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DOCKET NO. E-100, SUB 127

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N.C. Utilities Commission

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	INITIAL
Rates for Electric Utility Purchases from	)	STATEMENT OF
Qualifying Facilities - 2010	)	THE PUBLIC STAFF

NOW COMES THE PUBLIC STAFF - North Carolina Utilities Commission, by and through its Executive Director, Robert P. Gruber, pursuant to the Commission's Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing issued on May 5, 2010, and submits this initial statement responding to the electric utilities' statements and exhibits filed on November 1, 2010.

A. <u>INTRODUCTION</u>

Since the passage of the federal Public Utility Regulatory Policies Act of 1978 (PURPA) and the enactment of G.S. 62-156 by the North Carolina General Assembly in 1979, the Commission has held biennial proceedings to determine the electric utilities' avoided cost rates and the terms and conditions under which the rates must be offered to generating facilities that qualify under PURPA and to those that are eligible for contracts under G.S. 62-156.

Section 210 of PURPA, together with the regulations promulgated pursuant thereto by the Federal Energy Regulatory Commission (FERC), requires electric utilities to offer to purchase electric power from cogeneration and small power production facilities that obtain qualifying facility (QF) status under PURPA. For such purchases, a utility is required to pay rates that reflect the costs that it can avoid as a result of obtaining the energy and capacity from QFs, rather than generating the electricity itself or buying it from other suppliers.

Under G.S. 62-156, every two years the Commission must determine the rates electric utilities must pay small power producers. The definition of small power producers in G.S. 62-3(27a) is more restrictive than that contained in PURPA (which includes virtually all types of renewable fuels) and applies only to hydroelectric facilities with a capacity of 80 megawatts (MW) or less.

In its first proceeding under Section 210 of PURPA and G.S. 62-156, the Commission determined that the best way to implement both of these statutes was to approve long-term levelized rates for all QFs. Since then, the availability of long-term rates has been gradually reduced. Currently, ten-year and 15-year levelized rates are available only to hydro QFs and QFs fueled by trash or methane derived from landfills, solar, wind, hog or poultry waste-fueled or non-animal biomass-fueled, contracting to sell five MW or less. Other QFs contracting to sell three MW or less are eligible for five-year levelized rates.

B. PROPOSED RATES

Since the initial biennial proceedings, in which several different methodologies were approved for calculating avoided costs, the Commission has consistently approved the Peaker Methodology for Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), and Duke Energy Carolinas, LLC (Duke). Under this methodology, avoided capacity costs are estimated using the capital costs of a combustion turbine (CT), and avoided energy costs are estimated using a cost simulation model to analyze marginal system running costs with and without a block of QF power. The Commission also has consistently approved the differential revenue requirement (DRR) method for Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (NC Power). The DRR method involves a comparison of the revenue requirements that result from two different system expansion plans, one with and one without QF power. In Docket No. E-100, Sub 106, the Commission approved for NC Power in addition to the DRR method an LMP method based on market clearing prices of power in the market operated by PJM, Interconnection, LLC (PJM).

All three utilities generally calculated variable, five-year, ten-year, and 15-year capacity and energy rates in the same manner as in previous proceedings. Duke and PEC have increased their proposed avoided capacity rates above the levels approved in the 2008 avoided cost proceeding, while NC Power has proposed lower rates. PEC's proposed two-year, five-year, ten-year, and 15-year avoided capacity rates are 6% higher, on average, than the rates approved in the 2008 proceeding. For Duke, the average increase for the proposed two-year, five-year, ten-year, and 15-year avoided capacity rates is 2%. The average decrease proposed by NC Power is 19% for the proposed five-year, ten-year, and 15-year avoided capacity rates.

With respect to the proposed changes in the avoided energy rates, all three utilities have decreased their proposed rates above the levels approved in the 2008 avoided cost proceeding. PEC's proposed two-year, five-year, ten-year, and 15-year avoided energy rates are, on average, 3% lower than the approved rates in the 2008 proceeding. For Duke, the proposed two-year, five-year, ten-year, and 15-year avoided energy rates are, on average, 8% lower, than the approved rates in the 2008 proceeding. For NC Power, the proposed two-year, five-year, ten-year, and 15-year avoided energy rates are, on average, 29% lower than the approved rates in the 2008 proceeding. Some decrease is to be expected given that, in 2008, higher natural gas prices were predicted for the near term. However, the recent slowdown in the economy and the emergence of shale gas resources have contributed to projections of lower fuel prices, especially for natural gas.

It is important that the projected costs of the new CTs used in the determination of avoided capacity rates are consistent with the costs of new generation used in the utilities' respective generation expansion plans in each utility's IRP. Likewise, it is important that the projected costs of fuels and other assumptions used to simulate future avoided cost of energy are also used in determining the least cost mix of resources in the utilities' IRPs. The Public Staff has determined that PEC, Duke, and NC Power have employed many of the same assumptions that were also used to support their IRPs. The vast majority of the differences between the assumptions can be explained given the different applications of the models, i.e., IRP models focus on evaluating various mixes of resources over a wide range of scenarios and avoided cost or production cost models involve a more detailed unit commitment and dispatch program over certain blocks of time for every hour over the next 15 years.

The Public Staff's comments with respect to each utility's avoided cost calculations are summarized below. Unless otherwise noted, the rates discussed are for QFs that are interconnected at the distribution level. The rates for QFs interconnecting at the transmission level can be calculated by applying the appropriate adjustment for line losses (which lowers the rate somewhat).

PEC

Capacity: In regard to PEC's avoided capacity rates, the projected capital cost for an installed CT is the single most important factor. As in the 2008 proceeding, PEC selected Burns and McDonnell Engineering Company, Inc. (B&M), to provide a cost estimate for a CT. B&M projected the installed cost to be **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]** for a generic 190 MW CT at a four-unit site. This represents a 1% increase relative to the 2008 estimate of **[BEGIN CONFIDENTIAL **** END CONFIDENTIAL]** that underlies PEC's currently approved capacity rates and a **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** increase relative to the EPRI TAG estimate of **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** used by PEC in the 2006 proceeding.

The second most important factor in the determination of avoided capacity rates is the real or inflation-adjusted economic carrying charge rate. PEC's Exhibit 2, page 1 of 2, filed confidentially on November 1, 2010, shows the real economic carrying charge rate of **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** as compared to **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** in 2008. The rate is multiplied by the installed capacity cost per kW. The decrease in the real economic carrying charge rate is largely due to a decrease in the expected inflation rate. The **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** economic carrying charge rate includes a discount rate, projected inflation rate, depreciation costs, property taxes, and insurance. The increase in the real or inflation adjusted, economic carrying charge is largely due to a decrease in the projected inflation rate from 3.0% to 2.0%. PEC has proposed to decrease its net-of-tax nominal discount rate from **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]**. This decrease in the discount rate is attributable to decreases in PEC's projected cost of debt from **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]**. The effect of the decrease in PEC's cost of debt is partially offset by an increase in the amount of equity reflected in the discount rate. The discount rate embodied in the economic carrying charge in the previous two proceedings reflected a 50% common equity ratio and 50% long-term debt; however; in this proceeding PEC has applied a capital structure ratio consisting of 52% common equity and 48% long-term debt. As in previous proceedings, PEC has incorporated the effect of the Section 199 of the American Jobs Creation Act of 2004, which reduces the taxes associated with capital investments and job creation. The effect of the related tax deduction has reduced PEC's combined marginal tax rate to **[BEGIN CONFIDENTIAL *** . END CONFIDENTIAL]**

As in previous avoided cost proceedings, PEC made the following adjustments to the installed CT costs: (1) an adjustment to increase costs reflecting avoided general plant costs of **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]**; (2) a 2011 amount of fixed operation and maintenance (O&M) costs of **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** per kW-year which is inflated and then levelized for the two-year, five-year, ten-year, and 15-year periods, (3) an increase for working capital, which in this proceeding is **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]**; and (4) for transmission level rates, a marginal transmission capacity loss adjustment of **BEGIN CONFIDENTIAL] ** END CONFIDENTIAL]**. PEC then applied a performance adjustment factor (PAF) of 2.0 for hydroelectric QFs with no storage capacity and 1.2 for all other QFs, as approved by the Commission in previous avoided cost proceedings. Using the number of on-peak hours per season, PEC derived per-kilowatt-hour (kWh) seasonal capacity rates from the adjusted annual costs. These calculations are shown in PEC's Exhibits 4 and 5 that filed confidentially on November 1, 2010.

The following tables show PEC's proposed variable, five-year, ten-year, and 15-year levelized capacity rates during the summer and non-summer months and the percentage change from the 2008 rates, for hydroelectric QFs with no storage capacity and for all other QFs:

PEC's proposed Schedule CSP-27: Hydroelectric QFs with No Storage Capacity - Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	5.555	+8%	5.708	+7%	5.949	+5%	6.166	+3%
Non-summer	4.584	+8%	4.710	+7%	4.909	+5%	5.088	+3%

Note: The proposed levelized capacity rates are shown in PEC's proposed Schedule CSP-27, page 3 of 5.

PEC's proposed Schedule CSP-27: All Other QFs - Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	3.333	+8%	3.425	+7%	3.569	+5%	3.700	+3%
Non-summer	2.751	+8%	2.826	+7%	2.945	+5%	3.053	+3%

Note: The proposed levelized capacity rates are shown in PEC's proposed Schedule CSP-27, page 3 of 5.

Energy: PEC's avoided energy rates were calculated using the same methodology as in previous proceedings. PEC used PROSYM, a production simulation model developed by Ventyx Energy, LLC, to estimate its marginal avoided fuel costs for on-peak and off-peak periods over the next 15 years. Production simulation models that simulate hourly generation costs require hundreds of inputs. In regard to the calculation of avoided energy rates, the projected cost for fuels generally, has the largest influence in determining avoided energy rates. The Public Staff has reviewed the PROSYM inputs on the projected MWs of generation, variable O&M, outage rates of

PEC's generation units, the price forecasts for delivered natural gas, coal, oil, and uranium, the projected prices of SO_2 and NOX emission allowances, the projected MWh generation from renewable energy resources, projected energy purchases, and other inputs, such as the hourly energy cost per MWh required before a demand-side management program (DSM) is dispatched in the model. Based on its review, the Public Staff believes that the inputs used in the model are reasonable for the determination of PEC's avoided energy costs.

While the Public Staff supports the inputs incorporated in the PROSYM model there are concerns with the exclusion of start costs in the output data that contains the on-peak and off-peak marginal energy rates that underlie PEC's avoided energy costs. The Public Staff's concern is discussed in Section C, "Contested Issues and Concerns" below. PEC's proposed variable, five-year, ten-year, and 15-year levelized energy rates, in cents per kWh, for on-peak and off-peak periods, with the percentage change from existing rates, are shown below:

PEC's proposed Schedule CSP-27: Energy Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	4.758	-14%	5.161	-8%	5.751	-2%	6.150	+5%
Off-peak	4.136	-4%	4.271	-2%	4.468	0%	4.678	+5%

Note: The proposed levelized energy rates are shown in PEC's proposed Schedule CSP-27, page 3 of 5.

DUKE

Capacity: Duke's calculation of avoided capacity costs is based on the costs of a CT, which is the method consistently approved by the Commission in previous proceedings. Duke estimated that the cost to install a 204 MW CT is **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]** for a four-unit site. This represents a 4% decrease over the **[BEGIN CONFIDENTIAL ***** END CONFIDENTIAL]** per kW that underlies Duke's currently approved capacity rates and a

[BEGIN CONFIDENTIAL ** [END CONFIDENTIAL] increase relative to the 2006 estimate of **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]**.

Duke then multiplied the installed capacity cost per kW by a real fixed charge rate of **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]**, which includes a 2.3% inflation rate. This **[BEGIN CONFIDENTIAL ****** END CONFIDENTIAL]** long-term fixed charge rate that was incorporated in the 2008 proceeding, which also included a projected 2.30% inflation rate.

Similar to PEC's economic carrying charge rate, Duke's fixed charge rate includes a discount rate, projected inflation rate, depreciation costs, property taxes, and insurance. Relative to the 2008 biennial proceeding, Duke decreased its net-of-tax nominal discount rate from **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]**. The reduction in Duke's discount rate is partially attributable to the reduction in Duke's approved return on common equity from 11.0% to 10.7% in Docket No. E-7, Sub 909, a reduction in the projected cost of debt from **[BEGIN CONFIDENTIAL *** END CONFIDENTIAL]**, and a reduction in the ratio of common equity in the capital structure from 53.86% to 52.90%. Duke has incorporated the effect of the Section 199 of the American Jobs Creation Act of 2004, which has helped to reduce Duke's combined marginal tax rate to **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]**.

As in previous avoided cost proceedings, Duke made the following adjustments to the installed CT costs: (1) an adjustment to reflect avoided fixed O&M costs, which is **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]** per kW-year in this proceeding; (2) an adjustment for working capital, which is **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]** in this proceeding; and (3) a marginal transmission capacity loss adjustment of **[BEGIN CONFIDENTIAL ** END CONFIDENTIAL]**. Duke applied a PAF of 2.0 for hydroelectric QFs with no storage capacity and 1.2 for all other QFs. Based on the number of on-peak hours per season, Duke derived per-kWh seasonal capacity rates for transmission level rates.

Shown in the tables below are Duke's revised proposed variable, five-year, ten-year, and 15-year levelized capacity rates during the summer and non-summer months and the percentage change from the 2008 rates for (1) hydroelectric QFs under Option A and Under Option B and (2) other QFs under Option A and Option B:

Duke's Schedule PP: Hydroelectric QFs with No Storage Capacity - Option A Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	4.60	+7%	4.75	+5%	4.98	-1%	5.20	-3%
Off-peak	0.91	+7%	0.94	+4%	0.99	-1%	1.03	-3%

Note: The proposed levelized capacity rates are shown in Duke's Revised Exhibit 2, page 5 of 9.

Duke's Schedule PP: All Other QFs - Option A Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	2.76	+7%	2.85	+5%	2.99	-1%	3.12	-3%
Off-peak	0.55	+8%	0.56	+4%	0.59	-2%	0.62	-3%

Note: The proposed levelized capacity rates are shown in Duke's Revised Exhibit 2, pages 5 and 6 of 9.

Duke's Schedule PP: Hydroelectric QFs with No Storage Capacity - Option B Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	16.16	+7%	16.68	+4%	17.51	-1%	18.28	-3%
Off-peak	2.50	+7%	2.58	+4%	2.71	-1%	2.83	-3%

Note: The proposed levelized capacity rates are shown in Duke's Revised Exhibit 2, page 6 of 9.

Duke's Schedule PP: All Other QFs - Option B Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	9.70	+7%	10.01	+4%	10.51	-1%	10.97	-3%
Off-peak	1.50	+7%	1.55	+5%	1.63	-1%	1.70	-3%

Note: The proposed levelized capacity rates are shown in Duke's Revised Exhibit 2, page 6 of 9.

Energy: Duke's avoided energy rates were calculated using the same methodology as in previous proceedings. Duke used PROSYM to estimate its marginal avoided fuel costs for on-peak and off-peak periods over the next 15 years. The Public Staff has reviewed the PROSYM inputs on the projected operation of Duke's generation units, variable O&M, the price forecasts for delivered natural gas, coal, oil, and uranium, the projected prices of SO_2 and NOX emission allowances, the projected MWh generation from renewable energy resources, projected energy purchases, and other inputs, such as the hourly energy cost per MWh required before DSM is dispatched in the model. Based on its review, the Public Staff believes that the inputs into the model and the output data from the model are reasonable for the determination of Duke's avoided energy costs. Duke's proposed variable, five-year, ten-year, and 15-year levelized energy rates, in cents per kWh, for on-peak and off-peak periods, with the percentage change from existing rates, for both Option A and Option B, are shown below:

Duke's Schedule PP: Hydroelectric and Non-Hydroelectric QFs – Option A Energy Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	5.11	-19%	5.30	-16%	6.11	-5%	6.50	0%
Off-peak	3.98	-17%	4.07	-12%	4.46	+1%	4.67	+4%

Note: The proposed levelized energy rates are shown in Duke's Revised Exhibit 2, pages 2 and 6 of 9.

Duke's Schedule PP: Hydroelectric and Non-Hydroelectric QFs – Option B Energy Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	5.37	-19%	5.54	-16%	6.36	-4%	6.78	0%
Off-peak	4.29	-18%	4.40	-14%	4.94	-2%	5.20	+3%

Note: The proposed levelized energy rates are shown in Duke's Revised Exhibit 2, pages 2 and 6 of 9.

NC POWER

In its filing, NC Power maintains that the locational marginal pricing methodology offers several benefits, including the fact that it is transparent to all parties, it will enable QFs to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects true avoided costs. Under this proposal, QFs would be paid for delivered energy and capacity the equivalent of what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kW would be the PJM Dominion Zone Day-Ahead hourly locational marginal prices (LMPs) divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs who elect to supply energy only would be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website.

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

The DRR method is a more traditional method used to determine avoided costs, and it involves a comparison of the revenue requirements of two different system expansion plans. These plans are referred to as the "base" case and the "with" case. The "base" case plan assumes that all future power requirements are met entirely by NC Power's generation resources, market purchases, DSM, energy efficiency, and other resources. The "with" case plan assumes a zero cost 150 MW block of QF capacity is added to the system. All other assumptions in the model remain the same. The difference in the revenue requirements produced by the two plans represents the utility's avoided costs. The annual differences in these revenue requirements are then converted into present value terms.

<u>Capacity</u>: NC Power's Schedule 19-DRR includes a payment for capacity that incorporated the PJM reliability pricing model (RPM) as a proxy for avoided capacity costs for 2011 through 2013, to which NC Power then applied forecasted capacity prices from ICF International, Inc. (ICF), for 2014 through 2026. The projected capacity prices yielded a levelized five-year capacity cost of **[BEGIN CONFIDENTIAL**

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END CONFIDENTIAL]. The Public Staff performed a comparison of these forward prices to the projected costs of a CT by Duke and PEC. While the influence of the RPM significantly lowers the five-year capacity rate, the 10-year and 15-year rate are comparable to the rates proposed by Duke and PEC that reflect the installed cost of a CT. In conclusion, the Public Staff does not object to the proposed forward capacity costs being used to determine the avoided capacity rates for NC Power in this proceeding. The Public Staff, however, intends to review the use of the RPM prices as a proxy in future proceedings.

The proposed DRR-based five-year, ten-year, and 15-year levelized avoided capacity rates, with the percentage change from existing rates, are as shown in the following table in cents per kWh. The rates shown below reflect the 2011 initial year of operation.

NC Power's Schedule 19 – Capacity Rates Based on the DRR Method

	Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change
On-peak	0.379	-51%	0.905	-9%	1.131	+5%

Note: The proposed levelized capacity rates are shown in NC Power's Schedule 19-DRR, Paragraph VII in Exhibit DNCP-2.

Energy: NC Power's avoided energy rates were determined using PROMOD, a production simulation model developed by Ventyx Energy, LLC, to estimate its marginal avoided fuel costs for on-peak and off-peak periods over the next 15 years. NC Power incorporated a "base" case and "with" QF capacity case with the resulting output used to determine the avoided energy rates and energy mixes. The Public Staff has reviewed the PROMOD inputs on the projected MW generation, variable O&M, outage rates of generation units, the price forecasts for delivered natural gas, coal, oil, and uranium, the projected prices of SO_2 and NOX emission allowances, the projected MWh generation from renewable energy resources, projected energy purchases, and other inputs, such as the hourly energy cost per MWh required before DSM is dispatched in the model. Based on its review, the Public Staff believes that the inputs into the model and the output data from the model are reasonable for the determination of NC Power's avoided energy costs. The rates shown below reflect the 2011 initial year of operation and reflect the five-year, ten-year, and 15-year energy rates available for a QF with an aggregate nameplate rating of 100 kW or less.

NC Power's Schedule 19-DRR – 100 kW Firm Energy Rates

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	5.009	-46%	5.271	-34%	5.998	-24%	6.621	-19%
Off-peak	3.846	-44%	4.007	-31%	4.633	-21%	5.220	-15%

Note: The proposed levelized capacity rates are shown in NC Power's Schedule 19-DRR, Paragraph VI, Sections A and C, in Exhibit DNCP-2.

C. CONTESTED ISSUES AND CONCERNS

1. PEC's exclusion of start costs from PROSYM's output data values used to calculate avoided energy costs and rates

As discussed in the Public Staff's filings in the EPCOR and PEC arbitration case in Docket No. E-2, Sub 966, the Public Staff believes that PURPA requires the inclusion of the start costs included in the Total System Cost output from PROSYM in the calculation of on-peak and off-peak marginal energy costs. The arguments for relying on the Total System Cost output provided by EPCOR, which were supported by the Public Staff and Ms. Amparo Nieto of the National Economic Research Associates, Inc. (NERA), caused PEC to agree for purposes of the EPCOR proceeding to include start costs for the purpose of determining the avoided energy rates to which EPCOR was entitled (as noted in PEC's filing on August 9, 2010 in the above-referenced docket).

In the EPCOR arbitration case, arguments were made against PEC's focus on short-run marginal costs and the use of incremental or theoretical heat rates because such a focus understates fuel costs and does not represent the full cost incurred to run the marginal unit. In this proceeding, PEC assumed 100 MWs of QF power in its 100 MW Purchase Case, which it then compared to its Base Case. However, for purposing of proposing avoided energy rates for its standard tariff, it effectively assumed that the 100 MW would never alter its dispatch stack. In actuality, 100 MW of QF is likely to cause a peaking unit not to be started at all in some hours, thus avoiding the start up costs associated with that peaking unit. It also may alter the assumed dispatch of PEC's other generating units, as compared to PEC's Base Case. PEC considers its exclusion of start up costs to be appropriate because it believes small QFs will not affect the order in which its generating units are dispatched. While it might be appropriate to use incremental heat rates to calculate the avoided costs associated with an isolated, limited alternative generation source, the Public Staff does not believe it is an appropriate application of the Peaker Method for the purpose of calculating avoided energy costs.

Both EPCOR and the Public Staff argued in the arbitration proceeding that the inclusion of start costs as reflected in the Total System Cost is more accurate and more consistent with PURPA's avoided cost principles. While PEC agreed to the inclusion of start costs in the EPCOR proceeding, it filed an affidavit in that proceeding to the effect that the inclusion of start costs is applicable only to large QFs and not small QFs. The affidavit submitted by PEC witness of Larry Brockman, in Docket No. E-2, Sub 966, established two key arguments against the inclusion of start costs in the calculation of avoided energy costs for the CSP tariff: one, that the generation from a QF is too small to affect the utility's overnight decisions to start or shut down one of its generating units; and two, small QFs are unreliable and generally non-dispatchable which makes it difficult to include QFs in overnight planning considerations. Furthermore, PEC noted that the decision to commit units must be made in advance of the total load to be served and the decision includes conservatism inherent in a process which both relies on a forecast and places a very high premium on the after-the-fact reliability of the result. It has continued to maintain this position in this proceeding.

The Public Staff believes that PEC's position on the impacts of small QFs is not entirely consistent with positions PEC has taken in both this proceeding and in other proceedings. Based on its investigation in the EPCOR case and in this proceeding, it is the Public Staff's understanding that PEC believes it is appropriate to calculate an average of the marginal energy costs from the Base Case and the 100 MW Purchase Case to adjust for the reduction in PEC's marginal cost of energy that occurs with each additional QF. As such, the average calculation represents a proxy for the avoided energy costs for all QFs. While the Public Staff does not agree with PEC's position on averaging,[1] it must be noted that this position of PEC's, which is that the addition of each small QF affects marginal energy costs, seems to be inconsistent with PEC's

[1] The Public Staff's position is stated in paragraph 21 in its Statement of Position in the EPCOR case. That paragraph states that the Public Staff believes that PURPA clearly requires that the hourly marginal costs for the 100 MW Purchase Case be subtracted from the hourly marginal costs for the Base Case and that PEC's method of averaging the PROSYM results for the two cases fails to produce PEC's actual avoided energy costs. For this proceeding, because it does not make an appreciable difference in the rates, the Public Staff did not make an adjustment in this regard, which is not intended to prejudice its ability to make such an adjustment in the future.

position that such additions (even in the aggregate) will not ever affect whether or not PEC needs to start one of its generating units.

PEC's position on this issue also seems inconsistent with its consideration of start costs when it decides whether to buy energy in the wholesale market. PEC's position in this regard was identified through a Public Staff data request in PEC's last fuel case in Docket No. E-2, Sub 976. In that proceeding, PEC's decision to purchase 50 MW of energy in the wholesale market included the savings from not having to start one of its units. This highlights the extent to which avoiding start costs can have a dramatic impact on the economics associated with purchased power.

An equally important point is the fact that PEC's methodology is inconsistent with Duke's and NC Power's inclusion of start costs in the output data used to calculate their respective avoided energy costs. The Public Staff also believes excluding start costs in the determination of avoided energy rates for small QFs is inconsistent with PURPA.

Section 292.302(b) of the FERC's regulations, which are codified at 18 C.F.R. 292.101 *et seq.*, requires electric utilities subject thereto to make available to QFs, not less than every two years, data from which avoided costs may be derived. Subsection 1 of this section requires the estimated avoided cost related to the energy component to be provided for various levels of purchases from QFs stated in blocks of not more than 100 MW for systems with peak demand of 1,000 MW or more by year for the current year and for each of the next five years. In its Order adopting regulations pursuant to Section 210 of PURPA, the FERC specifically discussed determining avoided costs by calculating the costs that would be incurred by a utility to meet a specified demand in comparison to the cost the utility would incur if it purchased energy or capacity or both from a QF. The difference between the two would represent the utility's net avoided costs. (*Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policy Act of 1978,* 45 Fed. Reg. 12,214, at 12,216.)

As implemented by the Commission, avoided energy rates determined by the Peaker Method have focused on a 100 MW difference in system marginal running costs. For example, as described by Public Staff witness Ben Johnson in his testimony filed in 1986 in Docket No. E-100, Sub 53, to estimate avoided energy cost, Duke assumed an off-system purchase of 100 MW and CP&L (now PEC) assumed a 100 MW increase in load when using the production costing model PROMOD. In both cases, it was the difference between the two PROMOD runs (one with 100 MW of load or purchase and one without) that produced the avoided energy rates.

Whether or not an individual QF contracting to sell 5 MW or less to a utility alters the actual dispatch stack of that utility does not determine the issue. All QFs are entitled to full avoided energy costs whether or not they are dispatchable[2] or of sufficient size to actually change the dispatch stack and a utility's system marginal running costs. It is for this very reason the FERC's regulations speak in terms of a 100 MW block.

In addition, the Public Staff observes that during the last three biennial proceedings, PEC's approved energy rates on an annualized basis have been, on average, significantly lower than Duke's annualized approved avoided energy rates. Given this difference in avoided energy rates, the Public Staff began monitoring Duke's and PEC's hourly, real-time, day-ahead lambdas and has compiled data for 2006 through 2010. Both lambdas and avoided energy costs are based on marginal fuel costs, variable O&M, and emission costs associated with the last generating unit dispatched. The principal difference between the lambdas and avoided energy costs is that the lambdas are based on day-ahead marginal costs while avoided energy costs are based on a forecast of marginal costs for the period associated with each rate (i.e., two years for the variable rate, five years for the five-year rate, and so on). For the 2010 calendar year and generally for the four preceding years, across 8,760 hours each year, Duke's average hourly marginal energy costs have been lower than PEC's

[2] The extent to which a QF is dispatchable or otherwise committed to be available during system peak hours is discussed in the FERC's regulations in terms of computing avoided capacity rates or payments, not avoided energy rates.

average hourly marginal energy costs, while Duke's annualized avoided energy costs have been higher.

For purposes of this proceeding, the Public Staff compared PEC's proposed variable on-peak avoided energy rate with the comparable rate proposed by Duke (the variable on-peak energy rate under Option A). The two-year variable rate was used for this comparison because it is more reflective of current conditions and influenced less by long-term forecasts. Duke shows annualized avoided energy rates for each contract term on its Revised Duke Exhibit 3, page 1 of 4. The annualized variable two-year energy rate, as proposed and shown on that exhibit, is 4.52 cents/kWh. PEC does not show such a calculation in its filing, but using PEC's data and performing the same calculation produces an annualized variable two-year energy rate for PEC of 4.37 cents/kWh, which is 3% lower than Duke's comparable proposed rate. Because PEC's actual marginal energy costs are fairly consistently higher than Duke's, PEC's variable on-peak energy rate should be higher. This observation lends support for the inclusion of start costs in PEC's PROSYM model output. If start costs are included, PEC's avoided energy rates are increased to a level somewhat above Duke's proposed avoided energy rates, which would be consistent with the recently tracked difference between their lambdas.

While it is true that some QFs cannot be assumed to be online at the time of peak and therefore they cannot be used in overnight decisions to commit generation units, the Public Staff believes that both the proper application of the Peaker Method and PURPA require the inclusion of start costs in the calculation of avoided energy rates for all QFs. Accordingly, the Public Staff recommends that the Commission order PEC to re-file its avoided energy costs using the Total System Cost output data in PROSYM (which include start costs) for all four proposed avoided energy rates (i.e., variable, five-year, ten-year and 15-year).

2. Tariff/Contract Issues

A. Interim Lack of Standard Rate Options

Both Duke and NC Power have provisions that make the currently approved *avoided cost rates unavailable as of the expected due date for the utilities' filing of* proposed new rates in the next biennial avoided cost proceeding. This mechanism replaced the Commission's practice of allowing a utility to file a motion to suspend the availability of the currently approved avoided cost rates and tariff, with QFs that had their certificates of public convenience and necessity (CPCN) as of the date of the motion being entitled to the existing rates. QFs that did not yet have their CPCNs and signed contracts at the new, proposed rates were entitled to have their payments increased if the Commission approved avoided cost rates higher than the rates proposed by the utilities (without being subject to such rates being decreased if lower rates were approved). Given the Commission's recent interpretation of the FERC's regulations in the arbitration proceedings in Docket Nos. E-2, Sub 966, and SP-467, Sub 1, the Public Staff questions whether it is consistent with PURPA to end the availability of approved avoided cost rates as of the date new proposed avoided costs rates are expected to be filed.

In its Order dated January 26, 2011, in Docket No. E-2, Sub 966, the Commission quoted language from its Order dated June 18, 2010, in Docket No. SP-467, Sub 1, interpreting the FERC's rule, 18 C.F.R. 292.304(b), that creates a legally enforceable obligation. The Commission stated that this rule gives a QF two important options and the utility must work with the QF's choices. A QF has the option to choose to sell power "as available" or to sell pursuant to a legally enforceable obligation over a specified term. If a QF chooses the latter option, it then has the option of choosing rates based upon avoided costs calculated at the time the obligation is incurred. The Commission further held that the prerequisites for legally enforceable obligation to have occurred were the QF having CPCN and making it sufficiently clear to the utility that it wanted to commit itself to sell its output pursuant to a legally enforceable obligation over a specified term.

Based on the foregoing interpretation of Section 292.304(b) of the FERC's regulations, it does not appear to be consistent with PURPA for a QF to be denied the currently approved avoided cost rates, when that QF has its CPCN, is eligible for the standard rates, and has indicated that it intends to commit itself. Even if the Commission were to conclude otherwise, at a minimum, the QF qualifying for the standard rates should be entitled to the proposed avoided cost rates, subject to those rates being trued up if the Commission approved higher rates.

B. Whether NC Power's Standard Rate Options Are Sufficiently Fixed to Comply with the FERC's Interpretation in the *J.D. Wind* Cases

On rehearing of its *J.D. Wind* cases[3], the FERC stated that its intention in its Order No. 69 was to enable a QF "to establish a fixed contract price for its energy and capacity at the outset of its obligation." (February 19 Order, ¶ 23) The FERC went on to say that it has consistently affirmed the QF's right to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.

Standard rate options for NC Power historically have included changes based upon long-term levelized generation mixes with adjustable fuel prices for QFs larger than 100 kW that are otherwise eligible for the standard rate options. Thus, only the first two years of a 15-year standard contract are fixed and stated in the tariff. (See NC Power's filing of November 1, 2011, Schedule 19-DRR, Section VI(B).) Given the FERC's recent *J.D. Wind* orders and this Commission's interpretation of those orders, it is not clear that this consistent with PURPA.

C. Contract Provisions Allowing Changes to Rates Based upon Subsequent Regulatory Action

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[3] *J.D. Wind 1, LLC*, 129 FERC ¶ 61,148 (2009), *reconsideration denied*, 130 FERC ¶ 61,127 (2010)(February 19 Order).

Subsequent Ratemaking Action. NC Power's current standard agreement provides in effect that if relevant state regulatory authorities or the FERC disallow payments under the agreement for ratemaking purposes, the QF is required to repay such amounts (as defined in the agreement) within 28 days. Given that this is a standard agreement for renewable QFs contracting to sell five MW or less, such a provision seems unwarranted and likely to discourage QF development. In addition, this requirement has the effect of changing the rate paid to the QF because of subsequent regulatory action, which was rejected in 1983 when language was proposed that would have allowed existing standard contracts to be amended as the result of subsequent governmental or judicial action. (See, Order dated April 1, 1983 relating to Duke Power Company, which was affirmed by the full Commission by Order dated June 3, 1983 (except in one instance not relevant here).)

Line Loss Provisions. NC Power has proposed in this proceeding to amend the line loss provision in Schedule 19-DRR to provide that energy prices will be increased by 3% until such time as an effective Schedule 19-DRR subsequently amended and approved by the Commission, revises this percentage to a future value. Historically, the Commission has not allowed the rate paid to a QF to be changed after a contract is signed. Line loss percentages typically do not change sufficiently over time for this to be of sufficient concern to change a precedent in existence for over two decades.

3. Duke's Nominal Fixed Charge Rate Calculation

The Public Staff has a question about Duke's nominal fixed charge rate calculation in that it appears to include a higher debt component of ADC. Due to the lateness of the Public Staff's questions Duke was unable to fully investigate and respond to the Public Staff's inquiry before the Public Staff's due date for filing. Duke has agreed to review the matter further and to follow up in reply comments as appropriate.

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

Respectfully submitted this the 1st day of March, 2011.

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CERTIFICATE OF SERVICE

I certify that I have served a redacted, public copy of the foregoing Initial Statement of the Public Staff on all parties of record in this proceeding, or their attorneys of record, by depositing a copy of the same in the United States Mail, first class postage prepaid, properly addressed to each.

This the 1st day of March, 2011.

Gisele L. Rankin

Gisele L. Rankin