereto are discussed below in detail.

### **a. Unqualified 30-month deadline for achieving commercial operation**

In the 2012 Order the Commission approved a 30-month eligibility window (from the date of the relevant avoided cost order) for the new rate schedule; however, the Commission made clear 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.”<sup>95</sup> Consistent with the 2012 Order, DEC's and DEP's Rate Schedules include the 30-month eligibility window; however, they do not include the qualification, as directed by the Commission. In contrast, DNCP's Schedule 19 contains the qualifying language, consistent with the 2012 Order.

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<sup>94</sup> DEC March 2015 Filing, paragraphs 3-10; DEP March 2015 Filing, paragraphs 3-10.

<sup>95</sup> 2012 Order, p. 9.

Section 3 of DEC's Standard Contract and DEP's Standard Contract provides as follows:

Company at its sole discretion may terminate this Agreement on (30 months following the date of the order initially approving the rates selection shown above) 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 by upon mutual agreement by both parties.<sup>96</sup>

While Section 3 does provide that the "date may be extended upon mutual agreement by both parties," this qualification is nullified by the right of the utility, "in its sole discretion" to terminate the contract at the expiration of the 30-month window. Additionally, allowing the termination to arise in the event of the QF's being "unable to provide generation capacity and energy production consistent with the energy production levels specified in" conflicts with the Commission's 2012 Order. For purposes of the utility's Section 3 termination rights at 30 months, energy production is irrelevant because the stated value is only an estimate, not a binding contractual obligation, and because annual production numbers by definition are not available until December of the first year of operation at the earliest. Similarly, for purposes of the utility's Section 3 termination rights at 30 months, generating capacity is irrelevant. There is no reasonable basis on which a right to terminate should arise where the QF constructs and brings on line within 30 months a facility that may have a lower nameplate capacity than was estimated as of the date of the contract. Thus, the 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

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<sup>96</sup> DEC's Standard Contract, sec. 3; DEP's Standard Contract, sec. 3.

may be extended if the QF is making reasonable progress, and NCSEA recommends that the Commission direct DEC and DEP to amend their respective contracts accordingly.

**b. Application of availability limitation in DEP's service territory**

As discussed above, DEP proposes that the Commission-approved rates and contract terms not be available to a QF owned by a developer or affiliate who sells or will sell power to DEP from another QF located within one-half mile unless the combined capacity of the facilities is equal to or less than five (5) megawatts.<sup>97</sup> DEC's rate schedule has historically included an analogous limitation. As stated above, in the interest of fairness, consistency and ease of administration, NCSEA recommends that the Commission approve DEP's one-half mile proposal and limit DNCP to one-half mile, while maintaining the qualification that two QFs under the same or affiliated ownership are eligible for the standard offer so long as the combined capacity of those facilities does not exceed five (5) megawatts.

**c. Commencement of term under utility's control**

Both the DEC Standard Contract and the DEP Standard Contract propose that the term of the agreement begins on the earlier of a date certain (which will be specified in the contract) or "the date the Company is first ready to accept electricity from Seller."<sup>98</sup> The term of DEC's contract historically has commenced on the initial delivery date.<sup>99</sup> DNCP's Standard Contract provides that the term of the contract runs from the

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<sup>97</sup> DEP's Rate Schedule, Availability.

<sup>98</sup> DEC's Standard Contract, sec. 3; DEP's Standard Contract, sec. 3.

<sup>99</sup> See DEC March 2015 Filing, Exhibit 4, p. 4 (lining out section 4).

commercial operation date of the facility.<sup>100</sup> Commencing the term of the contract on the date when the QF actually begins delivering power to the utility is preferable to starting the term when the utility “is first ready to accept electricity from the seller” because it minimizes the possibility that term will begin to run before the QF is able to start delivering power to the utility, therefore depriving the QF of an opportunity to earn revenue. Furthermore, the phrase “ready to accept electricity from Seller” is unclear and gives the utility unfettered discretion with respect to commencement of the term. For these reasons, the Commission should reject this proposal and direct DEC and DEP to revise the contracts to commence the term as of the initial date of delivery.

**d. Reduction in contract energy charge / reduction in contract capacity charge**

As proposed, DEC’s Terms and Conditions and DEP’s Terms and Conditions would allow the utilities to apply to the Commission (on a case-by-case basis) for approval to impose a charge in the event that the average energy generated by a QF in the on-peak or off-peak periods or capacity during any 12-month period falls “significantly below the Contract annual kilowatt-hours or Contract Capacity.”<sup>101</sup> Prior to the 2012 Order, DEP’s standard contract had included a provision similar to that which has been proposed in this proceeding. In the 2012 biennial avoided cost proceeding, the Commission concluded as follows:

[T]he provisions in DEP’s Terms and Conditions that allow DEP to charge QFs a Reduction-in-Contract-Capacity and a Reduction-in-Contract-Energy starting two years after a QF begins operations are inconsistent with previous rulings of the Commission. Further, such charges are

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<sup>100</sup> DNCP’s Standard Contract, Art. 2.

<sup>101</sup> DEC’s Terms and Conditions, sec. 6; DEP’s Terms and Conditions, sec. 6.

inconsistent with DEP's stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts, as they may apply in both early (after two years) and later years of a contract. Accordingly, such provisions should be removed from the DEP's Terms and Conditions. In lieu thereof, DEP may propose a provision that allows it to take action if the harm it alleges the penalty is designed to fix occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval.<sup>102</sup>

Thus, despite striking this provision, the Commission invited DEP to propose an alternative provision that would "allow[] 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)." However, the current proposal, like the provision that was struck, is inconsistent with DEP's stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts, as it can apply in both early (after two years) and later years of a contract. NCSEA opposes this proposal primarily on the grounds that it is inconsistent with the 2012 Order. Additionally, like its predecessor, the provision is unnecessary and unduly punitive for QFs that generate electricity using variable resources and will inevitably present a barrier to the QFs' ability to obtain financing.

Moreover, the proposal is confusing for the following reasons. It combines shortfalls in capacity and shortfalls in delivered energy into a single triggering condition, which is nonsensical in that it purports to apply when the energy generated falls short of the capacity specified in the contract or when the capacity falls below the energy deliveries specified in the contract.

Additionally, the phrase "significantly below" is not defined. In response to a data request propounded by NCSEA, DEC provided that the utility interprets

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<sup>102</sup> 2012 Order, p. 42.

“significantly below” to mean “a permanent (six consecutive months or more) twenty-percent or more reduction in annual energy production or generator capacity.”<sup>103</sup>

It is not clear what it would mean for a QF’s delivered capacity to fall below the “Contract Capacity.”

The definition of the essential term “Contract Energy” is confusing insofar as it provides that this quantity (i) should be specified in advance in the power purchase agreement, but also (ii) registered by meter. This renders the reduction in contract energy clause difficult to comprehend. Although DEC explained, in response to a data request from NCSEA, that “contract energy” is intended to represent “the estimated annual energy production expressed in kilowatt-hours that the seller anticipates supplying to the Company annually,” as specified by the QF in the power purchase agreement,<sup>104</sup> this is not how the provision is drafted.

Finally, the basis for the calculated charge is obscure, and the Utilities have not established that it bears any relation to the ratepayer harm the charge is supposed to address—underproduction in later years of a contract which results in the overpayment during the early years of a levelized contract. In the first phase of this proceeding, the Commission received evidence on the issue of the Utilities’ exposure to overpayments in the context of long-term, levelized rates. In fact, the Commission weighed evidence presented by: (i) the Utilities, related to “degraded performance, financial failure, weather, fuel supply, or other risks that could lead to overpayment;” (ii) the Public Staff, related to the fact that facilities with predictable capital costs and no fuel do not present

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<sup>103</sup> DEC response to NCSEADR3-13, Exhibit 1, 028.

<sup>104</sup> DEC response to NCSEADR3-10, Exhibit 1, 029.

these risks; and (iii) NCSEA, related to the facts that facilities are typically financed over the term of the power purchase agreement and that default under the financing arrangements could result in such things as the change of control rights of equity investors being triggered and of the owners being required to pay liquidated damages under loan documents, both of which militate against nonperformance.<sup>105</sup> Ultimately, the Commission concluded as follows:

[E]xperience has shown that there is a limited risk of nonperformance. In addition, the testimony offered by the solar developers as to the restrictions and limitations in their financing offers a measure of assurance that a solar QF's output will not decrease over the long term. The fact that solar QFs do not have to rely on fuel contracts, the viability of a steam host or some other external factor also weighs in favor of allowing levelized rates to continue. A solar generating facility has fairly predictable capital costs, production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams.<sup>106</sup>

Given its many problems and flaws, NCSEA recommends that the Commission reject the proposal for the same reason that it rejected the provision in its 2012 Order.

**e. Increased rights to suspend and terminate**

As proposed, DEC's Terms and Conditions and DEP's Terms and Conditions give the utilities very broad discretion to suspend or terminate contracts.<sup>107</sup> Conditions that justify suspension and/or termination include: 1) any default or breach of the contract by the QF; 2) existence of a condition on the QF's side of the point of delivery known or "reasonably anticipated" by the utility to be dangerous to life or property, and 3) the QF's

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<sup>105</sup> Order Setting Parameters, pp 10-19.

<sup>106</sup> Order Setting Parameters, p. 20.

<sup>107</sup> DEC's Terms and Conditions, sec. 1(i); DEP's Terms and Conditions, sec. 1(i).

inability to deliver the quality and/or quantity of electricity specified in the PPA. NCSEA has the following concerns.

i. Notice and opportunity to cure. While the utility is required to give the QF advance notice of termination (except where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter), it provides no opportunity for the QF to cure the condition giving rise to termination. By contrast, DNCP provides a 30-day cure period for most defaults.<sup>108</sup>

Many circumstances of default are temporary and/or curable, and it would be commercially unreasonable not to include a cure provision. This is especially true given that the proposed Terms and Conditions authorize termination based on any default or breach of the contract by the QF.

DEC has stated in response to an NCSEA data request that it "believes that, in the event of a default, the reasons that would permit the Company to terminate or suspend the agreement would already be apparent and known by the [QF] before they come to the Company's attention."<sup>109</sup> However, the grounds for termination as stated in the proposed Terms and Conditions are broad and include any default or breach of the contract by the QF. It is, therefore, unreasonable to assume that all possible breaches would be apparent to the QF. The utility would not be prejudiced by the requirement of notice and the provision of an opportunity to cure.

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<sup>108</sup> DNCP's Standard Contract, Art. 7(b).

<sup>109</sup> DEC response to NCSEADR3-7, Exhibit 1, 030.



Finally, it is worth noting that prior to the 2012 Order, DEP's contract did not include a cure provision and that DEP agreed to add the cure periods in response to comments filed by parties to the 2012 biennial avoided cost proceeding.<sup>110</sup>

ii. Termination based on dangerous conditions. Giving the utility absolute discretion to terminate (with no notice required) based on the existence of a dangerous condition on the QF's side of the point of delivery (or the "reasonable anticipation" of such a condition) is draconian. This provision would, for example, allow termination based on a temporary fire caused by a lightning strike or other circumstances outside the QF's control. Again, it would be commercially unreasonable not to allow the QF the opportunity to cure the dangerous condition. Suspension would be a more appropriate remedy in this circumstance.

iii. Lack of clarity as to circumstances justifying suspension versus termination. The proposed termination provisions are problematic in that they provide no guidance as to what conduct or circumstances of default justify termination rather than temporary suspension of power purchases. In response to an NCSEA data request, DEC provided that "[t]ermination of the agreement is deemed a last resort in circumstances where the seller refuses to fulfill its obligation under the agreement."<sup>111</sup> NCSEA does not contest that termination may be justified in such circumstances, but this is not what the proposed language says. The proposed termination provisions must be modified to specify that termination is only appropriate when the QF either cannot or will not cure its default.

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<sup>110</sup> See Duke Energy Carolinas and Duke Energy Progress Joint Reply Comments, N.C.U.C. Docket No. E-100, Sub 136, March 28, 2013, paragraph 61.

<sup>111</sup> DEC response to NCSEADR3-7, Exhibit 1, 030.

iv. Termination based on inability to deliver energy as specified in contract. The proposed Terms and Conditions for DEC and DEP would allow the utility to terminate a contract “due to the Seller's inability to deliver to the Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement.” This provision is problematic for several reasons. First, the provision does not clearly define what the “quantity” and “quality” standards are that have to be met. Second, the provision does not define what degree of deviation from the “quality and/or quantity of electricity” specified in the contract (and for what period of time) justifies termination. Intermittent energy sources have no choice but to estimate their energy production and there may well be periods during which their deliveries of electricity fall short of those estimates. The proposed language appears to give the utility absolute discretion to terminate based on such shortfalls, which is unacceptable. Third, termination is an excessive remedy for under-delivery of energy or capacity and would be duplicative of the “reduction-in-contract-energy” and “reduction-in-contract-capacity” charges proposed in the Terms and Conditions, should the Commission allow those to stand. Finally, the provision is inconsistent with prior orders of the Commission.

Accordingly, for these reasons, section 1(i) of DEC's and DEP's Terms and Conditions should be modified to: a) provide the QF notice and a reasonable opportunity to cure prior to authorizing termination by the utility; b) provide clearer guidance on circumstances in which termination as opposed to suspension may be warranted; c) eliminate DEC's or DEP' right to terminate based on under-delivery of energy or capacity.

#### **f. Limitation on assignment rights**

DEC's Standard Contract and DEP's Standard Contract provide that the QF's rights under the contract may only be assigned to a third party if the utility is "reasonably satisfied" that the assignee will fulfill its obligations under the agreement and if the assignee furnishes "a satisfactory guarantee for the payment of any applicable bills."<sup>112</sup> This provision gives the utility undue discretion to disapprove or put onerous conditions on the assignment of rights such the requirement of financial security, which as discussed in the context of DNCP's Standard Contract, have the potential to serve as an impediment to QF development. Therefore, NCSEA recommends that the Commission direct DEC and DEP to revise this provision to require that the utility will not unreasonably withhold consent and will not require commercially unreasonable measures, such as security.

#### **g. Retroactive modification of terms and conditions**

DEC's and DEP's standard offer documents include contradictory provisions concerning the effect of government action and subsequent changes in law (and, in particular, Commission approval of revised regulations, terms and conditions) on existing contracts.

Specifically, the Standard Contracts provide that although fixed long-term rate schedules incorporated in an existing contract may not be changed by subsequent orders of the Commission, other provisions "are subject to change, revision, alteration or substitution, either in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction."<sup>113</sup>

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<sup>112</sup> DEP's Standard Contract, sec. 1(e); DEC's Standard Contract, sec. 1(e).

<sup>113</sup> DEC's Standard Contract, section 2; DEP's Standard Contract, section 2.

The Rate Schedules similarly provide that, with the exception of fixed long-term rates, the “Rate Schedule and Terms and Conditions for the Purchase of Electric Power are subject to change, revision, alteration or substitution, either in whole or in part, upon order of the Commission or any other regulatory authority having jurisdiction.”<sup>114</sup>

The Terms and Conditions provide that “This Agreement shall at all times be subject to changes by such governmental agencies, and the parties shall be subject to conditions and obligations, as such governmental agencies may, from time to time, direct in the exercise of their jurisdiction, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract.”<sup>115</sup>

Based on these contradictory provisions, it is unclear whether the essential non-rate terms of an existing contracts (including but not limited to fixed long-term rates) are subject to change when the Commission approves new standard offer language in a subsequent avoided cost proceeding.

In the first phase of the proceeding, the Commission received evidence regarding the fact that investors’ need for certainty is critical to QF development.<sup>116</sup> Similarly, in the 2012 biennial avoided cost proceeding, the Commission received evidence regarding the need for certainty; indeed, the Commission directed DNCP to remove its “regulatory disallowance” contract provision based upon this evidence.<sup>117</sup> Allowing settled expectations, embodied in the agreement between the QF and the utility, to be upset by

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<sup>114</sup> DEC’s Rate Schedule, Page 4 of 4; DEP’s Rate Schedule, Sheet 4 of 6.

<sup>115</sup> DEC’s Terms and Conditions, sec. 17; DEP’s Terms and Conditions, sec. 17.

<sup>116</sup> 2012 Order, pp 10-19.

<sup>117</sup> 2012 Order, pp 43-46.

later actions of the Commission, or by any governmental action, would interfere with contractual rights, create uncertainty for investors, pose a barrier to financing and, effectively, discourage QF development. Accordingly, the Commission should reject the proposed language that would allow essential non-rate terms of existing contracts to change as a result of subsequent government action.

**h. Inappropriate inclusion of interconnection terms**

DEC's and DEP's standard offer documents include various provisions related to the interconnection of QFs, some of which are unclear, with the potential to mislead, and contradictory. For example, section 4 of DEC's Standard Contract and DEP's Standard Contract addresses interconnection facilities as follows:

Unless otherwise required by Company, an Interconnection Agreement pursuant to the North Carolina Interconnection Procedures, Forms, and Agreements For State-Jurisdictional Generator Interconnections (Interconnection Standard) shall be executed by Seller, including payments of all charges and fees associated with the interconnection before Company will accept this Agreement. *(Either sentence (a) or (b) as follows is inserted into the agreement as appropriate)*(a) The Interconnection Facilities Charge shall be specified in the Interconnection Agreement. or (b) The Interconnection Facilities Charge shall be 1.1 % of the installed cost of metering equipment and is \$\_\_ per month.

Section 13 of the Terms and Conditions addresses interconnection and includes conditions related to quality of equipment used and manner of operation, payment for the cost of facilities, metering, access to the facility, and protection of the utility's system.<sup>118</sup>

Finally, DEP's Rate Schedule includes the following section related to interconnection facilities cost, which provides:

For Eligible Qualifying Facilities, the installed costs for all facilities constructed or installed by Company to interconnect and safely operate in parallel with Seller's equipment shall be determined in accordance with

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<sup>118</sup> DEC's Terms and Conditions, sec. 3; DEP's Terms and Conditions, sec. 3.

Company's Terms and Conditions for the Purchase of Electric Power. When only the installation of Company's meter is required for the purchase of electric power, the \$25 minimum monthly Interconnection Facilities Charge shall not be applicable. Interconnection of Seller's generation to Company's system shall be in accordance with the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generation Interconnections.<sup>119</sup>

Because the interconnection of QFs eligible for the standard offer is governed by the North Carolina Interconnection Procedures, Forms, and Agreements For State-Jurisdictional Generator Interconnections, NCSEA submits that terms and conditions related to the interconnection of the QF should be left to the interconnection agreement, in the interest of avoiding confusion and the potential for inconsistency between the documents that govern power sales and the documents that govern interconnection. NCSEA recommends that the Commission direct DEP and DEC to strike all provisions in the power sales documents related to interconnection, with the exception to a simple reference to the North Carolina Interconnection Procedures, Forms, and Agreements and the fact that an interconnection agreement is necessary in order to deliver output to the utility.

**i. Proposed adjustments for reactive power are confusing and have potential to penalize QF unfairly**

DEC's Rate Schedule includes a provision, labeled "Power Factor Correction", pursuant to which DEC proposes to reduce the number of kWh for which payment is made if the "average power factor" of the QF falls outside the parameters specified in the rate without any commensurate credit to the QF when it produces reactive power (measured in volt-ampere-reactive or "VAR") that benefit DEC. Similarly, DEP's Rate

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<sup>119</sup> DEP's Rate Schedule, Sheet 6 of 6. DEC's Rate Schedule includes a similar provision. See DEC's Rate Schedule, Page 4 of 4.

Schedule includes a related provision pursuant to which DEP proposes to bill the QF at a rate of \$0.34 multiplied by the number of kilo-VARs consumed or supplied by the QF. DEP's rate schedule contemplates that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control. However, as DEP's standard offer documents are silent as to the referenced "Operating Agreement," it is not clear how a QF requests the right to enter into such an agreement and what the terms and conditions of the agreement would be. At best, the provisions in DEC's and DEP's Rate Schedules related to reactive power are unclear; at worst, they have the potential to unfairly penalize a QF to the extent that the utility may benefit from reactive power. Thus, the Commission must carefully scrutinize these provisions.

**j. Limitation of availability to "single, contiguous premises" is unjustified and has potential to discourage QF development**

DEC's and DEP's Rate Schedules propose to limit availability as follows:

Service necessary for the delivery of power from the Seller's generating facilities into Company's system shall be furnished solely to the individual contracting Seller in a single enterprise, located entirely on a single, contiguous premise.

There is no legitimate basis upon which the Commission should approve the limitation that the QF be located on a "single, contiguous premise." As an initial matter, "single, contiguous premise" is not defined in the Rate Schedules. Moreover, the Commission has held, most recently in its Order Setting Parameters, that the Commission-approved standard offer rates and contract terms are available to QFs of up to 5 MW of capacity (with certain exceptions based on energy resource). Additionally, a practical matter, there are times when a 5 MW QF must be located on more than one parcel of property or located on a parcel of property that is bisected by a public right of way. Whether either

of these examples would run afoul of DEC's and DEP's proposed limitation is not clear. DEC and DEP have proposed one-half mile limitations, to which NCSEA does not object, as discussed above in greater detail. The "single, contiguous premise" limitation has the potential to be more restrictive than the one-half mile limitation. For these reasons, NCSEA recommends that the Commission reject this proposed limitation on availability.

#### **IV. Establishment of a Commitment to Sell**

The regulations of the FERC implementing PURPA establish that, in selling its electrical output to the utility, the QF may elect to:

provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

- i) the avoided costs calculated at the time of delivery; or
- ii) the avoided costs calculated at the time the obligation is incurred.<sup>120</sup>

In explaining a QF's options for selling its output, the FERC has provided that:

[A] QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. Accordingly, a QF, by committing itself to sell to an electric utility also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.<sup>121</sup>

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<sup>120</sup> 18 C.F.R. §292.304(d)(2).

<sup>121</sup> J.D. Wind 1, LLC, 129 FERC ¶ 61,148 (2009) ("JD Wind 1") ¶ 25.



It has been the FERC's long-standing practice to "leave to state commissions the issue of when and how a legally enforceable obligation ["LEO"] is created."<sup>122</sup> To this end, the Commission has previously ruled that a LEO is created when a QF: 1) has received a certificate of public convenience and necessity ("CPCN"); and 2) has committed itself to sell to the utility.<sup>123</sup>

In the context of establishing the availability of the standard offer rates and contract terms, the Commission has drawn from the LEO concept and found that each QF that: a) has obtained a CPCN or filed an RPC, as applicable, no later than November 1 of the year in which a biennial proceeding has been initiated (or the actual filing date of proposed rates if later); and b) has indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output is entitled to the fixed, long-term avoided costs rates approved in the immediately preceding biennial proceeding.<sup>124</sup>

During the evidentiary hearing of this proceeding, DNCP witness Williams testified as to DNCP's position that the test for establishing a LEO is "too vague to be implemented in a fair manner, particularly with regard to the second prong of the test, as there is not enough guidance regarding what it means for a QF to " 'commit itself to sell its output.' "<sup>125</sup> To this end, DNCP proposed the use of a form as a means to clarify this second prong of the test. In response to DNCP's proposal, the Commission noted that "no party expressed any opposition to it, but neither did any party express any support"

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<sup>122</sup> See J.D. Wind 1, reconsideration denied, 130 FERC ¶ 61,127 (2010), ¶ 24.

<sup>123</sup> See Order Denying Request for Waivers, N.C.U.C. Docket No. SP-4158, Sub 0, June 15, 2015, p. 6; 2012 Order, p. 35; Order on Motion to Suspend Avoided Cost Rates, N.C.U.C. Docket Nos. E-100, Sub 127 and E-100, Sub 136, December 21, 2012, p. 3.

<sup>124</sup> 2012 Order, FOF 15.

<sup>125</sup> Order Setting Parameters, p. 63.

and indicated an inclination to move toward this approach.<sup>126</sup> Therefore, its Order Setting Parameters, the Commission ordered that:

DNCP's proposal for a simple form to be used to determine the date of the commitment of a QF, along with how it should be implemented shall be approved with the details and implementation to be considered in the next phase of this proceeding and the parties are directed to address it in their filings.<sup>127</sup>

In its March 2015 Filing, DNCP proposes a form, to which it refers as Offer to Sell and Request for Power Purchase Agreement with Dominion North Carolina Power by a Qualifying Facility ("DNCP's Form"), and which it proposes to include as Exhibit A to its Schedule 19 tariffs.<sup>128</sup> In their March 2015 Filings, DEC and DEP have embraced DNCP's proposal to use a form to establish the QF's commitment to sell, providing that each utility "supports DNCP's proposal that the QF complete a simple form that states that the QF is making an offer to sell its output to the utility and sets the date of the LEO."<sup>129</sup>

While NCSEA is not opposed to the use of a form to clarify the date on which the QF has committed itself to sell to the utility, for the reasons set forth in detail below, DNCP's Form injects more complexity than simplicity into the process and includes provisions that are inconsistent with the Commission's precedent as well as federal regulations and precedent. Thus, DNCP's Form, as proposed, must not be approved by the Commission. As an alternative to DNCP's Form, NCSEA contends that each utility

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<sup>126</sup> Order Setting Parameters, p. 64.

<sup>127</sup> Order Setting Parameters, OP 17.

<sup>128</sup> DNCP March 2015 Filing, Section I.A, p. 5.

<sup>129</sup> DEC March 2015 Filing, paragraph 13; DEP March 2015 Filing, paragraph 13 (emphasis added).

should make available a truly simple form, such as the 2-page form set forth below (“NCSEA’s Form”) and attached hereto as Exhibit 5:

### COMMITMENT TO SELL OUTPUT TO UTILITY

1. [ ] (the "Seller") hereby commits to sell all of the electrical output generated by Seller's "Qualifying Cogeneration/Small Power Production Facility" located at [INSERT ADDRESS], North Carolina (the "Facility") to [IDENTIFY UTILITY] (the "Electric Utility") pursuant to:

CHECK ONE BOX BELOW

- ☐ [IDENTIFY COMMISSION-APPROVED RATE SCHEDULE AND ELIGIBILITY CRITERIA]; OR
- ☐ Rates, terms and conditions to be negotiated by and between the Seller and the Electric Utility.
2. The commitment made in Section 1 hereof (the "Commitment") shall take effect as of the date of transmission of the Commitment to the Electric Utility. For purposes of this Commitment, "date of transmission" means (a) the receipted date of deposit of this Commitment with the U.S. Postal Service for certified mail delivery to the Electric Utility, (b) the receipted date of deposit of this Commitment with a third-party courier (e.g., Federal Express, United Parcel Service) for trackable delivery to the Electric Utility, (c) the receipted date of hand delivery of this Commitment to the Electric Utility, or (d) the date on which an electronic copy of this Commitment is sent via email to the Electric Utility.
3. The name, address, and contact information for Seller, for purposes of this Commitment, is:
- NAME  
ADDRESS  
ADDRESS  
PHONE NUMBER  
EMAIL ADDRESS
4. The name, address, and contact information for the Electric Utility, for purposes of transmission of this Commitment in accordance with Section 2 hereof, is:
- NAME  
ADDRESS  
ADDRESS  
PHONE NUMBER  
EMAIL ADDRESS

\* \* \* \* \*

SELLER

\_\_\_\_\_

BY: \_\_\_\_\_

ITS: \_\_\_\_\_

#### ACKNOWLEDGEMENT

\_\_\_\_\_ County, North Carolina

I certify that the following person personally appeared before me this day, acknowledging to me that he or she signed the foregoing document: \_\_\_\_\_.

\_\_\_\_\_ Date: \_\_\_\_\_

[Official Signature of Notary]

\_\_\_\_\_, Notary Public

[Notary's printed or typed name]

My commission expires: \_\_\_\_\_ (Official Seal)

4812-0325-9429, v. 1

#### **A. Use of Form Must Be Permissive, Not Mandatory**

As an initial matter, DNCP proposes that the use of DNCP's Form be mandatory; in other words, DNCP proposes that a QF must use its form to be eligible for its Schedule

19 Tariffs.<sup>130</sup> In contrast, NCSEA proposes that use of the form by a QF be permissive rather than mandatory. NCSEA suggests that the Commission incent the use of the form by holding that, on a prospective basis: a) a QF's use of the form will give rise to a rebuttable presumption in favor of the QF that it has committed itself to sell to the utility as of a date certain – i.e., the date a QF transmits the form to the relevant utility; and b) a QF's failure to use the form will give rise to a rebuttable presumption in favor of the utility that the QF has not committed itself to sell to the utility.

By making use of its form the exclusive means for establishing a commitment, DNCP institutionalizes rigidity that elevates form over substance and has the potential to result in unfair outcomes. Despite stakeholders' best intentions, atypical factual situations are likely to arise, as illustrated by the oral argument exchange excerpted below in Section IV.C. hereof, and the Commission must be sure to preserve enough flexibility to address these situations on a case-by-case basis so that fairness triumphs over form. Under DNCP's proposed overly-rigid approach, QFs will have failed to establish an LEO if a form is not completed or is not completed correctly. However, under NCSEA's proposal (making use of twin rebuttable presumptions), these QFs would still have an opportunity, if circumstances merited, to secure a fair outcome by seeking to rebut the presumption that they had not adequately committed. NCSEA's proposal strikes a better balance between law, regulation, policy and practicality.

#### **B. DNCP's Form Is Unnecessarily Complicated**

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<sup>130</sup> DNCP March 2015 Filing, Section I.A, p. 5.

In support of its position that the second prong of the LEO test needs clarification, DNCP indicated that the lack of clarity gives rise to the possibility of gaming of rates by the QFs. Specifically, DNCP witness Williams testified:

[I]t is reasonable to require a level of commitment to the then-current rates if a QF wants to remain eligible for them. Requiring a QF to establish an LEO, and to promptly execute a PPA, would preclude eligibility for subsequent biennial rates, removing any ability for “cherry picking” rates between biennial periods.<sup>131</sup>

DNCP witness Williams suggested that the “best means to achieve this would be a simple document that states clearly the date both parties agree constitutes the LEO, prior to providing applicable rates to the QF.”<sup>132</sup> As to the content of the “simple document” he was proposing, DNCP witness Williams responded as follows, on cross examination:

- Q: I know that Dominion has made a proposal on the form that the developer would complete and provide to the Utility with respect to LEO date. Is it Dominion’s proposal that Dominion would have some say or right to negotiate when that LEO date occurs?
- A: Absolutely not. All we’re seeking is to have some sort of clarity between the developer and the Utility as to what the LEO date is. And the [form] is a means to do that, but you know, we’re open to other ideas.<sup>133</sup>

However, DNCP’s Form is not a “simple document” in which a QF would clearly and simply articulate its commitment as of a time certain. Instead, DNCP proposes a 4-page contract and proposes that the use of its form be the exclusive method for satisfying the “commitment to sell” test.<sup>134</sup>

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<sup>131</sup> Transcript of Testimony Heard July 9, 2014, Vol. 5 pp. 197-447, p. 349, N.C.U.C. Docket No. E-100, Sub 140.

<sup>132</sup> *Id.* at p. 352 (emphasis added).

<sup>133</sup> Transcript of Testimony Heard 7-10-14, Raleigh Vol. 6, p. 125, Commission Docket No. E-100, Sub 140 (30 July 2014).

<sup>134</sup> DNCP March 2015 Filing, Section I.A, p. 5.

For example, section 4 requires the QF to identify “the names and locations of any QF facilities that are owned or under development by Seller or its affiliates that will be located within one mile of the Facility.” The form is unclear whether provision of this information is optional or mandatory. Either way, this request introduces complexity that could give rise to disputes over the very form that is being proposed to minimize disputes.

Additionally, despite DNCP’s desire to “remov[e] any ability for ‘cherry picking’ rates between biennial periods[.]” section 5(e) of DNCP’s Form enables a QF to withdraw an earlier commitment to sell (so long as a power purchase agreement has not yet been executed) and then establish a later commitment date. It is not difficult to discern how such a provision could actually enable “cherry picking.” As such, inclusion of this provision in the form appears to run counter to one of DNCP’s key goals and invites the possibility of dispute.<sup>135</sup>

Finally, DNCP’s Form resembles a contract, as opposed to a form in which the QF makes a declaration. In fact, the title of the form – “Offer and Request” – unquestionably presents the concern that DNCP is putting itself in a position to “accept the offer,” which might give rise to a binding contract despite the absence of any express execution of the form by DNCP. The form includes a number of acknowledgements or representations by the QF,<sup>136</sup> including acknowledgements related to how and when an LEO arises and to termination of the LEO, that expressly survive the termination of the

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<sup>135</sup> DNCP’s Form, section 5(e).

<sup>136</sup> DNCP’s Form, section 5.



“Offer and Request.”<sup>137</sup> DNCP’s Form, which in effect is a “contract,” violates the spirit if not the letter of 18 C.F.R. § 292.304(d) and its “specific[] adopt[ion] to prevent utilities from circumventing the requirement of PURPA that utilities purchase energy and capacity from QFs.”<sup>138</sup> Additionally, such an approach contravenes the FERC’s clear guidance provided in JD Wind I that the LEO is a non-contractual obligation. Such a complicated “simple document” should not be approved.

### **C. DNCP’s Form Is Inconsistent With Law and Precedent**

Beyond complexity, DNCP’s Form conflicts with law and precedent regarding the LEO. Section 6 of DNCP’s form sets forth circumstances under which the “Offer and Request” shall automatically terminate, suggesting that these circumstances nullify the QF’s commitment and, by extension, the LEO. One of the circumstances under which automatic termination occurs is if a QF that is eligible for the standard offer rates and contract terms does not execute a PPA prior to the date set by the NCUC for the filing of updated rates and contracts.<sup>139</sup> The Commission-approved rate schedules for each of the Utilities includes a provision related to the availability of rates. Therefore, the availability of rates must not be addressed in the form but should be left to the Commission-approved rate schedules.

Another of the circumstances under which automatic termination occurs is if a QF that is not eligible for the standard offer does not execute a PPA within six months after the Company’s submittal of the PPA to the QF, with exception for PPAs that become

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<sup>137</sup> DNCP’s Form, section 7.

<sup>138</sup> In re. Virginia Electric and Power Company, 151 FERC ¶ 61,038 (2015) ¶¶ 24-25.

<sup>139</sup> DNCP’s Form, section 6.c.

subject to arbitration before Commission.<sup>140</sup> Even under the best of circumstances, PPA negotiation and execution can take longer than six months. Additionally, neither federal law and precedent nor the Commission's precedent related to the establishment of a LEO provide support for the proposition that a LEO is terminated after a specific period of time if the QF has not entered into a PPA with the utility. Thus, any provision that purports to terminate the commitment, and by extension the LEO, within a certain period of time must be rejected. The Commission has recently approved a 30-month time frame for completion of construction to retain eligibility for rates. The Commission declined to modify this time frame in its Order Setting Parameters.<sup>141</sup> This provision of DNCP's Form is another attempt to have the Commission modify this time frame.

In addition by requiring that a QF's commitment is not made until the form is received by the company, DNCP's Form is inconsistent with federal regulations and precedent for the following additional reason. Specifically, subsection 5(c) of DNCP's Form provides that,

[I]f on the date of the Company's receipt of an Offer and Request the QF has a CPCN from or has filed an RPC with the Commission for its facility, the LEO Date will be the date of the Company's *receipt* of the Offer and Request.<sup>142</sup>

Conditioning the establishment of a QF's commitment to sell (and, by extension, the LEO) on DNCP's receipt of a form rather than on the actual date the QF commits itself to sell to the utility, effectively shifts control over the LEO from the QF to the utility.

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<sup>140</sup> DNCP's Form, section 6.d.

<sup>141</sup> Order Setting Parameters, p. 64, OP 18.

<sup>142</sup> DNCP March 2015 Filing, Section I.A, p. 11 (emphasis added).

There is no better illustration of the problematic nature of DNCP's "receipt requirement" than the following exchange between Commissioner Beatty and DNCP's counsel during a recent oral argument on this issue:

[DNCP COUNSEL]: [The LEO date] would have been the date that the Power Contracts Department received it. So, say it was an e-mail and that person wasn't checking e-mails -- say it was Mr. Hampson and he was on vacation and when he got back and saw it and the date of the e-mail was the 31st, the LEO would have been established as of the 31st. It's the receipt by the department.

COMMISSIONER  
BEATTY: And I assume you're saying that would have been evidenced by some date stamp or something?

[DNCP COUNSEL]: You would think.

COMMISSIONER  
BEATTY: But we don't know?

[DNCP COUNSEL]: As for that piece of mail, no, there's no date stamp on it.

COMMISSIONER  
BEATTY: Suppose they had sent it to Mr. Farrell, the CEO, would the LEO have been on the date his office receives it or the date that the proper department received it?

[DNCP COUNSEL]: The date that the proper department received it. It doesn't -- it doesn't matter if they sent it to Mr. Farrell or to me or to Mr. Tomczak, all of those are not the proper recipient. It needs to go to Power Contracts.

COMMISSIONER  
BEATTY: Suppose the secretary in the right department didn't date stamp the letter, when is it effective?

[DNCP COUNSEL]: It's effective when it's received by Power Contracts. And in a situation where there's no date stamp, we'd

have someone, you know, someone's word -- I really can't speak to that hypothetical.<sup>143</sup>

As illustrated by this exchange, conditioning a QF's commitment on the utility's action creates the possibility that a QF's eligibility for a particular rate schedule would hinge on "someone's word" – i.e., on the word of a utility employee whose interests should be assumed to run counter to the QF developer's interests.

Moreover, the "receipt requirement" in DNCP's Form allows the utility to dictate the timing of the commitment, in violation of PURPA and the FERC's regulations. As the FERC explained, the concept of the LEO was adopted to give the utility an option of establishing an obligation in the event the utility refused to deal with the QF.<sup>144</sup> In other words, recognizing that the utility might not act, the FERC provided an option that does not depend on any action by the utility. This was affirmed in the recent decision of the FERC regarding the establishment of LEOs by nine QFs in North Carolina, in which the FERC held that LEOs arose as of the date on which the QFs had tendered notice of intent to sell to the off-taking utility, rather than the date on which that utility accepted that notice.<sup>145</sup> Thus, a QF's commitment should be established as of the date it transmits the form to the utility.

As this Commission has pointed out:

The LEO is based upon the QF's exercise of its options under PURPA and FERC rules. [The utility's] present contention that its employees' holiday vacations should in some way impact the avoided cost rates to be paid

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<sup>143</sup> Transcript of Oral Argument Held March 17, 2015, Raleigh, pp. 80-81, Commission Docket No. E-22, Sub 518.

<sup>144</sup> See Order No. 69 (explaining that the "[u]se of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility. ").

<sup>145</sup> In re. Virginia Electric and Power Company, 151 FERC ¶ 61,038 (2015).

EPCOR under new PURPA contracts confirms the need of FERC's LEO concept.<sup>146</sup>

The receipt requirement subverts PURPA's mandate that QFs may establish an obligation even as to an unwilling and obstructive utility and is inconsistent with law and precedent.

**D. NCSEA's Form and Proposed Implementation Are Simple and Straightforward**

For the reasons set out below, NCSEA believes that each utility should make available a truly simple form, and as such, proffers NCSEA's Form, which could be used as a means—but not the exclusive means—of establishing a commitment.

In contrast to DNCP's Form, NCSEA's Form is simple and straightforward, requiring only that the QF indicate its intention to sell to the utility pursuant to the Commission-approved standard rates and contract terms or to negotiated rates, terms and conditions, as applicable.<sup>147</sup>

In contrast to DNCP's "receipt requirement," NCSEA's Form relies on a "transmission" test that retains QF control in the face of an unwilling or obstructive utility yet ensures a reasonable temporal proximity between the date of a QF's actual commitment to sell and the date the relevant utility is notified of the commitment.

Specifically, NCSEA's Form contains the following Paragraph 2:

The commitment made in Section 1 hereof (the "Commitment") shall take effect as of the date of transmission of the Commitment to the Electric Utility. For purposes of this Commitment, "date of transmission" means (a) the receipted date of deposit of this Commitment with the U.S. Postal Service for certified mail delivery to the Electric Utility, (b) the receipted date of deposit of this Commitment with a third-party courier (e.g., Federal Express, United Parcel

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<sup>146</sup> Order on Arbitration, N.C.U.C. Docket No. E-2, Sub 966, January 26, 2011, p. 9.

<sup>147</sup> NCSEA's Form, section 1.

Service) for trackable delivery to the Electric Utility, (c) the receipted date of hand delivery of this Commitment to the Electric Utility, or (d) the date on which an electronic copy of this Commitment is sent via email to the Electric Utility.<sup>148</sup>

Finally, NCSEA's Form requires that the signature of the QF representative be executed by a person duly authorized to commit the QF and notarized, to provide the utility with reasonable assurance regarding the authenticity of the commitment.

With respect to implementation of a form, in its Order Setting Parameters, the Commission requested comment on the following issues: i) how the QF would know it needed to obtain the form; ii) how the QF would obtain the form; iii) whether or how the form could be submitted electronically; and iv) the extent to which the utility could change or withdraw the form without prior Commission approval.<sup>149</sup> As to these issues, NCSEA offers the following comments:

- i. As to how the QF would know it needed to obtain the form: The Utilities should make this requirement clear by all of the following means: (a) in instructions to QFs provided on the Utilities' websites; (b) in any "standard" instructions typically provided to QFs via mail or e-mail; and (c) by specification in the "availability" section of the applicable Commission-approved rate schedule.
- ii. As to how the QF would obtain the form: The form should be available on the Utilities' websites, with the website address provided by the same means that QFs are notified of their obligation to submit the form. If a utility changes the

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<sup>148</sup> NCSEA's Form, section 2.

<sup>149</sup> Order Setting Parameters, p. 64.

filename or location of the form on its website, it must ensure that the old link continues to function.

- iii. As to whether or how the form could be submitted electronically: It is essential that QFs be able to submit the form electronically, preferably by e-mail and alternative means. Providing a dedicated e-mail address for forms would allow the utility to specify routing instructions (and prevent confusion arising from improperly addressed communications) more easily than traditional mail. The ability of e-mail to ensure same-day receipt of communications would also obviate any questions about dates arising from transmittal and receipt of communications on different days. The utility could also make provisions to allow the form to be submitted via its web site. However, because web-based forms have limitations (such as the potential for server downtime, or text form fields that do not allow enough space to enter all relevant information) other methods for submitting the form, such as e-mail, hand delivery, U.S. mail, etc. must be available to the QF.
- iv. As to the extent to which the utility could change or withdraw the form without prior Commission approval: In the unlikely event that a utility must make more than minor administrative changes to the form, the utility should be required to obtain Commission approval to avoid any prejudice to QFs. If changes to routing information (such as the e-mail address to which the form must be sent) are made, the utility must ensure that the old information remains valid (in the event QFs do not learn of the change).

### **E. Conclusion and Recommendation**

For the foregoing reasons, NCSEA recommends that the Commission direct the Utilities to make available NCSEA's Form (tailored as appropriate for the relevant utility). As to implementation, the Commission should hold that use of the form by a QF is permissive rather than mandatory, making clear that the QF may evidence that it has committed itself through other actions. However, the Commission should encourage use of the form by holding that, on a prospective basis, that: a) a QF's use of the form will give rise to a rebuttable presumption in favor of the QF that it has committed to sell its output as of a date certain – *i.e.*, as of the date a QF transmits the form to the relevant utility; and b) a QF's failure to use the form will give rise to a rebuttable presumption in favor of the relevant utility that the QF has not committed to sell its output.

### **V. Requirement of Transparency**

In its Order Setting Parameters, the Commission directed that:

[I]n the calculation of the installed cost a CT, DEC, DEP and DNCP shall use data from publicly available industry sources and tailor it only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.<sup>150</sup>

By directing DEC, DEP and DNCP to use data from publicly available sources when calculating the installed cost a CT, the Commission's order advances PURPA's objective transparency in avoided cost proceedings. However—to comply with the letter of the law—NCSEA recommends that the Commission direct the Utilities, in future avoided cost proceedings, to file for public inspection the data from which their avoided costs are derived.

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<sup>150</sup> Order Setting Parameters, p. 65.



**A. FERC's Regulations Require Transparency of Underlying Data**

In its Order No. 69, the FERC provided the following relevant summary of its regulations implementing PURPA:

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting 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. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.<sup>151</sup>

Section 292.302 of the FERC's regulations governs the availability of electric utility system cost data.<sup>152</sup> Section 292.302(b) provides as follows:

General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain **for public inspection**, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and

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<sup>151</sup> Order No. 69, ¶ 12,215.

<sup>152</sup> 18 C.F.R. § 292.302

for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.<sup>153</sup>

The FERC explained its intent in adopting section 292.302(b) as follows:

[A]n investor needs to be able to estimate with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. **Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.**<sup>154</sup>

Thus, as explained by the FERC, section 292.302 is intended to assist those needing data from which avoided costs can be derived and, therefore, obligates electric utilities to maintain these data for public inspection. To the extent the Commission sees an advantage in requiring the Utilities to disclose a different set of data than is required by the foregoing rules, the FERC provides the Commission with discretion to require disclosure of a different set of data, so long as avoided costs can still be derived from such data. Specifically, section 292.302(d) provides, in relevant part, as follows:

(1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking

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<sup>153</sup> 18 C.F.R. § 292.302(b)(emphasis added).

<sup>154</sup> Order No. 69, ¶ 31,171 (emphasis added).

authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.<sup>155</sup>

Thus, should the Commission determine that “different data” are warranted, the FERC regulations provide a specific procedure for allowing this substitution.

#### **B. DEC’s and DEP’s Avoided Cost Filings Lack Transparency**

In this proceeding, DNCP has made an effort to use data from publicly available sources<sup>156</sup> and to **file for public inspection** the data underlying its avoided capacity cost calculation, with a narrative explanation that identifies the publicly available industry sources on which DNCP relied.<sup>157</sup> For ease of reference, the page from DNCP’s filing is excerpted below:

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<sup>155</sup> 18 CFR 292.302(d)(1)(emphasis added).

<sup>156</sup> In acknowledging that DNCP made an effort to use data from publicly available sources, NCSEA is not endorsing the sources or the adjustments made to the data in those sources.

<sup>157</sup> DNCP March 2015 Filing, Section III, p. 5.

**Dominion North Carolina Power Proposed**  
**Schedule 19 and Supporting Comments**  
**Docket No. E-100, Sub 140**

**FIGURE 1 – Hypothetical CT Costs, adjusted for 2014 COD (\$ in millions)**

<b>Equipment Cost - 2013 Gas Turbine World Handbook</b>				<u>Notes</u>
Gas Turbine & Equipment (\$2013)			98.8	Two Siemens SGT6-5000F CTs
Escalation to \$2014			2.55%	Based on Handy Whitman Index
<b>Gas Turbine &amp; Equipment (\$2014)</b>			<b>101.4</b>	
<b>Other Costs, including Owner &amp; Construction Costs - PJM Cost of New Entry (Dominion Area)</b>				
	Brattle		Adjusted	
	<u>Estimate</u>	<u>Adjustments</u>	<u>Estimate</u>	<u>Notes</u>
<b>Owner Furnished Equipment</b>				
Gas Turbines	98.6		98.6	
SCR	18.8	(18.8)	0.0	Removed SCR scope not expected for installation in NC/VA
Sales Tax	7.3	(2.1)	5.2	Adjusted for VA 5.3% sales tax
<b>Total Owner Furnished Equipment</b>	<b>124.7</b>		<b>103.8</b>	
<b>Other EPC Costs</b>				
Equipment	30.7		30.7	
Construction Labor	48.2	(27.1)	21.1	PJM adjustment for CONE basis
Other Labor	19.0		19.0	
Materials	9.4		9.4	
Sales Tax	2.5	(0.4)	2.1	Adjusted for VA 5.3% sales tax
EPC Contractor Fee	23.5	(4.8)	18.7	Reflects changes in scope & costs
EPC Contingency	25.8	(5.3)	20.5	Reflects changes in scope & costs
<b>Total Other EPC Costs</b>	<b>159.1</b>		<b>121.5</b>	
<b>Non-EPC Costs</b>				
Project Development	14.2	(2.9)	11.3	Brattle estimate based on 5% of EPC costs, reflects changes in EPC scope & costs
Mobilization and Start-Up	2.8	(0.6)	2.2	Brattle estimate based on 1% of EPC costs, reflects changes in EPC scope & costs
Net Start-Up Fuel Costs	4.7	(3.1)	1.6	Adjusted to be consistent with avoided fuel cost projections
Electrical Interconnection	12.9	(7.9)	5.0	Reflects economies of 4 CT site and exclusion of network upgrades.
Gas Interconnection	22.6	(19.0)	3.6	Reflects economies of 4 CT site and 1 mile lateral expected for installation in NC/VA
Land	1.6		1.6	
Fuel Inventories	5.2	(1.0)	4.2	Adjusted to be consistent with avoided fuel cost projections
Non-Fuel Inventories	1.4		1.4	
Owner's Contingency	5.9	(3.1)	2.8	Brattle estimate based on 9% of Non-EPC costs, reflects changes in scope & costs
Financing Fees	8.5	(8.5)	0.0	Financing fees and costs included in Economic Carrying Charge
<b>Total Non-EPC Costs</b>	<b>79.8</b>		<b>33.6</b>	
Total Capital Costs (\$2018 nominal)			258.9	
Annual Escalation Rate			3.0%	
Total Capital Costs (\$2014 nominal)			230.1	
Removal of Equipment Costs			(106.2)	Based on 2013 GTW Handbook - Two GE 7F 5 CTs, escalated to \$2014
<b>Other Costs, Incl. Owner &amp; Construction Costs (\$2014 nom.)</b>			<b>123.9</b>	
<b>Total Cost</b>				
<b>Total Cost (\$2014 nom., millions)</b>			<b>225.2</b>	
ISO Base Load Capacity (MW)			464	Based on 2013 GTW Handbook
Total Cost (\$2014 nom./kW)			485	

In their March 2015 Filings, neither DEC nor DEP included a DNCP-like disclosure of data underlying their avoided capacity cost calculations. Additionally, neither utility publicly disclosed the “publicly available industry sources” on which they

relied. This failure to disclose by DEC and DEP significantly delayed NCSEA's ability to analyze DEC's and DEP's March 2015 Filings, since NCSEA had to resort to the discovery process to obtain data, much of which was marked as "confidential" when provided.

Prior to the March 2015 Filings, DEC and DEP filed certain avoided cost information with the Commission in this docket, made pursuant to section 292.302(b) of the FERC's regulations.<sup>158</sup> However, in the filing, DEC redacted the capacity cost data, as follows:<sup>159</sup>

CAPITAL AND ENERGY COSTS OF PLANNED ADDITIONS	
18 C.F.R. § 292.302(b)(3)	
The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.	
<u>RESPONSE:</u>	
<u>ESTIMATED CAPITAL AND ENERGY COSTS FOR PLANNED CAPACITY ADDITIONS</u>	
(Capacity cost reflects generic unit assumptions, overnight in-service year \$, and excludes AFUDC. Energy cost reflects in-service year \$.)	
2017 (Nov)	670 MW Lee Combined Cycle Installation
	Capacity Cost - [REDACTED]
	Energy Cost - [REDACTED]
2020	866 MW Combined Cycle Installation
	Capacity Cost - [REDACTED]
	Energy Cost - [REDACTED]
2024	1,124 MW Lee Nuclear Installation
	Capacity Cost - [REDACTED]
	Energy Cost - [REDACTED]

DEP, likewise, redacted the capacity cost data as follows:<sup>160</sup>

<sup>158</sup> DEC and DEP's Avoided Cost Informational Filing, N.C.U.C. Docket No. E-100, Sub 140, December 23, 2014 (public version) ("DEC/DEP Informational Filing").

<sup>159</sup> DEC/DEP Informational Filing, p. 6.

<sup>160</sup> DEC/DEP Informational Filing, p. 10.

CAPITAL AND ENERGY COSTS OF PLANNED ADDITIONS 18 C.F.R. § 292.302(b)(3)	
The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.	
<u>RESPONSE:</u>	
<u>ESTIMATED CAPITAL AND ENERGY COSTS FOR PLANNED CAPACITY ADDITIONS</u>	
(Capacity cost reflects generic unit assumptions, overnight in-service year \$, and excludes AFUDC. Energy cost reflects in-service year \$.)	
2017	84 MW Aero Combustion Turbine Installation Capacity Cost – [REDACTED] Energy Cost – [REDACTED]
2018 (Dec)	126 MW Aero Combustion Turbine Installation Capacity Cost – [REDACTED] Energy Cost – [REDACTED]
2020	866 MW Combined Cycle Installation Capacity Cost – [REDACTED] Energy Cost – [REDACTED]
2021	792 MW Combustion Turbine Installation Capacity Cost – [REDACTED] Energy Cost – [REDACTED]
2022	866 MW Combined Cycle Station Installation Capacity Cost – [REDACTED] Energy Cost – [REDACTED]

By way of comparison, DNCP publicly disclosed the specific capacity data in its analogous filing in this docket.<sup>161</sup>

### **C. Action Is Necessary To Ensure Compliance with PURPA's Transparency Mandate**

In explaining its ability to penalize electric utilities for failing to comply with the public disclosure requirements of its regulations, the FERC emphasized the importance of public disclosure of these data:

As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived; § 292.302 is thus a critical element in this program. [FERC] believes that, with regard to utilities subject to section 133 of PURPA, [FERC] may exercise its authority under section 133 to require the data required by § 292.302(b) on

<sup>161</sup> DNCP's Avoided Cost Information Required by 18 C.F.R. § 292.302(b)(1)-(3), N.C.U.C. Docket No. E-100, Sub 140, March 2, 2015.

the basis that [FERC] finds such information necessary to allow determination of the costs associated with providing electric services.<sup>162</sup>

DEC and DEP failed to file for public inspection the specific capacity cost data required to be disclosed by section 292.302(b).<sup>163</sup> To date, the Commission has not authorized the filing of a PURPA-compliant alternative set of data from which their avoided costs can be derived, per section 292.302(d). At this time, NCSEA does not oppose DEC's and DEP's maintaining as confidential the specific capacity cost data required to be disclosed by section 292.302(b)(3), so long as DEC and DEP file for public inspection, pursuant to section 292.302(d), an alternative set of data from which avoided costs can be derived.

Thus, in light of the FERC's characterization of transparent data as a "critical element" in the avoided cost calculations, NCSEA recommends that the Commission require that the Utilities, in future biennial avoided cost proceedings, file for public inspection – as part of their initial filings – data underlying the capacity cost calculations.

### CONCLUSION

NCSEA respectfully requests that the Commission take the foregoing comments and recommendations into consideration in this docket.

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<sup>162</sup> Order No. 69, ¶¶ 30,340-30,341.

<sup>163</sup> NCSEA understands that DEC and DEP desire to maintain the confidentiality of the specific capacity data required to be disclosed by 18 C.F.R. § 292.302(b)(3) because these data:

reflect DEC's and DEP's costs to procure additional energy and/or capacity. For DEC and DEP to obtain the most cost effective energy and capacity necessary to meet the needs of their customers, each must protect from public disclosure its projected and actual costs to procure such energy, capacity, or both.

DEC/DEP's Avoided Cost Informational Filing, p. 1.

Respectfully submitted this the 22<sup>nd</sup> day of June, 2015.

LAW OFFICE OF CHARLOTTE MITCHELL, PLLC

/s Charlotte A. Mitchell  
NC Bar #34106  
Law Office of Charlotte Mitchell, PLLC  
PO Box 26212  
Raleigh, North Carolina 27611  
Telephone: (919) 260-9901  
E-mail: [cmitchell@lawofficecm.com](mailto:cmitchell@lawofficecm.com)

ATTORNEY FOR NCSEA



**CERTIFICATE OF SERVICE**

The undersigned certifies that she has served a copy of the foregoing **INITIAL COMMENTS BY NCSEA** upon the parties of record in this proceeding, or their attorneys, by electronic mail.

This 22<sup>nd</sup> day of June, 2015.

/s Charlotte A. Mitchell

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