STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E100, SUB 194

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023	)	**PARTIAL PROPOSED ORDER OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY**

BY THE COMMISSION: This is the 2023 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings are also held pursuant to G.S. § 62- 156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. § 62-3(27a).

Section 210 of PURPA and FERC's implementing regulations establish the responsibilities of FERC and state regulatory authorities, including this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring the purchase and sale of electric power by electric utilities to cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates that are just and reasonable to the ratepayers of the utility, are in the public interest, and do not

[1] Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30, 128 (1980); see also 45 Fed. Reg. 12,214 (1980).

discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state jurisdiction, FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC's rules.

The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the most recent biennial avoided cost proceeding. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also follows the mandate of G.S. § 62-156, which was enacted by the General Assembly in 1979. That statute provides that "no later than March 1, 1981, and at least every two years thereafter" the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in FERC regulations regarding factors to be considered in the determination of avoided cost rates. House Bill 589 (H589), S.L. 2017-192 made significant revisions to the state implementation of PURPA, while still leaving a number of implementation issues to the Commission for consideration in these biennial proceedings.

On August 7, 2023, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing. Pursuant to that Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (together, Duke or Duke Energy), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion or DENC), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Power and Light (New River) were made parties to these proceedings.

The following parties filed Petitions to Intervene that were granted by the Commission: North Carolina Sustainable Energy Association (NCSEA), Carolinas Clean Energy Business Association (CCEBA), Southern Alliance for Clean Energy (SACE), and the Carolina Industrial Group for Fair Utility Rates I (CIGFUR I), Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), and Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) (collectively, CIGFUR). Participation of the Public Staff was recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's Office (AGO) gave notice of its intervention pursuant to N.C. Gen. Stat. §§ 62-20, 114-2(8).

On November 1, 2023, DENC filed its Initial Statement and Exhibits and confidential avoided cost information. Also on November 1, 2023, Duke Energy filed its Joint Initial Statement and Exhibits and confidential avoided cost information. And also on November 1, 2023, WCU and New River filed joint comments and proposed rates.

On February 6, 2024, the Commission granted the Motion for Extension of Time filed by SACE, NCSEA, and CCEBA, extending the date for parties to file initial comments to February 21, 2024, and reply comments to March 27, 2024.

On February 15, 2024, Duke filed updates to its avoided cost rates and updated exhibits, reflecting the new P3 Fall Base reference portfolio identified in its Supplemental Planning Analysis, previously filed in the Carbon Plan-integrated resources plan proceeding, Docket No. E-100, Sub 190.

On February 21, 2024, SACE, NCSEA, the AGO, the Public Staff, and CCEBA separately filed initial comments.

On March 4, 2024, DENC filed contract amendments.

On March 27, 2024, DENC, Duke, NCSEA, the Public Staff, SACE, and CCEBA separately filed reply comments.

On April 10, 2024, this Commission issued an order requiring proposed orders and briefs be filed on or before May 10, 2024.

Based on the foregoing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. The Net Excess Energy Credit (NEEC) that customers receive for net excess energy exported to the grid above and beyond the customer's consumption within a given pricing period (month) should be based on a time horizon of 10 years.

2. A customer-sited solar generating system can be expected to continue operating for the system's entire expected useful life, which can be estimated to be twenty years at minimum, given the length of equipment warrantees and the economic incentives to continue operation.

3. It is reasonable and appropriate to use the same assumptions concerning the length of operation of a customer-sited solar generating system in the

integrated resources plan (IRP) or Carbon Plan-IRP (CPIRP) proceeding and the avoided cost proceeding.

4. As an incremental step toward a more accurate NEEC calculation and consistency across proceedings, it is reasonable and appropriate to use a ten-year term to calculate the NEEC for this proceeding, and it will be appropriate to evaluate using a twenty-year term in the next biennial avoided cost proceeding.

5. Behind-the-meter net-metered systems are likely to serve loads in close proximity to the system and therefore incur minimal distribution line losses, and lower distribution line losses than front-of-the-meter generation.

6. It is reasonable and appropriate for the NEEC to incorporate a distribution line loss factor in addition to the line loss factors used for distribution-connected QFs.

7. Behind-the-meter net-metered systems can allow the utility to avoid some transmission and distribution (T&D) costs.

8. It is reasonable and appropriate for the NEEC to include avoided transmission and distribution (T&D) costs, based on the methodological framework recommended by SACE's expert Justin Barnes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1-8

The evidence supporting these Findings of Fact is found in Duke Energy's Initial Statement, the Initial Statement of the Public Staff, the Initial Comments of SACE, the Initial Comments of the AGO, the Reply Comments of the Public Staff, the Reply Comments of NCSEA, and the Reply Comments of CCEBA.

Summary of the Comments

In Duke's Initial Statement, it explained that it calculated the NEEC in DEC Exhibit 11 and DEP Exhibit 11 based on a five-year term in a manner consistent with the two- and 10-year fixed term rates shown on Schedule PPs, then weighting the five-year rates based on a typical rooftop solar production profile to determine an annual value. Duke Initial Statement 42. Duke stated that the annual value includes an energy component, and a capacity component when applicable, and that for this proceeding both DEC and DEP have a need for capacity starting within the first five years, making the inclusion of a capacity component appropriate for each Company's NEEC at this time. *Id.*

In its Initial Statement, the Public Staff recommended approving Duke's proposed NEEC. Initial Statement of the Public Staff 15.

The Initial Comments of SACE recommended three refinements to Duke's calculation of the NEEC. SACE explained that its proposed refinements supported the two principles that guided its review of Duke's proposed NEEC: (1) it should accurately compensate rooftop solar customers for the costs that their solar generating facilities allow Duke to avoid, pursuant to G.S. § 62-156(b)(2), and (2) the proposed NEEC should comply with the law and the Commission's prior orders.

SACE's three refinements were supported by expert comments prepared by Justin Barnes, president of EQ Research, submitted as an attachment to SACE's Initial Comments. Initial Comments of SACE, Att. 4. First, SACE recommended using a time horizon of ten years or longer for the purpose of calculation, with the NEEC rate itself still updated in the biennial PURPA avoided cost proceeding for all customers. Mr. Barnes pointed out that the Public Staff had previously recommended using a term longer than two years because Duke incorporated net-metered generation into its integrated resources plan (IRP) modeling as a reduction in load, *id.* at 1, and that NCSEA had previously recommended a ten-year term because there was no basis to assume that a net-metered facility would not operate for longer than five years, most solar equipment is warranteed for at least ten years, and net-metering customers have a strong incentive to continue operating their systems for longer than ten years, *id.* at 1-2. Mr. Barnes recommended requiring a ten-year period for two reasons: first the Public Staff's implicit concerns about the time period over which a net-metered solar system can reasonably be expected to operate were unfounded and conflicted with Duke's IRP assumptions and the reasonable real-world expectation that a net-metered solar system will operate for at least twenty years. *Id.* at 2. And second, the NEEC rate would not become stale because it would be updated every two years. Mr. Barnes recommended a minimum term of ten years. *Id.*

Second, SACE recommended incorporating a distribution line loss factor specific to rooftop solar, in addition to the line loss factors used for distribution-connected QFs. Mr. Barnes explained that Duke's NEEC calculations included line losses, calculated for the categories of (a) generator step-up, (b) transmission line, and (c) transmission/ distribution transformation, but not for distribution line losses. *Id.* at 2-3. Mr. Barnes explained that this approach is appropriate for in-front-of-the-meter QFs that export substantial quantities of energy to the distribution grid, since the exported electricity would serve demand at locations remote from the generating facility, but not for net-metered systems, which are likely to serve loads in close proximity to the system and therefore incur minimal distribution line losses. *Id.* at 3.

Third, SACE recommended including avoided transmission and distribution (T&D) costs, calculated using a methodology proposed by SACE's expert in light of the continued absence of information concerning avoided T&D costs in Duke's filing. Mr. Barnes pointed out that the Commission's final order in the last biennial avoided cost proceeding anticipated revisiting the NEEC and whether avoided T&D costs should be included in its calculation in this proceeding. *Id.* He submitted four examples of commissions in other states—Kentucky, Utah, Minnesota, and California—that calculate avoided T&D costs for specific rates. *Id.* at 3-4.

For avoided transmission costs, Mr. Barnes began by pointing out that Duke's Carbon Plan-IRP (CPIRP) filing incorporates the costs associated with transmission upgrades. *Id.* at 4-5. To address the "lumpy" nature of transmission investments, Mr. Barnes recommended examining how Duke's forecasts of transmission costs under its preferred portfolio would change under the sensitivities that were evaluated for the low, base, and high forecasts of customer-sited solar generation. *Id.* at 5. Mr. Barnes explained that this comparison would identify the incremental transmission costs associated with varying levels of customer-sited solar, and the different capital investment costs could then be translated into differences in present value of revenue requirements for the different scenarios, which can then be translated into an avoided cost rate by dividing that amount by the differences in customer-sited solar energy generation in each scenario. *Id.* He explained that this approach would implicitly account for the various factors that influence transmission planning and investment. *Id.* Mr. Barnes recommended that the time horizon used for the comparison be the same as for calculating the NEEC, at least ten years. *Id.* He recommended using an average of the low-to-base and base-to-high customer-sited solar deployment scenarios, for lack of a reason to choose one over another, and in the interest of rate stability. *Id.*

For avoided distribution costs, Mr. Barnes explained that the value is determined by two primary inputs: (1) an accepted figure for marginal distribution costs, typically stated in terms of $/kW unit costs; and (2) an acceptable methodology for determining the effectiveness of a given resource at contributing to reduced distribution loads, which can be referred to as the effective capacity and is typically denominated as a percentage (%). *Id.* at 6. He stated that Duke's avoided generation capacity cost calculations for uncontrolled solar generation use these basic inputs, applying marginal generation capacity costs across time windows when capacity is needed and calculating avoided cost rates based on the coincidence of a solar production shape with those time periods. *Id.* And Mr. Barnes pointed out that the Commission has already accepted a figure for marginal distribution costs has already been established for use in evaluating the cost-effectiveness of the Companies' EE/DSM filings. *Id.* He explained that the remaining part of the analysis of avoided distribution value for the NEEC was simply a further evaluation of the relative coincidence of customer-sited solar generation with the distribution peaks that cause the need for additional distribution system investments. *Id.* Mr. Barnes recommended that, as a starting point, the effective capacity determination be made by analyzing the timing of circuit-level peaks throughout the year varied by month and time of day, resulting in the assignment of a weight for each hour of a 12 month X 24 hour representation of those peaks, to which a solar generation profile can then be applied. *Id.* Mr. Barnes recommended a number of additional refinements to that basic methodology, depending on data availability. *Id.* at 6-7.

In its Reply Comments, the Public Staff addressed the issues raised by SACE. Beginning with SACE's proposed refinements, the Public Staff first addressed SACE's proposal to use a ten-year term to calculate the NEEC. The Public Staff stated that it reviewed the information provided by SACE and agreed that a ten-year avoided cost term "may appear to be appropriate for calculating the NEEC from a conceptual standpoint" but opined that it may not be appropriate in terms of ensuring net metered customers are paid a rate for their excess energy that is fair to other consumers. Reply Comments of the Public Staff at 9.

The Public Staff explained its concern with a ten-year NEEC rate as follows. To calculate the levelized avoided energy rate over a particular term—such as ten years—requires taking the present value of a series of annual avoided energy costs that are based on the production cost modeling, and calculating a levelized rate that is equivalent to the annual rates, subject to the utility's discount rate. *Id.* The Public Staff explained that, mathematically, the levelized rate will typically fall somewhere between the lower and upper values over a given term. *Id.* at 10. It stated that the annual avoided cost rate varies over time—depending on projected fuel costs and the available generation resources in a given year—and in recent proceedings the annual rate increases over time as natural gas prices increase over time. *Id.* The Public Staff explained that, if natural gas prices increase steadily over time, and therefore annual avoided cost rates increase over time, a ten-year levelized NEEC would be higher than the annual avoided cost rate in early years (i.e., "overpaying" in those years relative to the annual rate) and lower than the annual rates in later years (i.e., "underpaying"). *Id.* The Public Staff acknowledged that if natural gas prices were expected to decline over time, the opposite would occur, and net metering customers would be underpaid. *Id.* at 11 n.12. The Public Staff expressed concern that a ten-year rate that was refreshed every two years in the biennial avoided cost proceeding would capture only the early years of "overpayment." *Id.* The Public Staff expressed concern that this would shift costs to non-rooftop solar customers. *Id.* at 10-11. However, the Public Staff found a five-year rate acceptable. *Id.*

Addressing SACE's second refinement—a distribution loss factor—the Public Staff stated that while it expects this incremental loss factor may be relatively small, "it still represents an incremental benefit to behind-the-meter generation exports that is not currently captured in the NEEC" for customers taking service under Riders Residential Solar Choice or Net Metering Bridge. *Id.* at 12. The Public Staff supported determining the incremental distribution loss factor for the NEEC and recommended the Commission direct Duke to calculate it and update the NEEC in this proceeding. *Id.*

Addressing SACE's third refinement—avoided T&D value—the Public Staff recommended that Duke perform an analysis based upon witness Barnes' recommendations of potential avoided T&D costs that can reasonably be avoided by behind-the-meter generation and discuss their potential inclusion in its next avoided cost proceeding. *Id.* at 11-12.

In its Reply Comments, NCSEA stated that it agreed with SACE's two principles guiding its review of Duke's proposed NEEC, as well as SACE's proposed refinements as described by Mr. Barnes. Reply Comments of NCSEA 8-9.

In its Reply Comments, CCEBA stated that it supported SACE's comments and proposals concerning the NEEC. Reply Comments of CCEBA 14.

Discussion and Conclusions

The Commission determines that each of SACE's three refinements to the NEEC should be adopted.

First, the Commission determines that a ten-year term is appropriate for this proceeding. The Commission finds it persuasive that Duke assumes that customer-sited solar systems will continue to operate for over two decades for the purpose of its CPIRP planning. In addition, the Commission recognizes the strong financial incentive that customers—both residential and non-residential—have to continue operating rooftop solar systems throughout their useful lives. Rooftop solar systems represent a significant expense to almost any customer and are not easily portable or put to another use. The Commission also finds it persuasive that the Public Staff would agree with SACE's proposed ten-year term but for its concern about cross-subsidization.

The Commission is not persuaded by the Public Staff's concern about cross-subsidization resulting from using a ten-year term to calculate the NEEC. As the Public Staff acknowledged in a footnote, this concern is based entirely on the assumption that natural gas prices will continue to increase indefinitely. But that assumption is unfounded. While natural gas prices have spiked in recent years, they have also declined again, and further variation can be expected as the result of multiple factors such as pipeline capacity expansion (decrease) or increasing liquefied natural gas exports (increase). Under DEC's proposed rates in its current fuel adjustment clause proceeding, rates would increase through the end of 2024 but decrease significantly in early 2025. Direct Testimony of Sigourney Clark for Duke Energy Carolinas, LLC, *In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities*, Docket No. E-7, SUB 1304 (N.C.U.C. Feb. 27, 2024). Furthermore, a NEEC term as short as five years would systematically under-value the capacity value of rooftop solar, since the utility's capacity needs typically are identified as arising more than a handful of years in the future.

Second, the Commission determines that it is appropriate to calculate and include a distribution line loss factor in the NEEC in this proceeding. Behind-the-meter solar can be expected to serve local loads in close proximity more than front-of-the-meter generation, resulting in lower line losses. No party opposed this refinement and the Public Staff supported it for this proceeding, along with NCSEA and CCEBA.

Finally, the Commission determines that it is appropriate to calculate and include avoided T&D costs in the NEEC in this proceeding, using as a starting point the methodologies provided by SACE's expert Mr. Barnes. The Commission expressed its interest in including avoided T&D costs in the NEEC previously, for the same reasons that it now requires calculating and including avoided T&D costs: customer-sited behind-the-meter solar can allow the utility to avoid some T&D costs and in the interest of accuracy this value should be reflected in the NEEC rates.

The Commission determines that the methodologies recommended by Mr. Barnes as starting points are reasonable for that purpose. In addition, the Commission notes that no alternatives were offered. Duke may refine Mr. Barnes' suggested methodologies for determining avoided T&D costs consistently with his recommendations. The Commission finds it persuasive that the Public Staff recommended requiring Duke to analyze avoided T&D costs based upon Mr. Barnes' recommendations. While the Commission recognizes that the Public Staff recommended requiring this analysis only in the next biennial avoided cost proceeding, the Public Staff did not state that it believed waiting was important or offer a reason for doing so, and in the interest of ensuring accurate NEEC rates the Commission will require the analysis for this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall recalculate its NEEC using a ten-year term.
2. That Duke shall calculate a distribution line loss factor for customer-sited behind-the-meter generating systems and incorporate the distribution line loss factor into the NEEC.
3. That Duke shall calculate avoided T&D costs resulting from customer-sited behind-the-meter generating systems using the methodologies recommended by Mr. Barnes with any appropriate refinements consistent with his comments, and include the value into the NEEC.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ___, 2024.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston, Chief Clerk