Initial Statement of the Public Staff

Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2020

Docket No. E-100, Sub 167

January 25, 2021

INTRODUCTION

Since the passage of the federal Public Utility Regulatory Policies Act of 1978 (PURPA) and the enactment of N.C. Gen. Stat. § 62-156 by the North Carolina General Assembly in 1979, the Commission has held biennial proceedings to determine the avoided cost rates of Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (New River) (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 N.C.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.

2020 STREAMLINED FILING

On August 13, 2020, the Commission issued an *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* to commence the

2020 biennial avoided cost proceeding in Docket No. E-100, Sub 167 (Scheduling Order). The Scheduling Order noted that the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 158 (Sub 158 Order) set forth a number of additional issues to be addressed by the electric utilities in their initial filings in this proceeding, including the following:

- real-time pricing tariffs;
- cost increments and decrements to the publicly available combustion turbine cost estimates;
- the use of other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support development of the performance adjustment factor (PAF);
- the extent of backflow at substations;
- the potential for qualifying facilities to provide ancillary services and appropriate compensation; and
- the results of an independent technical review of the Astrapé Study solar integration services charge (SISC) methodology.

On October 20, 2020, Duke and DENC filed a Notification of Intended Compliance with N.C.G.S. § 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements, and Request to Prospectively Modify Timing of Biennial Proceedings, which proposed to modify the Scheduling Order as follows:

(1) Notifies the Commission of the intention of Duke and DENC to comply with N.C.G.S. § 62-156(b) by filing "streamlined" 2020 avoided cost filings that will update the inputs in their avoided cost energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Sub 158 Order.

(2) Requests a continuance of the additional issues to be addressed by the utilities as outlined in the Sub 158 Order (Sub 158 Additional Issues) until November 1, 2021.

(3) Requests to modify the timing of the biennial avoided cost proceeding, by starting the next full biennial proceeding next year in 2021 and shifting all future proceedings to odd calendar years.

On October 30, 2020, the Commission issued its *Order Granting Motion and Establishing Reporting Requirements* (Continuance Order) in which it granted the request to conduct a streamlined proceeding for the 2020 avoided cost proceeding and to delay the Sub 158 Additional Issues until November 1, 2021, but added additional requirements for Duke and DENC to meet to seek to resolve the Sub 158 Additional Issues or otherwise achieve consensus with interested stakeholders before the commencement of the 2021 proceeding.

On November 2, 2020, Duke and DENC made their streamlined filings consistent with the Continuance Order. On December 22, 2020, WCU and New River also made their avoided cost filings in this docket.

Below are the Public Staff's individual comments on the fillings made by DEC, DEP, DENC, WCU, and New River to comply with the Continuance Order. Consistent with the streamlined approach to the 2020 biennial proceeding approved in the Continuance Order, the Public Staff focused its review on ensuring that the updated inputs used by the electric utilities in calculating their avoided cost energy rates and avoided capacity rates were reasonable and that the methodological guidelines and requirements used by the electric utilities were consistent with those approved in the Sub 158 Order. The following Proposed Rates section summarizes the changes in rates filed by the electric utilities, and is followed by an Issues and Concerns section that notes any points of disagreement identified by the Public Staff in its investigation of the 2020 biennial filings made by the electric utilities.

PROPOSED RATES[1]

In past biennial proceedings, the Commission has consistently approved the component or "peaker" methodology for the electric utilities. Under this methodology, avoided capacity costs are estimated using the capital costs of the lowest-cost capacity option available to the utility, typically a peaking unit (e.g., 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 Docket No. E-100, Sub 106 (2006 proceeding), the Commission approved the locational marginal pricing (LMP) method for Dominion

[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.

North Carolina Power (now DENC) in addition to the peaker method. The LMP method is based on market clearing prices of power in the market operated by PJM Interconnection, LLC (PJM).

In its filing, DENC 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 the 2006 proceeding. DENC maintains that the LMP methodology offers several benefits including transparency to all parties. In prior proceedings, DENC has stated that this methodology allows QFs to be paid for delivered energy and capacity equivalent to what DENC would have paid PJM if the QF generator had not been generating. The transparency of the LMP method allows QFs to make prudent decisions regarding the running of their facilities to maximize their revenues, and it more accurately reflects DENC's actual avoided energy costs. Schedule 19-FP offers QFs fixed levelized avoided energy and avoided capacity payments for variable and 10-year terms.[2]

The electric utilities have generally calculated the variable or two-year, as well as the ten-year capacity and energy rates in the same manner as approved in the 2018 Avoided Cost Proceeding, Docket No. E-100, Sub 158 (2018 Proceeding or Sub 158), and in previous proceedings. The impact of the electric utilities' proposed changes in avoided energy and capacity rates is best shown by comparing the utilities' proposed rates with their currently approved annualized

[2] Duke does not currently offer a real time pricing tariff. However, in the Sub 158 Order, the Commission directed Duke to "evaluate and, if found to be appropriate, offer an RTP-based avoided cost tariff as an optional alternative to their Schedule PP in the next avoided cost proceeding." Sub 158 Order at 27.

rates, which assume QF generation during all of the on-peak and off-peak energy and capacity hours as identified in their rate schedules.

The annualized proposed avoided capacity and avoided energy rates assume that a QF operates for all of the prescribed on-peak and off-peak hours for both energy and capacity credits and are interconnected at the distribution system. The electric utilities total annualized 10-year rates, energy rates, and capacity rates are shown in Table 1 below. Table 1 also contains rate comparisons to the rates approved in the 2018 Proceeding.

Table 1: 10-year Annualized Energy and Capacity Rates (cents/kWh) & Percent Change from 2018 Approved Rates[3]

	DEC		DEP		DENC	
	2020 Proposed Rate	% Change	2020 Proposed Rate	% Change	2020 Proposed Rate	% Change
Annualized Energy Rate	2.81	-7%	2.72	-1%	2.846	1%
Annualized Capacity Rate	0.39	547%	0.55	-15%	0.524	26%
Annualized Total Rate	3.20	4%	3.27	-4%	3.370	5%

Figure 1 below is a graph of the approved total avoided costs for the electric utilities from 2002 through 2018 and the proposed annualized avoided cost rates for 2020.

[3] The rates for WCU and New River are not included in this table, but as discussed later in these comments, would track the rates proposed by DEC, their wholesale supplier.

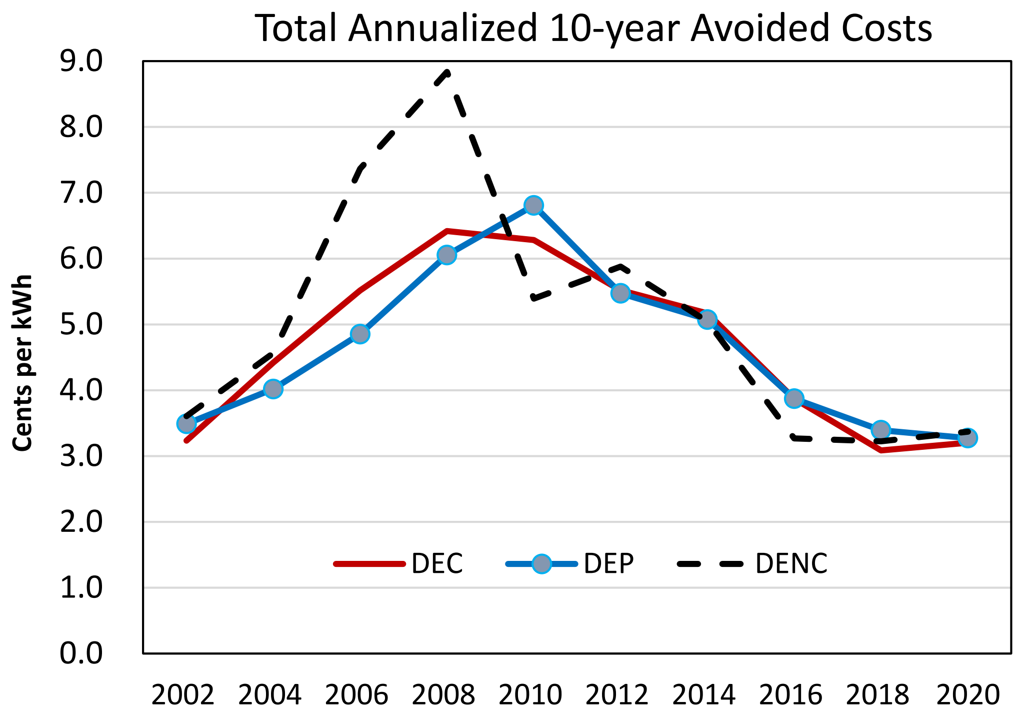

Figure 1: Total Annualized 10-year Avoided Costs (Approved and Proposed)

<u>AVOIDED COST OF CAPACITY</u>

First Capacity Need

The Commission's October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket E-100, Sub 148 (Sub 148 Order) found that avoided capacity value should be recognized beginning with the year that the utility's most recently filed Integrated Resource Plan (IRP) forecast shows a capacity need consistent with N.C.G.S. § 62-156(b)(3), as amended by House Bill 589.[4] In the Sub 158 Order, the Commission found that it is appropriate for an electric utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need for negotiated contracts

[4] Sub 148 Order at 10.

and for use in the Competitive Procurement of Renewable Energy (CPRE) Program and

> [b]eginning with the 2020 IRP, the Commission finds that it is appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding.[5]

The electric utilities' proposed avoided capacity rates provide for the payment of avoided capacity costs only when a future capacity need can be avoided. For DEC, its filed 2020 IRP indicates that the first need to be avoided is in 2026[6] and for DEP, its 2020 IRP indicates that the first need to be avoided is in 2024.[7] DENC's IRP shows the first deferrable capacity need in 2023.[8]

As such, QFs located in DEC's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2026; QFs located in DEP's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value avoided capacity costs beginning in 2024; and QFs located in DENC's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2023.

[5] Sub 158 Order at 40.
[6] DEC and DEP's Joint Initial Statement at 11.
[7] DEC and DEP's Joint Initial Statement at 12.
[8] DENC IRP Addendum filed September 1, 2020, Docket No. E-100, Sub 165.

CT Cost Calculations

The projected capital cost for an installed CT is the factor that has the most impact on the avoided capacity rate. In its *Order Setting Avoided Cost Input Parameters* issued December 31, 2014, in Docket No. E-100, Sub 140 (Sub 140 Order on Inputs), 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.[9]

Duke used publicly available information from the U.S. Energy Information Administration (EIA)[10] specific to Region 16 (SERC Reliability Corporation / Virginia-Carolinas SRVC) to provide the overnight capital cost estimate for a single advanced F-Class CT in simple-cycle configuration[11] for a greenfield site as modeled in the 2018 Proceeding, which was tailored to reflect the expected economies of scale associated with the gas interconnection costs for the Carolinas service area.[12] Duke's installed cost of the CT includes the cost of utilizing number

[9] Sub 140 Order on Inputs at 48.

[10] Capital Cost and Performance Characteristics Estimates for Utility Scale Electric Power Generating Technologies, U.S. Energy Information Administration, February 2020 (Duke response to Public Staff DR 3-3).

[11] Capital Cost and Performance Characteristics Estimates for Utility Scale Electric Power Generating Technologies, U.S. Energy Information Administration, February 2020, 6-1, 6.1 (Duke response to Public Staff DR 3-3).

[12] The Public Staff notes that the question of further costs increments and decrements to the publicly available cost estimates based on brownfield sites and existing infrastructure is one of the Sub 158 Additional Issues that the utilities are directed to further evaluate for inclusion in their November 1, 2021 filings.

#2 fuel oil as a backup fuel, which allowed Duke to exclude the cost of securing firm pipeline capacity for the CT.

While Duke uses publically available data for the cost of their hypothetical EIA-based CT, the cost of a CT increased and Duke's estimate for MW output decreased. These two changes lead to an increase in installed cost per kW. While there was a slight increase in the cost of the EIA-based CT, the majority of the increase was due to Duke decreasing the MW output for the EIA-based CT. In this proceeding, Duke used the net MW output, while in the 2018 Proceeding they used the nominal gross MW output.

Table 2 includes Duke's estimated CT installed costs ($ per kW) for DEC and DEP as compared to the cost estimate approved in the 2018 Proceeding.

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DENC'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 2020 IRP. For the other balance of plant items, DENC relied on data from the

Brattle Group's April 19, 2018 report, "PJM Cost of New Entry, Combustion Turbine and Combined Cycle Plants with June 1, 2022 Online Date," (Brattle Study). Table 3 shows DENC's estimated installed CT cost ($ per kW) as compared to cost ($ per kW) approved in the 2018 Proceeding.

Table 3: DENC's CT Installed Costs ($/kW)		
	2018	2020
DENC	$560	$592.5

The installed cost and the fixed operations and maintenance (O&M) costs (discussed below) are used to determine the annual revenue requirement, which is then converted to an economic carrying charge (discussed below).

CT Cost Adjustments

Similar to the approach taken by DENC in the 2018 Proceeding, DENC made adjustments based on its Greensville Combined Cycle (CC) Plant. DENC's Greensville-specific modifications focused on the extraction of the CT cost portion from the overall CC plant. DENC made additional cost adjustments to the data from the 2018 Brattle Study to reduce the cost of the CT, other equipment, labor costs, Virginia sales tax rate, fees, contingency costs, financing costs, and gas interconnection costs by assuming a shorter pipeline lateral.

An important factor used by Duke in the determination of avoided capacity rates is the real or inflation-adjusted fixed charge rate. Duke's real fixed charge rate includes the discount rate (which includes each company's allowed cost of equity), projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes. Multiplying the installed cost by the real fixed charge rate produces the annual carrying cost of the CT.

DEC's real fixed charge rate includes DEC's current discount rate that reflects the approved cost of common equity from DEC's 2017 rate case (Docket No. E-7, Sub 1146), AFUDC[13] rates, and state and federal tax rates. DEP's real fixed charge rate includes DEP's current discount rate that reflects the current approved cost of common equity from DEP's 2017 rate case (Docket No. E-2, Sub 1142).

In this proceeding, both DEC and DEP increased their real fixed charge rate, as compared to the real fixed charge rates approved in the 2018 Proceeding. Table 4 includes the 2020 fixed charge rate and the rate approved in the 2018 Proceeding.

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[13] AFUDC is an acronym for "Allowance for Funds Used During Construction."

Similar to the real fixed charge rate approach adopted by Duke, DENC's economic carrying charge rate is an impactful factor in the determination of DENC's avoided capacity rates. See Table 5 for DENC's proposed 2020 economic carrying charge rate, as compared to the rate approved in the 2018 Proceeding. The economic carrying charge rate includes the 6.830% discount rate (which includes a weighted average of the North Carolina and Virginia jurisdictional allowed returns on equity), a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes.

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In this proceeding, both DEC and DEP increased their adjustment for general plant such as office buildings and vehicle fleets avoided by QF generation, which increases the annual cost of the CT, as compared to the general plant factor adjustment approved in the 2018 Proceeding. The adjustment incorporates FERC Form 1 data and inputs from each utility's Cost of Service Manual. Duke's method for the general plant adjustment is consistent with previous methods (specifically the 2018 Proceeding) and the Public Staff finds the method and adjustment as reasonable.

In addition to the avoided general plant factor adjustment, Duke made other adjustments to the annual carrying cost of a CT. Table 6 shows the adjustment Duke made for working capital, as compared to the working capital adjustment approved in the 2018 Proceeding. Duke's method for the working capital adjustment is consistent with previous methods (specifically the 2018 Proceeding) and the Public Staff finds the method and adjustment reasonable.

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Table 7 shows the Performance Adjustment Factor (PAF) the electric utilities applied for hydroelectric QFs with no storage capacity, and the PAF applied for all other QFs. This difference in PAF results in an 89% higher annual capacity cost for hydroelectric QFs compared to all other QFs.

Table 7: Electric Utilities' Performance Adjustment Factors		
	Hydro QFs (no storage)	All Other QFs
DEC	2.0	1.06
DEP	2.0	1.06
DENC	2.0	1.07

In their initial statement, DEC and DEP noted that the Stipulation of Settlement Among Duke Energy Carolina, LLC, Duke Energy Progress, LLC, and North Carolina Hydro Group (Hydro Stipulation), which was filed in the 2014 biennial avoided cost proceeding, Docket No. E-100, Sub 140, on June 24, 2014, was scheduled to expire at the end of 2020. DEC and DEP indicated that they would continue to honor the 2.0 PAF for the purposes of calculating avoided cost rates for negotiated PPAs through December 31, 2020, and included the 2.0 PAF multiplier in their calculation of standard offer avoided capacity rates for hydroelectric QFs without storage.[14]

The Public Staff does not recommend any further changes during this proceeding to the PAF for hydroelectric QFs with no storage capacity, but recommends that Duke, consistent with the Commission's directive in the Sub 158 Order, should address the issue of the appropriate PAF to apply in calculating

[14] DEC and DEP Initial Comments at pp 17-18.

capacity rates capacity rates available to run-of-the-river hydro QFs as part of their initial statements filed in the next biennial avoided cost proceeding.[15]

In this proceeding, the electric utilities made an adjustment to the annual carrying cost of a CT, to reflect avoided fixed O&M cost. Table 8 shows the electric utilities proposed 2020 adjustments, per MW in 2020, and the approved per kW in 2018.

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Table 9 shows the adjustment to the annual carrying cost of a CT, proposed by Duke for marginal on-peak distribution and transmission line loss.

[15] *See* Sub 158 Order at pp 40-42.

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In the Sub 158 Order, the Commission found that power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continued to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated, and that it was appropriate that DENC continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network.

In regard to the avoided capacity cost rates for all other QFs, the combination of the annual CT carrying costs plus the impact of the PAF produces an annual capacity cost (prior to levelization), which, when divided by the megawatt (MW) rating of the CT, yields a levelized annual capacity cost ($/kW). Table 10 includes Duke's 2020 proposed annual CT carrying cost and Duke's levelized proposed annual capacity costs.

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Table 11 includes Duke's 2020 levelized proposed annual capacity costs ($ per kW) as comparable to the 2018 levelized approved annual capacity cost.

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Avoided Capacity Rates

The annual costs are levelized by determining the present value of the annual CT capacity costs and multiplying them by a two-year and a 10-year annuity factor. Using the present values of the future avoided capacity costs, the electric utilities continued the rate structure introduced, and ultimately approved, in the 2018 Proceeding.

Table 12 below provides DEC's proposed variable and ten-year levelized avoided capacity rates (cents/kWh) during the summer and winter months. The percent changes from 2018 approved rates pertain to the annualized cost rates for other QFs interconnected at the distribution level:

Table 12: DEC's Schedule PP (NC): Other Generation – Capacity				
	Variable		Ten-year	
	Rate	Change	Rate	Change
Summer Months PM	0.00	N/A	1.37	552%
Winter Months AM	0.00	N/A	6.37	557%
Winter Months PM	0.00	N/A	2.06	565%
Annualized	0.00	N/A	0.39	547%

Table 13 below provides DEP's proposed variable, and 10-year levelized capacity rates (cents/kWh) during the summer and non-summer months and the percentage change from the approved 2018 cost rates for other QFs interconnected at the distribution level:

Table 13: DEP's Schedule PP (NC): Other Generation – Capacity				
	Variable		Ten-year	
	Rate	Change	Rate	Change
Summer Months PM	0.00	N/A	0.00	N/A
Winter Months AM	0.00	-100%	9.29	-15%
Winter Months PM	0.00	-100%	3.98	-15%
Annualized	0.00	-100%	0.55	-15%

The Public Staff has reviewed Duke's capital cost inputs, line losses, seasonal allocations, and other assumptions incorporated in DEC's and DEP's avoided costs and finds them reasonable for the determination of their avoided capacity rates.

Table 14 below provides DENC's proposed capacity rates and the percent changes from 2018 approved rates for other QFs interconnected at the distribution level:

Table 14: DENC's Schedule 19-FP: For All Other QFs – Capacity				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer Month	0.00	NA	4.000	23%
Winter Month	0.00	NA	3.641	26%
Shoulder Month	0.00	NA	0.819	27%
Annualized	0.00	NA	0.524	26%

The Public Staff has reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates and finds them reasonable for the determination of DENC's avoided capacity rates.

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. DENC used the PJM Reliability Pricing Model (RPM) and the clearing prices from the PJM Base Residual Auction (BRA). Consistent with previous methodologies, DENC would allow the QF to receive an avoided capacity payment of 0.5378[16] cents per

[16] DENC Initial Statement, Exhibit DENC-4, p. 7 of 9.

kWh based on the BRA clearing prices commencing in a year in which there is a capacity need. As approved in previous proceedings, DENC adjusts 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 is based on historical operational data during the five PJM coincident peak hours during the prior year's summer peak season (defined by PJM as the period June 1 through September 30), and is applied as a multiplier (between 0 and 1.0) to the QF's capacity payment.

Capacity Rate Seasonal Allocation

Duke allocated the annual avoided capacity cost by season. Similar to the 2018 Proceeding, DEC weighted 10% of the avoided capacity cost to the summer and the rest to the winter season; the winter season portion was then further allocated with 68% to the winter AM period and 22% to the winter PM period.

DEP used similar granularity in developing its capacity rates, and allocated all of its avoided capacity costs to the winter season, with 70% of the avoided capacity costs allocated to the winter AM period and 30% to the winter PM period. The seasonal allocation of the annual capacity costs is divided by the number of seasonal peak hours in order to yield the avoided capacity rates per kilowatt-hour (kWh).

For weighting capacity value between seasons, and calculating avoided capacity rates, DENC allocated CT costs consistent with the Sub 158 Order as follows: 45% summer, 40% winter, and 15% shoulder.

SWINE AND POULTRY AVOIDED CAPACITY RATES FOR DUKE AND DENC

In the 2018 Proceeding, the Commission directed that the:

> "[u]tilities shall amend their Standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended in House Bill 329.[17]

The avoided capacity credits used to calculate avoided cost rates for swine or poultry QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begins in the first year of a utility's capacity need. The Public Staff has reviewed these capacity credits, and other assumptions, incorporated in Duke's and DENC's proposed rates for swine and poultry QFs, and finds them reasonable for the determination of Duke's and DENC's avoided capacity credits.

AVOIDED COST OF ENERGY

Duke's Avoided Cost of Energy

As in previous proceedings, Duke used Prosym to estimate their marginal avoided energy costs for on-peak and off-peak hours over the next two and 10 years. Prosym is an hourly chronological model that dispatches generating units in a least cost manner subject to various constraints such as scheduled

[17] Sub 158 Order at pp 10-11.

maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its IRP. The Public Staff has reviewed the Prosym inputs on the projected operation of Duke's generation units, including the following: variable O&M; the price forecasts for delivered natural gas, coal, oil, and uranium; the projected prices of SO_2 and NO_x emission allowances; the projected megawatt-hour (MWh) generation from renewable energy resources; projected energy purchases; and other inputs. Based on its review, the Public Staff finds that the MW capacities, heat rates, and other inputs that characterize the Companies' generation units are reasonably consistent with the 2018 Proceeding and are appropriate for this proceeding. This opinion is supported by the Public Staff's review of recent fuel reports and an analysis using 2020 hourly day-ahead lambdas in the place of Duke's proposed summer and non-summer on-peak and off-peak rates.

While the Public Staff believes that Duke's projection of its annual energy prices are reasonable for the short-term variable energy rate, the Public Staff has concerns with Duke's projected avoided energy costs over the entire 10 years, which is used to calculate the 10-Year Fixed energy rate, due to the assumption of increased reliance on lower-priced shale gas, which is discussed in the Issues and Concerns section of these Comments. The Public Staff also has concerns about the way Duke modeled its start-up costs for its thermal generation units, which has resulted in counter-intuitive tariff pricing. This issue is discussed further in the Issues and Concerns section of these Comments.

Figure 2 displays annualized avoided energy costs projected by DEC & DEP:

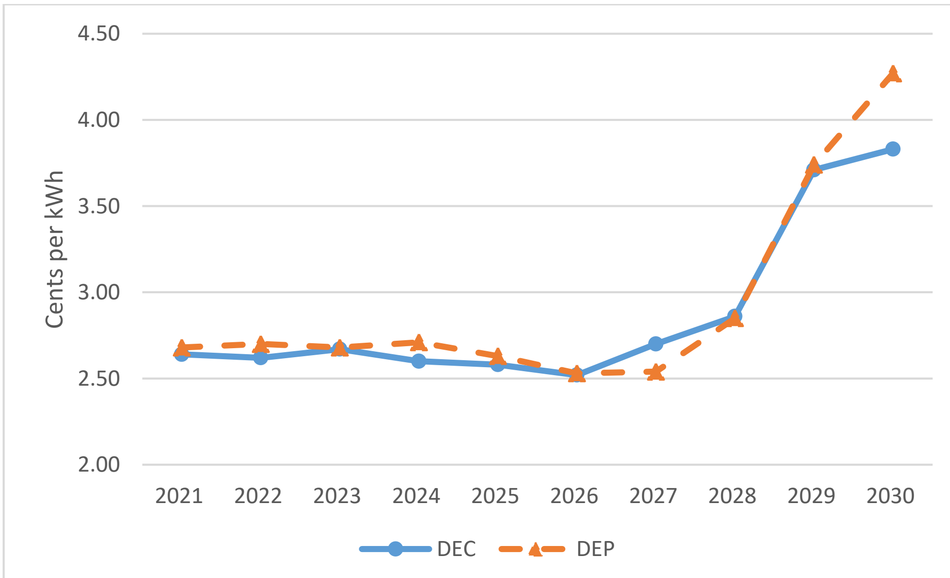

Figure 2: Duke's Annualized Avoided Energy Costs

Duke's proposed variable and 10-year levelized energy rates (cents per kWh) for QFs interconnected at the distribution level, along with the proposed annualized rates (cents per kWh) with the percentage change from the approved rates in the 2018 Proceeding, are shown in Tables 15 and 16 below:

Table 15: DEC's Schedule PP (NC): Energy Credits				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	3.56	3%	3.35	-23%
Summer PM Peak	2.77	-25%	3.25	-24%
Summer Off-Peak	2.52	-12%	2.74	3%
Winter Premium Peak	3.84	-20%	4.23	-25%
Winter AM Peak	0.66	-84%	3.39	-15%
Winter PM Peak	3.15	-22%	3.46	-20%
Winter Off-Peak	2.75	5%	2.92	7%
Shoulder Peak	2.14	-38%	2.15	-38%
Shoulder Off-Peak	2.64	-1%	2.74	10%
Annualized	2.62	-13%	2.81	-7%

Table 16: DEP's Schedule PP (NC): Energy Credits				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	3.60	-14%	3.42	-9%
Summer PM Peak	2.67	-15%	2.89	-11%
Summer Off Peak	2.60	-8%	2.75	0%
Winter Premium Peak	2.98	-5%	3.26	-30%
Winter AM Peak	1.93	-44%	2.90	-11%
Winter PM Peak	3.60	7%	3.79	4%
Winter Off Peak	2.52	-5%	2.99	13%
Shoulder Peak	2.83	-9%	2.96	0%
Shoulder Off Peak	2.05	-18%	2.15	-3%
Annualized	2.54	-11%	2.72	-1%

DENC's Schedule 19-FP Energy Rates

DENC's method for calculating avoided energy costs for Schedule 19-FP is largely consistent with methods employed in the 2018 Proceeding. DENC used PROMOD to calculate avoided costs in the 2018 Proceeding, but switched to PLEXOS, a utility production costing model leased from Energy Exemplar, to calculate the avoided energy costs contained in Schedule 19-FP in this proceeding. DENC noted that "[a]lthough the production costing model the Company is using has changed, the process for developing the avoided energy costs are the same as in previous filings."[18] In its initial filing, DENC also cites the various improvements as the reason for the switch from PROMOD to PLEXOS.[19]

The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts using the Company's generation expansion plan "B" included in its 2020 IRP. DENC incorporated a "without QF" case and a "with QF" case using the resulting output to determine the avoided energy rates. The Public Staff has reviewed the PLEXOS inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs.

Consistent with the Sub 158 Order, DENC calculated avoided energy rates using four pricing periods: summer on-peak; winter on-peak am; winter on-peak pm; and shoulder on-peak. Also consistent with the Sub 158 proceeding, DENC included avoided fuel hedging values in its avoided energy calculations based on

[18] DENC Initial Statement, III.a.ii, at 4.
[19] DENC Initial Statement, III.a.ii, at pp 4-5.

the Black-Scholes option pricing model, using an estimate for gas price volatility, a risk free interest rate, and the strike price, which yielded a net option price of $0.0027mmbtu. The hedging benefit was modeled with the 7.0 mmbtu/MWh heat rate of a natural gas combined cycle unit to yield a hedging value of $0.02/MWh to supplement DENC's avoided energy costs.

DENC continues to apply a $0.78/MWh re-dispatch charge that was originally approved in the Sub 158 Order. In its 2020 filing, DENC proposed a protocol for avoidance of the re-dispatch charge, as required by the Sub 158 Order.[20] The proposal would allow a QF to reduce the re-dispatch charge "to the extent that the QF reduces the variability of its output through the use of an energy storage device (ESD)."[21] Under the proposed protocol, DENC will calculate variability for each case on a calendar year basis as the sum of the hourly absolute output variance from a QF-provided generation forecast. Additional commentary regarding this proposal can be found in the Issues and Concerns section below.

The rates shown in Table 17 below reflect the variable and 10-year energy rates for the 2020 initial year of operation.

[20] Sub 158 Order, at 113.
[21] DENC Initial Statement, III.a.ii, at 10.

Table 17: DENC's Schedule 19-FP: For All Other QFs – Energy				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer – Premium Peak	3.932	20%	4.531	29%
Summer – On Peak	3.047	2%	3.516	6%
Summer – Off Peak	2.103	-3%	2.450	-2%
Winter – Premium Peak	4.217	12%	4.159	13%
Winter – On Peak (AM)	3.567	-1%	3.524	2%
Winter – On Peak (PM)	3.609	-3%	3.568	-2%
Winter – Off Peak	2.874	-9%	2.994	-3%
Shoulder On-Peak	2.884	-2%	2.872	4%
Shoulder Off-Peak	2.119	-9%	2.260	-5%
Annualized	2.665	-3%	2.846	1%

Figure 3 displays annualized avoided energy costs projected by DENC.

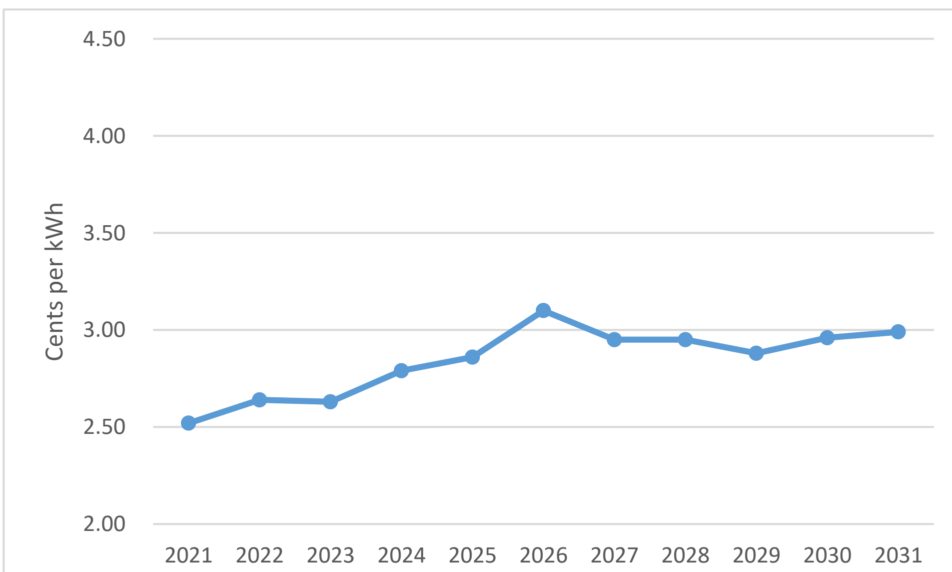

Figure 3: DENC's Annualized Avoided Energy Costs

DENC's Schedule 19-LMP Energy Rates

The proposed Schedule 19-LMP energy is based on the hourly PJM Day Ahead LMPs at the nearest PJM-defined nodal location to the QF. To derive the cents per kWh price, the dollars per MWh PJM Dominion Zone Day-Ahead hourly LMPs are divided by 10 and then multiplied by the QF's hourly net generation.

WCU AND NEW RIVER AVOIDED COST RATES

In their initial statement, WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved avoided cost rates for QFs interconnected at distribution.[22] As proposed, WCU and New River would offer Schedules WCU PP-N and NRLP PP-N, respectively, for non-hydroelectric QFs and WCU-H and NRLP-H, respectively, for hydroelectric QFs.

DEC is WCU's requirements supplier, and it is indirectly New River's supplier through Blue Ridge Electric Membership Corporation. The purchased power agreement between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis à vis Blue Ridge. In their statement, WCU and NRLP note that they will continue to take generation supplies from DEC through 2021, but on January 1, 2022, will be switching power suppliers to Carolina Power Partners (CPP), which operates a 450 MW gas-fired plant in Kings Mountain, NC, in 2022 and beyond. WCU and

[22] WCU and New River incorrectly reference tracking DEC's 5, 10, and 15-year Schedule PP rates, but understand that WCU and New River would track DEC's variable and 10-year Schedule PP rates.

New River noted that neither utility offers net metering, and both have limited QFs operating on their systems.[23]

The Public Staff does not object to WCU and New River's proposed rates for purposes of the 2020 proceeding, but recommends that to the extent the Commission makes changes DEC's proposed avoided cost rates, those will need to be reflected in the long-term avoided cost rates of WCU and New River.

ISSUES AND CONCERNS

DENC RE-DISPATCH CHARGE AVOIDANCE PROPOSAL

As discussed above, in DENC's Initial Statement, it proposes a Protocol for Avoidance of Solar Integration (Re-Dispatch) Charge (Protocol) for Controlled Solar Generators (CSG), consistent with Commission direction in the Sub 158 Order.[24] DENC proposes that CSGs reduce the variability of their output with an energy storage device (ESD). This option is available to any QF in DENC's territory that sells its power to DENC under PURPA.[25] DENC proposes that CSGs seeking to avoid the Re-Dispatch Charge (RDC) must submit an hourly generation output forecast for the solar plus storage facility for the entire calendar year, on or before

[23] WCU noted that it entered into one renewable energy contract with a QF in 1986, but that supplier has offered no electricity for sale to WCU in over twenty years. In 2010, WCU entered into an agreement to allow a residential consumer to install a small rooftop solar application (8 kW) on his house, and now has three solar customers. NRLP is also working with several renewable suppliers interested m placing renewable energy on its system.

[24] Duke filed its analogous Requirements for Avoidance of SISC (Solar Integration Services Charge) on November 18, 2019, in Docket No. E-100, Sub 158. The Commission issued an Order Requesting Comments on Proposed Requirements for Avoidance of SISC on May 12, 2020. A final order has not yet been issued.

[25] This implies that intermittent QFs between one MW and 20 MW are eligible for RDC avoidance. DENC's obligation under PURPA to purchase energy and capacity from QFs is limited to QFs with a net capacity of 20 MW or less. *See Virginia Electric and Power Company*, 124 FERC ¶ 61,045 (2008).

90 days prior to the start of each calendar year of the contract. These CSGs must also have separate metering on the solar-only output of the facility and the combined solar plus storage output. Every April of the subsequent year, DENC will calculate (i) the sum of absolute output variance between the hourly forecast and the hourly metered solar-only output (Solar Variability) and (ii) the sum of absolute output variance between the hourly forecast and the hourly metered solar plus storage output (Combined Variability). The CSGs will be eligible for an annual RDC credit, based upon a $0.78 per MWh RDC, according to the following formula:

$$RDC\ Credit = Annual\ Output[MWh] * \frac{\$0.78}{MWh} * \left(1 - \frac{Combined\ Variability}{Solar\ Variability}\right)$$

The Public Staff first notes that DENC defines re-dispatch costs as the "additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day."[26]

Through conversations with the Company, the Public Staff has identified that the re-dispatch costs incurred by DENC, due to intermittent QFs, are largely driven by variance between their day-ahead projected load and their real-time actual load. This variance occurs because DENC does not bid QF output into the PJM energy and capacity markets; rather, DENC utilizes a complex combination of forecasting tools to estimate the total load it must secure from PJM as a Load Serving Entity (LSE). Among other factors, this calculation attempts to estimate

[26] DENC Initial Statements and Exhibits, filed November 1, 2018 in Docket No. E-100, Sub 158, at 12.

the amount of load *reduction* that is provided by QF output;[27] this estimate combines vendor forecasts, weather variables, and prior day QF output, but does not incorporate forecasts provided by QFs. When the DENC LSE requests a certain amount of load in the day-ahead market, variations in both load and QF output may cause DENC to need to either purchase or sell load in the real time market; this variation, coupled with unfavorable price differentials between the day-ahead and real-time markets, will tend to increase costs to ratepayers.[28]

In investigating the proposed Protocol, the Public Staff sought to determine if a CSG that is able to reduce its variability, and subsequently receive an RDC credit, would actually decrease costs to ratepayers. The Public Staff believes that the ideal method to ensure that the avoided re-dispatch costs match the RDC credit issued is for CSGs to provide more frequent forecasts (weekly or day-ahead), which DENC would then incorporate into its day-ahead load calculations (Option 1). At this time, DENC acknowledges that the hourly output forecasts provided by CSGs will not be used in estimating total QF load reduction,[29] as the current process for estimating QF load reduction is built into the load forecasting model and would require significant effort to modify. Because the number of QFs that would seek to avoid the RDC is currently unknown, the Public Staff agrees

[27] DENC refers to this as "behind the meter" QF generation.

[28] For example, if DENC underestimates load, it will have to bid additional load requirements into the real time market. As load forecast errors are correlated across utilities, if DENC underestimates load, most other utilities will also underestimate load, driving the real-time load price higher than the day-ahead price. The same is true for overestimating load, but in the opposite direction. Thus, load forecast errors tend to always incur increased costs, whether or not they are under- or over-forecast errors.

[29] See DENC response to PS DR 7-6.

with DENC that it is not reasonable at this time to modify DENC's existing load forecasting tools to incorporate QF forecasts.

The Public Staff believes that the next best method to ensure that the avoided re-dispatch costs match the RDC credit issued would be to compare actual CSG output to the QF load reduction estimate utilized in the DENC LSE load forecast (Option 2). This method would negate the need for the CSG to provide forecasts, and would instead evaluate CSG variability against DENC's estimates for QF load reduction, which is directly tied to the error between the day-ahead load forecasts and real-time load requirements. However, this method is a challenge due to data limitations. DENC currently cannot extract the QF load reduction estimate from the total load forecast, making this analysis impossible. Due to this limitation, DENC cannot share the QF load reduction estimate with CSGs; thus, a CSG would not be able to modify its output to match DENC's load reduction estimate. Thus, the RDC credit calculated for each CSG would not be in the CSG's control.

With Option 1 impractical at this time due to integration difficulties, and Option 2 infeasible due to data availability issues, the Public Staff believes that the Protocol proposed by DENC is a reasonable "third best" proxy for estimating the reduction in re-dispatch costs incurred by CSGs. This is largely due to the fact that DENC's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables). Thus, over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate will take that predictability into account. The Public Staff does not currently object to the Protocol as proposed, but anticipates that QF developers may have additional concerns that will be shared in their initial comments and will respond to those concerns, as appropriate, in our reply comments.[30]

However, the Public Staff would like to bring one potential issue to the Commission's attention. The RDC credit depends not only on how the CSG dispatches the ESD, but also what type of forecast is provided. DENC has indicated through discovery that it expects CSGs to provide a "predictable, consistent, smooth generation profile against which to measure actual generation volatility," which would ignore the impact of weather forecasts and instead takes into account solar irradiance. A CSG that intends to use its ESD to "smooth" its output profile would likely provide this type of forecast. However, a CSG that intends to use its ESD to shift energy from off-peak to on-peak hours will likely wish to provide a forecast that anticipates this energy shifting dispatch.

Consider the two examples presented below – the first chart shows the daily forecast, solar only output, and solar plus storage output for a CSG that intends to smooth its output.[31] The second chart shows the same information for an identical CSG that intends to shift its output to on-peak hours.[32] Using the Protocol calculation, the Smoothing CSG would qualify for a 25% RDC credit, while the Energy Shifting CSG would qualify for a 38% RDC credit. Despite this higher credit

[30] The Public Staff reached out to intervenors in an attempt to discuss the RDC prior to this filing, but did not receive substantive feedback that could be incorporated into our comments.

[31] This is the same example provided by DENC in its Initial Statement and Exhibits, at 12.

[32] This is an extreme example, with 100% of energy generated discharged during winter on-peak hours.

assigned to the Energy Shifting CSG, it is unclear if ratepayers actually benefit more from energy shifting dispatch than smoothing dispatch.

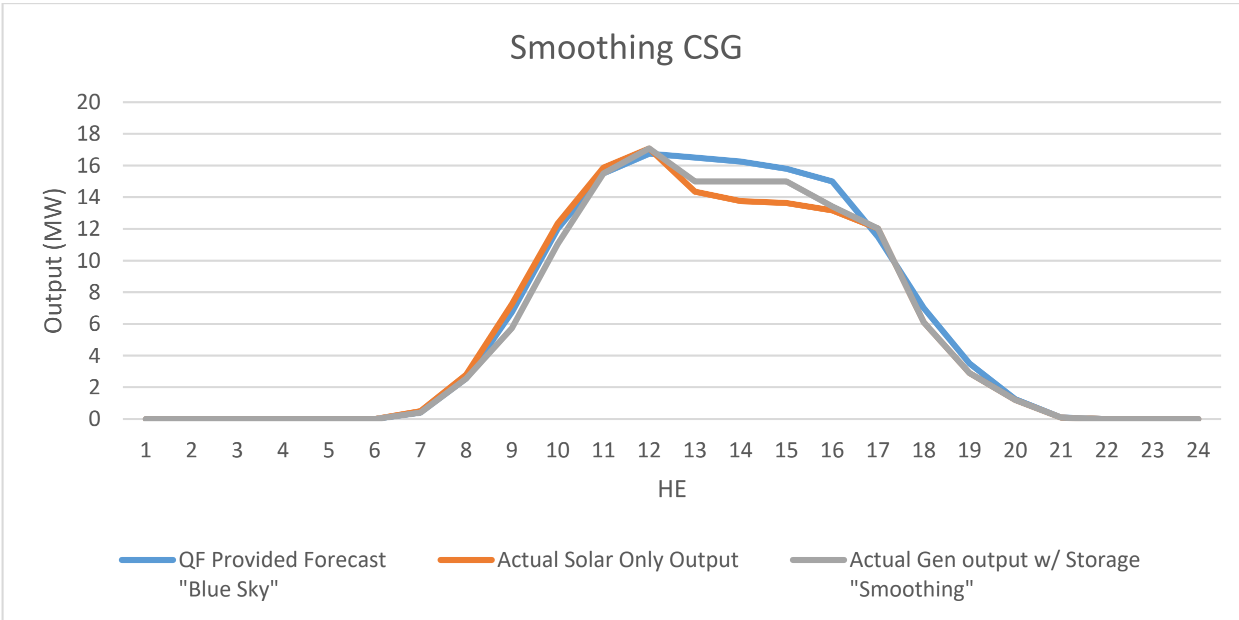

Figure 4: Example CSG Output – Smoothing

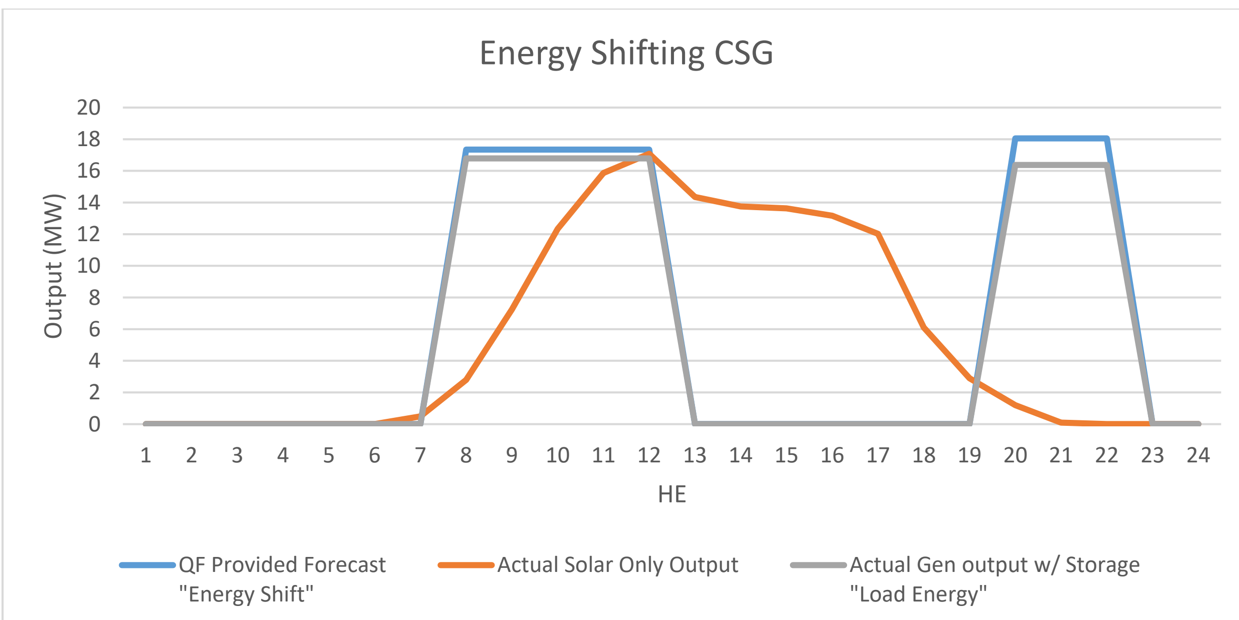

Figure 5: Example CSG Output – Energy Shifting

To allay these concerns, the Public Staff recommends that DENC monitor the types of forecasts and the ESD dispatch behavior for CSGs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory in its future avoided cost filings.[33] In addition, the Public Staff recommends that DENC specifically address CSGs seeking RDC avoidance in each future fuel rider proceeding, providing the specific facility(ies) and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on CSGs seeking to avoid the RDC.[34] Should evidence emerge that CSGs are able to game their forecasts and output to obtain excessive RDC credits, or if a large number of QFs install an ESD to smooth volatility, the Public Staff may recommend that DENC take measures to address the Protocol deficiencies identified herein in future avoided cost proceedings, up to and including adoption of Option 1 or Option 2 as proposed by the Public Staff.

INCLUSION OF CARBON COSTS IN AVOIDED ENERGY RATES

In its Sub 140 Order on Inputs, the Commission concluded that the calculation of avoided costs should be based on "known and verifiable" costs, finding that the costs of carbon emissions are not sufficiently certain to be included in avoided costs.[35] Further, the Commission ruled that the generation expansion

[33] These biennial reports would be similar to the SISC Avoidance reports recommended by NCSEA, NCCEBA, and the Public Staff for DEP and DEC in the Sub 158 Proceeding. *See* Initial Comments of NCSEA and NCCEBA, filed July 13, 2020 in Docket No. E-100, Sub 158, at 5; and the Public Staff's Reply Comments on SISC Avoidance, filed July 31, 2020, at 3.

[34] The Public Staff made the same request of DEP and DEC in the Sub 158 proceeding. See the Public Staff's Reply Comments on SISC Avoidance filed on July 31, 2020 in Docket E-100, Sub 158, at 5.

[35] Sub 140 Order on Inputs, Finding of Fact 14, pp 42-44.

plans used in the calculation of avoided energy should be based on IRP expansion plans that take into account only known and quantifiable costs.[36] The Commission reiterated its ruling in its December 17, 2015, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* (Sub 140 Order), finding that "DEC's and DEP's calculation of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of the CO2 costs is inconsistent with the Commission's directives from the Order on Inputs."[37]

In its calculation of avoided energy rates, DEC and DEP utilize their Portfolio A from their 2020 IRP, which is the base case without carbon policy. The production cost model inputs used in the calculation of avoided energy rates do not include a carbon price, consistent with Portfolio A. The Public Staff agrees the use of Portfolio A is appropriate and consistent with prior Commission direction to consider only "known and verifiable" costs, as neither DEC nor DEP are currently subject to any regulations imposing a carbon price.

DENC calculates the avoided energy rates utilizing its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165. Alternative Plan B is the least-cost plan that complies with all applicable state law, including the Virginia Clean Economy Act and Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI), effective January 1, 2021. While there is some uncertainty regarding the projected future cost of RGGI carbon allowances, the existence of a

[36] *Id*. Finding of Fact 15, pp 42-44.
[37] Sub 140 Order, pp 23-24.

RGGI carbon price is sufficiently "known and verifiable" based on current law.[38] Therefore, it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates.[39]

However, through discovery, the Public Staff's investigation has found that the CO2 price included in its avoided energy rates does not match the RGGI CO2 price forecasts included in its 2020 IRP. Figure 6 below summarizes this discrepancy. There are two issues: First, the CO2 price used in the production cost model for avoided energy exceeds the RGGI only CO2 price forecast used in the IRP in years 2020 through 2023. DENC states that this deviation is due to the use of RGGI market futures pricing used in the first 18 months; these market prices are then blended into their fundamental forecast, consistent with how DENC forecasts natural gas prices. The Public Staff finds this explanation reasonable.

Second, the CO2 price also includes a federal CO2 price in addition to the RGGI CO2 price in years 2026 and beyond. The inclusion of a federal CO2 price is inconsistent with prior Public Staff positions and the Sub 140 Order on Inputs – the avoided energy rate should only include "known and verifiable" costs. As no federal CO2 price currently exists, it should not be included in the calculation of avoided energy rates. The Public Staff recommends that DENC rerun its

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[38] For example, RGGI auction clearing prices for past years are published online and available for review. Future carbon prices are forecast by external consultants. RGGI also forecasts future carbon allowance estimates for "control" or compliance periods, which directly influence the future price forecasts. See more information at https://www.rggi.org/.

[39] The cost of CO2 imposed on VA generation by VA laws and regulations should be treated no differently than the cost of nitrous oxides (NOx) or sulfur dioxide (SO2) imposed on VA generation by VA laws and regulations.

production cost model using a RGGI price forecast without a federal CO2 price, and file revised avoided energy rates.[40]

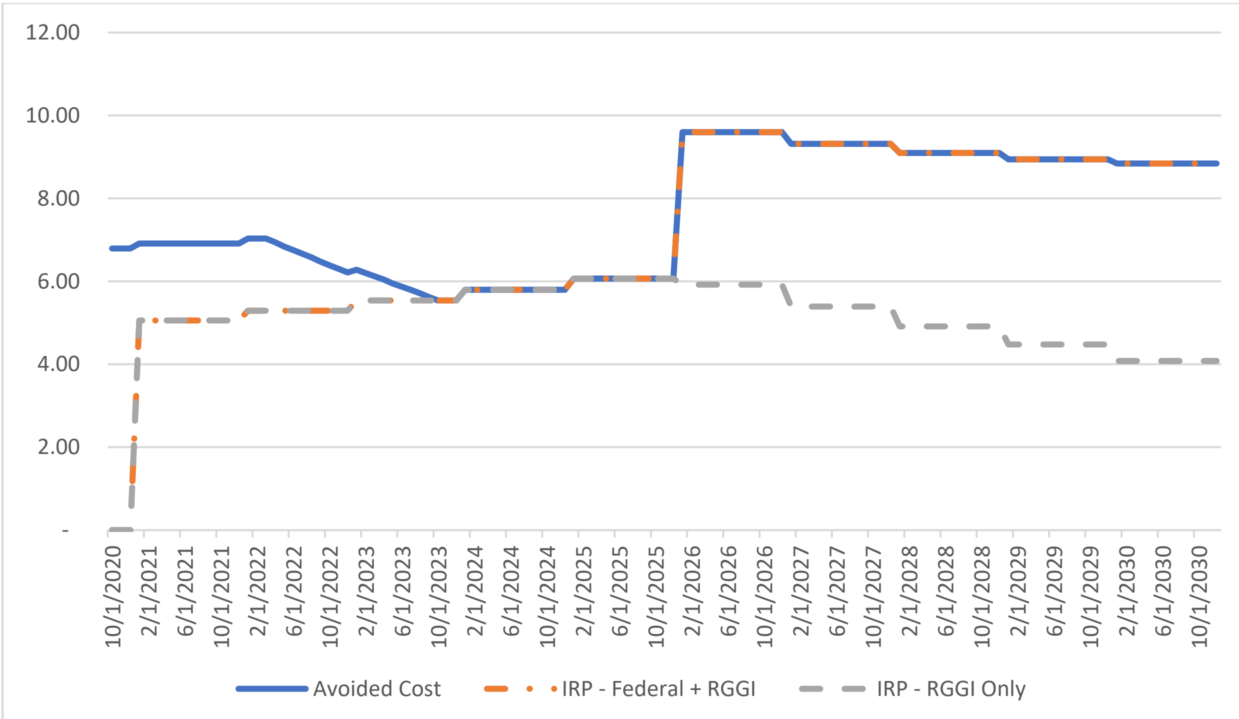

Figure 6: Comparison of Carbon Pricing in DENC"s IRP and avoided cost filing.

<u>DEC'S AND DEP'S PRICE FORECASTS FOR NATURAL GAS</u>

For purposes of calculating its avoided cost energy rates, DEC and DEP have incorporated forward basis natural gas prices for the first eight years, and for years nine and ten Duke has incorporated on its fundamental gas price forecast. This approach is consistent with the Commission Orders in Docket No. E-100, Subs 148, and 158 respectively.

[40] DENC has clarified that the RGGI Only price used in the IRP is a price forecast made under the influence of a federal CO2 price. The RGGI Only price decline in years 2026 through 2030 is due to downward pressure on emissions resultant from the federal CO2 price. The RGGI Only price forecast in absence of the Federal CO2 price will actually slightly increase in years 2026 through 2030.

While the Public Staff appreciates the difficulty in forecasting long-range prices of natural gas, as well as other fuels, we have concerns with the natural gas price forecasts utilized by DEC and DEP in the IRP. In particular, a comparison of the historical **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** natural gas pricing to calculate such fuel costs may be problematic.

On average, the Duke is projecting that its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In addition, Duke has included transportation cost estimates for the required interstate and intrastate capacity for the delivery of the shale gas. Similarly, these assumptions were previously incorporated in Duke's 2018 avoided cost filings, albeit to a lesser extent than in the 2020 avoided cost filing. **[BEGIN CONFIDENTIAL]** [redacted]

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[41] As used by Duke in the 2020 biennial IRP proceeding in Docket No. E-100, Sub 165, the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[redacted]

[redacted]

[redacted]

[42] DEC's existing CC facilities include Buck (716 MW), Dan River (718 MW), and WS Lee (792 MW). DEP's existing CC facilities include Asheville (560 MW), Lee (1059 MW), and Smith (1250 MW), and Sutton (719 MW). Capacity values are winter ratings.

[43] This estimate of annual gas demand from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is based upon a 70% capacity factor assigned to each combined cycle plant, utilizing the no duct firing winter capacity and the MNDC heat rate used in the production cost models.

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**.

The Public Staff recognizes that in prior IRP proceedings, Duke was relying on the Atlantic Coast pipeline (ACP) to transport natural gas into North Carolina. ACP was a 600-mile, 42-inch natural gas interstate pipeline that would have transported approximately 1.5 billion cubic feet (Bcf) per day of Appalachian gas on a firm transportation basis to the Zone 5 region. DEC and DEP, along with Piedmont Natural Gas, had contracted for about 48% of its capacity or roughly about 725,000 dekatherms (dts) per day. The cancellation of the ACP in July 2020 has brought Duke's assumptions of having additional increased interstate pipeline capacity from the Appalachian basin by 2026 into question, especially given the political and economic issues surrounding the construction of new natural gas pipelines.

Another interstate pipeline project currently under construction is the 303 mile, two-Bcf/day Mountain Valley Pipeline (MVP) mainline project which is designed to flow large volumes of firm transportation volumes at the lower cost gas cost out of the Appalachian region and into the markets of Virginia and North Carolina is now delayed and scheduled to enter service in late 2022[44]. The MVP also faces additional legal challenges, calling into question the future of this pipeline. MVP Southgate, an offshoot to MVP, a 24-inch interstate pipe running approximately 75 miles from Southern Virginia to central North Carolina and

[44] For additional information on the Mountain Valley Pipeline, please see: https://www.mountainvalleypipeline.info/overview/.

carrying 375,000 dts/day of shale gas cannot start construction until the MVP mainline project has all federal permits approved[45].

Duke has put forward what they consider to be a conservative timeline to obtain natural gas from the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Although currently, the growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast markets.

As shown in its 2020 IRP, Duke has **[BEGIN CONFIDENTIAL]** [redacted]

[45] For additional information on the MVP Southgate Project, please see: http://www.mvpsouthgate.com/.

[redacted] **[END CONFIDENTIAL]**. This would provide an alternative price point until definitive capacity can be obtained on an operational pipeline.

The Public Staff accepts the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** will cause the capacity expansion models to overly rely on natural gas. Therefore, we recommend that Duke in its 2021 avoided cost filing re-evaluate its assumptions regarding the availability of additional interstate pipeline capacity. If Duke continues to assert that adequate capacity will be available, it should provide the Commission and stakeholders with a detailed narrative that identifies expected actions by various pipeline developers and other parties with expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential new interstate pipelines. Consistent with the Public Staff's comments to be filed in the 2020 IRP proceeding, Duke should also consider developing an IRP portfolio or sensitivity in the 2021 IRP Update that is similar to their base case but which includes natural gas import restrictions or less reliance on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** gas.

AVOIDED ENERGY – RATE STRUCTURE AND RATES

DEC AND DEP TREATMENT OF START COSTS

In the 2018 Proceeding, the Public Staff worked with Duke to establish a more granular rate design for avoided costs. This rate design, as well as guidelines and a methodology for updating the rate design in the future to accommodate system changes, was memorialized in the Stipulation of Partial Settlement Among DEC, DEP, and the Public Staff (Rate Design Stipulation). The Rate Design Stipulation introduced a third ‘shoulder’ season as well as a ‘premium peak’ pricing period for winter and summer seasons, reflecting the high cost of energy during high load hours.

In this proceeding, the Public Staff identified that the avoided energy rates filed by DEC and DEP exhibited counterintuitive behavior in some schedules. For example, the variable rate for both DEP and DEC, and the 10 year fixed rate for DEP, all have a winter AM-peak rate that is actually lower than the winter off-peak rate; and the 10 year fixed rate for DEC has a shoulder on-peak rate that is lower than the shoulder off-peak rate. The Public Staff was concerned that this behavior was not reflective of actual avoided costs, and might in fact be an artifact of the production cost modeling; in that case, the time variant rates would not incentivize the appropriate operational behavior from dispatchable QFs.

Upon investigation, the Public Staff determined that the primary driver for these counterintuitive rates was due to a change in the way the Duke has treated start-up costs in the production cost model that is used to determine avoided energy costs. Start-up costs for certain units, particularly coal units, can be very expensive – running into the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Prior to these proceedings, these start costs would be converted to a $ per MWh rate, based on how long the unit was run after it was start up. Sometime in 2019, Duke changed its methodology, and start costs are now allocated entirely to the hour in which they occurred. According to Duke, this likely explains the very low rates for winter AM-peak rates, which is the shortest rate period (only one hour preceding and one hour following the winter premium peak period).

Duke has notified the Public Staff that it intends to re-run its production cost models using the Sub 158 methodology of spreading the start costs over each unit's run time. The Public Staff believes that this problem will be resolved through this change, and anticipates Duke will file a revised rate schedule incorporating this change. However, Duke has indicated that it plans to continue to evaluate the most accurate method to allocate unit start costs for both integrated resource planning and avoided cost modeling purposes, and the Public Staff anticipates working with Duke on this issue prior to the November 2021 avoided cost filing.

LINE LOSS ADDER

The Public Staff has reviewed the information filed by the Utilities related to line loss adders and back-feeding of substations, and agrees with their proposals.

For the reasons articulated in the Sub 148 Order,[46] it is appropriate for DENC to continue to have its line loss adder removed from its standard offer avoided costs rates and DEC and DEP to continue to include a line loss adder.[47] DENC demonstrated that the amount of "back feed" from renewable generation occurring and expected to continue to occur on the DENC system justifies the

[46] See Finding of Facts 17, 18, and 19, Sub 148 Order at 8, 91-93.

[47] Line Loss adder is a 3% increment to account for less losses occurring across the transmission and distribution system as centralized generation stations provide service. In theory, if distributed generation is matched in harmony with load, the distributed generation will negate the Utilities' system losses.

removal of a line loss adder. DEC and DEP continue to have a level of unsubscribed or “open” substation capacity at this time that would allow the line loss adders to be included. The Public Staff will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings, and recommends that the Commission direct the utilities to continue to file information to support the removal/inclusion of the line loss adder in their proposed avoided cost rates in future avoided cost proceedings. As part of the next avoided cost filing, the Public Staff further recommends that DEC and DEP evaluate and report on any geographical concentrations of back-feeding substations and whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate in order to provide appropriate market-based signals to QFs regarding the value of the energy at the selected location.

MODIFICATIONS TO TERMS AND CONDITIONS

QF REPORTING REQUIREMENTS

In the standard contracts filed with their Initial Statements, DEP and DEC proposed to amend Section 6 of their standard offer PPA forms to reduce the threshold from three MW to 100 kW for requiring QFs to provide prior notice of annual, monthly, and day-ahead forecasted hourly production, as specified by the respective utility. DEC and DEP indicate that they do not have a present intent to require such information from small standard offer QFs, but believed the change was appropriate “to better align this provision with revised standard offer eligibility under HB 589 and to recognize that it may become appropriate in the future to request operational data from smaller QFs during the terms of these PPAs as increasing penetrations of distributed energy resources are installed on the Companies' systems."[48]

The Public Staff notes that these reporting requirements were last addressed by the Commission in the Sub 140 Order, in which DEC and DEP proposed a similar 100 kW threshold for requiring forecasted hourly production rates from QFs. In that proceeding, DEC, DEP, and the Public Staff ultimately agreed to alternative language limiting the reporting requirements to facilities larger than three MW. DEC and DEP noted in their Joint Reply Comments that the forecast information would aid them in procuring alternative resources when a QF plans reduced operations, but acknowledged that a request for planned operational information was unlikely to be necessary for QFs below three MW based upon current system operations. The Commission in its Sub 140 Order found that the three MW threshold agreed to by DEC, DEP, and the Public Staff should allow DEC and DEP to plan system operations without being unduly onerous to the QFs.[49]

The Public Staff recognizes the value of accurate production date for system operations and has concerns that lowering the reporting threshold from three MW to 100 kW may be onerous and costly for some small QFs. In addition, the Public Staff questions whether it is likely now or in the foreseeable future for the utilities to rely on the production forecasting information from small QFs for procuring alternative resources. The Public Staff further notes that DEC and DEP

[48] DEC and DEP Initial Statement at 34-35.
[49] Sub 140 Order at 34.

indicated in response to Public Staff data requests that they have not requested operational forecasts information from any QFs less than five MW in the past five years.[50]

The Public Staff also acknowledges Duke's goal to align this provision with revised standard contract eligibility established under HB 589, but notes that since neither DEC or DEP have entered into purchase contracts in the aggregate capacity of 100 MW or more with facilities that established legally enforceable obligations after November 1, 2016, the current threshold remains at one MW for standard offer contract eligibility pursuant to N.C.G.S § 62-156(b)(1).[51] The Public Staff finds that a facility greater than one MW may be better situated to agree to certain production forecasting reporting requirements as part of a negotiated contract process with DEC or DEP, and therefore recommends that the Commission direct DEC and DEP to revise their standard offer contracts to require the forecasted hourly production rates from QFs only from facilities greater than one MW in capacity.

CONCLUSIONS

In summary, the Public Staff recommends that the Commission:

[50] DEC and DEP Response to Public Staff Data Request 10-1(d).

[51] Since November 1, 2018, DEC and DEP have received 11 Notices of Commitment for approximately 5.56 MW under the Sub 158 Schedule PP standard offer, and have received 2 Notices of Commitment from larger QFs (not eligible for the Sub 158 Standard Offer) for approximately 8.4 MW requesting to negotiate a PURPA PPA. *See* DEC and DEP Initial Statement at 35.

(1) direct Duke to address the issue of the appropriate PAF to apply in calculating capacity rates capacity rates available to run-of-the-river hydro QFs as part of their initial statements filed in the next biennial avoided cost proceeding, consistent with the Sub 158 Order;

(2) direct DENC to file a report on the types of forecasts and the ESD dispatch behavior for CSGs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory in its future avoided cost filings;

(3) direct DENC to specifically address CSGs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facility(ies) and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on CSGs seeking to avoid the RDC;

(4) direct DENC to revise its avoided energy costs to remove any federal CO2 cost assumptions included in the energy production model that are not yet known or verifiable;

(5) direct Duke to refile its avoided energy rates reflecting the allocation of start costs over all hours the unit runs, consistent with the Sub 158 Rate Design Stipulation;

(6) direct Duke in its 2021 filing to provide additional support regarding its assumptions on the availability of additional interstate and intrastate pipeline capacity as described in these comments;

(7) direct Duke to evaluate and report on any geographical concentrations of back-feeding substations and whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate; and

(8) direct Duke to revise the production forecast reporting requirements to only apply to QFs greater than one MW in capacity.

WHEREFORE, the Public Staff respectfully requests that the Commission take the foregoing comments and recommendations into consideration.

Respectfully submitted this the 25th day of January, 2021.

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CERTIFICATE OF SERVICE

I certify that a copy of these Comments have been served on all parties of record or their attorneys, or both, by United States mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 25th day of January, 2021.

Electronically submitted
/s/ Tim R. Dodge