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June 22, 2015

<u>Via Electronic Filing</u>

Ms. Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014
Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed for filing in the referenced docket are Initial Comments of Southern Alliance for Clean Energy. By copy of this letter, I am serving all parties of record on the service list.

Please let me know if you have any questions about this filing.

Sincerely,

s/ Robin G. Dunn
Administrative Legal Assistant
N.C. Certified Paralegal

RGD
Enclosures
cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 140

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014	))))))	**INITIAL COMMENTS OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**

Pursuant to the Commission's January 8, 2015 Order Establishing Procedural Schedule and Scheduling Public Hearing, as modified by its May 29, 2015 Order Granting Motion for Extension of Time, Southern Alliance for Clean Energy ("SACE") files these initial comments on the proposed rates and standard form contracts filed on March 2, 2015 by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") (together, "Duke"), and Dominion North Carolina Power ("DNCP") (collectively, "the Utilities").

Background

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") requires large electric utilities to purchase available energy and capacity from small independent power producers, known as "qualifying facilities" or QFs. See generally 16 U.S.C. § 2601 et seq. PURPA requires that rates for the purchase of energy from QFs by electric utilities 1) shall be just and reasonable to the consumers of the electric utility and in the public interest, and 2) shall not discriminate against qualifying cogenerators or qualifying small power producers. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1). PURPA rates are set at the utility's avoided cost of producing the next incremental unit of electricity. 16 U.S.C. § 824a-3. In promulgating regulations to implement PURPA, the Federal Energy Regulatory Commission ("FERC") made it clear that QFs are entitled to rates for purchases that equal the utility's full avoided costs. Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12,214, 12,223 (Feb. 25, 1980). The PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts ("kW") or less, and also gives state commissions the authority to develop standard rates for larger QFs. 18 C.F.R. § 292.304(c)(1), (2).

Under PURPA and its implementing regulations, FERC has delegated to state regulatory commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority. State ex rel. Utilities Comm'n v. North Carolina Power, 338 N.C. 412, 417, 450 S.E.2d 896, 899 (1994) (citing 16 U.S.C. § 824a-3(f)). This Commission has elected to implement Section 210 of PURPA by holding biennial proceedings, such as the current proceeding.

This is the second phase of this biennial proceeding. In the first phase, the Commission requested testimony regarding 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 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 to which QFs are entitled under PURPA. After receiving testimony from the parties and holding an evidentiary hearing on these issues, the Commission issued an Order Setting Avoided Cost Parameters on

December 31, 2014 ("Phase I Order"). The Phase I Order, among other things, established certain parameters by which avoided cost rates should be calculated. In its January 8, 2015, Order Establishing Procedural Schedule and Scheduling Public Hearing, the Commission indicated that it would attempt to resolve all remaining issues in this docket based on written filings. Accordingly, the Commission required that the Utilities file their proposed avoided cost rates for purchases from qualifying facilities ("QFs") and standard forms of contract for power purchased from QFs on March 2, 2015. The Commission also directed the non-utility parties to file comments and exhibits by May 4, 2015, later extended to June 22, 2015.

SACE retained Synapse Energy Economics, Inc. ("Synapse"), a research and consulting firm specializing in energy, economic, and environmental topics, to review the Utilities' March 2, 2015 filings and underlying data to determine whether the Utilities' proposed avoided cost rates and standard forms of contract comply with the Commission's Phase I Order. Based on this review, Synapse determined that the Utilities have complied with most of the ordering paragraphs in the Phase I Order.[1] However, the Utilities have failed to comply with the Phase I Order in certain key respects, as explained in the following sections. As a result, the Utilities' proposed rates likely do not capture all of the costs that purchases of power from QFs allow them to avoid, and accordingly, may not represent fair rates that allow QFs to be compensated at the full avoided cost rate to which they are entitled under PURPA.

[1] SACE and Synapse reserve the right to revisit this initial determination in reply comments based on further review after the opportunity to review the other non-utility parties' initial comments in this phase of the proceeding.

The Utilities' Compliance With the Commission's Phase I Order

A. Dominion North Carolina Power

1. DNCP's Tailoring of Combustion Turbine Installation Costs

Ordering paragraph no. 6 of the Commission's Phase I Order provides that "in the calculation of the installed cost [of] a CT [natural gas combustion turbine], DEC, DEP and DNCP shall use data from publicly available industry sources and tailor it *only to the extent clearly needed* to adapt any such information to the Carolinas and Virginia."[2] It is not clear that all of DNCP's tailoring adjustments were needed to adapt the information to North Carolina and Virginia. In its calculation of installed CT costs, DNCP relies on the *2013 Gas Turbine World Handbook* estimate for equipment costs, and on the PJM cost of new entry estimates for the remaining costs. However, DNCP makes a number of downward adjustments to the construction and owner costs that have the cumulative effect of significantly lowering the installed CT costs. Such adjustments include, but are not limited to, pollution control costs, construction labor costs and electric and gas interconnection costs.[3] In tailoring the publicly available data, it appears that DNCP has endeavored to incorporate reduced values where possible. The result of these adjustments—which have not been demonstrated to be "clearly needed"—may be that DNCP's installed CT cost is artificially low, and that therefore its avoided capacity cost is too low.

2. DNCP's Fuel Hedging Estimates

Ordering paragraph no. 9 of the Commission's Phase I Order provides that each of the Utilities "shall calculate and include the fuel hedging benefits associated with

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[2] North Carolina Utilities Commission, Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140 at 65 (emphasis added) (hereinafter, "Phase I Order").

[3] DNCP, Schedule 19 and Supporting Comments, Section III, Fig. 1.

purchases of renewable energy, as discussed in this Order, in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding." There are several issues with the way DNCP has calculated fuel hedging benefits associated with purchases of renewable energy from QFs.

First, in response to a data request, DNCP states that "the avoided hedging cost is based on a high-end estimate of $3.2 million (based on 2012/2013 cost data) for gas broker transaction costs and financing costs, divided by the aggregate MWh amount of non-nuclear energy supply that could potentially be displaced by renewable generation."[4] DNCP's hedging costs of $3.2 million should be for the Company's combined North Carolina and Virginia service territory, since they appear to be dividing these costs by their total generation across their two-state system. If DNCP incurred additional hedging costs in Virginia, these should be included.

Second, and more significantly, DNCP should have calculated avoided hedging costs for natural gas before other resources. DNCP has divided its hedging costs by the megawatt-hours ("MWh") of non-nuclear energy generation that could potentially be displaced by renewables. DNCP appears to assume that 1 MWh of renewable generation could displace 1 MWh of any non-nuclear-fueled generation with equal likelihood, regardless of where that generation sits in the dispatch order.

In reality, it is likely that much more of the displaced generation will be fueled by natural gas. Renewables will have the lowest variable operating costs because they are fuel-free resources. As a result, they will displace the highest-priced, marginal unit, which is a natural gas-fired CT. Therefore, to calculate the avoided hedging costs, the

[4] DNCP, Response to Public Staff Data Request No. 3, Question No. 14.

Company should have first calculated the avoided hedging cost per MWh of natural gas generation. Then the Company should have used the results of its production cost model (PROMOD) runs for avoided energy costs to determine what types of generation would be displaced by renewable QFs. The avoided hedging cost per MWh of natural gas generation would then be multiplied by the percent of avoided natural gas generation to determine the average avoided hedge value per MWh of QF generation.

A third concern with DNCP's fuel hedging calculations is the duration of the hedge. While DNCP only hedges for one-year terms, it is unreasonable to assume that DNCP will not hedge at all for any of the future years, and including zeroes for the hedge value for future years makes such an assumption. Hedging values, even if based on a one-year term, should be included for future years. DNCP should model a hedging cost similar to that of the first year in each year modeled.

3. <u>DNCP Has Failed to Define "Firm" Capacity</u>

Under DNCP's Schedule 19, Section IV, QFs have three options for designating their mode of operation: non-reimbursement, non-firm or firm. QFs will only be compensated for capacity if they elect the "firm" mode of operation.[5] However, DNCP's Schedule 19 does not provide a definition of "firm" or "non-firm," leaving QFs with no guidance to determine whether or not they are qualified to provide firm capacity and energy when designating their mode of operation. This lack of guidance is likely to engender confusion and encourage QFs to designate their mode of operation as "non-firm," in which case they will receive payment only for avoided energy costs, even if they may be entitled to payment for avoided capacity costs as well.

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[5] DNCP, Schedule 19, Section IV.

4. DNCP'S Distance Requirement

DNCP has added a restriction in its Schedule 19 that excludes a renewable resource QF "which is owned by a developer, or affiliate of a developer, who is selling or will sell power to the Company from another renewable resource QF located within one mile if the combined output of such renewable resource QFs will exceed 5,000 kW (ac)."[6]

When determining whether two generators near one another should be viewed as a single facility or two separate facilities for purposes of a capacity threshold under PURPA, there are three criteria to be considered: distance between the facilities (measured between the respective facilities' electric generating equipment), ownership, and the type of energy resource. The requirement that two facilities be located more than one mile apart only applies to facilities under common ownership that use the same type of energy resource.[7] FERC has made clear that these criteria represent rules and not rebuttable presumptions.

Thus, the one-mile radius restriction and the 5,000 kW restriction in DNCP's Schedule 19 should only apply when the two proposed facilities under common ownership use the same energy resource. Furthermore, it should be made clear that the distance between facilities is measured from the electrical generating equipment of a facility for purposes of making the one-mile determination.

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[6] DNCP, Comments, Exhibits and Avoided Cost Schedules of Dominion North Carolina Power (March 2, 2015) at 10.

[7] See FERC, Order Granting Applications for Commission Certification, 139 FERC ¶ 61,201, Docket Nos. QF11-235-001 and QF12-99-001, available at http://www.ferc.gov/EventCalendar/Files/20120611162140-QF11-235-001.pdf.

B. Duke Energy Carolinas and Duke Energy Progress

1. <u>DEC and DEP's CT Installation Costs: Economies of Scale vs. Scope</u>

Ordering paragraph no. 7 of the Commission's Phase I Order details the costs associated with CT construction that are to be included in capacity cost calculations, stating that:

> [I]n the calculation of the installed cost of a CT, DEC, DEP, and DNCP shall include transmission interconnection costs (but not network upgrade costs), equipment and construction costs with a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, a reasonable estimate of useful life of a CT, the cost of land for a greenfield site, and economies of scale for up to four CTs constructed on the same site. *DEC, DEP, and DNCP shall not include any economies of scope associated with the construction of more than once CT at the same time*.[8]

Despite the Commission's clear directive not to use economies of scope, DEC and DEP admit in response to a data request that they incorporated economies of scope in their CT installed cost calculations.[9] DEC and DEP seek to use the 2x2-unit $/kW CT cost estimate developed by the Electric Power Research Institute, which incorporates both economies of scale and of scope. DEC and DEP urge that they have not been able to locate data differentiating between economies of scale and scope and believe they would violate the Commission's order by not including some economies of scale. Implicit in Duke's explanation is that building four units at the same site would result in not only economies of scale (shared land, engineering, roads, etc.) but also economies of scope (building identical units at the same time). Therefore, the only construction estimates that do not include economies of scope are 1x1-unit construction estimates – building a single CT at a site.

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[8] Phase I Order at 66 (emphasis added).

[9] DEC Response to Public Staff Data Request No. 7, Question No. 3.

Contrary to DEC and DEP's position that their CT cost estimate must incorporate economies of scale, the Commission's order explicitly refers to economies of scale *up to* four CT units. In other words, the Commission's Phase I Order does not require that economies of scale be included if that data is unavailable. What the order does clearly provide is that the Utilities shall not include economies of scope in calculating the installed cost of a CT.

2. Data Underlying Duke's Installed CT Costs

Ordering paragraph no. 6 of the Commission's Phase I Order provides that "in the calculation of the installed cost [of] a CT [natural gas combustion turbine], DEC, DEP and DNCP *shall use data from publicly available industry sources* and tailor it only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."[10]

In their March 2, 2015 filings, neither DEC nor DEP disclosed the data underlying their calculations of the installed cost of a CT. Instead, interested parties had to resort to data requests to obtain this information, much of which was marked as "confidential" when provided. In this regard, DEC and DEP have failed to comply with the Commission's admonition in the Phase I Order to use data from publicly available industry sources in calculating the installed cost of a CT.

3. DEC and DEP's Fuel Hedging Estimates

As mentioned above, ordering paragraph 9 of the Commission's Phase I Order states that each of the Utilities "shall calculate and include the fuel hedging benefits associated with purchases of renewable energy, as discussed in this Order, in the avoided

[10] Phase I Order at 65 (emphasis added).

energy component of its avoided cost rates to be filed in phase two of this proceeding."[11] In response to data requests, DEC and DEP assert that they use the "ask" gas forecast rather than the midpoint of the "bid" and "ask" for all gas prices.[12] The result, they claim, is that they are modeling a fully hedged gas price.

There are two problems with using the "ask" gas forecast as the basis for fuel hedging benefits. First, gas commodity price forecasts do not have a "bid" and "ask" price, just a clearing price. It is unclear where the "ask" prices used by DEC and DEP came from. While DEC and DEP do provide monthly gas prices for the next fifteen years, they do not provide any explanation or source for those forecasts, nor do they provide any explanation on how the values were adjusted from a typical non-hedged purchase price to the so-called "ask" price.

Second, fuel hedging involves purchasing natural gas futures, not purchasing natural gas at forecasted prices. Therefore, utilities should use natural gas futures prices, not commodity prices, when calculating the fuel hedging benefits associated with purchases of renewable energy from QFs.

4. <u>DEC and DEP's Distance Requirement</u>

DEC and DEP both include language in their standard contract, Purchased Power Schedule PP-1, to the effect that "[t]his Schedule is not available to a Qualifying Facility owned by a Seller or affiliate or partner of a Seller, who sells power to the Company from another Qualifying Facility located within one-half mile unless the combined capacity is equal to or less than five (5) megawatts."[13] This broad language goes beyond what recent

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[11] <u>Id.</u>
[12] DEC and DEP Responses to Public Staff Data Request 6, Question No. 17. Gas forecasts are made available in DEC and DEP Responses to Public Staff Data Request 6, Question No. 1.
[13] DEC Exhibit 2 at 1; DEP Exhibit 2 at 1.

FERC orders permit. As detailed in the DNCP section above, DEP and DEC appear to restrict a developer from building two generators too closely even if they rely on different energy sources – an apparent contradiction with FERC precedent. Just as with DNCP, it should also be made clear that the distance between facilities is measured from the electrical generating equipment of a facility for purposes of making the half-mile determination.

Conclusion

As explained in the preceding sections, the Utilities have failed to comply with the Phase I Order in certain key respects. In particular, DNCP has made adjustments to publicly available CT installation cost data without demonstrating that all of these adjustments are clearly needed to adapt the costs to the Carolinas and Virginia. The cumulative effect of these downward adjustments may artificially deflate DNCP's avoided capacity costs. DNCP's calculation of the fuel hedging benefits of renewables should also receive close scrutiny, as it may not include all costs, and it makes incorrect assumptions regarding the type of generation most likely to be displaced by renewable QFs. Duke improperly includes economies of scope in its estimates of CT installation cost and also based those estimates on confidential data, in contravention of the Commission's mandate to use publicly available data. Duke's fuel hedging estimates based on "ask" prices are also problematic. Finally, all of the Utilities' distance requirements are overly broad and in need of clarification. As a result, the Utilities' proposed rates likely do not capture all of the costs that purchases of power from QFs allow them to avoid, and accordingly, may not represent fair rates that allow QFs to be compensated at the full avoided cost rate to which they are entitled under PURPA.

Respectfully submitted this 22nd day of June, 2015.

s/ Gudrun Thompson
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CERTIFICATE OF SERVICE

I certify that the foregoing Initial Comments of Southern Alliance for Clean Energy as filed today in Docket No. E-100, Sub 140 has been served on all parties of record either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 22nd day of June, 20154.

s/ Robin G. Dunn