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May 20, 2024

VIA ELECTRONIG FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: *Joint Proposed Order of Dominion Energy North Carolina and the Public Staff*
Docket No. E-100, Sub 194

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceeding on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina and the Public Staff is their *Joint Proposed Order*.

Thank you for your assistance with this matter. Feel free to contact me with any questions about this filing.

Sincerely,

/s/Andrea R. Kells

ARK:tll

Enclosure

cc: Lauren W. Biskie

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, 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	)))))	JOINT PROPOSED ORDER OF DOMINION ENERGY NORTH CAROLINA AND THE PUBLIC STAFF

BY THE COMMISSION: On August 7, 2023, the North Carolina Utilities Commission (Commission) issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing (2023 Scheduling Order) for the purpose of determining avoided cost rates pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a--3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegate responsibilities in that regard to the Commission. This proceeding is also held pursuant to N.C.G.S. § 62--156, which requires the Commission to determine the rates to be paid by electric utilities for power purchased from small power producers, as defined in N.C. Gen. Stat. § 62--3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC prescribe the responsibilities of FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires FERC to adopt such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. In adopting such rules, FERC stated:

> Under Section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities [QFs], and thus become eligible for the rates and exemptions set forth under Section 210 of PURPA.

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv.*

Corp. v. FERC, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Each electric utility is required under Section 210 of PURPA to offer 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 which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not 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 regulation, FERC delegated the implementation of these rules to the 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 as required by N.C.G.S. § 62--156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

As noted above, this proceeding also results from the mandate of N.C.G.S. § 62--156, which was enacted by the General Assembly in 1979. This 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 in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The General Assembly amended N.C.G.S. § 62--156 in 2017 through enactment of Session Law 2017--192 (House Bill 589) and again in 2019 through enactment of Session Law 2019--132 (House Bill 329).

Pursuant to the 2023 Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke Energy), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (New River) were made parties to the proceeding.

The 2023 Scheduling Order stated that given the recurring nature of the issues and decisions that have traditionally arisen in these proceedings, the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules rather than a full evidentiary hearing. The Commission established February 7, 2024, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; as the deadline for reply comments; and the deadlines for additional comments, additional reply comments and proposed orders to be established by further order of the Commission. The 2023 Scheduling Order also scheduled a public hearing for February 6, 2024, solely for the purpose of taking non-expert public witness testimony. Finally, the 2023 Scheduling Order required the Utilities to publish notice in newspapers having general circulation in their respective North Carolina service areas and submit affidavits of publication to the Commission no later than the date of the hearing.

The following parties filed timely petitions to intervene that the Commission granted: the North Carolina Attorney General's Office (AGO), the North Carolina Sustainable Energy Association (NCSEA), the Carolina's Clean Energy Business Alliance (CCEBA), the Southern Alliance for Clean Energy (SACE), and the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR). Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62--15(d) and Commission Rule R1--19(e).

On November 1, 2023, pursuant to the 2023 Scheduling Order DENC filed its Initial Statement and Exhibits (DENC Initial Statement), along with DENC's avoided cost information as required by 18 C.F.R § 292.302(b)(1)-(3).

On November 1, 2023, WCU and New River filed their Joint Comments and Proposed Rates.

On January 9, 2024, DENC filed a letter providing the Commission and the parties a status update regarding Virginia's withdrawal from the Regional Greenhouse Gas Initiative (RGGI).

On January 30, 2024, NCSEA, CCEBA, and SACE filed a Joint Motion for Extension of Time through and including February 21, 2024, for the parties to file their initial comments and through and including March 27, 2024, for parties to file their reply comments, which was granted by Commission order issued on February 6, 2024.

On January 22, 2024, DENC filed Proof of Publication of the notice of hearing. On February 5, 2024, Duke Energy filed affidavits of publication of notice.

On February 6, 2024, the public witness hearing portion of the proceeding was held as scheduled, and no witnesses appeared to testify.

On February 21, 2024, the Public Staff, AGO, SACE, CCEBA, and NCSEA filed Initial Comments.

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

On April 10, 2024, the Commission issued its Order Requiring the Filing of Proposed Orders and Briefs, determining that a full evidentiary hearing was not required.

On May 7, 2024, the Commission issued its Order Granting Motion for Extension of Time filed jointly by Duke Energy and the Public Staff and ordering that all parties may file proposed orders or briefs in this proceeding on or before May 20, 2024.

On May 20, 2024, proposed orders and briefs were filed by the parties.

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

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DENC to offer long-term levelized capacity rates and energy rates for ten-year periods as a standard option to all QFs contracting to sell one MW or less capacity. The standard levelized rate option of ten years should include a condition making the contracts under that option renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration.

2. It is appropriate for the Utilities to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shallbe regarded

as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

3. DENC should continue to offer in its Schedule 19--LMP, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, L.L.C. (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (Sub 148 Order).

4. It is reasonable and appropriate for the Utilities to continue using the peaker methodology to calculate the avoided capacity cost rates for purposes of this proceeding, and to base that calculation on a combustion turbine (CT).

5. The Utilities should consider, and evaluate, alternative capacity resources such as advanced class CTs in the next biennial proceeding.

6. DENC's proposed installed cost of a CT is appropriate for use in calculating avoided cost capacity costs in this proceeding.

7. DENC has appropriately identified in its 2023 Integrated Resource Plan (2023 IRP) its first avoidable capacity need as starting in 2024 and relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

8. It is reasonable and appropriate for DENC to use a 5-year average Weighted Equivalent Unforced Outage Factor (WEUOF) to determine the Performance Adjustment Factor (PAF) in its avoided cost calculations for all QFs. DENC's calculation of a PAF of 1.09 for this proceeding is reasonable and appropriate.

9. [2023 IRP Alternative Plan basis for Schedule 19-FP avoided energy cost determination – to be addressed by separate proposed orders]

10. [Updated Re-dispatch charge – to be addressed by separate proposed orders]

11. DENC's proposed non-IRP input assumptions to be used in determining its proposed avoided energy rate are appropriate for use in this proceeding.

12. It is reasonable and appropriate for DENC to continue not to include a line loss adder in its standard offer avoided cost payments to solar QFs on its distribution network.

13. It is reasonable and appropriate for DENC to maintain its proposed re-dispatch charge (RDC) avoidance protocol as approved in the Sub 175 Order.

14. DENC's proposal to continue to use the energy and capacity rate design approved in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 175 Order) issued on November 22, 2022, in Docket No. E-100, Sub 175 (Sub 175 proceeding) is reasonable and appropriate for purposes of this proceeding.

15. DENC's proposal to continue to use seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons that were approved in the Sub 175 Order is reasonable and appropriate for purposes of this proceeding.

16. It is reasonable and appropriate for DENC to continue using Retrofit Storage Legally Enforceable Obligation (LEO) Forms as approved in the Sub 175 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

The evidence supporting these findings of fact is found in the DENC Initial Statement and exhibits attached thereto and the Public Staff Initial Statement. These findings are essentially jurisdictional and administrative and are not contested.

Summary of the Evidence

With its Initial Statement, DENC filed Schedule 19--FP and Schedule 19--LMP, to be available to any QF eligible for these tariffs that has (a) submitted to the Commission a report of proposed construction pursuant to N.C.G.S. § 62--110.1(g) and Rule R8--65, (b) submitted to DENC an Interconnection Request pursuant to Section 2 or Section 3 of the North Carolina Interconnection Procedures (NCIP), and (c) submitted to DENC a duly executed "Notice of Commitment to Sell the Output of a Qualifying Facility of No Greater Than 1 Megawatt Maximum Capacity to Dominion Energy North Carolina" by no later than the date on which proposed rates are filed in the next biennial avoided cost proceeding.

DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19--LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone (DOM Zone) Day-Ahead hourly locational marginal prices (LMPs) divided by 10 to convert LMP from $/MWh to cents/kWh, and multiplied by the QF's hourly generation in kWh, while the smaller QFs that elect to supply energy only would be paid the average of the PJM DOM Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (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) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the DOM Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations.

In its Initial Statement the Public Staff reviews and summarizes DENC's proposed rate schedules but does not recommend any changes to DENC's proposed standard offer term and eligibility thresholds. No other party proposed changes to the standard offer term and eligibility thresholds or otherwise raised objections to the approval of the rate schedules proposed DENC.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

In past biennial avoided cost proceedings the Commission determined that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years.

The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission and demonstration that the solicitation meets the Competitive Solicitation Price criteria established under 18 C.F.R. § 292.304(b)(8). Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM RPM, subject to the same conditions as approved in the Sub 106 Order and restated in the Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence supporting these findings of fact is found in DENC's Initial Statement and Reply Comments, Duke Energy's Reply Comments, the Public Staff's Initial Statement and Reply Comments, AGO Initial Comments, and CCEBA's Initial and Reply Comments. and the entire record herein.

<u>Summary of the Evidence</u>

In its Initial Statement, DENC states that it has used the peaker method to calculate the avoided capacity cost rates for the Schedule 19-FP rate schedule since the 2012 biennial avoided cost proceeding in Docket No. E-100, Sub 136 (Sub 136 proceeding). DENC notes that in the Sub 175 Order, the Commission found the peaker method remained a reasonable method by which to calculate avoided capacity costs at the time and directed the parties to evaluate, before the next biennial proceeding, whether to propose an alternative method to calculate avoided costs, including those FERC had recently determined to be reasonable and appropriate in Order No. 872 that are included in 18 C.F.R. § 292.304(b).

DENC states that it has determined it to be reasonable to continue utilizing the peaker method for purposes of this proceeding. As discussed further in Finding of Fact No. 11, DENC's updated backflow analysis demonstrates that solar distributed generation continues to exceed the load requirements of the circuits with transformers connected to such generation. In other words, in DENC's view, solar distributed generation currently exceeds the Company's need in its North Carolina service territory. DENC continues that, as amended by Order No. 872, section 292.304(b)(8) of FERC's regulations provides that a price determined pursuant to a competitive solicitation process may be used to establish energy and/or capacity rates for QFs, provided that the competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner. Due to the already existing over-supply of capacity in its North Carolina service area, the Company did not determine it to be appropriate to initiate a competitive solicitation process to procure additional capacity. Further, DENC notes that as it continues to offer Schedule 19-LMP as an option for QFs, it does not believe any incremental value to QFs or DENC would result from offering an avoided cost rate calculated pursuant to an additional alternative methodology.

DENC recounts that in the Sub 158 Order the Commission directed the Utilities to "evaluate and apply … cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility." (Sub 158 Order at Ordering Paragraph 9.) DENC reports that it engaged in multiple discussions with the Public Staff on this topic throughout 2021 and reported on these discussions through the Sub 158 Additional Issues status updates filed in the Sub 167 docket. DENC also reports that it worked with Duke Energy to simplify and increase the transparency of the calculation of CT cost estimates. DENC represents that the common goal of the Utilities' work on this matter was to present CT cost estimates based on agreed-upon inputs such that the inputs may be updated more easily in each biennial avoided cost case as needed, without the need to relitigate the underlying methodology for calculating the CT cost estimate in every case. DENC's proposed methodology for determining the installed CT cost to be used in calculating the avoided capacity rate in the Sub 175 proceeding was based on the consensus reached with Duke Energy and approved by the Commission in the Sub 175 Order. (DENC Initial Statement at 18-19.)

For this proceeding, DENC maintained the same approach for calculating avoided capacity rates as it utilized in 2021. Specifically, DENC utilized the 2023 United States Energy Information Administration (EIA) Annual Energy outlook costs for an F-class turbine. DENC did not make any adjustments to the CT equipment costs and did make adjustments to reflect economies of scale and the cost benefits associated with building four CTs at a single site. Based on the resulting 7.4% cost reduction, DENC applied the same 7.0% reduction to the EIA estimate to determine the adjusted capital cost in 2022 dollars, and escalated to 2023 dollars. The resulting total cost of the hypothetical CT was $763/kW. (Id. at 19-20.)

In its Initial Comments the Public Staff notes that the Commission has consistently approved use of the peaker method, which estimates avoided capacity costs by using the capital costs of the lowest-cost capacity option available to the utility, typically a peaking unit such as a combustion turbine (CT). The Public Staff states that DENC and Duke Energy have chosen F-frame CTs as the basis for their respective peaker method calculations and that while such CTs are still widely used for power generation, advanced class (or H-class) CTs are becoming increasingly available and will likely replace F-frame CTs in the future as the preferred source of peaking capacity. (Public Staff Initial Statement at 13). The Public Staff observes that cost data on F-frame CTs has been readily available for many years and reliably used by the utilities to determine avoided capacity payments to QFs. The Public Staff continues that H-class CTs currently have limited available data on their operations and actual construction costs. As such, the Public Staff supports the use of an F-frame CT in this proceeding; however, if no other publicly available cost data exists, the Public Staff recommends that the utilities calculate their avoided capacity payments based upon more advanced CTs in the next avoided cost proceeding, along with an offset to the cost of the unit based upon the energy value associated with an advanced CT, should such an adjustment be found to be material (the net peaker method). (Id. at 14).

In its Initial Comments, CCEBA recommends that the Commission direct DENC and Duke Energy to undertake a stakeholder process to fully consider all alternatives to the peaker methodology and identify the most appropriate method for calculating avoided costs to be used in the next biennial avoided cost proceeding. In the alternative CCEBA advocates for a technical conference or evidentiary hearing. (CCEBA Initial Statement at 5-6).

In its Reply Comments, DENC recognizes the benefits of relying on public EIA data as a starting point for generic CT cost estimates used for determinations of avoided capacity rates. DENC continues that to be able to use a particular CT class to determine avoided capacity costs, sufficient information regarding that CT class's cost and performance must be publicly available. Since the availability and depth of public data on advanced class CTs are currently limited, DENC posits that the appropriate course is to determine the specific CT class that has the best publicly available data in 2025, at the time the next biennial avoided cost filing is prepared. DENC also notes that its own expertise is a contributing factor to which CT class it uses for these determinations, and that its operating experience is with F-class CTs. DENC clarifies that it does continue to review various types of generation resources, including advanced class CTs, for consideration in future IRPs. For purposes of these biennial proceedings, however, DENC states that the most prudent course is to review the available public information on CT costs and consider the most recently filed IRP to determine which CT class should be used in avoided capacity cost determinations. DENC concludes that it does not oppose potential use of advanced class, H-class CTs in the future for purposes of calculating avoided costs as long as adequate and reliable public data is available and it has sufficient expertise to support the analysis. DENC is willing to review this issue with the Public Staff before the next avoided cost filing. (Id. at 9-10).

DENC explains that it fully considered alternatives to the peaker method in the course of preparing the avoided cost rates and terms proposed in this proceeding and discussed the results of that analysis in its Initial Statement. DENC notes that as these proceedings are biennial, interested parties had ample time to pursue this topic within the proceeding's framework, which included phases for discovery, comments, and reply comments. DENC concludes that separate and additional proceedings to consider this issue are not required. (Id. at 11). In its Reply Comments, Duke Energy states that continued use of the peaker method is consistent with its current, standardized approach to calculating avoided costs under G.S. 62-156(b) and (c), remains non-discriminatory to QFs and just and reasonable to the electric consumer and in the public interest at this time. Duke Energy notes that the biennial cadence of the Commission's review of the utilities' avoided cost rates provides ample and regular opportunity for this issue to be reassessed and reviewed. Since CCEBA did not propose any alternative to the peaker method, there is no alternate to be evaluated in this proceeding. Duke Energy concludes that for all these reasons CCEBA's proposals would not be an efficient use of the Commission's or the parties' resources. (Duke Energy Reply at 6-7) Duke Energy also reiterates its support of use of an F-frame CT as the peaking unit in this proceeding and commits to further discuss this issue with the Public Staff in advance of the next avoided cost proceeding. (Duke Energy Reply Comments at 21).

In its Reply Comments, the Public Staff recommends that, in lieu of stakeholder meetings, the Commission require the Utilities to evaluate other least-cost capacity resources, as they become commercially viable, in future avoided cost proceedings. The Public Staff states that CTs will continue to be a capacity resource for the foreseeable future whether fueled by hydrogen or fossil fuels. (PS Reply at 3)

Discussion and Conclusions

Based upon the entire record, the Commission continues to find that the peaker method remains a reasonable method by which to calculate avoided capacity costs for purposes of this proceeding. The Commission also finds that the Utilities have sufficiently evaluated alternative methods to the peaker method consistent with the directive of the Sub 175 Order. The Commission is not persuaded that additional process or engagement on this issue is necessary or beneficial at this time. The peaker methodology remains a reasonable and accepted approach to calculating avoided costs and specific evidence to support a shift away from the peaker methodology has not been presented in this docket. Any proposals to adjust or replace the peaker methodology can be addressed in future biennial avoided cost proceedings. Further, based on the evidence presented the Commission finds that as it may be the case by the time of the next biennial avoided cost proceeding that sufficient publicly available data for advanced class CTs is available to determine avoided capacity costs based on data for such units, it is appropriate that the Utilities evaluate other least-cost capacity resources, as they become commercially viable, in their initial filings in the next biennial proceeding.

The Commission further finds based upon the entire record, that DENC appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT, in this case a hypothetical F-class CT, and that DENC developed its source information in a manner consistent with the Commission's previously provided guidance. The Commission finds that DENC's use of the approach agreed upon by the utilities in the Sub 175 proceeding to simplify and increase the transparency of the calculation of CT cost estimates continues to be reasonable, will allow for more efficient updates in subsequent proceedings, and is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in DENC's Initial Statement, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Evidence

In its Initial Statement, DENC states that Addendum 5 to the Company's IRP filed on May 1, 2023 in Docket No. E-100, Sub 192 identified DENC's next undesignated capacity need as arising in 2024. The calculation of seasonal levelized rates shown in its Initial Statement Confidential Exhibit DENC-8 includes avoided capacity costs beginning 2024 and continuing through 2033. (DENC Initial Statement at 22-23.)

In the Public Staff's Initial Statement, the Public Staff explains that the calculation of avoided capacity rates for each utility reflects the present value of avoided capacity costs beginning in its first year of need for all resources except certain QFs fueled by swine waste, poultry waste, and certain existing hydro power QFs less than 5 MW. The Public Staff states that DENC's 2024 first year of capacity need is reasonable and based upon DENC's most recently filed IRP. (Public Staff Initial Statement at 21.)

No other party commented on DENC's statement of capacity need.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission determines that the avoided capacity cost of DENC have been calculated consistently with the North Carolina General Statutes and the Commission's prior orders on this matter.

Based on the foregoing, the Commission concludes that DENC's Addendum 5 to its 2023 Plan filed on May 1, 2024, in Docket No. E-22, Sub 192 identifies that DENC's next year of undesignated capacity need is 2024, and that DENC appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is found in DENC's Initial Statement, the Public Staff's Initial Statement, and the entire record herein.

Summary of the Evidence

In its Initial Statement, DENC recalls that in the Sub 158 Order, the Commission ruled that "with input from the Public Staff, [the Utilities] shall evaluate appropriateness of using other reliability indices, specifically the EUOR [equivalent unplanned outage rate] metric, to support development of the PAF prior to the next biennial avoided cost filing." (Sub 158 Order at Ordering Paragraph 13.) DENC explains that for the purposes of the streamlined 2020 Avoided Cost Case, it continued to apply the PAF that was approved in the Sub 158 Order and the Commission approved this proposal in the Sub 167 Order. DENC notes that in the Sub 175 proceeding, it reached consensus with the Public Staff on using the Weighted Equivalent Unforced Outage Factor (WEUOF) to determine the PAF. DENC calculated a PAF of 1.07 using five years of history for the months January, February, June, July, and August. In the Sub 175 Order, the Commission found these determinations appropriate, and directed the Utilities to address the inclusion of solar and wind generator outage data in the PAF calculating in future avoided cost proceedings. (Sub 175 Order at 20; Ordering Paragraph 10).

For purposes of this proceeding, DENC again implemented the WEUOF method to calculate a PAF of 1.09 using five years of history for the same months used in the 2021 proceeding. (DENC Initial Statement at 23). Pursuant to the Commission's Sub 175 Order, DENC reports that solar and wind generator outage data was not available at the time it filed its initial statement in this proceeding and that it will monitor data availability and appropriateness of including the same in the PAF calculation once it becomes available. (DENC Initial Statement at 23-24.)

In its Initial Statement, the Public Staff notes that the Utilities appropriately used the WEUOF metric to calculate the PAF consistent with the agreement reached by the Utilities and the Public Staff in the Sub 175 proceeding and supports DENC's proposed PAF. (Public Staff Initial Statement at 46). The Public Staff also notes that to calculate their WEUOF, the Utilities use the Generating Availability Data System (GADS) developed by the North American Electric Reliability Corporation (NERC), and that GADS did not begin collecting availability data for solar facilities until January 1, 2024. The Public Staff concludes that the Utilities do not currently have enough information to use solar availability to calculate the PAF. The Public Staff continues that NERC has required wind turbine generators to report outage data to GADS since 2018, but North Carolina has only one wind facility in operation. The Public Staff expects that the Utilities will begin utilizing solar outage data in the calculation of the PAF in the next avoided cost proceeding. (Id. at 5)

No other party commented on DENC's proposed PAF or the calculation methodology underlying DENC's PAF.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to use a PAF of 1.09 in its avoided cost calculations for all QFs and to use the WEUOF method to determine the PAF in this proceeding. The Commission finds that DENC's proposal to continue to use the WEUOF method to calculate its PAF is reasonable for purposes of this proceeding. Usage of the WEUOF methodology continues to meet the Commission's directive in recent biennial Orders to consider the appropriateness of using other reliability indices such as the EUOR metric to support development of the PAF. The Commission also continues to find DENC's and the Public Staff's agreement to use a 5-year average, with DENC determining the months used, in the PAF calculation to be reasonable as the months selected by DENC align with PJM's "Peak Period Months" in the PJM Manual 10.

The Commission also acknowledges DENC's report that solar and wind generator outage data was not available at the time it filed its initial statement in this proceeding and directs the Utilities to evaluate the appropriateness of utilize solar outage data and, to the extent available wind data, in the calculation of the PAF in the next biennial avoided cost filings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9
[Alternative Plan basis for Schedule 19-FP energy rates]

[ ]

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10
[Updated Re-dispatch Charge]

[ ]

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is found in DENC's Initial Statement and Reply Comments and the Initial Statement of the Public Staff.

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC used the PLEXOS model for the calculation and used its generation expansion plan "B" from its most recent 2023 IRP filed on May 1, 2023, in Docket No. E100, Sub 192 as the starting point for its analysis as the "without QF case." DENC ran a second PLEXOS case, the "with QF" case, with an additional QF resource. DENC explains that the input assumptions in this modeling process falls into three categories:

(1) assumptions regarding generating unit operating characteristics, (2) purchase power assumptions and non-utility generator sources, and (3) the variable (or dispatch) costs of generating units (including fuel, variable O&M, and emission and start-up costs). DENC notes that, unlike the previous two biennial proceedings in which the Commission approved DENC's inclusion of RGGI costs in the third category, for this proceeding, the third category does not include RGGI or federal carbon costs. (DENC Initial Statement at 5.) With these inputs, the resulting PLEXOS output was used to calculate the levelized long-term fixed energy rates under Schedule 19-FP for each of the nine pricing periods approved in the Sub 175 Order. (DENC Initial Statement at 56.)

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International (ICF) prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the Sub 175 Avoided Cost Case. (Id. at 6.)

DENC explains that consistent with the Commission's conclusions in the, the Sub 158 Order, the Sub 167 Order, and the Sub 175 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that locational marginal prices (LMPs) in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs in support of its adjustment of the avoided energy cost rate proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the DOM Zone. (Id. at 7-8.)

DENC recalls that in the December 31, 2014 Order Setting Avoided Cost Input Parameters issued in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC also recalls that in Phase 2 of that proceeding, the Commission's December 17, 2015 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 140 Phase Two Order) required the Utilities to utilize the Black-Scholes Option Pricing Model (Black-Scholes Model), or a similar model, to determine the fuel price hedging value of renewable generation. Consistent with its proposal in the Sub 148, Sub 158, and Sub 167 Avoided Cost Cases, which the Commission approved in the Sub 175 Order, DENC proposes to continue to use the same Black-Scholes Model to determine fuel hedging benefits that was proposed by the Public Staff in Docket No. E-100, Sub 140, with a resulting fuel price hedging value of $1.19/MWh, which was assumed constant for all years of the Schedule 19-FP contract. (Id. at 8-9.)

In its Initial Statement the Public Staff states that based on its review of the PLEXOS inputs, the inputs into the model, and the output data from the model are reasonable for the determination of DENC's avoided energy costs. The Public Staff confirms that DENC's calculation of avoided energy rates is consistent with the Sub 175 Order, as is DENC's inclusion of avoided fuel hedging values based on the Black-Scholes Model. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices or DENC's calculation of the fuel hedge value. (Public Staff Initial Statement at 41-44.)

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed avoided energy inputs are reasonable for the purposes of this proceeding and should be approved. With respect to forward commodity prices DENC used in its modeling, the Commission determines that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings continues to be appropriate. The Commission also concludes that DENC has calculated avoided hedging costs appropriately for purposes of this proceeding and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value. Additionally, based on the uncontested evidence presented by DENC updating the continued disparity in LMPs in its service territory, the Commission concludes that it continues to be appropriate for DENC to include the historical average price differentials for all periods in its calculation of proposed energy costs for purposes of this proceeding. Finally, in light of Virginia's exit from RGGI on December 31, 2023, the Commission concludes that it is reasonable for purposes of this proceeding to approve DENC's avoided energy rates based on modelling that excludes RGGI costs, consistent with Commission precedent that that the generation expansion plans used in the calculation of avoided energy should be based on IRP expansion plans that take into account only known and quantifiable costs. (Sub 140 Phase One Order at 42-44)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in DENC's Initial Statement, the Public Staff Initial Statement, and the entire record herein.

Summary of the Evidence

In its Initial Statement, DENC recounts that in the Sub 148 Order, the Commission approved DENC's proposal to eliminate the 3% line loss adder that had historically been included in its avoided energy rates. DENC also recalls that in subsequent avoided cost proceedings, DENC updated its analysis of power flow at its substations showing that power backflow on its North Carolina substations continued to increase such that avoided line loss benefits associated with distributed generation were either reduced or negated, and the Commission found it appropriate for DENC to continue to exclude a line loss adder from its standard avoided cost payments. (DENC Initial Statement 9). DENC notes that in the Sub 175 proceeding, the Commission concluded that DENC's updated line loss study demonstrated increasing backflow and a decrease in the number of transformers with capacity for additional load reduction capability and predicts this pattern increasing over time. (Sub 175 Order at 33).

Exhibit DENC-7 to DENC's Initial Statement shows that compared to the 2021 study, the number of transformers experiencing backflow has continued to increase as more Solar DG has become operational. Of the 43 transformers with Solar DG connected, 36 transformers realize consistent backflow, compared to 16 in the 2018 study, 24 in the 2020 study, and 34 in the 2021 study. (Id. at 9-10, Exhibit DENC-7.)

In its Initial Statement the Public Staff supports DENC continuing to exclude a line loss adder from the standard offer avoided cost rate given the high backflow at DENC's North Carolina substations. (Public Staff Initial Comments at 42.) No other parties commented on DENC's removal of the line loss adder.

Discussion and Conclusions

Based on the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to not include an adder for line losses in the calculation of avoided energy payments to QFs. Exhibit DENC-7 demonstrates a continued increase in the number of transformers on DENC's North Carolina portion experiencing consistent backflow, and the Commission anticipates that this pattern will continue in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in DENC's Initial Statement and the Public Staff Initial Statement.

Summary of the Evidence

As directed by the Commission in the Sub 158 Order, DENC proposed in the Sub 167 proceeding that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD). DENC defined an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage. DENC proposed to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. The output for the case without storage will be the actual metered output of the facility excluding the impact of storage, and the output for the case with storage will be the actual metered output for the facility including the impact of storage. DENC noted that determining the impact of storage will require that the storage device is separately metered. DENC explained that for a QF to be eligible for the RDC cost reduction, it must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date (COD) and then for subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract. If no updated forecast is provided, DENC would use the previously provided forecast to calculate the RDC reduction credit. Every April, DENC would calculate the re-dispatch cost reduction using the prior calendar year forecast and metered data. DENC would provide the RDC reduction as a line item credit with the first payment following the April calculation. (DENC Initial Statement at 14-15.)

In the Sub 167 Order, the Commission concluded that DENC's proposed RDC avoidance protocol was appropriate and DENC complied with the Sub 158 Order directive to file a protocol for the avoidance of the RDC. The Commission found it reasonable to reduce the RDC to the extent a QF reduces the variability of its output through the use of an ESD and that the protocol is a reasonable proxy for estimating that reduction in costs. The Commission also concluded that, if any controlled solar generators (CSGs) seek to avail themselves of the RDC avoidance protocol, it may be helpful for purposes of evaluating the results of the protocol in the future for DENC to monitor and provide the information regarding the types of forecasts, dispatch behavior, and solar volatility of CSGs that avail themselves of the RDC avoidance protocol, as requested by the Public Staff. The Commission encouraged DENC and the Public Staff to continue to discuss this information and directed DENC to address its proposed monitoring and reporting of this information in its initial filing in this proceeding. (Id. at 15.) In the Sub 175 proceeding, the Commission again found the protocol to be reasonable and agreed with DENC's proposal that if any QFs seek to avail themselves of the RDC avoidance protocol, DENC would file a report on the types of forecasts and dispatch behavior for QFs that attempt to avoid the RDC and include this information in future avoided cost filings. (DENC Initial Statement at 15-16).

DENC explains in its Initial Statement that it plans to maintain the RDC avoidance protocol as approved in the Sub 175 order for the purposes of this proceeding. DENC notes that with regard to the information that it agreed to monitor on an annual basis per the Public Staff's recommendation, no QFs (CSGs) have sought to avail themselves of the protocol, but if any CSGs do avail themselves of the protocol, DENC will continue to monitor the information requested by the Public Staff and will report on that information as needed in a future biennial avoided cost proceeding. (Id. at 16.)

The Public Staff finds the protocol reasonable for this proceeding and notes that as of the filing of DENC's Initial Statement, no QFs in DENC's territory are currently avoiding the RDC and that DENC does not charge an RDC to facilities selling power under the schedule 19-LMP tariff. (Public Staff Initial Statement at 45).

No party filed reply comments on DENC's RDC avoidance protocol.

Discussion and Conclusions

In the Sub 167 Order, the Commission concluded that DENC's proposed RDC avoidance protocol was appropriate for use in that proceeding, finding the proposed protocol reasonable because it allowed the RDC to be reduced to the extent the QF reduces the variability of its output through the use of an ESD and that the proposed protocol is a reasonable proxy for estimating the reduction in redispatch costs incurred by CSGs. The Commission relied on the Public Staff's determination that the protocol is reasonable in part because DENC's QF load reduction estimates incorporate output from the prior day (in addition to other variables), such that over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. (Sub 167 Order at 48.) In the Sub 175 Order, the Commission agreed that DENC's protocol is reasonable for the reasons articulated in the Sub 167 order. (Sub 175 Order at 49).

The Commission continues to find DENC's protocol reasonable for the reasons articulated in the Sub 167 Order. No party raised any new issues with the RDC avoidance protocol and DENC has not made any changes from the protocol as approved in the Sub 167 Order.

The Commission also continues to find that, if any CSGs that are actually paired with ESDs seek to avail themselves of the RDC avoidance protocol, the information that the Public Staff requests DENC to monitor and provide may be helpful for purposes of evaluating the results of the protocol in the future. The Commission therefore continues to find that should any CSGs paired with an ESD seek to avail themselves of the RDC avoidance protocol, DENC should file a report on the types of forecasts and the ESD dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs in DENC's service territory in its future avoided cost filings. DENC should also address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC.

Based on the evidence presented, the Commission concludes that DENC's avoidance protocol is appropriate for use in this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence supporting these findings of fact is found in DENC's Initial Statement and the Public Staff's Initial Statement.

Summary of the Evidence

In its Initial Statement, DENC describes the method it used for purposes of calculating energy rates. That rate design, which the Commission approved in the Sub 175 Order, comprises nine pricing periods: summer off-peak; summer on-peak; summer premium peak; winter off-peak; winter on-peak am; winter on-peak pm; winter premium peak; and shoulder on- and off-peak periods. DENC has maintained these pricing periods in calculating avoided energy cost rates for purposes of this proceeding. DENC has continued to allocate its CT costs using the seasonal allocation weighting approved in the Sub 175 Order of 45% summer, 40% winter, and 15% shoulder. (DENC Initial Statement at 21.)

In its Initial Statement, the Public Staff states that DENC's method for designing energy and capacity rates for Schedule 19-FP is largely consistent with methods employed in the Sub 175 proceeding and does not raise any concerns with maintaining this rate design. (Public Staff Initial Statement at 41-44.) The Public Staff also acknowledges that DENC's weighting capacity value between seasons remains consistent with the Sub 158 Order and does not raise any concerns with maintaining this weighting. (Id. at 32.)

No other party proposes changes to DENC's rate design or seasonal allocation weightings or otherwise raises objections with respect to these issues.

Discussion and Conclusions

In the Sub 158 Order, the Commission found it appropriate to require DENC to use the rate design agreed upon by DENC and the Public Staff in that proceeding. The Commission found that the revised rate design was responsive to the directives in the Sub 148 Order and the Sub 158 Scheduling Order by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further found that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons were appropriate for use in weighting capacity value between seasons, as these weightings continued to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder capacity. (Sub 158 Order at 98.) The Commission concluded it to be appropriate for DENC to continue using this rate design and seasonal allocation weightings in the Sub 167 Order. (Sub 167 Order at 42.) In the Sub 175 Order, the Commission similarly found that DENC's proposed rate design, which remained the same as the previous two proceedings, was appropriate for calculating rates for DENC's nine pricing periods. (Sub 175 Order at 57).

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed rate design, unchanged from the rate design approved in the Sub 158, Sub 167, and Sub 175 Orders, is appropriate to continue using to calculate rates for DENC's nine pricing periods for purposes of this proceeding. No party has raised any concern with DENC's rate design, which continues to provide QFs with granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further concludes that DENC's continued use of the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons, also unchanged from the seasonal allocations approved in the Sub 158, Sub 167, and Sub 175 Orders and without objection in this proceeding, are appropriate for use in weighting capacity value between seasons for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting these findings of fact is found in DENC's Initial Statement and Exhibits and Reply Comments and the entire record herein.

Summary of the Evidence

In its Initial Statement, DENC explains that it is not proposing any changes to the LEO Forms that the Commission approved in the Sub 175 Order. (DENC Initial Statement at 25).

No parties raised any concerns with DENC's proposed Retrofit Storage LEO Forms.. In its Initial Statement, the Public Staff recommends Commission approval of DENC's LEO Forms. (Public Staff Initial Statement at 52).

Discussion and Conclusions

The Commission finds that it is reasonable and appropriate for DENC to continue using Retrofit Storage Legally Enforceable Obligation (LEO) Forms as approved in the Sub 175 Order.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DENC shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs contracting to sell 1 MW or less capacity. The standard ten-year levelized rate option should include a condition making contracts renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration;

2. That DENC shall continue to offer, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market-clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's 2006 Sub 106 Order and most recently restated in the 2018 Sub 158 Order;

3. That DEP, DEC, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the

QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding;

4. That DEC, DEP, and DENC shall continue to calculate avoided capacity costs using the peaker methodology and include a levelized payment for capacity over the term of the contract that provides a payment for capacity to QFs other than those using swine or poultry resources, or hydroelectric resources less than 5 MW, in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3);

5. That the Utilities shall evaluate other least-cost capacity resources, as they become commercially viable, for the purpose of determining avoided capacity cost rates in their initial filings in the next biennial proceeding.

6. That DENC's proposed non-IRP input assumptions to be used in determining its proposed energy rates shall be used in calculating DENC's rates in this proceeding;

7. That DENC shall continue to use the re-dispatch charge avoidance protocol approved in the Sub 167 Order;

8. That DENC shall continue to use the rate design approved in Docket No. E 100, Sub 158 in calculating rates in this proceeding;

9. That DENC shall continue to use the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons approved in Docket No. E-100, Sub 158 in calculating rates in this proceeding;

10. That DENC shall continue to not include an adder for line losses in the calculation of avoided energy payments to QFs;

11. That DENC shall use a PAF of 1.09 in its avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

12. That DENC has appropriately identified in its 2023 Integrated Resource Plan (2023 IRP) its first avoidable capacity need as occurring in 2024 and relied on that identified first avoidable capacity need to determine the first year of avoidable capacity need for purposes of this proceeding;

13. That DENC shall continue using LEO Forms approved by the Commission in the Sub 175 Order;

14. That, within 30 days after the date of this Order, the Utilities shall file revised versions of their rate schedules and standard contracts in redline and clean versions that comply with the rate methodologies and contract terms approved in this Order, to become effective 15 days after the filing date unless specific objections are raised as to the accuracy of the calculations.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _______________, 2024.

NORTH CAROLINA UTILITIES COMMISSION

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Joint Proposed Order*, as filed in Docket No. E-100, Sub 194, was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 20th day of May, 2024.

/s/Andrea R. Kells
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