NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

June 22, 2015

Ms. Gail Mount, Chief Clerk
North Carolina Utilities Commission
Mail Service Center 4325
Raleigh, North Carolina 27699-4325

Re: Docket No. E-100, Sub 140

Dear Ms. Mount:

In connection with the above-referenced docket, I transmit herewith for filing the Initial Statement of the Public Staff.

By copy of this letter, I am serving all parties of record with the public version of this report. Parties that have signed confidentiality agreements will be served with confidential versions as appropriate.

Sincerely,

/s/ Tim R. Dodge
Tim R. Dodge
Staff Attorney
tim.dodge@psncuc.nc.gov

Attachment

cc: Parties of record

PUBLIC

Initial Statement of the Public Staff

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

Docket No. E-100, Sub 140

June 22, 2015

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INTRODUCTION

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 avoided cost rates of Dominion North Carolina Power (DNCP), Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, Inc. (DEP), (collectively, "the electric utilities"), 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 (Docket No. E-100, Sub 41), 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 reduced. Currently, ten-year and 15-year levelized rates are available only to hydroelectric QFs, QFs fueled by trash or methane derived from landfills, solar, wind, hog or poultry waste, or non-animal biomass-fueled QFs, contracting to sell five MW or less. Other QFs contracting to sell three MW or less are eligible for five-year levelized rates.

PHASE ONE ORDER SETTING INPUT PARAMETERS

On February 25, 2014, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing in Docket No. E-100, Sub 140 for the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (the 2012 proceeding). The Commission initiated the first phase of the 2014 avoided cost proceeding in advance of requiring the filing of new proposed rates by the utilities, stating that such rates would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing "to consider changes to the method used to calculate avoided cost payments, particularly capacity payments, including, but not limited to, whether a 2.0 performance adjustment factor (PAF) for run-of-river hydroelectric facilities with no storage capability should be continued, whether avoided capacity payments are more appropriately calculated based on installed capacity rather than a per-kWh capacity payment, and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided costs."

On December 31, 2014, the Commission issued an Order Setting Avoided Cost Parameters (Phase One Order) which, among other things, established certain parameters by which avoided cost rates should be calculated and resolved several outstanding issues. As such, the Commission's Phase One Order provides significant guidance to the Public Staff's comments on the proposed rates filed by the utilities. On January 8, 2015, the Commission issued an Order directing the parties to proceed with the second phase of the E-100, Sub 140 proceedings, focusing on the proposed rates to be filed by the utilities. The Commission indicated its goal was to resolve all remaining issues in the docket based on the evidentiary record and written comments without conducting another full evidentiary hearing for the purpose of receiving expert testimony.

PROPOSED RATES[1]

Since the initial biennial proceeding, in which several different methodologies were approved for calculating avoided costs, the Commission has consistently approved the peaker methodology for DEC and DEP. DNCP traditionally used the Differential Revenue Requirements (DRR) methodology.

[1] For ease of comparison, the Public Staff uses the avoided capacity rates and avoided energy rates for QFs interconnected to the distribution system. The rates for QFs interconnecting at the transmission level can be calculated by applying the appropriate adjustment for line losses.

Starting in the 2012 proceeding, in response to the Commission's directive that DNCP file proposed fixed long-term levelized avoided energy rates for QFs entitled to standard contracts, DNCP also began to utilize the peaker methodology to calculate the avoided cost rates in its proposed Schedule 19-FP. Under the peaker 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. In addition, in its December 19, 2007, Order in Docket No. E-100, Sub 106, the Commission approved the locational marginal price (LMP) method for determining DNCP's avoided energy costs. The LMP method is based on market clearing prices of power in the market operated by PJM Interconnection, LLC (PJM).

As required by the Commission's January 8, 2015, Order, the electric utilities filed their Statements and Exhibits showing their proposed rates on March 2, 2015. DEC, DEP, and DNCP have generally calculated variable, five-year, ten-year, and 15-year capacity and energy rates in the same manner as approved in the 2012 proceeding. On an annualized basis[2] for both Option A and B rates, DEC has proposed to raise its 15-year capacity rates by approximately 6% and reduce the 15-year avoided energy rates by 19%. DEP's proposed annualized 15-year avoided capacity rates are 19% lower and its 15-year avoided energy rates are

[2] This approach presumes that the QF is operating during all of the tariff's prescribed on-peak and off-peak hours.

approximately 14% lower than the rates approved in the 2012 proceeding Similarly, DNCP has proposed to lower its annualized 15-year avoided capacity rates by 36% and its 15-year avoided energy rates by 17%.

The total annualized avoided cost rates for both energy and capacity may also be compared as shown in the table below:

Approved Option A and B Rates with a PAF=1.2 over a 15-Year Term

	DEC	DEP	DNCP
Annualized Energy Rate	5.02	4.87	5.071[3]
Annualized Capacity Rate	0.82	1.01	1.115
Annualized Total Rate	5.84	5.88	6.187

Proposed Option A and B Rates with a PAF=1.2 over a 15-Year Term

	DEC	DEP	DNCP
Annualized Energy Rate	4.09	4.18	4.207[4]
Annualized Capacity Rate	0.87	0.82	0.718
Annualized Total Rate	4.96	5.00	4.925

The Public Staff's comments with respect to each utility's avoided cost calculations are summarized in the following paragraphs.

[3] DNCP's approved annualized energy rate for Option A is shown above. The Option B rate is 5.065 cents per kWh, which makes the total annualized rate 6.181.

[4] DNCP's proposed annualized energy rate for Option A is shown above. The Option B rate is 4.203 cents per kWh, which makes the total annualized rate 4.921.

DEC

Capacity

The projected capital cost for an installed CT is the single most important factor in determining the avoided capacity rate. In the Phase One Order, the Commission concluded that:

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

Phase One Order at p.48.

DEC used the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG)[5] to provide the overnight capital cost estimate for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that were tailored to reflect the expected costs for the Carolina service area.[6]

[5] The EPRI TAG data is available by paid subscription only, which limits the public availability of the cost information, as opposed to the reports prepared by the U.S. Department of Energy, Energy Information Administration (EIA) and publications by PJM and other Regional Transmission Organizations (RTOs).

[6] In Docket No. E-100, Sub 127 (2010 proceeding) and in prior proceedings, DEC's installed estimate was based on the GE-7FA units.

DEC calculated the installed cost for a seasonal weighted four-unit site of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW to be **[BEGIN CONFIDENTIAL]** $[redacted] **[END CONFIDENTIAL]** which equates to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kilowatt (kW) as compared to the proposed cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW and the settled cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW approved in the 2012 proceeding. These cost estimates can also be compared with the rates of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW approved for DEC in the 2010 proceeding. The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** proposed cost estimate reflects an **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the approved installed cost per kW in the 2012 proceeding. The installed cost of the CT includes the cost of utilizing number #2 oil as a backup fuel, which allowed the Company to exclude the cost of securing firm pipeline capacity for the CT.

The second most important factor in the determination of avoided capacity rates is the real or inflation-adjusted fixed charge rate. The real fixed charge rate includes the discount rate (which includes the Company's allowed cost of equity), projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes. In this proceeding DEC reduced its fixed charge rate to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, as compared to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** approved in the

2012 and 2010 proceedings, respectively. The reductions in the real fixed charge rates are largely the result of the reduction in DEC's approved return on equity, a lower cost rate for long-term debt, expected reductions in the federal rate due to the use of the Manufacturing Tax Deduction, and lower state income tax rates. The multiplication of the installed cost times the real fixed charge rate produces the annual carrying cost of the CT.

Unlike previous avoided cost proceedings, DEC adopted an adjustment for avoided general plant that DEP had previously included. The adjustment increased the annual cost of the CT by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the estimated portion of general plant, such as corporate office buildings and vehicle fleets avoided by QF generation. As in previous proceedings, DEC made the following adjustments to the CT annual carrying costs: (1) an adjustment to reflect avoided fixed operations and maintenance (O&M) costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is a decrease from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW in 2012, and an increase from the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW from the 2010 biennial proceeding; (2) an adjustment for working capital of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**; and (3) marginal on-peak distribution and transmission loss adjustments of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, respectively. DEC applied a Performance Adjustment Factor (PAF) of 2.0 for hydroelectric QFs with no storage capacity and

1.2 for all other QFs. With respect to the non-hydroelectric QFs, which comprise the bulk of QFs interconnected with DEC's system, the combination of the annual CT carrying costs plus the impact of the 1.2 PAF and other adjustments produced **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the annual capacity cost (prior to levelization) as shown on page 11 of DEC Exhibit 6 or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year, as compared to the approximate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year approved in the 2012 proceeding. The increase in DEC's installed CT costs in this proceeding, was partially offset by the reductions in the discount rate, income taxes, and fixed O&M rate, resulting in annualized avoided capacity rates that are approximately 7% higher than those approved in the 2012 proceeding. The annual costs are levelized by determining the present value of the annual CT capacity costs and multiplying them by a 2-year, 5-year, 10-year, and 15-year annuity factor. Then the resulting annual credit is allocated between the on-peak and off-peak seasons to produce the capacity cost rate per kW, which is then divided by the number on-peak and off-peak hours to produce the on-peak and off-peak avoided capacity rates. DEC maintains that the allocation is based on the value of capacity during the on-peak months relative to the off-peak months. In this proceeding, DEC lowered the seasonal allocation for its on-peak months and raised the allocation for its off-peak months for both Option A and Option B rates for its hydroelectric and non-hydroelectric rate schedules. Because DEC shifted more of its seasonal allocation to off-peak months, it is difficult to compare the proposed on-peak and off-peak rates to those approved in 2012; however, an assessment can be conducted by comparing the annualized rates among the utilities.

The Public Staff does not take issue with DEC's calculation of its avoided cost of capacity for this proceeding. Shown in the tables below are DEC'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 approved 2012 cost rates for (1) hydroelectric QFs under Option A and Under Option B and (2) other QFs under Option A and Option B:

DEC's Schedule PP (NC): 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	3.18	-7%	3.29	-7%	3.47	-7%	3.64	-7%
Off-peak	1.59	134%	1.64	134%	1.73	134%	1.82	133%
Annualized	1.27	7%	1.31	7%	1.38	6%	1.45	7%

Note: The proposed capacity rates are shown in DEC's Exhibit 2, page 2 of 4, and the annualized rates are shown in DEC's Exhibit 3, page 3 of 4.

DEC's Schedule PP (NC): All Other QFs – Option A – Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	1.91	-7%	1.97	-8%	2.08	-7%	2.18	-7%
Off-peak	0.95	132%	0.99	136%	1.04	136%	1.09	132%
Annualized	0.76	6%	0.79	7%	0.83	6%	0.87	6%

Note: The proposed capacity rates are shown in DEC's Exhibit 2, page 2 of 4, and the annualized rates are shown in DEC's Exhibit 3, page 1 of 4.

DEC's Schedule PP (NC): 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	9.99	-17%	10.35	-17%	10.91	-17%	11.44	-17%
Off-peak	3.65	96%	3.78	97%	3.98	96%	4.18	96%
Annualized	1.27	7%	1.31	7%	1.38	6%	1.45	6%

Note: The proposed capacity rates are shown in DEC's Exhibit 2, page 3 of 4, and the annualized rates are shown in DEC's Exhibit 3, page 4 of 4.

DEC's Schedule PP (NC): All Other QFs – Option B – Capacity Credits								
	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
On-peak	6.00	-17%	6.21	-17%	6.55	-17%	6.87	-17%
Off-peak	2.19	96%	2.27	97%	2.39	96%	2.51	96%
Annualized	0.76	6%	0.79	7%	0.83	6%	0.87	6%

Note: The proposed capacity rates are shown in DEC's Exhibit 2, page 3 of 4, and the annualized rates are shown in DEC's Exhibit 3, page 2 of 4.

Energy

As in previous proceedings, DEC used Prosym to estimate its marginal avoided energy costs for its on-peak and off-peak hours over the next 2, 5, 10, and 15 years. The Public Staff has reviewed the Prosym inputs on the projected operation of DEC'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. Based on its review, the Public Staff has concerns with DEC's price forecasts for natural gas and coal, which are discussed later in Section D. Otherwise, the Public Staff believes that the remaining inputs into the model are reasonable for the determination of DEC's avoided energy costs.

In the Phase One Order, the Commission acknowledged that "purchasing solar power can be seen as the equivalent of buying natural gas forwards" and that "a utility's fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers." As such, 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," noting, however, that the hedging benefits "should be valued over the hedging terms actually used by DEC, DEP, and DNCP." (Phase One Order at 42)

In response to the Commission's directive, DEC likened the value of hedging to the purchase of a gas futures contract at the bid price; thereby, fixing the future price for which a third party would sell the gas. The Public Staff has concerns with this approach, as discussed in Section D.

DEC'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:

DEC's Schedule PP (NC): 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	3.86	-20%	3.97	-20%	4.20	-20%	4.54	-19%
Off-peak	3.09	-18%	3.18	-19%	3.47	-18%	3.69	-18%
Annualized	3.45	-19%	3.55	-20%	3.82	-19%	4.09	-19%

Note: The proposed levelized energy rates are shown in DEC's Exhibit 2, page 2 of 4 and the annualized rates are shown in DEC's Exhibit 3, page 1 of 4.

DEC's Schedule PP (NC): 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	3.87	-24%	3.96	-25%	4.24	-24%	4.58	-23%
Off-peak	3.33	-18%	3.44	-19%	3.70	-18%	3.96	-17%
Annualized	3.45	-19%	3.55	-20%	3.82	-19%	4.09	-19%

Note: The proposed levelized energy rates are shown in DEC's Exhibit 2, page 3 of 4 and the annualized rates are shown in DEC's Exhibit 3, page 2 of 4.

DEP

Capacity

Similar to DEC, DEP selected publically available data from EPRI to provide a cost estimate for a CT. Based on the studies, DEC projected the installed cost for a seasonal weighted four-unit site totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MW to be **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which equates to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kilowatt (kW) as compared to the settled cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW approved in the 2012 proceeding and the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW approved in the 2010 proceeding. The proposed rate reflects an increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the installed cost per kW approved in the 2012 proceeding.

As with DEC, the second most important factor in the determination of avoided capacity rates is the real or inflation-adjusted fixed charge rate. In an effort to bring more uniformity to the filings between the two companies, DEP substituted the fixed charge rate for the annual economic carrying charge rate. The economic carrying charge rate is similar to the fixed charge rate in that it reflects DEP's discount rate, projected inflation rate, depreciation costs, and taxes. Both methods are acceptable practices to convert a stream of costs into a single cost rate. DEP's Exhibit 6, page 11 of 36, filed confidentially on March 2, 2015, shows its CT real fixed charge rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Given the different capital cost recovery methods, there is limited value in comparing the real fixed charge rate in this proceeding to the economic carrying charge rate applied in the 2012 proceeding. However, it is noteworthy that DEP's cost of equity in its discount rate is based on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In addition, DEP included a lower cost rate for long-term debt, expected reductions in the federal rate due to the use of the Manufacturing Tax Deduction, and lower state income tax rates. DEP included an adjustment for avoided general plant which increased the annual cost of the CT by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the estimated portion of general plant, such as corporate office buildings and vehicle fleets avoided by QF generation. As in previous proceedings DEP made the following adjustments to the CT annual carrying costs: (1) an adjustment to reflect avoided fixed O&M costs of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which is a decrease from the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW approved in the 2012 proceeding, and a decrease from $5.12 per kW from the 2010 proceeding; (2) an adjustment for working capital of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in this proceeding; and (3) marginal on peak distribution and transmission loss adjustments of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, respectively. The combination of the annual CT carrying costs plus the adjustments produced an annual capacity cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. With respect to all other non-hydroelectric QFs, which comprise the bulk of the QFs interconnected to DEP's system, DEP applied a PAF of 1.2 and a marginal loss factor of 1.0221, which raised the annual capacity cost to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as shown on page 11 of DEP Exhibit 6, equating to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year. This annual capacity cost is lower than the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW-year approved in the 2012 proceeding. The approximate 20% decrease in DEP's annualized avoided capacity rates from the 2012 approved rates is largely attributable to the reductions in the discount rate, income taxes, and fixed O&M rate despite the increase in DEP's installed CT costs in this proceeding.

The Public Staff does not take issue with DEP's calculation of its avoided cost of capacity for this proceeding. The following tables show DEP'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 2012 rates, for hydroelectric QFs with no storage capacity and for all other QFs:

DEP's Schedule PP-1: 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
Summer	6.23	30%	6.45	30%	6.81	30%	7.14	31%
Non-summer	1.99	-48%	2.06	-48%	2.17	-48%	2.28	-47%
Annualized	1.19	-20%	1.23	-20%	1.30	-19%	1.36	-19%

Note: The proposed capacity rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 3 of 4.

DEP's Schedule PP-1: All Other QFs – Option A – Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	3.74	30%	3.87	30%	4.08	30%	4.29	31%
Non-summer	1.19	-48%	1.24	-48%	1.31	-47%	1.37	-47%
Annualized	0.17	-20%	0.74	-20%	0.78	-20%	0.82	-19%

Note: The proposed capacity rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 1 of 4.

DEP's Schedule PP-1: 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
Summer	9.38	17%	9.72	17%	10.25	18%	10.76	18%
Non-summer	3.43	-44%	3.55	-44%	3.74	-43%	3.93	-43%
Annualized	1.19	-20%	1.23	-20%	1.30	-19%	1.36	-19%

Note: The proposed capacity rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 4 of 4.

DEP's Schedule PP-1: All Other QFs – Option B – Capacity Credits								
	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	5.63	17%	5.83	17%	6.15	18%	6.45	18%
Non-summer	2.05	-44%	2.13	-44%	2.25	-43%	2.36	-43%
Annualized	0.71	-20%	0.74	-20%	0.78	-20%	0.82	-19%

Note: The proposed capacity rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 2 of 4.

Energy

DEP's avoided energy rates were calculated using the same methodology as in previous proceedings. DEP used Prosym to estimate its marginal avoided energy 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 DEP'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 has concerns with DEP's price forecasts for natural gas and coal, which are discussed in Section D below. In addition, DEP followed the same approach as DEC with regard to avoided hedging costs and did not value options using the Black-Scholes model; rather, it incorporated the "ask" price from quotes in futures market with its natural gas price forecast over the first 10 years of its 15-year price forecast.

The Public Staff believes that the other inputs into the model are reasonable for the determination of DEP's avoided energy costs. DEP'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:

DEP's Schedule PP-1: 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	3.65	-11%	3.85	-12%	4.20	-15%	4.54	-15%
Off-peak	3.32	-11%	3.42	-11%	3.66	-14%	3.99	-14%
Annualized	3.44	-10%	3.58	-10%	3.86	-13%	4.18	-13%

Note: The proposed energy rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 1 of 4.

DEP's Schedule PP-1: 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	3.78	-5%	3.91	-13%	4.30	-15%	4.64	-16%
Off-peak	3.35	-13%	3.49	-11%	3.74	-14%	4.06	-13%
Annualized	3.44	-11%	3.58	-12%	3.86	-14%	4.18	-14%

Note: The proposed energy rates are shown in DEP's Exhibit 2, page 3 of 6, and the annualized rates are shown in DEP's Exhibit 3, page 2 of 4.

DNCP

In its filing, DNCP proposed two avoided cost rate schedules, Schedule 19-LMP based on LMPs and Schedule 19-FP based on the Peaker Method. The practice of offering dual tariffs was first established in Docket No. E-100, Sub 106 (2006 proceeding). DNCP maintains that the LMP methodology offers several benefits, including transparency to all parties. DNCP states that this methodology allows QFs to be paid for delivered energy and capacity equivalent to what DNCP would have paid PJM if the QF generator had not been generating and to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects DNCP's true avoided costs. Schedule 19-FP offers QFs fixed levelized avoided energy and avoided capacity payments for five, ten, and 15 years. Similar to DEC and DEP, DNCP's rate schedule has seasonal on-peak and off-peak hours and avoided capacity rates for hydroelectric QFs reflecting a PAF of 2.0, and for all other eligible QFs reflecting a PAF of 1.2.

Schedule 19-LMP Capacity

The capacity credits under Schedule 19-LMP 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. DNCP used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs for the next three years, which are expressed as $ per MW-day and converted to a cents per kWh price. As proposed in the last proceeding, DNCP 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 for five individual days during the prior year's summer peak season (defined by PJM as the period June 1 through September 30). Depending on prior year's operations of the QF, the SPPF will be one of the following: 0, 0.2, 0.4, 0.6, 0.8, or 1.0.

Schedule 19-LMP Energy

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 LMPs expressed in dollars per MWH. The electricity prices are divided by 10 to derive cents per kWh price, 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.

Schedule 19-FP Capacity

DNCP's calculation of avoided capacity costs for Schedule 19-FP is based on the installed cost of a CT and is consistent with the installed cost of a CT utilized in its 2014 Integrated Resource Plan (IRP).

DNCP selected the Siemens SGT6-5000F turbine, with the underlying installed cost based on the cost estimates provided in the 2013 edition of Gas

Turbine World Handbook (GTW).[7] The Siemens unit has a capacity rating of 232 MW at ISO conditions and a total capacity of 464 MW for a 2-unit site. For the construction costs and other capital costs, DNCP relied on data from the Brattle Group's May 15, 2014 report, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," (2014 Brattle Report). DNCP made additional cost adjustments to the data from the 2014 Brattle Report to remove the equipment cost of selective catalytic reduction; reduce the labor costs, principally with the use of non-union labor; reduce the sales tax rate applicable to Virginia; reduce the gas interconnection costs by assuming a shorter pipeline lateral of one mile, as opposed to the five miles assumed in the Brattle Report; reduce electrical interconnection costs associated with the economies of scale with a four-unit site, as opposed to a two-unit site; adjust the fuel costs for start-up and inventories to be consistent with the assumptions in the PROMOD model (a production simulation model similar to Prosym, which is developed by Ventyx Energy, LLC) for avoided fuel costs; and removing the financing fees as they are already included in the economic carrying charge rate calculations. The effect of the 464 MW capacity rating for a two-unit Siemens CT and these adjustments is an installed cost of $485 per kW as shown in Figure 1 of DNCP's filing, as compared to the stipulated[8] cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[7] Gas Turbine World, "Gas Turbine World 2013 GTW Handbook," Perquot Publishing, Inc., Vol. 30;34. (January 2013).

[8] A stipulation between the Company and the Public Staff as to the installed cost of a CT was filed on October 28, 2013, in Docket No. E-100, Sub 136.

per kW, based on a two-unit GE 7FA facility with a total capacity rating of 400 MW accepted by the Commission in the 2012 proceeding. The proposed rate reflects a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the installed cost of a CT. The last time any electric utility proposed an installed cost estimate below **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** proceedings, respectively.[9]

The second most important factor in the determination of DNCP's avoided capacity rates is the economic carrying charge rate, which is similar to the real fixed charge rate approach adopted by DEC and DEP. DNCP reduced its rate to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which was incorporated in the 2012 proceeding. Like the fixed charge rate, the economic carrying charge rate includes the discount rate (which includes Company's allowed cost of equity), projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes. The reduction in the rate is largely the result of the use of a lower return on equity than in the 2012 proceeding. Consistent with previous years, DNCP's combined tax rate did not include the expected reductions in the federal rate due to the use of the Manufacturing Tax Credit.

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[9] *See* September 27, 2013, testimony of Public Staff witness John R. Hinton in the 2012 proceeding.

DNCP did not include adjustments for avoided general plant, step up transformer losses, or distribution losses as DEC and DEP have done in this and prior proceedings. DNCP's estimate for fixed O&M for 2015 is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW, escalated at a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** annual rate. This fixed O&M rate is less than the approximate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per kW projected in the 2012 proceeding, which included the same annual escalation rate.

The use of the Siemens CT with adjustments to the 2014 Brattle Report produced an annual capacity cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the initial year, which is annually escalated at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This annual capacity cost is significantly lower than that projected in the 2012 proceeding, which started at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the initial year, which was annually escalated at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The combination of the lower installed costs and higher MW output of the Siemens CTs, the lower fixed O&M cost rate, and other adjustments reduced DNCP's overall annual avoided capacity costs by 35%, as compared to its 2012 capacity costs. DNCP applied a PAF of 2.0 for hydroelectric QFs with no storage capacity and 1.2 for all other QFs. With respect to all other QFs, which constitute the bulk of the QFs interconnected to DNCP's system, DNCP allocated 60% of the annual capacity costs to the summer months and 40% to the non-summer months, spread these costs over the number of peak and non-peak hours, and then levelized them to produce the following avoided capacity rates:

DNCP's Schedule 19–FP- 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
Summer	NA	NA	3.761	-36%	3.903	-36%	4.032	-36%
Non-summer	NA	NA	2.507	-36%	2.602	-36%	2.688	-36%
Annualized	NA	NA	1.116	-36%	1.158	-36%	1.197	-36%

Note: The proposed capacity rates are shown in paragraph VII of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 2 of 2.

DNCP's Schedule 19–FP- All Other QFs – Option A - Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	NA	NA	2.257	-36%	2.342	-36%	2.419	-36%
Non-summer	NA	NA	1.504	-36%	1.561	-36%	1.613	-36%
Annualized	NA	NA	0.670	-36%	0.695	-36%	0.718	-36%

Note: The proposed capacity rates are shown in paragraph VII of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 1 of 2.

DNCP's Schedule 19–FP- 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
Summer	NA	NA	8.628	-36%	8.954	-36%	9.250	-36%
Non-summer	NA	NA	3.326	-36%	3.452	-36%	3.566	-36%
Annualized	NA	NA	0.670	-36%	0.695	-36%	0.718	-36%

Note: The proposed capacity rates are shown in paragraph VII of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 2 of 2.

DNCP's Schedule 19–FP - All Other QFs – Option B - Capacity Credits

	Variable		Five-year		Ten-year		15-year	
	Rate	Change	Rate	Change	Rate	Change	Rate	Change
Summer	NA	NA	5.177	-36%	3.903	-36%	4.032	-36%
Non-summer	NA	NA	1.996	-36%	2.071	-36%	2.140	-36%
Annualized	NA	NA	0.670	-36%	0.695	-36%	0.718	-36%

Note: The proposed capacity rates are shown in paragraph VII of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 1 of 2.

Schedule 19-FP Energy

DNCP's method for calculating avoided energy costs for Schedule 19-DRR and Schedule 19-FP is consistent with methods previously employed in the 2012 proceeding. DNCP used PROMOD to estimate its marginal avoided energy costs for on-peak and off-peak periods over the next 15 years utilizing the generation expansion plan from the no-carbon scenario included in its 2014 IRP. DNCP incorporated a "base" case and a "with QF capacity" case, using the resulting output to determine the avoided energy rates.

To comply with the Commission's directive from the Phase One Order to include avoided fuel hedging values in its avoided energy calculations, DNCP estimated the value of its hedge using the reduced brokerage fees in purchasing its twelve-month natural gas hedges, as opposed to valuing the enhanced fuel price stability. It appears that DNCP interpreted the Order to view the hedging value from renewable energy to apply only to one year, which raises concerns, as addressed in Section D.

The Public Staff has reviewed the PROMOD inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DNCP's avoided energy costs. The rates shown below reflect the 2015 initial year of operation and reflect the five-year, ten-year, and 15-year energy rates.

DNCP's Schedule 19-FP – Firm Energy Rates - 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	3.769	-17%	3.900	-23%	4.390	-21%	4.756	-18%
Off-peak	3.035	-12%	3.132	-21%	3.605	-18%	3.903	-16%
Annualized	3.296	-14%	3.406	-22%	3.885	-19%	4.207	-17%

Note: The proposed levelized capacity rates are shown in paragraph VI of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 2 of 2.

DNCP's Schedule 19-FP – Firm Energy Rates 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	3.773	-19%	3.930	-24%	4.442	-22%	4.838	-19%
Off-peak	3.164	-12%	3.259	-21%	3.730	-18%	4.032	-16%
Annualized	3.296	-14%	3.406	-22%	3.885	-19%	4.207	-17%

Note: The proposed levelized capacity rates are shown in paragraph VI of Exhibit DNCP-1, and the annualized rates are shown in DNCP's Exhibit 6, page 1 of 2.

ISSUES AND CONCERNS

DEC's and DEP's Generation Expansion Plans

One of the most important issues in these biennial proceeding continues to be the need for consistency with the utilities' IRPs. The avoided energy costs are generated from production cost models utilizing the utilities' current resources combined with their future resource expansion plans as derived in the IRPs. In this proceeding, the interval between the two filings was slightly longer than normal; nonetheless, the fuel forecasts and other data inputs should be fairly equivalent. The assumptions used in the utilities' IRPs and their avoided cost calculations are often the same or very comparable given the similarities in the two key computer models used in the proceedings. The System Optimizer and

Strategist models are most often used in determining IRPs, while the more detailed production cost models, known as Prosym and PROMOD, are used in avoided cost proceedings. Both types of models optimize to arrive at the least cost dispatch of resources; however, the models differ in their focus. For example, the System Optimizer and Strategist models evaluate various least cost combinations of supply and demand side resources over a wide range of scenarios, whereas the Prosym and PROMOD models allow for a more detailed cost analysis of the chronological dispatch of one specific portfolio of resources over 8,760 hours of individual years into the future.

In the Phase One Order, the Commission held for the purpose of calculating avoided energy rates, the generation expansion plans used in the avoided production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs. The Commission further found that CO_2 costs "are not sufficiently certain to be included in avoided costs at this time." Phase One Order at 44. In this proceeding, DNCP utilized a generation expansion plan to calculate avoided energy costs that did not consider carbon costs. The generation expansion plans incorporated by DEC and DEP in their avoided energy cost calculations, however, are based on assumptions that include CO_2 emissions costs as reflected in certain scenarios in their 2014 IRPs. Utilizing a generation expansion plan that included carbon prices, while at the same time excluding avoided carbon prices as an input into avoided energy rates, can distort the avoided energy calculations and may result in an underestimation of avoided energy costs. For example, the inclusion of carbon prices in IRP modeling may result in the selection of new nuclear units, as it did with DEC's base case in its 2014 IRP. The low cost energy provided from the new nuclear units can then result in an underestimation of avoided fuel costs. The Public Staff therefore recommends that the Commission direct DEC and DEP to recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2.

DEC's and DEP's Natural Gas and Coal Price Forecasts

In developing a utility's avoided energy costs, the fuel price forecasts generally have the greatest impact. Through discovery, the Public Staff determined that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations that they used in their 2014 IRPs. For their avoided energy rates, DEC and DEP incorporated ten years of future spot prices and other forward price indices; but in their 2014 IRPs, they relied on five years of forward price data. This change in methodology largely explains the significant difference in the slope of the forecasts in 2020 and 2025 of the gas price forecasts in the IRPs and the avoided cost filing, respectively. The Public Staff further notes that in both its 2012 IRP and 2012 avoided cost proceeding, DEC used only two years of forward price data combined with 24 months of transitional data that it merged with its long-term fundamental natural gas price forecast. In comparison, DNCP incorporates **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

In past proceedings, the Public Staff has generally accepted the use of revised or updated forecasted data between the two filings, with the understanding that the revisions were generally minor, especially when in the past there was typically only a two-month lag between the IRP and biennial filings. However, in the 2002 Biennial proceeding, Docket No. E-100, Sub 96, the Public Staff argued that the natural gas price forecast in DEP's avoided cost proceeding was overly conservative. The Commission agreed and ordered DEP to re-run its PROMOD model to reflect a realistic long-term forecast of its natural gas prices and recalculate its avoided energy rates.

In this proceeding, the Commission has emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. The use of five years is appropriate, because the market for ten year futures is relatively illiquid, meaning that the number of natural gas price investors willing to make buy and sell decisions on prices ten years out in the future is much smaller than with the number of investors in the futures market for five years into the future; furthermore, there are disadvantages to simply substituting forward prices with a forecast. A forward price, on the other hand, is the price that could be locked-in today for natural gas or coal delivery at some future date. Spot price forecasts and forward prices are different and have different applications. One such difference is in the dramatic changes in forward prices, especially as futures traders respond to temporary conditions in illiquid markets, compared to spot price forecasts based on future demand and supply conditions that involve a more measured and tempered response to expected changes in the natural gas market.

The Public Staff supports the use of forward prices as a component in the development of near-term forecasts as they transition to the long-term. Prior to 2012, DEC incorporated two-year forward prices combined with a long-term fundamental natural gas price forecast in developing its IRP. More recently, in its 2013 and 2014 IRPs, DEC and DEP incorporated five years of future prices with their long-term forecasts. However, DEC and DEP used ten years of forward data to develop their 2014 avoided energy rates. An over-reliance on forward price data can call into question the reliability of the long-term forecasts. The Public Staff believes that problems with the use of forward prices for coal are even more apparent than with natural gas. This concern is evident in DEC's response to Item 10 of Public Staff Data Request No. 1 in the 2012 IRP in Docket No. E-100, Sub 137, where it noted,

> The construction of coal price forecasts is much more complex due the non-fungible nature of the fuel and the lack of transparency in the coal markets. Duke's fuel procurement group utilizes available market pricing as well as current contracts and responses to coal supply RFP's to construct a fuel supply plan for each coal station with varying coal qualities within the fuel spec. The market prices were derived in March, 2012 and were used for run years 2012 through 2015, followed by a three year transition to the fundamental curve and pure fundamentals for 2019 and beyond."

The Public Staff agrees with DEC that the non-fungible nature of coal and the lack of transparency in markets for coal decrease the confidence that can be placed in a forecast, particularly one consisting of ten years of forward prices. The difference between the forward prices and spot forecasts is illustrated by comparing DEC's proposed natural gas price forecasts constructed with ten years of forward prices with forecasts constructed with only five years of forward prices as shown below:

Figure 1- DEC's Natural Gas Price Forecasts with Forward Prices
[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

A similar observation can be made with the coal price forecast used in the 2014 IRP and the coal price forecast proposed in this proceeding for the Marshall coal fired power station as shown below:

Figure 2- DEC's Predicted Coal Prices at the Marshall Units
[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

In this proceeding, DEC's and DEP's proposed use of ten years of forward prices actually lowers the avoided energy costs. In conclusion, the Public Staff recommends that the Commission require DEC and DEP to reconstruct their natural gas and coal price forecasts using only five years of forward price data, consistent with the approach utilized in their 2014 IRPs. Further, given the importance of the price projections for natural gas and coal, the Public Staff recommends that the Commission require DEC and DEP to re-calculate their Prosym-based avoided energy cost using the fuel price forecast methods utilized in the preparation of their 2014 IRPs.

The Hedge Value of Renewable Energy

The Commission concluded in its Phase One Order that "hedging benefits should be valued only over the hedging terms (time period) actually used by DEC, DEP, and DNCP and that utilities should calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding." DEC and DEP used forward market indices for the years 2015 through 2025 to determine their respective avoided energy costs. The companies accounted for hedging costs by using the "ask" price, rather than the mid-point in developing their fuel price forecasts. In a data request response, DEP stated that 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). When developing estimates of future gas prices, the mid-point between the "bid" and the "ask" price is typically used as a reasonable estimate of future gas markets. However, if the Company actually wanted to hedge the natural gas, it could have to pay the full "ask" price for the natural gas. The Company stated that, in practice, it may be able to negotiate something closer to the mid-point, but for purposes of the data used in the avoided cost analysis, the Company assumed it would pay the full "ask" price rather than the mid-point of the “bid” price and "ask" price.

The Public Staff does not believe that the utilities have properly reflected the hedging value of renewables in developing their respective avoided energy cost rates. As the Commission stated at page 42 of the Phase One Order,

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

DEC and DEP utilized forward prices to determine their respective avoided energy costs; however, as addressed earlier in these comments, the Public Staff has concerns with DEC and DEP’s fuel price forecasts and recommends use of a different method that does not rely heavily on forward prices. DNCP’s avoided energy costs include the hedging fees that it expects to incur related to the purchase of natural gas; however, these fees are transaction costs that DNCP will pay to purchase natural gas.

As a result, the Public Staff does not believe that the avoided energy costs of the utilities fully reflect the fuel price hedging benefits that result from the substitution of renewable generation for fossil-fueled generation. Avoided energy costs should reflect both projected fuel costs and the fuel price hedging benefits of renewable generation for each year of the contract. The Public Staff evaluated the prices of at-the-money Henry Hub natural gas options using the Black-Scholes Option Pricing Model. Henry Hub natural gas options were used in the evaluation because, unlike coal, these financial instruments over terms of less than three years are publicly traded in a robust marketplace with transparent prices. Based on this evaluation, the Public Staff determined that a net option price, the price of a call option minus the price of a put option, for "at-the-money" Henry Hub natural gas options is approximately $.04 per dekatherm for the 12- and 24-month hedge terms used by the utilities. The Public Staff then converted the $.04 per dekatherm net option price to a hedge value of 0.028 cents per kWh.

The Public Staff recommends that the Commission direct DEC, DEP, and DNCP to recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation.

DNCP's Selection of the Siemens Model CT

As previously noted, DNCP projected its avoided capacity costs using the GTW data on two Siemens Model SGT6-5000F CTs with a combined capacity rating of 464 MW. This is the same unit DNCP utilized in its 2013 and 2014 IRPs, as compared to its reliance on the GE Model 7FA units used in the 2012 proceeding. DNCP made a number of adjustments to the installed costs estimated by the 2014 Brattle Report for the DOM zone as previously discussed in Section C. The Public Staff has reviewed these adjustments and generally finds them to be reasonable. However, the Public Staff is concerned with the selection of the Siemens Model CT itself. As the Commission noted in the Phase One Order,

> 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 [the] installed cost of CT per kW from publicly available industry sources, such as the EIA [Energy Information Administration] or PJM's cost of new entry studies or comparable data. Data on the installed cost of a CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Phase One Order at 48.

At this time, DNCP does not have a Siemens Model CT in its fleet, nor does it have experience with the construction and operation of a Siemens Model CT. As a result, a number of other adjustments such as the applicable contingency factor associated with the facility, capital spare parts, and O&M would need to be adjusted to reflect DNCP's limited experience with the unit.

Currently, DNCP has recently brought online a combined cycle (CC) plant in Warren County, Virginia and is in the process of building a CC in Brunswick County, Virginia, both of which utilize Mitsubishi Heavy Industries (MHI) Model

501GAC CTs.[10] In addition, DNCP has also selected these same MHI CTs for its recently announced project in Greensville County, Virginia. In response to Public Staff discovery, DNCP maintained that because there is limited data on how the MHI turbines operate on fuel oil, it did not consider the use of the 501GAC Model CTs as a stand-alone CT option. However, the Company appears to have similar limited data on how the Siemens CTs operate with natural gas and oil within its North Carolina and Virginia service areas.

DNCP also stated in response to a Public Staff data request that it had assumed that the hypothetical Siemens Model CTs utilized in its avoided capacity cost calculations would operate with annual capacity factors of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent. This reflects a significant change from DNCP's position in Phase One of this proceeding, where DNCP witness Petrie proposed the Net Peaker method based on the projected increased use of newer, high efficiency GE-7FA Model CTs that could potentially be operated with capacity factors of up to **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** [11]

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[10] In a November 24, 2010, letter to the Virginia Department of Environmental Quality regarding its application for an air permit for the Warren County project, DNCP defended the selection of the MHI Model turbine over the GE Model 7FA.05 turbine and the Siemens Model SGT6-5000F turbine. DNCP noted that all performance characteristics and environmental emissions were included in the evaluation to make the equipment selection of the gas turbine and the associated steam turbine. *See* Comments of Virginia Electric and Power Company, Warren County Combined Cycle Project, Prevention of Significant Deterioration Permit, November 24, 2010. http://www.deq.virginia.gov/Portals/0/DEQ/Air/Permitting/PowerPlants/DominionWarren/Andy_Gates_Pam_Faggert.pdf.

[11] Phase One T7 at 175.

A utility's projected CT costs must be reasonable so as to comply with PURPA. As the Commission noted in the Phase One Order, "the FERC's order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF. Indeed, the FERC concluded that ratepayers benefit anyway because of the resulting reduced use of fossil fuels, the addition of smaller increments of capacity, and the resulting diversity of power supply." The Public Staff does not take issue with the Company's cost adjustments performed to arrive at the $485 cost rate to install the CT; rather, it questions the likelihood that the Siemens Model CT would actually be selected by DNCP for construction and, thus, whether it is reasonable to use this model to derive DNCP's future avoided capacity costs. The 2011[12] and the 2014[13] Brattle Reports prepared for PJM utilized the same GE Model 7FA relied on by DNCP in the 2012 proceeding, in part because it is the predominant turbine type built in PJM. The 2014 Brattle Report contains a table of types of CTs that have come online in a simple cycle configuration in the United States since 2008- it shows that relatively few Siemens Model 501 CTs have come online as compared to a larger number of GE-7FA units. The GE Model 7FA CT selection in the 2011 and 2014 Brattle Reports was also found to be reasonable

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

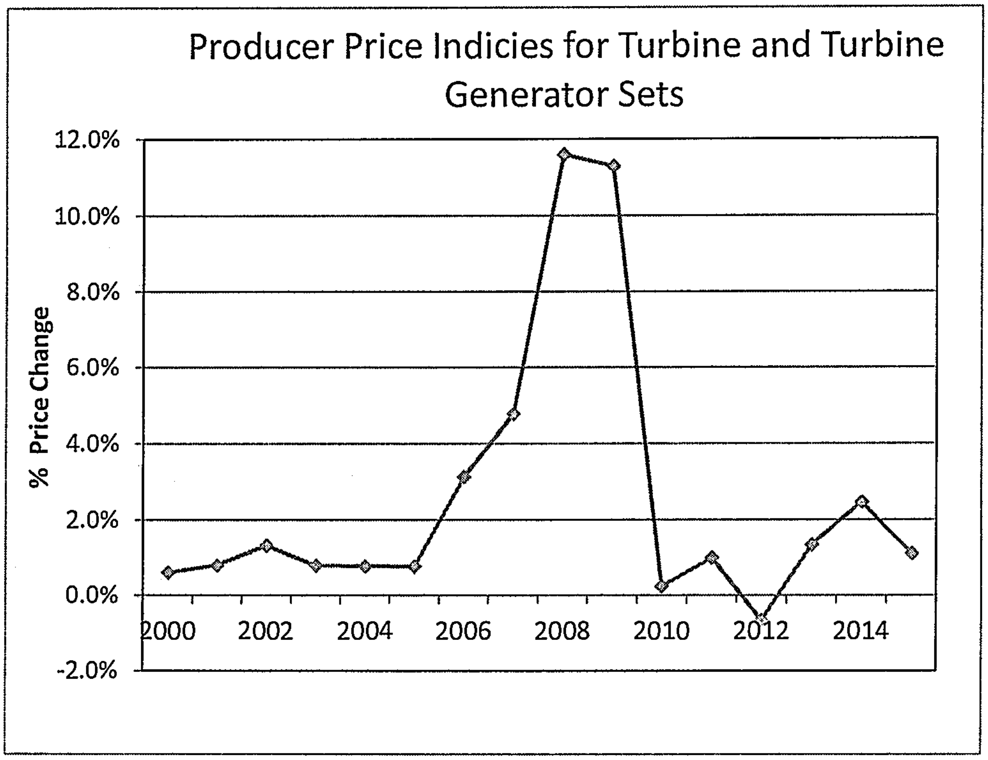
[13] Newell, Samuel, J. Michael Hagerty, Kathleen Spees, Johannes Pfeifenberger, and Quincy Liao (2014), Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, May 15, 2014, (2014 Brattle Report).

by Pasteris Energy, Inc.,[14] as part of its review for Monitoring Analytics, LLC, PJM's independent market monitor. The 2014 Brattle Report discussed its selection process, noting that "while we believe the turbine model should change if the market reveals such a preference, we do not find a basis to make a change in turbine model for PJM in the current study" (Brattle Report at 8). Last, as previously noted, DEC and DEP have a long history of utilizing the GE Model 7FA CTs to calculate their avoided capacity costs.

In regard to changes in turbine prices since 2012, as previously noted that the projected installed CT costs for DEC and DEP increased at approximately 2% per year, which is close to the overall inflation rate. In comparison, DNCP's installed costs fell by 35%. The Public Staff's review of the Bureau of Labor Statistics' record of its Producer Price Indices for Turbine and Turbine Generator Sets over the last couple of years reveals an average cost increase of 1.9% per year in the prices of turbines since 2012, as shown below:

[14] Brattle CONE Combustion Turbine Revenue Requirements Review, Pasteris Energy, Inc., July 25, 2014.

Figure 3- % Producer Price Indices for Turbine and Turbine Generator Sets



The Public Staff notes that other than the Rockingham Power Station that DEC acquired from Dynegy after several years of operation that utilizes the Siemens turbines, DEC only has GE model CTs and CCs in its fleet. The vast majority of DEP's CTs are also GE units, though three of its CC units incorporate Siemens frame turbines, in part, because of their low cost relative to other turbines. However, DEP has consistently utilized the GE Model 7FA CTs for estimating the installed costs of a hypothetical peaking unit for avoided cost purposes. DNCP's adjustments to the cost estimates in the 2014 Brattle Report contributed to the lower cost estimate proposed by DNCP, but the Public Staff believes that the lower costs and higher capacity of the Siemens Model CT selected is the predominant basis for the difference in its avoided capacity costs.

Despite the information that DNCP provided to support its position, the Public Staff believes that questions remain on the appropriateness of its projected installed cost of a CT. In view of the relatively stable price trends for turbine and turbine-related equipment costs, the Public Staff believes that much of the publicly available CT cost information identified by the 2014 Brattle Report is appropriate on which to base an estimate; however, the overall reasonableness of the cost adjustments should be evaluated within the context of other studies. Such studies contemplated by the Commission would include the EIA's 2013 location-based installed cost estimate for an advanced CT in North Carolina of $648 per kW and the estimate of $651 plus or minus 25% cost per kW by the National Renewable Energy Laboratory[15]. While these studies were published several years ago, these studies, which were relied upon by the Public Staff in the 2012 avoided cost proceeding, remain relevant in today's environment due to the relatively stable price trends of CTs. As such, the Public Staff believes that DNCP's projected installed cost is overly conservative and recommends that the Commission direct DNCP to refile its avoided capacity costs based on a GE Model 7FA unit or a comparable unit from one of the publicly available sources, with appropriate cost adjustments.

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[15] National Renewable Energy Laboratory, "Cost Report: Cost and Performance Data for Power Generation Technologies." Prepared by Black & Veatch, February 2012, at 11.

Allocation of Avoided Capacity Costs Between Summer and Non-Summer Months

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

DNCP also applied a 60/40 summer/non-summer allocation to its avoided capacity costs for similar reasons to those stated by DEP and DEC. In response to the Public Staff's data request, DNCP further stated that the capacity "value" was more critical during the summer peak load times. However, DNCP also acknowledged the occurrence of winter peak loads and that winter loads tended to be more volatile. DNCP further indicated that PJM has proposed to revise its capacity market rules to address the winter peak loads and fuel issues, recognizing the importance of system reliability during both winter and summer peak seasons. DNCP indicated that the FERC was reviewing PJM's proposal, and that DNCP anticipates reviewing he summer/winter allocation going forward as the PJM capacity market proposal is finalized and approved.[16]

The Public Staff does not take issue with the weightings or methodologies used by the utilities to weight avoided capacity costs in this proceeding. However, the Public Staff is interested in further evaluating the differences in the winter and summer peak loads, how the utilities meet their peak load obligations for each season, and the cost impacts associated with the distinct differences in the need for, and character of system capacity. Given the peak load conditions that have been observed in North Carolina in both the winter and summer seasons, the Public Staff believes that continued use of a seasonal allocation of avoided capacity costs in the manner proposed by the utilities may need further review. Therefore, the Public Staff recommends that in the next avoided cost proceeding, the utilities assemble their hourly CT operational data and marginal cost data on a season-specific basis, to determine whether the allocation factors proposed in this proceeding remain reasonable. The Public Staff will continue to work with the utilities to determine the exact data needed to inform this evaluation.

[16] *See* http://www.pjm.com/~/media/documents/ferc/2015-orders/20150609-er15-623-000-el15-29-000-and-er15-623-001.ashx

Administrative or Metering Charges

DEC and DEP proposed changes to their administrative charges[17] in their avoided cost tariffs. DNCP did not propose any change to its meter-related (administrative) charges. In response to the Public Staff's data request, both DEC and DEP provided information supporting their respective administrative charges. They indicated that the charges are based on the unit cost studies provided as part of their respective last general rate cases.[18] The Public Staff reviewed these unit cost studies and found the proposed administrative charges for both DEP and DEC to be reasonable.

Legally Enforceable Obligation Form

In Phase One, Dominion North Carolina Power (DNCP) witness Roger T. Williams explained that the Commission held in the 2012 avoided cost proceeding that a legally enforceable obligation (LEO) is established when a qualifying facility (QF) has (1) obtained a Certificate of Public Convenience and Necessity (CPCN) (or filed a Report of Proposed Construction (ROPC), if applicable) and (2) "indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output" to that utility. *See* 2012 Avoided Cost Order at 37. He further testified that DNCP believes that the standard is still too vague to be implemented

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[17] DEP currently applies a month seller charge based on the capacity of the QF. The proposed administrative charge will replace DEP's monthly seller charge.

[18] For DEC, see Docket No. E-7, Sub 1026. For DEP, see Docket No. E-2, Sub 1023.

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." Phase One T Vol 5 Pt. 2 at 351. In regard to DNCP's past practice,[19] Mr. Williams stated that "[t]ypically, we would consider, once a developer comes to us and requests rates and indicates the intent to sell, we would deem that the LEO date." Phase One T6 at 126. DNCP proposed that the Commission adopt a form through which QFs could clearly show their intent to sell their output to a utility, thereby setting the date that an LEO is established (assuming that the first prong of the test had been met).

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

> how the QF would know it needed to obtain the form, how it would obtain it (e.g., from a specified place on a utility's website), whether or how it could be submitted electronically, and the extent to which

[19] Some of the uncertainty and confusion around establishing an LEO in DNCP's service territory may be attributable to the difference between DNCP's approach to interconnecting and negotiating PPAs with non-utility generators and the approach taken by DEC and DEP. It is the Public Staff's understanding that in the past, DEC and DEP's interconnection and power contracting processes have operated somewhat in tandem, thus a small power producer seeking to interconnect has also worked with the same DEC or DEP personnel to negotiate a PPA. DNCP, however, has two separate departments - the Distributed Generation Integration Department, which handles interconnection agreements, and the Power Contracts Department, which negotiates and prepares PPAs. Developers familiar with DEC and DEP's processes may have believed that DNCP would consider information provided in the interconnection process with DNCP's Distributed Generation Integration Department to be sufficient to create an LEO. However, this has not proven to be the case.

> the utility could change or withdraw the form without prior Commission approval.
>
> Phase One Order at 64.

In their Initial Statements filed March 2, 2015, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, Inc. (DEP), supported DNCP's proposal that a QF complete a simple form stating that it offers to sell its output, thereby setting the date of the LEO, to increase clarity and to "prevent 'gaming' of the LEO date." With respect to demonstrating that a QF has obtained a CPCN or filed an ROPC, DEC and DEP indicated that an LEO form should require the QF to provide the date and docket number in which it received a CPCN or filed an ROPC with the Commission. If the QF has not received a CPCN or filed an ROPC, the form should indicate when the CPCN application or ROPC was or will be filed, and the QF should be responsible for reporting to the utility or supplementing the form when a CPCN has been obtained or an ROPC has been filed.

With respect to the demonstration of the QF's commitment to sell its output to the utility, DEC and DEP stated that the form should be signed and dated by a person authorized to make such a commitment. DEC and DEP also indicated that they would make the form available on their websites, and would not object to QFs submitting the forms electronically. Finally, DEC and DEP noted that after initial Commission approval of a form, no further approval would be necessary unless the utility makes material changes to the form or ceases to use it. DEC and DEP did not propose a particular form for approval by the Commission.

In its Comments, Exhibits, and Avoided Cost Schedules of Dominion North Carolina Power filed March 2, 2015, DNCP included comments responsive to the Commission's conclusions and questions in its Phase One Order regarding DNCP's LEO form proposal. DNCP also included a proposed LEO form as Exhibit A to Schedules 19-FP and 19-LMP (LEO Form). DNCP noted that its proposed LEO Form contains:

- a formal request by the QF that the Company enter into a purchase power agreement (PPA) to purchase electricity supplied to the Company's system from the QF facility;
- the QF's contact information;
- certifications by the QF, including, as applicable, that it has received or applied for a CPCN, that it has filed or will file an ROPC, or that it has or will provide the CPCN or ROPC to the Company;
- designation of Schedule 19-FP, Schedule 19-LMP, or negotiated rates;
- provisions regarding the determination of the QF's LEO date;
- termination provisions; and
- a survival clause.

In regard to the determination of the QF's LEO date, Subsection 5(c) of DNCP's LEO Form provides that if on the date of the Company's receipt of the LEO Form, the QF has a CPCN or has filed an ROPC, the LEO date will be the date of the Company's receipt of the LEO Form. Subsection 5(d) of the Form provides that if on the date of the Company's receipt of the LEO Form, the QF does not have a CPCN or has not filed an ROPC, the LEO date will be the date the Commission issues a CPCN or the filing date of the ROPC, as applicable. DNCP stated that the LEO Form would be available to QFs on the Company's web site as an exhibit to Schedules 19-FP and 19-LMP. DNCP proposes that a QF may deliver an executed LEO Form to it by certified mail, courier, hand delivery, or e-mail. Finally, as the LEO Form is part of Schedules 19-FP and 19-LMP, DNCP would not be able to make changes to the LEO Form without Commission approval.

The Public Staff supports the creation of a simple form by which QFs and the utilities could clearly establish the date of an LEO. Such a form could help clarify the rights and obligations of each party and avoid disputes that may ultimately have to be brought to the Commission for adjudication or to the Public Staff for informal resolution.

The approved LEO form for each utility should be publicly available on each utility's website in sections dealing with interconnection agreements and PPAs. Moreover, to the extent to which they are not already doing so, the Public Staff recommends that all the utilities should be required make clear to developers on their websites how to establish an LEO and which departments must be contacted to negotiate interconnection agreements and PPAs. Further, the Public Staff proposes that each utility, in the notification that it sends out to an interconnection customer confirming receipt of an interconnection request, include a statement as follows: "The submission of an interconnection request does not constitute an indication of a customer's commitment to sell the output of a facility to the utility. For information on submitting a legally enforceable obligation (LEO) form or requesting a power purchase agreement (PPA), please see the following website: (provide relevant website link)."

Turning to the specific details of an LEO form, the Public Staff agrees with all the items proposed by DEC and DEP for inclusion in the form. The Public Staff recommends that the form also include several of the additional elements proposed by DNCP. The items that the Public Staff believe should be included are:

- the date and docket number of the QF's CPCN, or
- if the QF is exempt from the certification requirement, the date and docket number of its filed ROPC, or
- if the QF has not yet received a CPCN or filed an ROPC, when the application for a CPCN or ROPC has been or will be filed. The QF should bear the responsibility to report back to the utility. The form should be supplemented when the CPCN is obtained or the ROPC filed;
- signature and title of a person duly authorized stating that the QF commits to sell its output to the utility;
- the QF's contact information;
- directions as to how the form should be delivered to the utility;

- date on which form was sent to the utility;
- provisions regarding the termination of the LEO.

The Public Staff proposes the following revisions to DNCP's proposed LEO Form:

1) DNCP has proposed to attach its LEO Form to its tariff Schedules 19-FP and 19-LMP. While the Public Staff does not object to DNCP attaching the form to the applicable tariffs, the Public Staff does not believe that it is necessary for the form to be part of a particular tariff.

2) DNCP's proposed form is termed an offer to sell and request for a PPA. The second prong of the LEO test requires a notice to the utility of its intent to sell, a unilateral action by the QF. By DNCP's terming the document as an offer, it appears that the QF is initiating the negotiation of a contract, which requires action by both the QF and the utility. While the giving of notice by the QF to the utility of its intent to sell its output may indicate to DNCP that the process of negotiating a PPA should begin, it is not necessarily part of the process of negotiating a PPA.[20] Thus, the Public Staff recommends that reflect that the form represents a notice to the utility by the QF, rather than an offer and request for a PPA.

[20] The interconnection section of DEC's website states, "If the customer intends to sell its electricity production to Duke Energy Carolinas on Rate Schedule PP-N (NC) or Schedule PP-H (NC), Duke Energy will prepare a Purchased Power Agreement based on the interconnection request information and mail to the customer for signature." http://www.duke-energy.com/generate-your-own-power/nc-connect-to-the-grid.asp

3) Sections 3.c.ii. and iv. require an applicant that is exempt from the CPCN requirements and that must instead file an ROPC either to submit a copy of the ROPC as an Exhibit to the LEO form if it has already been filed, or to provide the Company with a copy upon filing of the ROPC. The Public Staff believes that the form should be amended to require an applicant to provide only the docket number for the ROPC rather than the actual form, or if the docket number is not yet known, to notify the Company of the docket number once the ROPC has been filed. As an applicant is already required under R8-65(c) to serve a copy of the ROPC on the utility to which the generating facility will be interconnected, this requirement is redundant, would require the applicant to provide a large amount of information that is easily verifiable elsewhere, and would potentially increase the chance for error on the part of the applicant.

4) Similarly, Sections 3.c.i. and iii. require an applicant that is subject to the CPCN requirements to provide the docket number and the date on which the CPCN was approved by the Commission, and to submit a copy of the order as an exhibit to the LEO Form. With regard to CPCNs, Rule R8-64(c)(1) already requires an applicant to mail a copy of the CPCN application and public notice to the utility to which the applicant plans to sell the electricity to be generated. The Public Staff recommends that the form be amended to require the applicant to provide the docket number for the CPCN and date on which the CPCN was granted by the Commission. In the event that an applicant has not yet applied or received its CPCN, then the form should direct the applicant to provide the

Company with the docket number and date on which the CPCN is granted upon issuance of the order by the Commission. This step would again reduce the amount of information required to be included with the LEO Form, reduce the administrative burden associated with submitting the information, and reduce the potential for the submission of incomplete forms.

5) Section 4 of the LEO Form requires an applicant to indicate whether it is seeking to enter into a PPA under Schedule 19-FP, Schedule 19-LMP, or negotiated rates. While this information would provide DNCP with some of the information it needs to draw up a PPA for the applicant, it is not necessary for the purpose of establishing the date of an LEO. Section 4 also requires that an applicant to submit the names and locations of any QF facilities that are owned or under development by the QF or its affiliates that will be located within one mile of the QF facility, to the extent known. While this information would factor into the determination made by the utility as to the eligibility of the applicant for standard avoided cost rates under the schedules filed by all three utilities, and may also impact the utility's overall obligation to purchase from the applicant, it is not necessary for the purpose of establishing the date of an LEO. However, the Public Staff agrees with requiring the applicant to provide this information as part of the PPA process.

6) Section 6 of the LEO Form provides that the Offer and Request form will automatically terminate under several circumstances; specifically, Subsection 6.c. provides that if a seller eligible for standard rates does not execute a PPA

prior to the date set by the Commission for the filing of updated avoided cost rates and contracts, then the LEO established by the form would terminate. While the Public Staff believes the intent of this provision is to prevent a QF from "cherry picking" the most favorable rate, the provision could in certain circumstances result in a QF having insufficient time to execute the PPA after receiving it from DNCP. The Public Staff believes that a QF that has obtained its CPCN and established an LEO should have some commercially reasonable period of time, not less than thirty days after being presented with an executable PPA from the utility, to execute the PPA before the rates expire.

7) Section 7 includes a survival clause referring to the acknowledgments in Section 5 of the LEO Form. The Public Staff believes this survival clause is unnecessary and should be deleted from the LEO Form, along with the cross reference ("Except as provided in Section 7") in Section 6.

QF Reporting Requirements

DEP and DEC have included language in their PPAs (Exhibit 4 for each Company) that requires a QF larger than 100 kW to provide notice of annual, monthly, and day-ahead forecasted hourly production. The Public Staff discussed this requirement with both DEP and DEC regarding the difficulty and ambiguity of this reporting requirement. DEC and DEP indicated that the reporting requirement was intended to give system operations ample notice of QF operations to allow them to plan generation accordingly, particularly when a QF was experiencing an outage. The Public Staff believes such reporting may be appropriate for certain facilities. However, the threshold for reporting and the degree of detail associated with the QF's operations, appears onerous on its face and does not provide clear direction to the QF when it is necessary to report such operations.

As a result of these the discussions, the Public Staff, DEC, and DEP have agreed to the following language to replace paragraph 5 in the PPAs of DEC and DEP:

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

CONCLUSION

In summary, the Public Staff makes the following recommendations:

- That the Commission direct DEC and DEP to recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2;
- That the Commission require DEC and DEP to reconstruct their natural gas and coal price forecasts using only five years of forward price data, consistent with the approach utilized in their 2014 IRPs;

- That the Commission require DEC and DEP to re-calculate their Prosym-based avoided energy cost using the fuel price forecast methods utilized in the preparation of their 2014 IRPs;
- That the Commission direct DEC, DEP, and DNCP to recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation;
- That the Commission direct DNCP to refile its avoided capacity costs based on a GE Model 7FA unit or a comparable unit from one of the publicly available sources, with appropriate cost adjustments;
- That in the next avoided cost proceeding, the utilities assemble their hourly CT operational data and marginal cost data on a season-specific basis, to determine whether the allocation factors proposed in this proceeding remain reasonable;
- That to the extent to which they are not already doing so, all the utilities be required make clear to developers on their websites how to establish an LEO and which departments must be contacted to negotiate interconnection agreements and PPAs.
- That each utility, in the notification that it sends out to an interconnection customer confirming receipt of an interconnection request, include a statement as follows: "The submission of an

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

- That the Commission require DNCP to make the revisions to its LEO Form as specified by the Public Staff above; and
- That DEC and DEP replace paragraph 5 of their PPAs with the reporting language they have agreed to with the Public Staff.

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.