McGuireWoods

McGuireWoods LLP
501 Fayetteville St.
Suite 500
Raleigh, NC 27601
Phone: 919.755.6600
Fax: 919.755.6699
www.mcguirewoods.com

E. Brett Breitschwerdt
Direct: 919.755.6563
bbreitschwerdt@mcguirewoods.com

May 20, 2024

VIA Electronic 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 Establishing Standard Rates and Contract Terms for Qualifying Facilities of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Public Staff – North Carolina Utilities Commission
Docket No. E-100, Sub 194

Dear Ms. Dunston:

Enclosed for filing in the above-captioned docket on behalf of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke Energy"), and the Public Staff – North Carolina Utilities Commission ("Public Staff"), is their Joint Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities ("Joint Proposed Order").

The Joint Proposed Order reflects the efforts of Duke Energy and the Public Staff to compromise and reach alignment as to all issues before the Commission and relating to Duke Energy's calculation of its avoided costs in this docket. As such, this Proposed Order presents several findings of fact and conclusions that reflect Duke Energy's and the Public Staff's efforts to reconcile positions and resolve issues before the Commission in this proceeding. Of particular note, DEC and DEP have agreed to recalculate their respective Net Excess Energy Credits to incorporate a residential-only distribution line loss factor as part of their compliance filing in this docket.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Very truly yours,

/s/E. Brett Breitschwerdt

EBB/als

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 194

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023	)))))))	**PROPOSED ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES OF DUKE ENERGY CAROLINAS, LLC, DUKE ENERGY PROGRESS, LLC, 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. § 824a3, 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 this 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).

Section 210 of PURPA also requires each electric utility 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. 18 C.F.R. 292.304(a).

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).

In the 2023 Scheduling Order, the Commission made 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) 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; 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, Duke Energy and DENC filed their proposed avoided cost rates, standard power purchase agreements (PPAs), and terms and conditions, consistent with the 2023 Scheduling Order. WCU and New River filed their Joint Comments and Proposed Rates.

On February 15, 2024, Duke Energy filed updates to its avoided cost rates, including by submitting updated DEC Updated Exhibits 1, 2, 5, and 11 and DEP Updated Exhibits 1, 2, 5, and 11 to its Joint Initial Statement.

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

On March 27, 2024, Duke Energy, DENC, the Public Staff, NCSEA, SACE, and CCEBA filed Reply Comments.

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.

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

FINDINGS OF FACT

1. It is appropriate for DEC and DEP to offer long-term levelized capacity payments and energy payments for ten-year periods as a standard option to all QFs with a design capacity up to and including one megawatt (MW). The standard levelized rate option of ten years should include a condition making the contracts under that option subject to renewal 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 DEC and DEP 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 as-available energy rate, including either the As-Available Rate or 2-Year Fixed 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.

Avoided Capacity Costs

3. DEC's and DEP's quantification of their avoided capacity costs using the peaker methodology and their resulting avoided capacity rates are reasonable.

4. DEC's and DEP's hypothetical avoided combustion turbine (CT) costs for a single F-Class CT constructed at a greenfield site, adjusted to reflect infrastructure economies of scale, are reasonable, based on publicly available

Energy Information Administration (EIA) data, and appropriate for use in calculating avoided capacity costs in this proceeding.

5. DEC's and DEP's first years of avoidable capacity need are appropriate and have been determined consistent with the *2021 Sub 167 Order* and *2022 Sub 175 Order* and align with avoidable resource needs identified in the Companies' 2023 Carbon Plan and Integrated Resource Plan ("CPIRP").

6. DEC and DEP have also appropriately included in their standard offer schedules provisions recognizing that, in certain circumstances, QFs fueled by swine waste, poultry waste, and hydropower less than 5 MW receive capacity payments calculated without incorporating the Companies' demonstrated first year of need for future capacity as reflected in their respective IRPs.

7. It is appropriate to require DEC and DEP to utilize a performance adjustment factor (PAF) of 1.05 for DEC and 1.07 for DEP in their respective avoided cost calculations for all QFs.

8. Because the June 24, 2014 Stipulation of Settlement Among DEC, DEP, and North Carolina Hydro Group expired on December 31, 2020 (Hydro Stipulation), the Companies are no longer required to offer a 2.0 PAF to hydro QFs in negotiated power purchase agreements (PPAs), and it is appropriate for DEC and DEP to discontinue use of the 2.0 PAF for hydro QFs in their respective avoided cost calculations.

Avoided Energy Costs

9. DEC's and DEP's quantification of their avoided energy costs using the peaker methodology and their resulting avoided capacity rates are reasonable.

10. It is appropriate in this proceeding to require DEC and DEP to calculate their avoided energy costs using forward natural gas prices for no more than five years followed by three years of blending before transitioning to fundamental forecast data for the remainder of the planning period.

11. It is appropriate for DEC and DEP to rely on the average of fundamental forecasts for Henry Hub prices developed by U.S. EIA and private firm IHS.

12. DEC's and DEP's use of their respective 2023 CPIRP natural gas transportation and pricing assumptions are reasonable for purposes of calculating avoided costs in this proceeding.

13. DEC's and DEP's fuel hedging adjustment is reasonable and appropriate for purposes of this proceeding.

14. DEC's and DEP's calculation of avoided energy rates, using inputs from their 2023 CPIRP, including the Supplemental Planning Analysis, that do not

reflect a carbon price, is appropriate in this proceeding because the Commission has previously directed that only known and verifiable costs should be considered in calculating avoided cost rates.

15. DEC's and DEP's proposed distribution line loss adder included in their standard offer Schedule PPs is appropriate for distribution-interconnected QFs in the DEC and DEP service territories.

16. For QFs greater than 1 MW, DEC's and DEP's proposal to assess the individual characteristics of the QF and address through negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value on a case-by-case basis is reasonable and appropriate.

17. DEC's and DEP's solar integration decrements of $1.09 per MWh for DEC and $1.62 per MWh for DEP, based on the analysis in the 2023 Solar Integration Services Charge Study prepared by Astrapé Consulting are reasonable and appropriate for purposes of this proceeding.

18. DEC's and DEP's proposed solar integration services charge (SISC) avoidance protocols and process are appropriate and in compliance with the Commission's *Sub 158 SISC Avoidance Order*.

19. At this time, it is not appropriate for utilities to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid DEC's and DEP's SISC by smoothing their volatility.

As-Available Rates

20. It is reasonable and appropriate for DEC and DEP to use the hourly marginal cost of producing energy to calculate avoided costs for QFs that elect to sell energy to the Companies on an "as-available" basis.

Schedule PP Rate Design

21. DEC's and DEP's proposed seasonal allocation weightings of 100% for winter are appropriate for use in weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

22. DEC's and DEP's avoided cost rates and rate design are reasonable and appropriate.

Standard Offer Terms and Conditions

23. DEC's and DEP's updates and minor administrative revisions to Schedule PP are reasonable and appropriate for the purposes of this proceeding.

24. DEC's and DEP's updates to the Standard Offer PPA are reasonable and appropriate for the purposes of this proceeding.

25. DEC's and DEP's updates and minor revisions to the Notice of Commitment form are reasonable and appropriate for the purposes of this proceeding.

Energy Storage System Retrofit Rates

26. It is reasonable and appropriate for DEC and DEP to discontinue the expired predetermined Energy Storage System Retrofit Rates ("ESS Retrofit Rates") and to offer eligible QFs avoided cost rates calculated at the time the QF submits a Notice of Commitment Form based on the most recent Commission-approved avoided cost methodology.

Net Energy Metering

27. It is reasonable and appropriate for DEC and DEP to calculate the Net Excess Energy Credit (NEEC), annualized over a 5-year term, including both energy and capacity credits where applicable, using a typical rooftop solar profile.

28. It is reasonable and appropriate for DEC and DEP to re-calculate their respective NEECs for residential customers only to reflect the incremental distribution loss factor.

Timing of Future Biennial Avoided Cost Proceedings

29. It is reasonable and appropriate for DEC and DEP to continue to base avoided cost rates on the most recently filed IRP and to continue the current schedule for biennial avoided cost filings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is found in Duke Energy's verified Initial Statement, including all exhibits and updated exhibits thereto, the Initial Statement of the Public Staff, and the entire record herein. These findings are essentially jurisdictional and administrative and are not contested.

<u>Summary of the Comments</u>

In its Initial Statement—specifically through DEC Updated Exhibit 1 and DEP Updated Exhibit 1—Duke Energy filed updated standard offer avoided cost rates available to all QFs that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PPs and that establish a legally enforceable obligation (LEO) committing to sell the output of their QF generating facility to DEC or DEP on or after November 1, 2023, but prior to the initial filing in the next biennial avoided cost proceeding in November 2024. As provided in these schedules:

> In order to be an Eligible Qualifying Facility and receive Energy Credits under this Schedule, the Qualifying Facility must be a hydroelectric or a generator fueled by trash or methane derived from

landfills, solar, wind, hog or poultry waste-fueled or non-animal biomass-fueled Qualifying Facility with a Contract Capacity of one (1) megawatt or less, based on the nameplate rating of the generator(s), which are interconnected directly with the Company's system and which are Qualifying Facilities as defined by the Federal Energy Regulatory Commission pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978.

Duke Energy's Schedule PP further states that, pursuant to N.C.G.S. § 62-156(b)(3), electric generation fueled by swine waste and poultry waste may be eligible for a different avoided capacity rate "if Seller sells the output of its facility, including renewable energy credits," to Duke for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements set forth in N.C.G.S. § 62-133.8(e) and (f).

The Public Staff's Initial Statement reviews and summarizes the Schedule PP rate schedules proposed by DEC and DEP, and does not recommend any changes to the standard offer term and eligibility thresholds proposed by DEC and DEP. 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 by DEC and DEP.

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 with a design capacity up to and including 1 MW.

In past biennial avoided cost proceedings, the Commission has ruled 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 offer 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 as-available energy rate, including either the As-Available Rate or 2-year Fixed 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 parties choose the As-Available Rate option, 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 also recognizes that DEC and DEP have initiated and are planning recurring annual procurements of solar generation as part of their ongoing Carbon Plan execution pursuant to N.C.G.S. § 62-110.9, and Commission's Order Authorizing a Competitive Procurement of Solar Resources Pursuant to House Bill 951 and Establishing Further Procedures, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (May 26, 2022). Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179 (Dec. 30, 2022) To date, the Commission has not received a motion, nor issued an order, addressing the exact points of when an active solicitation shall be regarded as beginning or ending, nor has the Commission addressed whether these open and recurring solar procurement programs may be considered an active solicitation establishing a Competitive Solicitation Price for PURPA compliance purposes. Accordingly, it is appropriate for the arbitration option to remain available for issues arising during negotiations between a utility and QF at this time.

AVOIDED CAPACITY RATES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

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

Summary of the Comments

In its Initial Statement, Duke Energy explains that DEC and DEP have again used the peaker methodology to develop their avoided capacity and energy costs for QFs committing to deliver their full capacity and energy output for a specified fixed future term. Duke Energy's Initial Statement notes that the Commission has consistently approved Duke Energy's use of the peaker methodology as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs, and that the peaker methodology is widely accepted for calculating avoided costs throughout the nationwide electric industry. Duke Energy explains that the Commission's 2021 Sub 175 Order directed the Utilities "to evaluate before the next biennial proceeding whether to propose an alternative method to calculate avoided costs, including those FERC has recently determined to be reasonable and appropriate for calculating avoided costs in Order No. 872 and that are now included in 18 C.F.R. 292.304(b)."[1] To comply with this directive, Duke Energy explains that it evaluated the three non-exclusive potential methodologies for calculating a utility's avoided costs identified in FERC Order No. 872: Locational Marginal Price; Competitive Price; and Competitive Solicitation Price. Duke Energy explains that the Companies' most recently approved methodology for calculating its as-available energy or marginal cost rate generally aligns with the Locational Marginal Price concept as applicable to the Carolinas. Duke Energy Initial Statement at 11-12.

Duke Energy explains that it reviewed its current PURPA implementation framework as directed in the Sub 175 Order and determined that it is not necessary to further update their PURPA implementation framework to adopt any of the methodologies identified in Order No. 872 for the purpose of setting long-term fixed rates for avoided capacity and energy at this time. According to Duke Energy, continued use of the Commission-approved peaker method to calculate the Companies' forecasted avoided costs of capacity and energy is consistent with the Companies' current, standardized approach to calculating avoided costs under N.C.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. *Id.* at 11-14.

Duke Energy also states in its Initial Statement that DEC and DEP used the installed cost of a CT unit derived from publicly available industry sources such as the EIA to calculate its avoided capacity costs under the peaker method. Duke Energy states that this approach is consistent with the consensus standardized approach developed by Duke Energy, the Public Staff, and DENC in advance of the 2021 Sub 175 proceeding, which the Commission subsequently approved. Duke Energy further explains that the fixed operations and maintenance (FOM) cost component is based on publicly available FOM data from the same EIA data source with adjustments using internal data to reflect the FOM economies of scale associated with a four-unit CT project. *Id.* at 16-17.

In its Initial Statement, the Public Staff supports the Companies' continued use of the peaker method and recommends that the Commission approve Duke Energy's avoided capacity and energy rate methods. Public Staff Initial Statement at 50. The Public Staff further states that it supports the use of an F-frame CT as proposed by Duke Energy in this proceeding. The Public Staff states that while cost data on F-frame CTs has been readily available for many years and is reliably used by the Utilities to determine avoided capacity payments to QFs, EIA's January 2024 *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies* included cost estimates for H-Class CTs. The Public Staff, in its Initial Statement, recommends that the Utilities calculate

[1] Sub 175 Order at 14-17 (Ordering Paragraph No. 5).

their avoided capacity payments based upon more advanced CTs in the next biennial avoided cost proceeding if no other publicly available cost data exists. *Id.* at 13-14.

The AGO, in its Comments, likewise continues to support the Companies' use of the peaker method but recommends the peaker method should be adjusted to incorporate an avoidable cost of carbon. AGO Comments at 14-15. In its Comments, the AGO suggests that there is a "growing disconnect" between generation expansion plans and avoided energy inputs. The AGO states that it is no longer valid for Duke Energy to calculate avoided costs using an F-Class CT because Duke Energy did not include an F-class CT as a selectable resource in its most recent Carbon Plan and Integrated Resource Plan ("CPIRP") and because Duke Energy uses a hydrogen-capable advanced class CT to calculate avoided capacity costs in its demand-side management and energy efficiency mechanism. *Id.* at 15.

In its Initial Comments, CCEBA argues that Duke did not fully evaluate alternatives to the peaker method. CCEBA states that the peaker method is likely soon to be outdated as more and more renewable energy and storage is integrated into the grid. According to CCEBA, the Commission should order Duke to undertake a process that will, in light of the changing energy and regulatory landscape, fully consider all alternatives to the peaker method and identify the most accurate method for calculating avoided costs going forward. In CCEBA's view, an appropriate first step would be for the Commission to order a stakeholder process and to direct the parties to report back to the Commission by a time certain. Alternatively, CCEBA proposes that a technical conference or evidentiary hearing would provide an opportunity for the Commission to receive information related to this issue from multiple sources. CCEBA Initial Comments at 4-5.

CCEBA also argues that Duke Energy's proposed avoided cost rates do not appropriately account for the capacity value of solar. First, CCEBA suggests that Duke Energy does not properly account for the capacity value of solar related to its synergistic effect with storage resources, including both battery storage and pumped hydro storage. CCEBA recommends that the Commission should require Duke to update its Effective Load Carrying Capacity ("ELCC") analysis to account for these values. CCEBA further notes that Duke Energy's rates do not provide capacity payments for existing QFs that execute new PPAs following the expiration of their existing PPAs. According to CCEBA, as those projects reach the end of their contractual tenor, it can be assumed that the capacity value they provide will need to be replaced, either through the recontracting of those facilities or through the addition of new solar resources. CCEBA further states that Duke Energy's CPIRP modeling assumes that these facilities will renew their PPAs and continue contributing carbon-free energy to the system. CCEBA Initial Comments at 8-9.

In its Reply Comments, Duke Energy explained that it fully considered alternatives to the peaker method in the months leading up to their November 1, 2023 avoided cost filing in this docket. According to Duke Energy, of the three non-exclusive potential methodologies for calculating a utility's avoided cost identified in FERC Order No. 872—Locational Marginal Price, Competitive Price, and Competitive Solicitation Price—none are more appropriate for calculating the Companies' avoided costs than the peaker method at this time. Duke Energy explains that it already uses a proxy to the Locational Marginal Price model to calculate its As-Available Rate and FERC's regulations make clear that the Competitive Price method is specific to the calculation of as-available rates. Duke Energy explains that using a Competitive Solicitation Price to determine avoidable cost would be a significant change to establishing the Companies' avoided cost as the Commission would no longer set an administratively-determined avoided cost rate for must-take capacity and energy offered by QFs. To the extent a QF desires to receive a purely market-based rate, it can elect to participate in the robust annual CPRE process established under HB 951 and supervised by the Commission. Duke Energy notes that the biennial cadence in which the Commission reviews the utilities' avoided cost rates provides ample and regular opportunity for the Companies to re-assess and for the Commission to review this issue and that a stakeholder proceeding or technical conference to evaluate potential alternatives would not be an efficient use of the Commission's or the parties' time. Duke Energy Reply Comments at 6-7.

Duke Energy also states, in its Reply Comments, that DEC and DEP agree with the Public Staff that it is appropriate to use publicly available cost data and commits to engaging with the Public Staff in advance of the next biennial proceeding to consider the appropriate peaking unit for use in developing DEC's and DEP's avoided capacity costs. Duke Energy disagrees with the AGO's contention that an F-Frame CT is no longer a valid peaking unit. Duke Energy notes that while the AGO is correct that DEC and DEP did not include F-frame CTs as a selectable resource in developing their proposed CPIRP, its calculation of avoided costs using the F-frame turbine under the peaker method continues to establish a reasonable proxy of the avoidable cost of capacity on the system today as well as future planned capacity resources expected to be online during the term of the contract. Duke Energy explains that the peaker methodology assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. Under the theoretical corollary of the peaker methodology, even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology can still provide an accurate estimate the utility's avoided costs. Duke Energy further notes that from an installed cost perspective, simple cycle F-frame peaking units and H-class peaking units are generally similarly priced and the least expensive type of traditional resource that the Companies can construct to provide capacity for reliability purposes. *Id.* at 19-20.

Regarding the capacity value of solar, Duke Energy explains, in its Reply Comments, that it has long used the loss of load risk identified in its most recent resource adequacy study as the basis for seasonal and hourly allocations of capacity payments. This approach was part of the Commission-approved rate design stipulation between the Companies and the Public Staff in the 2018 Sub 158 Proceeding, and the Companies used the loss of load risk identified in the 2023 Resource Adequacy Study to update the avoided capacity rate design in this proceeding. Duke Energy further notes that because avoided cost rates are generic rates applicable to all QFs and derived based on the system's capacity need, a QF's specific attributes do not impact the Companies' avoided cost rates (except indirectly to the extent those attributes or characteristics enable/limit the QFs' ability to deliver energy during peak periods when DEC or DEP has an avoidable capacity need). Accordingly, Duke Energy explains, solar ELCC values do not play a role in setting the seasonal and/or hourly capacity allocation nor are the specific attributes of solar (or solar paired with any other resource) used in the calculation of avoided capacity rates. *Id.* at 21-22.

Duke Energy also explains that it has historically (1) recognized that a QF's commitment to provide capacity extends only for the duration or "specified term"[2] of its PPA; and (2) treated all existing and newly constructed QFs similarly, such that existing QFs do not receive preferential treatment over new QFs. Duke Energy notes that the Commission considered this issue in the context of expiring hydro QFs PPAs in the 2018 Sub 158 Order and agreed with the Companies' approach, finding that "it would be imprudent resource planning to assume that QFs are obligating themselves to deliver capacity and energy past the end of their contract term."[3] *Id.* at 22.

In its Reply Comments, the Public Staff reiterates its support for use of the peaker method in this proceeding. In lieu of stakeholder meetings as suggested by CCEBA, the Public Staff recommends that 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 notes that CTs will continue to be a capacity resource for the foreseeable future whether fueled by hydrogen or fossil fuels. Public Staff Reply Comments at 2-3.

The Public Staff, in its Reply Comments, also disagrees with CCEBA's contention that Duke Energy's avoided capacity rates do not provide payments for capacity to new solar. The Public Staff notes that while Duke Energy's proposed avoided cost rates do not provide capacity payments specific to solar facilities, Duke Energy has proposed higher energy payments during peak demand times and capacity payments during times when the system has the highest loss of load risk, which has the effect of financially rewarding energy provided by any QF when customers need it the most. The Public staff also notes that Duke Energy's 2023

[2] 18 C.F.R. § 292.304(d)(1)(ii).

[3] Sub 158 Order at 51-52.

Resource Adequacy Study, which assumes all existing QF contracts are "replaced in kind" at the end of their contract term. According to the Public Staff, this assumption may cause Duke to discount the capacity value of QFs, particularly solar QFs, in the summer. Accordingly, the Public Staff recommends that the Commission direct Duke Energy to address the potential materiality of expiring QF contracts on the seasonal allocation of loss of load risk in the next avoided cost proceeding. *Id.* at 6-7.

In its Reply Comments, CCEBA asks the Commission to order Duke Energy to undertake an expedited stakeholder process that would allow the Commission to make any necessary modifications to its approved avoided cost methodology well before the next biennial avoided cost proceeding. CCEBA notes that there are some QFs on DEC's and DEP's systems for which existing contracts will expire in 2027. According to CCEBA, in order for both the QF and Duke to plan for the future contribution of those resources to Duke Energy's system and to HB 951 compliance, these QFs will need to make a determination by early 2026 as to whether to seek a new PURPA PPA from Duke Energy or make some alternative arrangement which will allow the Companies to make appropriate resource planning assumptions. CCEBA states that the stakeholder process should be defined and collaborative with a firm deadline for completion that allows the Commission to approve an alternative methodology in advance of the next biennial avoided cost proceeding. CCEBA Reply Comments at 11.

CCEBA further claims affirmative steps are needed to ensure that existing QFs continue to provide carbon-free power to Duke's system after the expiration of their contract term. CCEBA notes that most of the QFs with PPAs expiring in the next few years are projects around 5 MW capacity. CCEBA recommends that Duke Energy should explore, with other stakeholders, the possibility that there may be other contracting structures that would provide more certainty about the availability of these QFs, and potentially provide more value and flexibility to the system than traditional PURPA "must-take" contracts process. Discussing other contracting structures should begin now. CCEBA Reply Comments at 4, 11.

In its Reply Comments, NCSEA agrees with the Public Staff that the peaker method and use of an F-frame CT as proposed by Duke Energy is appropriate in this proceeding. NCSEA also supports CCEBA's proposal for a stakeholder process to fully consider alternatives to the peaker method and develop consensus of the appropriate methodology prior to the start of the next biennial avoided cost proceeding. NCSEA also argues that Duke Energy should not use an F-frame CT to calculate avoided costs in future proceedings. NCSEA Reply Comments at 4.

NCSEA, in its Reply Comments, joins in CCEBA's concern about the lack of capacity payments for new and existing solar QFs. NCSEA notes that Duke Energy's methodology for calculating loss of load risk originated in an agreement between the Public Staff and Duke Energy in the 2019 Sub 158 proceeding, predating HB 951 and the Carbon Plan proceedings. NCSEA recommends that Duke Energy's loss of load risk methodology be incorporated into the proposed stakeholder process and discussed with interested parties. NCSEA also agrees with CCEBA that the expiration of existing solar QF PPAs, if not renewed, will create a capacity need. According to CCEBA, HB 951 necessitates the review of past Commission decisions regarding the treatment of expiring QF PPAs because, in a carbon constrained environment, prudent resource planning requires encouragement of contract renewals for renewable resources. In NCSEA's view, each additional unit of solar procured should help avoid the next unit of carbon, not backfill lost carbon-free capacity, and renewing QFs should therefore be compensated for the benefit their capacity provides. *Id.* at 6-8.

In its Reply Comments, SACE argues that the peaker method will continue to grow increasingly inaccurate over time and supports a stakeholder process to develop an updated and accurate avoided cost methodology that would conclude in time for Duke Energy to apply the selected methodology in its next avoided cost filing. CCEBA recommends that the stakeholder process should be overseen by an independent third party and that the Commission should establish a deadline by which the process will render a recommendation and select the methodology far in advance of Duke's November 1, 2025, avoided cost filing. SACE Reply Comments at 4-5.

SACE, in its Reply Comments, also raises concerns about continued use of an F-frame CT as a peaking unit. SACE states that it would not oppose recalculating avoided costs in this proceeding using an H-class CT, but states that avoided cost rates in future proceeding should be based on a methodology selected through a stakeholder process. *Id.* at 5-6.

<u>Discussion and Conclusions</u>

Based on the entire record, the Commission finds that the peaker method remains a reasonable method by which to calculate avoided capacity costs at this time. The Commission has approved the use of the peaker method as reasonable and appropriate for deriving forecasted avoided capacity costs in the 2021 Sub 175 proceeding and a number of prior biennial avoided cost proceedings. *See* Sub 175 Order at 14, 70 (Order Paragraph No. 5); Sub 167 Order at 60 (Ordering Paragraph No. 8); 2018 Sub 158 Order at 134 (Ordering Paragraph No. 10); *see also Order Setting Avoided Cost Inputs,* Docket No. E-100, Sub 140, at 8 (Finding of Fact 6) (issued Dec. 31, 2014) (Sub 140 Phase One Order*)*. The Commission has also developed significant guidance through prior orders in past biennial avoided cost proceedings that inform how the peaker method is applied by utilities in North Carolina and the Commission finds value in retaining this framework for this proceeding.

The Commission is also persuaded that Duke Energy appropriately considered alternate approaches to calculating avoided costs in advance of this proceeding. The Commission, in particular, notes that Duke Energy considered each of the non-exclusive potential methodologies for calculating a utility's avoided cost identified in FERC Order No. 872 and that Duke Energy is already using a proxy to the Locational Marginal Price method to calculate its as-available rates. In contrast, no other party proposed an alternate methodology for the Commission's consideration in this proceeding.

The Commission further finds based on the entirety of the record that Duke Energy appropriately relied on publicly available industry sources for determining the installed $/kW cost of a CT, a hypothetical F-class CT, and that they developed their respective source information in a manner consistent with the guidance the Commission previously provided. The Commission agrees with the Public Staff that the F-frame CT remains appropriate for use as a peaking resource in this proceeding. Although, as the AGO notes, the Companies no longer use F-frame CTs in modeling their CPIRP and the Companies are planning for the construction of more advanced class CTs in the future, F-frame CTs are still widely used for power generation, including on Duke Energy's system and provide a reasonable proxy for the cost of a peaking generation facility at this time. With respect to the economies of scale adjustment to fixed O&M costs, the Commission approved this approach in its 2021 Sub 175 Order and no party objects to its use in this proceeding. The Commission therefore finds that the CT cost information and adjustments that DEC and DEP use are reasonable, consistent with prior Commission orders, and appropriate for purposes of calculating avoided capacity costs in this proceeding.

The Commission further finds that Duke Energy's avoided cost calculation methodology assigns appropriate capacity value to solar QFs. In the 2018 Sub 158 Order, this Commission held that "it would be discriminatory between QFs to assume that a pre-existing QF has a priority right to enter into a new contract to sell and deliver capacity over a new term versus the rights of any other QF to commit itself to avoid the utility's capacity need."[4] Similarly here, the Commission finds that it would not be prudent resource planning for Duke Energy to assume expiring solar QFs will certainly renew their expiring PPAs. QFs have equal rights to obligate themselves to deliver energy or capacity over a specified term, and it would be unjustly discriminatory between QFs to give a legacy solar QF a priority right over a new QF or to assume a legacy solar QF will deliver power beyond the specified term of its contract or obligation absent some binding commitment on behalf of the QF to do so. 18 C.F.R. 292.304(d)(1)(ii). The Commission therefore also declines to adopt CCEBA's position, as it would be inappropriate for Duke

[4] *Id.* at 51.

Energy to continue providing capacity payments to QFs beyond the expiration of their PPA (e.g., beyond the specified term of their legally enforceable obligation to sell power to DEC or DEP) in the absence of a new commitment by the QF and an updated assessment and demonstration of the utility's capacity need. Moreover, to ensure QF power is accurately valued and incented to be delivered during peak demand periods when needed most, Duke Energy has appropriately proposed higher capacity payments during winter mornings, when the system has the highest loss of load risk. The record before the Commission does not demonstrate that solar QFs have the capability or are in any way obligating themselves to provide different or greater capacity value to the Companies' systems than other QFs and the Commission finds that Duke Energy's proposed avoided cost rates are reasonably based on the utility's system needs and appropriately do not provide for solar-specific capacity rates. Instead, the avoided capacity rate design and seasonal allocation of capacity value based upon the avoidable capacity needs of the utility's system has the effect of financially rewarding energy provided by any QF when customers need it most. For all of these reasons, the Commission finds that Duke Energy's capacity rates appropriately capture the capacity value of solar and are nondiscriminatory to any QF and are just and reasonable to the customers' obligation to pay for QF power under PURPA.

Nevertheless, the Commission finds that solar QFs with expiring PPAs likely can provide value to the system beyond the term of their current contracts and directs Duke Energy to explore options to encourage these QFs to enter into new PPAs and to continue selling energy to the Companies after the expiration of their existing PPAs. While the Commission declines to direct a formal stakeholder process, as recommended by certain parties, QF owners and other stakeholders are free to engage Duke Energy regarding such proposals and the Commission directs Duke Energy, after consultation with the Public Staff, to address in its next biennial avoided cost filing (1) the number of QFs with expiring PPAs over the next five years; (2) the process for existing QFs with expiring PPAs to obligate themselves to sell power for a new term; and (3) whether designing and offering a competitive solicitation process open to QFs with expiring PPAs would be reasonable and in the public interest. This competitive solicitation could be conducted either as part of Duke Energy's ongoing competitive solicitations for new resources under its Carbon Plan or as a separate program or process and could be designed to provide additional value to Duke Energy and customers beyond the current must-purchase avoided cost framework by soliciting purchases of energy, capacity, and environmental and renewable attributes from QFs and/or negotiating commitments by the QF owner to allow the procuring electric public utility rights to dispatch, operate, and control the solicited QFsin the same manner as the utility's own generating resources. G.S. § 62-110.9(2)b.

Finally, the Commission remains open to evaluating the avoided cost method in the future as long as any new or altered method meets PURPA's requirements. At this time, however, the Commission is not persuaded that a stakeholder proceeding to select an alternate avoided cost methodology would be an efficient use of the Commission's or the parties' resources. The biennial cadence with which the Commission reviews the utilities' proposed avoided cost methodology and rates provides a regular opportunity for the utilities to re-assess their respective approaches to calculating avoided costs and for the Commission to review this issue. Accordingly, the Commission directs Duke Energy to evaluate before the next biennial proceeding whether to propose an alternative method to calculate avoided costs. The Commission further directs Duke Energy to evaluate in future Avoided Cost dockets other least-cost capacity resources, including an advanced class CT, as they become commercially viable, as recommended by the Public Staff, and to address whether any changes to the avoidable resource used in the peaker methodology are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-6

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

Summary of the Comments

In its Initial Statement, Duke Energy explains that DEC and DEP developed respective avoided capacity rates consistent with the methodology the Commission approved in the 2018 Sub 158, 2020 Sub 167, and 2021 Sub 175 proceedings. The Commission's 2018 Sub 158 Order directed DEC and DEP to include in future IRPs a clear statement identifying each utility's first year of avoidable capacity need to be used in determining their respective avoided capacity costs. 2018 Sub 158 Order at 10 (Finding of Fact Nos. 19, 22).

Duke Energy's Initial Statement and corresponding DEC/DEP Exhibit 8 explain that DEC and DEP generally assess their respective first year of undesignated capacity need as part of the biennial IRP process as well as through updates to their IRPs. Initial Statement at 15; Initial Statement DEC/DEP Exhibit 8 at 2. DEP's next avoidable undesignated capacity need occurs in 2024, while DEC's next avoidable undesignated capacity need occurs in 2025. Initial Statement at 16; Feb. 15 Update Letter at 2. Compared to the 2021 Sub 175 proceeding, DEC's first year of capacity need shifts forward three years, from 2028 to 2025. DEP's first year of avoidable capacity need is unchanged. *Id*. In its Initial Statement, Duke Energy explains that due to the passage of time, this represents an earlier capacity need in the 10-year calculation span than used to calculate the prior 2021 Sub 175 avoided cost rates. *Id*.

Consistent with the Sub 175 Order and N.C.G.S. § 62-156(b)(3), DEC's and DEP's Schedule PP rates also appropriately include alternative avoided capacity rate calculations, which recognize that certain QFs fueled by swine waste, poultry waste, and certain hydro power QFs less than 5 MWs, are assigned immediate capacity value. *Id.* at 16.

In its Initial Statement, the Public Staff states that DEC's and DEP's calculations of avoided capacity rates appropriately reflect the present value of avoided capacity costs beginning in their respective 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 finds DEC's and DEP's first year of avoidable undesignated capacity need to be reasonable. Public Staff Initial Statement at 21. No other parties commented on this issue.

<u>Discussions and Conclusions</u>

Based upon the foregoing and the entire record herein, the Commission determines that Duke Energy has calculated DEC's and DEP's avoided capacity costs consistently with the North Carolina General Statutes and the Commission's prior orders on this matter. N.C.G.S. § 62-156(b)(3), which guides the Commission's conclusions on this issue, provides that, with respect to the rates to be paid by electric public utilities for capacity purchased by QFs:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission . . . has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other than for (i) swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f) and (ii) hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than five megawatts.

No party disputed DEC's or DEP's proposed first year of need or their proposed standard offer schedules showing that, in certain circumstances, QFs fueled by swine waste, poultry waste, and hydropower, receive capacity payments that begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begin in the first year of a utility's capacity need.

The Commission finds DEC's and DEP's calculation of their respective first year of avoidable capacity need to be reasonable. Based on the foregoing, the

Commission finds and concludes that DEC's and DEP's first year of need and proposed avoided capacity rates presented in the February 15 update to DEC's and DEP's avoided cost rates align with the Companies' Supplemental Planning Analysis filed in Docket No. E-100, Sub 190 are reasonable and appropriate and therefore approves them.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-8

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

Summary of the Comments

Duke Energy's Initial Statement states that the Commission has previously recognized the PAF as a capacity multiplier designed to address the fact that standard avoided capacity rates are paid on a per-kWh basis, such that setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours. According to Duke Energy, this leaves the QF without any reasonable opportunity to experience outages during each peak hour to receive the total avoided capacity payment. Duke Energy explains that the PAF recognizes that the utilities' generating units experience outages during peak periods and thus a QF should not be required to operate during 100% of the on-peak hours to receive a full capacity payment for the year. Duke Energy explains that, prior to making their initial filing in the 2021 Sub 175 proceeding, DEC and DEP worked with DENC and the Public Staff to consider the use of appropriate reliability metrics for developing the PAF. These discussions resulted in a consensus to adopt the Weighted Equivalent Unplanned Outage Factor ("WEUOF") metric for each utility's respective generation fleet to calculate the PAF, and the Commission approved this consensus approach in its Sub 175 Order. Accordingly, Duke Energy explains that DEC and DEP have continued to use the standardized WEUOF methodology to calculate their respective PAFs in the current proceeding. Duke Energy states that DEC's and DEP's respective system WEUOF averages to approximately 4.8% and 6.5%, respectively, which results in a PAF of 1.05 for DEC and 1.07 for DEP. Duke Energy Initial Statement at 17-18.

In its Initial Statement, Duke Energy also provides its position on continuing the PAF for hydroelectric ("hydro") QFs that are eligible for the standard offer (1 MW or less). Duke Energy explains that North Carolina's legacy implementation of PURPA afforded hydro QFs with unique treatment that resulted in the Utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[5] *Id.* at 16. As Duke notes, the Commission approved a 2.0 PAF for run-of-river hydro QFs more than two decades ago in the 1996 avoided cost proceeding in Docket

[5] Prior to Session Law 2017-192's ("HB 589") enactment, the statutory definition of small power producer was limited to hydroelectric renewable resources. *See* 2017 N.C. Sess. Laws 2017-192, Part I (amending N.C.G.S. § 62-3(27a)).

No. E-100, Sub 79.[6] Based in part on that unique legislative treatment and the Commission's then-existing 2.0 PAF for run-of-river hydro QFs without storage, Duke Energy explains that it entered into a stipulations with the NC Hydro Group in 2014 in Docket No. E-100, Sub 140[7] ("Hydro Stipulation"), in which the parties agreed, among other things, that DEC and DEP would continue to include the previously-approved 2.0 PAF in standard offer tariffs filed at the Commission prior to December 31, 2020 and to use a 2.0 PAF to calculate the avoided cost rates for small hydro QFs of 5 MWs or less through December 31, 2020.[8] *Id.* at 19.

Duke Energy notes that the General Assembly has subsequently amended the State's implementation of PURPA through Session Law 2017-192 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while, at the same time, establishing flexibility for the Companies to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in calculating future avoided cost rates.[9] Because of these legislative changes, Duke Energy states, the Commission found it appropriate in Docket No. E-100, Sub 158 "to consider again the question of the appropriate PAF to apply in calculating capacity rates to run-of-the-river hydro QFs after the natural expiration of the Hydro Stipulation."[10] *Id.* at 20.

Duke Energy explains that in the 2020 Sub 167 proceeding, when the expiration of the Hydro Stipulation was imminent, the Companies explained that they would retain the 2.0 PAF for run-of-river hydro QFs that are 1 MW and less as eligible for the standard offer (in effect from November 1, 2020, until October 31, 2021), but noted that the Hydro Stipulation was set to expire on December 31, 2020. Duke Energy explains that in the Sub 167 Order*,* the Commission cited the expiration of the Hydro Stipulation and provided that, after December 31, 2020, DEC and DEP "are no longer required to offer a 2.0 PAF to run-of-river hydro QFs greater than 1 MW but less than 5 MWs."[11] The Commission also directed the Companies to address the appropriate PAF for run-of-river standard offer hydro QFs in their Sub 175 initial statement.[12] *Id.* at 20.

In the 2021 Sub 175 proceeding, Duke Energy explains, DEC and DEP proposed to discontinue the 2.0 PAF on the grounds that the Hydro Stipulation

[6] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 79, at 19 (June 19, 1997).

[7] Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and NC Hydro Group, Docket No. E-100, Sub 140 (Jun. 24, 2014).

[8] Hydro Stipulation at ¶¶ 3(a), 4.

[9] *See* N.C.G.S. §§ 62-156(b)(3), (c).

[10] Sub 158 Order at 42.

[11] Sub 167 Order at 20.

[12] *Id.* at 20-21.

does not require the continuation beyond December 31, 2020, of an elevated PAF for any run-of-river hydro QFs under 5 MWs in capacity. Duke Energy explains that it also highlighted, in the 2021 Sub 175 proceeding, the State's reforms to PURPA implementation providing flexibility to enter into longer-term avoided cost rate contracts with certain QFs and to value legacy hydro QF capacity less than 5 MW in calculating new avoided cost rates for these facilities. In that proceeding, the Commission acknowledged expiration of the Hydro Stipulation and the fact that no party offered any justification for extending the 2.0 PAF but found that "the parties did not fully litigate this issue" and directed the Companies to continue the 2.0 PAF. Duke Energy explains that the Commission noted that it may consider whether to discontinue the 2.0 PAF based on evidence in the current avoided cost proceeding. *Id.* at 21.

Duke Energy explains that in this proceeding, DEC and DEP are proposing standard offer avoided cost rates for run-of-river hydro QFs that are equivalent to other QFs and reflect the same standard PAF of 1.05 for DEC and 1.07 for DEP, not the elevated and outdated PAF of 2.0. Duke Energy notes that the Commission has already approved standardizing the PAF adder for run-of-river hydro QFs that are in excess of 1 MW and subject to bilaterally negotiated PPAs with the PAFs paid to the other renewable resource generators. Duke Energy explains that in Docket No. E-7, Sub 1254, the Commission denied the claim of Northbrook Carolina Hydro, LLC ("Northbrook"), a 5 MW run-of-river hydro QF, that it was entitled to a 2.0 PAF in a negotiated PPA to be executed in 2021. In denying Northbrook's claim, Duke Energy explains, the Commission concluded that "[a]fter the expiration of the Hydro Stipulation, or after December 31, 2020, the Commission-approved avoided cost methodology for the PAF for Small Hydro QFs is the same for all other QFs."[13] *Id.* at 22.'

Duke Energy states that continuing to apply the elevated 2.0 PAF does not reflect the Companies' forecast of avoided capacity costs or results in customer indifference and runs contrary to the basic principles of PURPA. *Id.*

In its Initial Statement, the Public Staff states that it supports the PAFs proposed by Duke Energy. Public Staff Initial Statement at 46. The Public Staff further supports Duke Energy's request to discontinue the 2.0 PAF for run-of-river hydro QFs eligible for the standard offer to preserve fairness to other QFs and to Duke's customers that pay for QF power. In addition, the Public Staff recommends that Duke Energy should use solar outage data to calculate their PAF in next avoided cost proceeding. *Id.* at 15-16. The Public Staff notes that the Utilities use the Generating Availability Data System (GADS) developed by the North American Electric Reliability Corporation (NERC) to calculate their WEUOF. According to the Public Staff, GADS did not begin collecting availability data for solar facilities until January 1, 2024, and accordingly the utilities do not currently have enough information to consider solar availability in calculating their PAFs in this proceeding. Nevertheless, the Public Staff states that it expects the Utilities to

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[13] Northbrook Order at 7.

begin using solar outage data to calculate their respective PAFs in the next biennial proceeding. *Id.* at 5-6.

In its Initial Comments, CCEBA recommends that Duke Energy should incorporate its experience in the outages during Winter Storm Elliot in December 2022, during which gas supply and CT performance fell well below expectations, into its PAF analysis. CCEBA suggests that Duke should reevaluate this value and assume a lower ELCC for such units during winter events, as other utilities such as PJM have recently done. CCEBA Initial Comments at 9-10.

Duke Energy, in its Reply Comments reiterates its proposal to discontinue the outdated 2.0 PFA for run-of-river hydro QFs and asserts those QFs should receive avoided cost rates, reflecting the same standard PAF of 1.05 for DEC and 1.07 for DEP. According to Duke Energy, these changes appropriately reflect both (1) legislative amendments to the State's PURPA implementation in Session Law 2017-192 and Session Law 2019-329 which no longer designate hydroelectric generators as unique small power producers; and (2) the expiration of the Sub 140 Hydro Stipulation. Duke Energy Reply Comments at 24.

Duke Energy further states that it recognizes the importance of incorporating solar outage data into the PAF, as recommended by the Public Staff. However, Duke Energy explains that NERC has designed a phased approach for reporting solar data in the GADS database whereby solar plants with a total installed capacity of 100 MW or more are to begin mandatory reporting by January 1, 2024, and solar plants with a total installed capacity of 20 MW or more are to begin mandatory reporting by January 1, 2025. Duke Energy reports that while DEC and DEP do not own any utility-owned solar facilities with a total installed capacity of 100 MW or more, they plan to implement a pilot reporting program sometime in 2024 to test GADS reporting for some facilities and will plan to include solar outage data in determination of the PAF as the data becomes available. However, Duke Energy explains that DEC and DEP will have gathered very limited solar outage data before their next biennial avoided cost filing in November 2025. Because the PAF is generally calculated based on data from the past five calendar years, Duke Energy states that DEC and DEP will be unable to fully incorporate solar outage data into their November 2025 avoided cost filing. Duke Energy also states that it plans to discuss this approach with the Public Staff in advance of future biennial avoided cost filings. Duke Energy Reply Comments at 24-25.

Responding to CCEBA recommendation, Duke Energy further notes that DEC and DEP have already incorporated their operating experience during Winter Storm Elliot as outage data for all of 2022. Data from December 2022 when Winter Storm Elliot occurred, is in the historic WEUOF dataset used to calculate the PAF. *Id.* at 25.

Discussion and Conclusions

Based on the foregoing, the Commission finds and concludes that DEC's proposed PAF of 1.05 and DEP's proposed PAF of 1.07 for all QFs, including hydro QFs, is reasonable and appropriate. DEC's and DEP's proposed PAFs were calculated using the consensus approach approved by this Commission in Docket No. E-100, Sub 175, they are supported by the Public Staff, and not controverted by any other intervenor.

The Commission further agrees with Duke Energy's proposal to discontinue the 2.0 PAF for run-of-river Hydro QFs that are subject to the standard offer. Given that the General Assembly has amended the unique legislation that supported the smaller, run-of-river hydro receiving a 2.0 PAF, the Hydro Stipulation has expired, and no party has asked or offered any justification to extend the 2.0 PAF, the Commission finds that the 2.0 PAF is outdated. Applying the same PAF used to fairly compensate other QFs is more reasonable and appropriate to reflect the capacity value to Duke Energy's customers that the PAF is designed to represent. As the Commission previously found when considering whether the 5 MW Northbrook facility had a right to a 2.0 PAF, "[a]fter the expiration of the Hydro Stipulation, or after December 31, 2020, the Commission-approved avoided cost methodology for the PAF for Small Hydro QFs is the same for all other QFs."[14] Because Northbrook exceeded 1 MW, the Commission did not directly address the question of the appropriate PAF for hydro QFs 1 MW or less that remain eligible for the standard offer. However, the Commission noted in its discussion that "the method by which avoided costs are calculated should, to the extent possible, remain consistent in both standard and negotiated contacts."[15] Accordingly, the Commission approves DEC's proposed 1.05 PAF and DEP's proposed 1.07 PAF for all QFs eligible for the standard offer.

AVOIDED ENERGY COSTS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-13

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

Summary of the Comments

In its Initial Statement, Duke Energy states that DEC and DEP developed their avoided energy costs relying upon five years of forward natural gas pricing followed by three years of blending before transitioning to fundamental forecast data for the remaining planning period. Initial Statement at 22-23. Duke Energy further states that DEC and DEP relied on the average of fundamental forecasts

[14] Northbrook Order at 7.

[15] *Id.* at 6 (internal quotation omitted).

developed by EIA and private firm, IHS, to calculate market fundamental pricing. *Id*.

Duke Energy further states that it utilized the Black-Scholes option pricing method to determine the hedging value of renewable generation. Duke Energy explains that the Commission approved DEC's and DEP's fuel hedging adjustment in Docket No. E-100, Sub 175, and DEC and DEP have applied the same standardized approach to calculate the avoided fuel hedging adjustment in this proceeding. Duke Energy states that its Black-Scholes calculation resulted in a fuel hedge value of $0.80/MWh and is incorporated into DEC's and DEP's avoided energy rates. Duke Energy Initial Statement at 24.

In its Initial Statement, the Public Staff states that it finds Duke Energy's natural gas price forecasting methodology to be reasonable and consistent with the 2023 CPIRP. With respect to fuel hedging, the Public Staff does not recommend any changes based upon its review and notes that Duke Energy's calculation of fuel hedging benefits is consistent with the approach approved 2018 Sub 158 Order. Initial Statement of the Public Staff at 35-37. No other party commented on this issue.

<u>Discussion and Conclusions</u>

Duke Energy's natural gas forecasting method in this proceeding is consistent with the methodology Duke Energy used to calculate natural gas price forecasts in the 2023 CPIRP proceeding. As the Commission noted in the 2021 Sub 175 Order, this consistency is warranted and appropriate and, moreover, no party disputed Duke Energy's proposed methodology. Upon the foregoing and the entire record herein, the Commission approves Duke Energy's methodological approach of calculating avoided energy costs using market-based forward contract natural gas prices for no more than five years before transitioning to fundamental forecast data for the remainder of the planning period used to develop long-term fixed avoided cost rates for this proceeding.

The Commission likewise finds reasonable Duke Energy's proposed hedging value. Importantly, Duke Energy continues to use the consensus methodology approved by the Commission in Docket No. E-100 Sub 175 to calculate the avoided hedging value, and no party disputes this approach. Accordingly, based on the foregoing, the Commission concludes that Duke Energy's fuel hedging value is reasonable and approves its inclusion in DEC's and DEP's avoided energy rate calculation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in Duke Energy's Initial Statement and Reply Comments, the Public Staff's Initial Statement and Reply Comments; the AGO's Comments; and the Reply Comments of CCEBA, NCSEA, and SACE.

Summary of the Comments

In its Initial Statement, Duke Energy explains that the Commission's 2021 Sub 175 Order directed DEC and DEP to "explain in their next biennial avoided cost filings how the Carbon Plan has been incorporated into avoided cost rates and how any Commission-approved avoidable cost of carbon is factored into Duke's calculation of avoided cost rates."[16] According to Duke Energy, the Sub 175 Order also reiterated the Commission's expectation that inputs and assumptions used to develop avoided cost rates should be aligned with resource planning assumptions used in the Companies' most recent resource plan, which is the Companies' CPIRP as filed with the Commission on August 17, 2023, in Docket No. E-100 Sub 190.[17]

Duke Energy explains that DEC and DEP appropriately incorporated the CPIRP into their respective avoided cost rates by using data from the 2023 CPIRP Core Portfolio P3 Base (Portfolio P3), which is the reference portfolio identified in Duke Energy's most recent biennial CPIRP filed with the Commission. According to Duke Energy, using Portfolio P3 is consistent with past Commission guidance to align the avoided cost filing with the utility's most recent IRP—here, the 2023 CPIRP.[18] In its February 15, 2024 Update letter to the Commission, Duke Energy presents updates to DEC's and DEP's standard offer avoided cost rates to reflect the new P3 Fall Base reference portfolio identified in Duke Energy's Supplemental Planning Analysis in the current CPIRP proceeding, Docket No. E-100, Sub 190. Duke Energy explains that DEC's and DEP's respective updated Schedule PPs, annualized rates, and Net Excess Energy Credit (NEEC) incorporate input changes to align with new reference Portfolio P3 Fall Base while utilizing the same standardized methodology and approach used to calculate the rates filed on November 1, 2023. February 15 Letter at 1-2.

In its Initial Statement, the Public Staff supports approval of Duke Energy's avoided energy and capacity rate methods using Portfolio P3 Fall Base from the 2023 CPIRP Supplemental Planning Analysis. Public Staff Initial Statement at 50. The Public Staff further contends that, since the Sub 167 Proceeding, the costs for reducing carbon emissions have become more known and verifiable. According to the Public Staff, while Duke Energy's carbon-constrained capacity expansion plan in the CPIRP considers the carbon cap, it may not fully capture the avoided costs of carbon compliance in the future. The Public Staff references its position in Docket Nos. E-2, Sub 931; E-7, Sub 1032; and E-100, Sub 179 (DSM/EE Mechanism Review Dockets), that generation expansion plans subject to a carbon

[16] Sub 175 Order at 30 (Ordering Paragraph No. 14).

[17] Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 190 (Aug. 17, 2023).

[18] Sub 175 Order at 30 ("The Commission directs DEC and DEP to explain in their biennial avoided cost filings how they have incorporated the Carbon Plan into avoided cost calculation and rate design.").

emission limit would include lower emitting resources that reduce avoided energy costs without a commensurate increase to avoided capacity costs as calculated under the peaker method. In the DSM/EE Mechanism Review Dockets, the Public Staff noted that Commission could approve a carbon reduction benefits adder for avoided energy rates, initially set at $0 per MWh as a placeholder, and direct parties to propose a calculation methodology in the next biennial avoided cost proceeding or Duke's next CPIRP filing. *Id.* at 8-9.

In its Comments, the AGO argues that Duke Energy should use CPIRP Portfolio P1 Fall Base to calculate avoided cost rates. According to the AGO, the Commission has limited discretion to extend the Interim Compliance date beyond 2030, and it is therefore inappropriate for DEC and DEP to base their respective avoided cost rates on a portfolio that AGO argues does not meet HB 951's carbon emission reduction targets. The AGO recommends that the Commission should direct the Companies to recalculate their avoided cost calculations within 90 days of the Commission's approval of its next and subsequent CPIRPs. AGO Comments at 17-19.

The AGO also argues that Duke Energy's proposed avoided cost rates do not reflect the value of carbon emissions reductions of many QFs and thus fail to fully reflect DEC's and DEP's avoided costs as required by PURPA. AGO Comments at 8. The AGO states that carbon emission reductions in the Duke Energy's 2023 CPIRP are based on known and verifiable mass caps on carbon emissions. According to the AGO, setting a mass cap will yield a model result with an implied price on carbon, which is indicative of the cost per ton of carbon abatement. Therefore, in the AGO's view, the cost of carbon is now "known and verifiable." The AGO likens HB 951 to Virginia's previous participation in the Regional Greenhouse Gas Initiative (RGGI), arguing that the Commission previously approved an avoided cost of carbon when it approved DENC's avoided cost rates in the 2021 Sub 175 Proceeding. For these reasons, the AGO recommends that the Commission should direct Duke Energy, in consultation with the AGO, the Public Staff, and other interested intervenors, to develop a method of deriving the value of carbon emission reductions from the CPIRP to be included in avoided cost rates for carbon free QFs. AGO Comments at 11-13.

In its Reply Comments, Duke Energy notes that the Commission has long held that a utility's avoided cost rates should be based on its most recently filed integrated resource plan (IRP). Duke Energy states that it would be inappropriate for DEC and DEP to recalculate their avoided cost rates using Portfolio P1 Fall Supplemental because (1) requiring the Companies to develop avoided cost rates based on a portfolio *other than* the Companies' identified IRP reference portfolio would mark an unwarranted departure from longstanding practice in avoided cost dockets; (2) as explained in the CPIRP, Portfolio P1 Base—and, by extension, Portfolio P1 Fall Supplemental—is unattainable and not the most reasonable, least cost, and least risk planning pathway that Duke Energy is planning to execute in the future; and (3) even if Duke Energy could reliably execute P1 Fall Base Supplemental, the practical result of accelerating the incremental near-term renewable resource additions identified as needed in Portfolio P1 Fall Supplemental would have the effect of decreasing avoided energy rates since must-take PURPA QFs are marginal energy resources that are valued after recognizing the capacity and energy value of renewables planned for in an IRP. This expected decrease in the avoided energy rate would unjustly and inaccurately decrease the avoided energy rate for must-take PURPA QFs based on an amount of IRP-selected solar that the Companies do not believe is executable. Duke Reply Comments at 8-9.

Duke Energy further explains that the Commission has long held that avoided costs should be calculated using only "known and verifiable" costs, and that "speculative costs" that are not "sufficiently certain" to be avoided by customers should not be included in avoided costs.[19] According to Duke Energy, the Commission's position on this issue is informed by and consistent with FERC's guidance that only "real costs" that are actually avoidable by a utility and its customers when the utility purchases QF power are properly accounted for and included in a utility's avoided costs.[20] Duke Energy further notes that, in its Sub 175 Order, the Commission confirmed that it was "not appropriate to include an implied cost of avoided carbon emissions in DEC's and DEP's avoided cost calculation at this time" because such costs were not "known and verifiable." Duke Energy Reply Comments at 11, citing Sub 175 Order at 29.

Regarding the AGO's contention that the costs of carbon are now known and verifiable, Duke Energy explains that the mass cap modeling approach used to model the CPIRP does not result in any additional "known and verifiable" avoidable carbon emissions cost as the AGO contends. Duke Energy notes that the North Carolina General Assembly, in enacting HB 951, could have but did not choose to assign a cost of carbon emissions by establishing an explicit carbon tax or avoidable cost of carbon to be paid by customers to QFs. Instead, the General Assembly designed HB 951 to drive an orderly reduction of carbon emissions through an at-the-stack emissions reduction framework. Duke Energy further states that its customers will be disadvantaged if required to pay an avoided cost of carbon to PURPA QFs because HB 951 requires that all environmental and renewable attributes associated with new solar generation selected through the CPIRP must be conveyed to the utility for the benefit of its customers while the traditional standard PURPA contract for capacity and energy does not convey such attributes. G.S. § 62-1561(2)b. Accordingly, Duke Energy explains that

[19] Phase I Sub 140 Order, at 8 (Finding of Fact No. 14), 14 ("The costs of carbon emissions control are not sufficiently certain to be included in avoided costs at this time. If in the future carbon costs become known and verifiable, it may be appropriate for those costs to be included at that time.").

[20] *See e.g., Cal. Pub. Utility Comm'n*., 132 FERC ¶ 61, 047, 61,267-68 (July 15, 2010), *clarification granted & rehearing denied*, 133 FERC ¶ 61, 059 (October 21, 2010), *rehearing denied*, 134 FERC ¶ 61,044 (Jan. 20, 2011) (clarifying that if environmental costs "are real costs that would be incurred by utilities," then they "may be accounted for in a determination of avoided cost rates" but that "a state may not include a bonus or an adder in the avoided cost rate unless it reflects actual costs avoided[.]).

compensating QFs for an avoided cost of carbon without requiring the transfer of environmental and renewable attributes to the utility would increase costs for customers and fail to maintain customer indifference between the utility generating or purchasing power and purchasing power from a QF. *Id.* at 13.

Duke Energy also distinguishes the Commission's approval of DENC's avoided cost rates in Docket No. E-100, Sub 175, which were developed using a resource plan that incorporated RGGI's carbon price. According to Duke Energy, the RGGI sets an explicit price on carbon allowances that utilities from member states can purchase at quarterly auctions and/or buy and sell in secondary markets. In contrast, Duke Energy explains that HB 951 directs the Commission to determine and the Companies to then execute the most reasonable least cost plan to reduce carbon emissions from the generating fleet and to transition to carbon neutrality. There is no separate known and verifiable cost associated with reducing carbon emissions that purchases of non-renewable QF energy and capacity will allow the Companies to avoid. Accordingly, Duke Energy states that comparison of DENC's inclusion of the RGGI's carbon price to the carbon reduction targets of HB 951 is an apples to oranges comparison. For all of these reasons, Duke Energy states that DEC and DEP have already appropriately incorporated the CPIRP into their avoided cost rates and no additional "known and verifiable" cost of carbon exists for incorporation into their avoided cost rates. *Id.* at 13-14.

In its Reply Comments, the Public Staff agrees with Duke Energy that the Commission has historically set avoided cost rates based on the utility's most recently filed IRP using the preferred portfolio and that continuing this practice is reasonable. The Public Staff further notes that using Portfolio 1 Fall Supplemental to calculate avoided cost rates, as the AGO recommended, would result in the highest cost and highest execution risk of all three portfolios presented in the CPIRP. Public Staff Reply Comments at 3-4.

In its Reply Comments, the Public Staff also comments that no party has recommended a method for calculating an incremental value of carbon-free QF power that can be evaluated and expresses support for further assessment of this issue through a Commission-directed stakeholder process, in advance of the next avoided cost proceeding. The Public Staff also identifies that it may be appropriate to consider potential alternative methods to determine the value of carbon free QF power such as the differential revenue requirements method, which the Commission previously authorized for use in calculating utility avoided costs in North Carolina dating back to the 1991 avoided cost proceeding. *Id.* at 4-5.

CCEBA, in its Reply Comments, states its support for a stakeholder process to consider alternate methodologies for calculating the Utility's avoided costs. According to CCEBA, this stakeholder process should include efforts to accurately reflect the actual value that carbon-free resources bring to the grid. CCEBA Reply Comments at 10. According to CCEBA, improper valuation of carbon free resources fails to account for externalities and will eventually result in a disconnect between value and system planning, posing risks to ratepayers and reliability of the system. *Id*. at 12. NCSEA likewise supports a stakeholder process to develop consensus on a variety of items before the next biennial avoided cost proceeding, including the appropriate method to derive and compensate the value of carbon emission reductions. NCSEA Reply Comments at 9-10.

SACE's Reply Comments express support for the AGO's proposal to use the Commission-approved CPIRP portfolio as a basis for calculating avoided cost rates as opposed to the Companies' proposed CPIRP portfolio. SACE Reply Comments at 5. SACE also supports a stakeholder proceeding to ensure that Duke Energy's avoided cost methodology keeps pace with North Carolina's evolving electric grid and accurately captures the costs avoided by PURPA QFs. *Id.* at 4.

<u>Discussion and Conclusions</u>

As a threshold matter, this Commission has consistently approved utilities' avoided cost rates based on the most recently filed IRP. *See, e.g.*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 11 (Finding of Fact No. 24), Docket No. E-100 (Apr. 15, 2020) ("Sub 158 Order") (directing utilities to incorporate the first year of need identified in the utility's "most recently filed IRP"); Sub 148 Order at 109 (Ordering Paragraph No. 6) ("DEC, DEP, and Dominion shall, in future avoided cost proceedings propose commodity price forecast methodologies that are consistent with those proposed in the utility's most recently filed IRP."); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* at 65 (Ordering Paragraph No. 8), Docket No. E-100, Sub 140 (Dec. 17, 2015) (the "Phase I Sub 140 Order") ("[T]he generation expansion plans used in the avoided cost production cost models for the purpose of calculating avoided energy rates shall be based on IRP expansion plans that take into account only known and quantifiable costs."). No party has articulated a reasonable justification for the Commission to depart from this precedent.

The Commission considers the Utilities' avoided cost calculation methodologies and rates on a biennial basis and has never required utilities to file updated standard offer avoided cost rates following issuance of a final IRP ruling and between biennial proceedings. Doing so would create administrative inefficiency that is unnecessary given the frequency with which the standard offer rates are updated. Under the biennial Carbon Plan update process required by G.S. § 62-110.9(1), the Commission's final order on Duke Energy's proposed CPIRP is scheduled to issue on or before December 31, 2024, and Duke Energy's next biennial avoided cost filing must be submitted to the Commission just ten months later, on or before November 1, 2025. The practical result of an additional compliance filing after the CPIRP order issues, as the AGO suggests would have Duke Energy making separate filings to update their avoided cost rates and Schedule PP tariffs within months of each other. Accordingly, the Commission finds that it is reasonable for utilities to continue calculating avoided cost rates using inputs from the reference portfolio in their most recently filed IRP.

The Commission further finds, based on the foregoing evidence and the entire record in this proceeding, that it is not appropriate to include any adder or adjustment representing an implied cost of future avoidable carbon emissions in DEC's and DEP's avoided cost calculation. As the Commission has previously concluded, North Carolina ratepayers should not bear speculative or uncertain costs that will not actually be avoided through purchasing power from a QF. Instead, DEC and DEP should base their avoided costs only on "known and verifiable" costs that are actually avoidable, meaning DEC and DEP must only include an adder or adjustment to avoided costs to account for future costs that are actually avoidable by the utility and customers from purchasing QF power versus generating incremental power from utility-owned resources or purchasing energy from another source. The Commission affirms its prior findings in the 2020 Sub 167 Order and earlier Sub 140 Phase One Order that avoided costs should be calculated using only "known and verifiable" costs, and that "speculative costs" that are not "sufficiently certain" to be avoided by customers should not be included in avoided costs at this time. The Commission's determination on this issue also comports with the FERC's interpretation of the avoided cost framework under PURPA, finding that only real costs that will actually be incurred by utilities and would be avoided by QF purchases may be accounted for in determination a utility's avoided cost rates. Cal. Pub. Utility Comm'n., 133 FERC. P61,059, 61,267-61,268 (FERC October 21, 2010), *rehearing denied* 134 FERC 61,044 (Jan. 20, 2011) (clarifying that only if environmental costs "are real costs that would be incurred by utilities," then they "may be accounted for in a determination of avoided cost rates" but that "a state may not include a bonus or an adder in the avoided cost rate unless it reflects actual costs avoided[.]"). Based on the foregoing, DEC and DEP have appropriately calculated avoided energy costs based on their current CPIRP reference portfolio, which does not include any adder or increase in avoidable costs resulting from purchases from a QF that may avoid future carbon emissions on the DEC and DEP systems.

The Commission also does not agree with the AGO's and SACE's generalized assertions that carbon emission-related costs now are "known and verifiable" in light of the Commission-approved 2022 Carbon Plan. As Duke Energy notes, the mass cap modeling approach used to model the CPIRP reasonably reflects the actual, avoidable costs of DEC's and DEP's future system operations and does not result in a "known and verifiable" avoidable carbon emissions cost like the explicit price on carbon allowances set through the RGGI and previously included in DENC's avoided cost rates. The Commission also notes that DENC's updated avoided cost rates presented in this proceeding no longer incorporate any implied or assumed avoidable cost of carbon in light of the Commonwealth of Virginia's decision to exit RGGI effective December 31, 2023. Because DENC customers will no longer avoid any future real or known and verifiable cost associated with RGGI compliance by purchasing power from QFs—similar to Duke Energy's customers—the Commission's determination in this proceeding is reasonable and consistent between the respective utilities in its implementation of avoided costs.

In addition to finding that there is no known and verifiable cost of future carbon emissions that a QF would avoid, the Commission also agrees with Duke Energy that it would be unjust and unreasonable to Duke Energy's customers to compensate QFs for avoiding future carbon emissions on Duke Energy's system because, absent negotiated agreement otherwise, PURPA QFs are not required to convey environmental and renewable attributes to the utility. In contrast to controllable renewable resources procured through execution of the CPIRP under G.S. § 62-110.9(2)(b), a QF asserting its rights to sell power (energy and capacity) under PURPA retains the environmental and renewable attributes associated with its generation sold to DEC or DEP and may claim, retire or separately seek to sell those attributes to customers other than Duke Energy. Accordingly, in addition to finding that Duke Energy has appropriately accounted for future system costs avoidable by QFs through the CPIRP modeling process, there is also no cost avoided by Duke Energy and its customers associated with purchasing carbon free energy from QFs, as Duke Energy does not receive and cannot claim the environmental and renewable attributes associated with QF power purchased under PURPA's mandatory purchase obligation avoided cost framework. Based on the foregoing, DEC and DEP have reasonably and appropriately applied the peaker method in this proceeding to determine the avoidable capacity and energy cost of QF power based upon their most recently filed CPIRP and the Commission does not find based on the current record any incremental or additional known and verifiable costs that non-carbon emitting QFs will allow DEC or DEP to avoid. The Commission also appreciates the Public Staff's continued focus on this issue to ensure that avoided cost rates remain accurately calculated and non-discriminatory for the benefit of QFs and just and reasonable to the customers that are obligated to pay avoided costs for QF purchases. Accordingly, while the Commission declines to initiate a formal stakeholder process as recommended by some parties, the Commission will direct Duke Energy to further consider this issue as part of its assessment of the continued use of the peaker methodology through discussions with the Public Staff in advance of the 2025 avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

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

Summary of the Comments

Duke Energy's Initial Statement notes that DEC's and DEP's Schedule PP rates, as approved in 2021 Sub 175 proceeding and prior proceedings, include avoided energy credits that vary depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. In the past, Duke Energy explains, DEC and DEP have consistently supported offering different avoided energy credits based on the point of interconnection to DEC's and DEP's systems, because this approach more accurately reflected differences in DEC's or DEP's actual avoided costs due to differences in avoided energy line losses for transmission level and distribution level QFs. Initial Statement at 24-25.

Duke Energy further reports that in the 2021 Sub 175 proceeding, it evaluated the geographic concentration of backfeeding substations and found that both DEC and DEP are currently experiencing increasing levels of backflow into the transmission system due to increasing QF solar generation. Initial Statement at 24-25. Duke Energy notes that its updated backflow analysis found 26% of substation banks are backfeeding into transmission system for DEP and 4.7% for DEC. Initial Statement at 26. Duke Energy proposes to maintain the line loss adder for standard offer-eligible QFs contracting under Schedule PP and continue to evaluate negotiated QFs on a case-by-case basis per the previously approved methodology. Initial Statement 26-27. The Public Staff supports Duke Energy's continued inclusion of the line loss adder for the standard offer avoided cost rate and recommends Commission approval of the same. Public Staff Initial Statement at 48. No other party commented on this issue.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission finds Duke Energy's inclusion of the line loss adders for the standard avoided cost rates to be reasonable and appropriate. The Commission further approves Duke Energy's proposal to continue evaluating negotiated QFs on a case-by-case basis per the methodology approved by the Commission in the 2021 Sub 175 proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-18

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

Summary of the Comments

In its Initial Statement, Duke Energy notes that the avoided costs (and the potential for increased ancillary service costs) associated with integrating incremental solar generation has been an issue of significant importance in recent avoided cost proceedings as North Carolina has experienced significant growth in utility-scale QF solar interconnected with and injecting power into the Companies' systems. Initial Statement at 27. Duke Energy explains that since the last three avoided cost proceedings, the Commission has approved its proposed integration service charge specific to integrating new intermittent solar energy generation into the Companies' systems, which were conducted Astrapé Consulting in 2018 and 2021. Initial Statement at 27. For this proceeding, Duke Energy again retained Astrapé to conduct the 2023 SISC Study,[21] and Astrapé followed the same methodology to prepare revised SISC quantifications as supported by the Technical Review Committee ("TRC") and approved by the Commission in its 2021 Sub 175 Order. Initial Statement at 27-29. Duke Energy also notes that the 2023

[21] Duke Energy attaches the 2023 SISC Study as DEC/DEP Exhibit 10 to its Joint Initial Statement.

SISC Study complied with the 2021 Sub 175 Order directive to consider the impact of SEEM and address appropriate operating reserve levels. Initial Statement at 29. Based on Astrapé's 2023 SISC Study, the Companies have incorporated solar integration cost decrements of $1.09 per MWh for DEC and $1.62 per MWh for DEP into the uncontrolled solar avoided energy rates. Initial Statement at 28-29. Further, consistent with 2021 Sub 175 Order directive, Duke Energy reports that no QFs have attempted to avoid the SISC. Duke Energy Initial Statement at 30.

In its Initial Statement, the Public Staff notes that Duke Energy satisfied the requirements of the 2018 Sub 158 Order and incorporated significant feedback from the TRC into the 2023 SISC Study and recommends that the Commission approve Duke Energy's proposed SISCs. Public Staff Initial Statement at 40-41. The Public Staff also recommends that the Commission direct Duke Energy to (1) file a report on QFs attempting to avoid the SISC in future avoided cost proceedings; and (2) address QFs seeking SISC avoidance in fuel rider direct testimony, including by providing the specific facilities and amount of SISC credit issued, supporting workpapers, and reports on any audits performed on QFs attempting to avoid the SISC. Public Staff Initial Statement at 52.

In its Reply Comments, Duke Energy states that it agrees to report on QFs attempting to avoid the SISC as recommended by the Public Staff. Duke Energy Reply Comments at 26. No other party commented on these issues.

Discussion and Conclusions

In the 2021 Sub 175 Order, the Commission noted that its 2018 Sub 158 Order directed Duke Energy to assemble a technical review committee to provide a further review of Astrapé's SISC Study and also outlined the scope of this review. 2021 Sub 175 Order at 37. Based on its review of the 2023 SISC Study, the Commission agrees with the Public Staff that the 2023 SISC Study incorporated significant feedback from the TRC. Accordingly, the Commission approves Duke Energy's SISC as presented in the 2023 SISC Study. The Commission also agrees with the Public Staff's recommendations regarding SISC avoidance. The Commission therefore directs Duke Energy to file a report on QFs that attempt to avoid the SISC, and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in Duke's service territories in future avoided cost filings, and also directs Duke Energy to address QFs seeking SISC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of SISC credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 19

The evidence supporting this finding of fact is found in Duke Energy's Reply Comments, the Public Staff's Initial Statement and Reply Comments, CCEBA's

Initial Comments and Reply Comments, NCSEA's Initial Comments and Reply Comments, and SACE's Initial Comments and Reply Comments.

Summary of the Comments

In its Initial Statement, the Public Staff addresses Duke Energy's Inverter-Based Resource (IBR) Testing Report (IBR Report) filed on August 1, 2023 in Docket No. E-100, Sub 175. According to the Public Staff, the IBR Report describes Duke Energy's efforts to provide ancillary services using its Elm City and Monroe solar facilities and the Asheville Rock Hill battery. The Public Staff notes that Duke Energy stated in the IBR Report that further study and testing of different Duke-owned IBR resource types such as standalone batteries and solar plus storage, will help determine whether a pilot program would be worthwhile. The Public Staff states that its review of the IBR Report reveals the need for research using larger scale batteries, which are not subject to the sunlight variations that affect solar facilities. Public Staff Initial Statement at 12-13.

CCEBA, in its Initial Comments, states that study performed by Duke was too limited and substantially failed to address the actual performance over longer periods of these inverter-based resources. SACE recommends that the Commission should direct Duke to conduct additional, comprehensive testing and to work with stakeholders to design the study, rather than relying on a limited analysis of a few of its own resources. CCEBA Initial Comments at 5.

In its Initial Comments, NCSEA likewise opines that Duke should conduct further testing on the ability of IBRs to provide ancillary services, including potential benefits of solar paired with storage. To design future testing, NCSEA recommends that Duke Energy should engage with stakeholders regarding the types of equipment Duke intends to test and the design(s) of the testing. NCSEA also recommends that the Commission should require regular studies given continuing rapid evolution of technology. According to NCSEA, the IBR Test Report identified that IBRs are already providing reactive power management and voltage support without compensation. NCSEA recommends that Duke should launch a pilot program to determine the actual reactive power management/voltage support IBRs would provide if appropriately compensated. NCSEA Initial Comments at 20-21.

Duke Energy explains in its Reply Comments that the IBR Report showed that it is infeasible for standalone solar to provide measurable ancillary services such as active power regulation on a partly to mostly cloudy day and that, instead, solar facilities *actually increased* the need for ancillary services from conventional resources during cloudy days.[22] The Report further concluded that additional testing with different and larger utility-owned IBR resource types (including

[22] *Id.* at 17.

standalone batteries and solar plus storage) would be useful to more "thoroughly evaluate the capabilities of IBRs to provide certain ancillary services."[23]

Duke Energy notes that the IBR Report did not identify a timeline for conducting additional testing but explains that larger scale batteries would need to be added to DEC's and/or DEP's systems before additional testing could produce meaningful results. In other words, Duke Energy anticipates that additional testing and study could take place in 2025 after a battery storage facility of 25 MW has been connected to the DEC system and a battery storage facility of 30 MW has been connected to the DEP system. Duke Energy additionally proposes that further testing of its IBR resources should be evaluated in the CPIRP proceeding—and not the avoided cost proceeding—as part of Duke Energy's ongoing planning and execution efforts that must maintain or improve the reliability of their system. Duke Energy Reply Comments at 15-16.

With respect to NCSEA's recommendation to launch a pilot program, Duke Energy explains that FERC has already considered and rejected the idea of compensating QFs for providing reactive power when it established the *pro forma* Large Generator Interconnection Procedures and Large Generator Interconnection Agreement in Order No. 2023 and *required* all generating facilities to provide reactive power within a specified range.[24] FERC explained its determination in a subsequent case, noting that "[w]here a transmission provider does not separately compensate its own or affiliated generators for reactive power service within the deadband, it need not separately compensate non-affiliated (IPP) generators for reactive power service within the deadband."[25] According to FERC:

> [A]n interconnecting generator should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation. Providing reactive power within the deadband is an obligation of a generator, and is as much an obligation of a generator as, for example, operating in accordance with Good Utility Practice.[26]

Duke Energy explains that the same logic applies here. Because Duke Energy does not compensate its own fleet generators for reactive power service, it would

[23] *Id*.

[24] *See* Order No. 2003, FERC Stats. & Reg. ¶ 31,146 at P 546 (2003); *see also* Order No. 827 at 29, P 34.

[25] *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007).

[26] *Id.* at P 29.

not be appropriate to provide reactive power compensation to QFs simply for reliably operating in parallel with Duke Energy. *Id.* at 16-18.

In its Reply Comments, the Public Staff agrees with Duke Energy that there is not enough QF storage on the DEC and DEP systems to support further IBR study at this time. The Public Staff also agrees with Duke Energy that the appropriate timing for the study should be determined in the CPIRP docket. The Public Staff states that it will request that the Commission require a study at the appropriate time. Public Staff Reply Comments at 7-8.

NCSEA's Reply Comments reiterate its recommendation for a more thorough study of ancillary services provided by IBRs. NCSEA further recommends that Duke should scope a pilot program that accurately compensates IBRs for the reactive power management and voltage support ancillary services they already provide. Finally, NCSEA requests that conducting an ancillary services study should become an iterative study with stakeholder input. NCSEA Reply Comments at 4.

CCEBA, in its Reply Comments agrees with NCSEA that more robust testing is needed to determine the value of ancillary services provided by IBR resources. CCEBA suggests that the Commission should require more robust testing of solar, solar plus storage, and standalone storage resources before the next proceeding and that IBR testing should be conducted with input from stakeholders. CCEBA argues that a pilot program to determine the value of reactive power and/or voltage supports provided by IRBs would be helpful. *Id*. at 14.

SACE likewise supports further study of IBR resources in its Reply Comments. According to SACE, the Commission should ensure that the information it relies on to make decisions about the potential value of solar plus storage and standalone storage facilities accurately captures their full value. Finally, SACE agrees with the Public Staff that more research regarding larger batteries is needed to determine the ancillary services potentially provided by IBRs. SACE Reply Comments at 3-5.

Discussion and Conclusions

Duke Energy and the Public Staff are aligned in their view that this issue is more appropriately considered in the CPIRP docket and that larger scale batteries are needed on DEC's and DEP's systems before additional testing of IBR resources could produce meaningful results. Recognizing that Duke Energy anticipates that additional testing and study could take place in 2025 following the interconnection of a planned 25 MW battery storage facility to the Duke Energy system, the Commission will not order any immediate additional study. The Commission recognizes the significant efforts Duke Energy took to prepare the initial pilot study and does not find there to be any utility in further testing before

Duke Energy is able to interconnect larger scale batteries to the system. In addition, the Commission agrees with the Public Staff and Duke Energy that issues related to the testing of IBR resources to provide ancillary services to the Duke Energy system are more appropriately addressed in CPIRP dockets going forward, as no party has explained how a QF owner-controlled IBR or battery system can provide ancillary services to Duke Energy's system.

Based on the evidence presented herein, the Commission finds that Duke Energy's avoided cost rates fully compensate QFs for delivering energy and capacity, and no party has presented evidence that incremental compensation for ancillary services, even if feasible to be reliably provided by uncontrolled QF IBR generators, is required or appropriate under PURPA. The Commission is also persuaded by FERC precedent cited by Duke Energy that it would be inappropriate to compensate QFs for providing reactive power management and voltage support. FERC has held that "[w]here a transmission provider does not separately compensate its own or affiliated generators for reactive power service within the deadband, it need not separately compensate non-affiliated (IPP) generators for reactive power service within the deadband." Here, the uncontroverted evidence demonstrates that Duke Energy does not compensate its fleet generators for reactive power service. Accordingly, it would be inappropriate for Duke Energy to provide reactive power compensation to QFs that operate in parallel with the DEC and DEP systems.

AS-AVAILABLE RATES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 20

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

Summary of Comments

In its Initial Statement, Duke Energy explains that the consistent with FERC Order No. 872, Duke Energy updated its respective Schedule PP tariffs in the 2021 Sub 175 proceeding to use the hourly marginal cost of producing energy to calculate avoided costs for QFs that elect to sell energy to it on an "as-available" basis. Initial Statement at 32. Duke Energy states that its Schedule PP for this proceeding replaces the phrase "Marginal Cost Rate" with "As-Available Rate" to align with the terminology used in FERC's regulations and with DEC's and DEP's avoided cost rate tariffs filed with the South Carolina Public Service Commission. Initial Statement at 32. Duke Energy further notes that it is offering "as-available" rates calculated using the same methodology that the Commission approved in its Sub 175 Order and that it is retaining the Two-Year Fixed Rate contract option that exists under the Schedule PP approved in the 2021 Sub 175 Order. Initial Statement at 32.

In its Initial Statement, the Public Staff supports Duke Energy's As-Available Rate calculation. Public Staff Initial Statement at 19-20. No other party comments on Duke Energy's As-Available Rates.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission accepts Duke Energy's calculation of As-Available Rates as reasonable, appropriate, and consistent with the methodology approved in the 2021 Sub 175 Order. The Commission finds Duke Energy's nomenclature adjustment to be appropriate. Finally, the Commission finds reasonable and appropriate Duke Energy's retention of the Two-Year Fixed Rate contract option under its Schedule PP.

SCHEDULE PP RATE DESIGN

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-22

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

Summary of the Comments

In its Initial Statement, Duke Energy explains that Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity is paid on a ¢/kWh basis versus a separate fixed payment for capacity).[27] According to Duke Energy, the rates are designed to credit QFs for avoided energy supplied during pre-designated on-peak and off-peak hours. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak, premium-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours. Duke Energy Initial Statement at 33.

Duke Energy also explains that in the 2018 Sub 158 proceeding, DEC and DEP initially proposed an updated Schedule PP rate design that eliminated the pre-existing Option A and Option B rate structures and proposed more granular rate designs to better recognize the value of QF energy and capacity. In the 2018 Sub 158 proceeding, Duke Energy and the Public Staff filed a Partial Settlement on April 18, 2019, agreeing on the appropriate avoided energy and avoided capacity rate design methodologies (Sub 158 Rate Design Stipulation) for use in the Sub 158 and future proceedings that sought to better balance the need for a granular rate design with providing Schedule PP customers clear and consistent price signals through the term of customers' contracts. The Sub 158 Order approved the Sub 158 Rate Design Stipulation and found the rate designs included therein to be appropriate for use in calculating DEC's and DEP's avoided energy

[27] Due to the smaller size of QF Sellers under the standard offer, the Schedule PP rates are technically paid on ¢/kWh basis.

and capacity rates. Duke Energy explains that it has utilized the same rate design in both the 2020 Sub 167 and 2021 Sub 175 proceedings, and the Commission has approved the same. Duke Energy Initial Statement at 34.

Duke Energy explains that in this proceeding, it is continuing to utilize the standardized Commission-approved avoided energy rate design methodology outlined in the Sub 158 Rate Design Stipulation. Based on the Rate Design Stipulation's review process for the continued appropriateness of the rate design, Duke Energy is also proposing some adjustments to the hourly definitions within the existing nine (9) energy price blocks for both DEC and DEP to better align with forecasted energy values. *Id.*

Duke Energy explains that, under the Sub 158 Rate Design Stipulation, QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent with the approach Duke Energy has historically utilized with respect to QF rate design under prior vintages of Schedule PP. The Public Staff and Duke Energy agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize the DEC's and DEP's seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé 2018 Solar Capacity Value Study. Astrapé completed a new resource adequacy study in 2023 (2023 Resource Adequacy Study)[28] and Duke Energy has used the loss of load risk identified in this more recent study for updating the avoided capacity rate design in this proceeding. *Id.* at 35.

According to Duke Energy, the Sub 194 Schedule PP capacity rate design reflects updated pricing periods to most accurately reflect the marginal capacity value to customers during each period. Duke Energy explains that based on results from the 2023 Resource Adequacy Study, the loss of load risk for both DEC and DEP is now exclusively in the winter periods and thus the prior summer PM capacity payment period for DEC has been discontinued. The loss of load risk is concentrated in the winter months of December through February and the prior capacity payment month of March has been discontinued for both DEC and DEP. The capacity payment period for both utilities consists of defined AM hours for each utility during the winter months of December through February. *Id.* at 35-36.

Duke Energy notes that the seasonal allocation of capacity value remains heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. DEP's loss of load risk is 100% Winter, which is unchanged from that approved in the Sub 175 Order. DEC's loss of load risk is also now 100% winter based on the new 2023 Resource Adequacy Study and

[28] The 2023 Resource Adequacy Study was included as Attachment I to the 2023 CPIRP filed in Docket No. E-100, Sub 190.

increased from 96% winter in the 2021 Sub 175 proceeding based on the 2020 Resource Adequacy Study. *Id.* at 36.

In its Initial Statement, the Public Staff states that it supports Duke Energy's proposed modifications to DEC's and DEP's rate design as consistent with the intent of the Sub 158 Rate Design Stipulation. Public Staff Initial Comments at 38-39. The Public Staff also supports the capacity seasonal allocation factors proposed in this proceeding to be reasonable. Public Staff Initial Comments at 28. No other party commented on this issue.

<u>Discussion and Conclusions</u>

In the 2016 Sub 148 Order, the Commission observed that "avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities." 2016 Sub 148 Order at 56. The Commission therefore required the Utilities to consider refinements to the avoided capacity rate and to address these refinements in the Sub 158 proceeding. *Id*. The Commission directed the Utilities to consider "a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods." *Id.*

In the 2018 Sub 158 Scheduling Order, the Commission similarly directed the Utilities to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules." 2018 Sub 158 Scheduling Order at 1-2. In response to those directives, Duke Energy and the Public Staff worked together through the course of the Sub 158 Proceeding to reach the Sub 158 Rate Design Stipulation, which was approved by the Commission. 2018 Sub 158 Order at 25. As explained in the Sub 167 Order, the Commission specifically approved the Sub 158 Rate Design Stipulation because (1) the Commission found merit in the general approach utilized by the Public Staff to develop granular pricing methods for avoided energy that more accurately reflect Duke Energy's highest production cost hours and loads to increase the likelihood that the interests of ratepayers and developers of QF generators align; (2) the modifications made through discussions between the Public Staff and Duke Energy to further refine the rate design approach, as memorialized in the Sub 158 Rate Design Stipulation, struck an appropriate balance between accurate avoided cost pricing, administrative efficiency, and the general acknowledgment that these factors will continue to change over time; and (3) the stipulated rate design was the result of a methodological approach to evaluate system costs and impacts as described in the Rate Design Stipulation and properly aligned price signals provided in the rate design with Duke Energy's avoided energy costs. Sub 167 Order at 39-40.

In this proceeding, based upon the foregoing and the entire record herein, the Commission finds that Duke Energy has adhered to the intent of the Sub 158

Rate Design Stipulation in proposing its avoided energy and avoided capacity rate design and appropriately utilized the loss of load risk identified in Duke Energy's most recent 2023 Resource Adequacy Study for updating the avoided capacity rate design to fairly and accurately value QF energy delivered to DEC and DEP.

For purposes of this proceeding, the Commission approves DEC's and DEP's rate design and resulting avoided energy and capacity rates, as updated using the 2023 Resource Adequacy Study and as presented in Duke Energy's Initial Statement. The Commission also approves DEC's and DEP's seasonal allocation of capacity value of 100% to winter. The Public Staff supports, and no other parties take issue with, Duke Energy's Initial Statement on these issues.

STANDARD OFFER TERMS AND CONDITIONS

EVIDENCE AND CONCLUSIONS TO SUPPORT FINDINGS OF FACT NOS. 23-25

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

Summary of the Evidence

In its Initial Statement, Duke Energy explains that it has made limited and minor modifications to its Schedule PP consisting of administrative revisions, such as adjusting the current docket number, revisions related to naming conventions, and minor clarifications regarding QFs that elected to receive the Variable Rate and those electing As-Available Rates. Initial Statement at 38. For its Terms and Conditions for the Purchase of Electric Power, Duke Energy proposes to revise: (1) Section 1 and Section 3 to further define the notification and administrative requirements for a change of control and Duke Energy's right to terminate; (2) Section 6 to adjust the calculation methodology in the event of an early contract termination; (3) Section 9 to limit the period for billing adjustments due to error to three (3) years; and (4) Section 13 to clarify the triggering date of the Seller's obligation to pay the Interconnection facilities charges. Initial Statement at 38. Duke Energy also explains that its revised standard offer PPA forms now refer to the renamed As-Available Rates and Two-Year Fixed Rates and contain updated contact information. Initial Statement at 39. Regarding its Notice of Commitment Forms for Standard Offer and Large QFs, Duke Energy notes that the Commission approved its revised Notice of Commitment Form in the 2021 Sub 175 Proceeding. Initial Statement at 40-41. In this proceeding. Duke Energy proposes to more clearly define the "Submittal Date" and for Small QF Notice of Commitment Form, more clearly state the applicable interconnection requirements. Initial Statement at 41.

In its Initial Statement, the Public Staff supports all of Duke Energy's adjustments to its tariffs and Terms and Conditions. Public Staff Initial Statement at 49-53. No other party commented on these issues.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission approves Duke Energy's modifications to its Schedule PPs, Terms and Conditions, standard offer PPA, and Notice of Commitment Forms.

ENERGY STORAGE SYSTEM RETROFIT RATES

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 26

Summary of the Comments

In its Initial Statement, Duke Energy proposes to discontinue the predetermined Energy Storage System (ESS) Retrofit Rates after November 1, 2023. Duke Energy explains that DEC and DEP first proposed an ESS Retrofit framework in its September 29, 2021 Compliance Filing in Docket Nos. E-100, Sub 101 and E-100, Sub 158. According to Duke Energy, the Compliance Filing provided that to establish eligibility for published ESS Retrofit avoided cost rates, an ESS Retrofit project must submit a Notice of Commitment Form prior to November 1, 2023 and that published ESS Retrofit Rates would remain available until the earlier of November 1, 2023, or when 100 MW of incremental ESS retrofit additions have submitted Notice of Commitment forms under the new rates. Finally, the Compliance Filing provided that any ESS Retrofit project that submits a Notice of Commitment Form after November 1, 2023 would be eligible for a negotiated rate based on the most recent Commission-approved avoided cost methodology and rates available for the ESS Retrofit project. Duke Energy Initial Statement at 42-43.

Duke Energy explains that the Commission approved the Companies' proposal for eligibility for ESS Retrofit rates in its May 12, 2022 Order Granting Waivers to Implement Energy Storage System Expedited Study Processes and Approving Process to Establish Eligibility of avoided Cost Rates for Retrofit Energy Storage Systems (the ESS Retrofit Order). According to Duke Energy the ESS Retrofit Order The Commission further directed the Companies to "submit a report on the status of ESS Retrofit projects with sufficient information for the Commission to determine if the eligibility for avoided cost rates should be expanded to include QFs with LEOs established after November 1, 2016." ESS Retrofit Order at 5. The Commission further clarified that it "will revisit the eligibility for QFs with a LEO established after November 15, 2016, and the availability of standard rates for ESS Retrofits that submit a NOC after November 1, 2023, once Duke provides information regarding the implementation of the ESS Retrofit process through the reports required in this order." Duke Energy Initial Statement. at 43.

Pursuant to the ESS Retrofit Order, on January 23, 2023, DEC and DEP filed their Update Regarding Expedited Study Processes Available to ESS Retrofit in Docket Nos. E-100 Sub, 101 and E-100 Sub 158, notifying the Commission that there was no relevant data to report given the absence of any ESS Retrofit projects participating in the 2022 DISIS Phase 1 study. On July 31, 2023, DEC and DEP filed a second update informing the Commission that the Companies still had not received any ESS Retrofit project applications or Notice of Commitment Forms. Duke Energy Initial Statement. at 44.

Duke Energy states that, to date, no party has requested extension of the ESS Retrofit eligibility window and the Commission has not made any additional rulings on the matter. In addition, as of the date of this Joint Initial Statement, there continue to be no QFs that have submitted a Notice of Commitment Form or otherwise elected to receive ESS Retrofit Rates. Consistent with the ESS Retrofit Order, eligibility for the ESS Retrofit rates that the Commission approved in the 2021 Sub 175 proceeding expired on November 1, 2023. Based upon the foregoing considerations, Duke Energy is proposing to discontinue the predetermined ESS Retrofit Rates after November 1, 2023. Consistent with Duke Energy's proposal in the Compliance Filing and the ESS Retrofit Order, Duke Energy explains that QFs that submit their Notice of Commitment Forms after November 1, 2023, will be eligible for a negotiated rate calculated at the time the Notice of Commitment Form is submitted based on the most recent Commission-approved avoided cost methodology. *Id.* at 44.

In its Initial Statement, the Public Staff agrees with Duke Energy's proposal to discontinue its ESS Retrofit Rates, noting the lack of interest by QFs and the adoption of cluster studies under queue reform. The Public Staff notes that any QF wishing to add battery storage to an existing facility can submit an interconnection request to one of Duke Energy's annual Definitive Interconnection System Impact Study clusters. Public Staff Initial Statement at 12-13.

In its Initial Comments, NCSEA contends that the lack of applications in the ESS Retrofit program is not due to a lack of interest from eligible QFs. According to NCSEA, the framework of the program combined with macroeconomic conditions beyond the control of eligible QFs prevented eligible facilities from having the economic certainty and incentives to pursue this offering. Accordingly, NCSEA recommends that Duke Energy should continue to offer predetermined ESS Retrofit Rates to QFs that renew their PPA for an additional term and agree to materially alter the existing facility by co-locating a battery energy storage system. NCSEA proposes to amend the ESS Retrofit framework by limiting ESS Retrofit avoided cost rates to QFs that renew their PPA for a subsequent term and developing only one set of rates (the 10-year ESS Retrofit avoided cost rates) as opposed to current framework, which includes nine separate sets of rates. NCSEA recommends that the Commission order Duke Energy to develop updated predetermined ESS rates for consideration in the 2025 avoided cost proceeding and recommends amending the current framework. NCSEA Initial Comments at 5-11.

CCEBA, in its Initial Comments, likewise opposes Duke Energy's proposed discontinuation of the predetermined ESS Retrofit Rates after November 1, 2023. CCEBA agrees with NCSEA that it is too early to determine whether QFs will seek to capitalize on the opportunity provided by these rates, particularly in light of the confluence of macroeconomic factors that have affected the energy and storage market since the ESS Retrofit Option was put in place in the E-100 Sub 175 Docket in 2022. CCEBA Initial Comments at 10.

In its Reply Comments, Duke Energy states that NCSEA's proposal (which CCEBA supports) would require the Companies to pay "renewing" QFs that elect to add energy storage at rates *above* the Companies' avoided costs and for future contract terms that do not align with North Carolina law limiting negotiated QF PPAs to rates established for "a fixed five-year term."[29] Duke Energy explains that in its Sub 175 Order, the Commission approved the Public Staff's bifurcated rate proposal, which required QFs to separately meter energy output from their original facility and new battery storage system. Under this bifurcated rate design, energy from an existing facility was to be compensated pursuant to the rate set forth in the original PPA, while energy from any energy storage system was to be compensated at then-current avoided cost rates. Importantly, however, these rates were available only for the remaining term of the QF's existing PPA entered into prior to enactment of HB 589's revisions to the State's PURPA implementation framework. In proposing that Duke Energy should develop new, predetermined ESS Retrofit Rates which will become available only upon the expiration of an existing PPA, Duke Energy states that NCSEA is implicitly suggesting that Duke Energy should pay these existing facilities for a new PPA term at avoided costs fixed for longer than five years, presumably to incentivize the addition of energy storage. Duke Energy Reply Comments at 28.

Duke Energy notes that the "must purchase" obligation under PURPA requires utilities to offer to purchase QF power at just and reasonable rates that make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives. Accordingly, at the expiration of the contract term, the existing facility, with or without new energy storage, would be eligible for Duke Energy's avoided cost rates available at that time and there is no need to develop any separate, special ESS Retrofit Rates. Duke Energy states that it continues to believe that the most appropriate course is to offer negotiated rates to QFs electing to add storage to their existing facility at the expiry of their current PPA term consistent with North Carolina law implementing PURPA. *Id.* at 28-29.

In its Reply Comments, the Public Staff recommends that Duke Energy initiate a voluntary competitive solicitation for energy storage co-located at existing QFs. The Public Staff advocates for this approach in lieu of updating ESS Retrofit rates in the next avoided cost proceeding as recommended by NCSEA and

[29] N.C.G.S. § 62-156(c)

CCEBA. The Public Staff notes that it intends to expand on this recommendation in its CPIRP testimony. Public Staff Reply Comments at 13.

NCSEA, in Reply Comments, asks the Commission to adopt the proposed amended framework for ESS Retrofit rates that NCSEA proposed in its Initial Comments. NCSEA notes that fixed ESS Retrofit rates ensure that existing solar QFs remain on Duke system and that the Companies are maximizing the use of existing solar QFs to improve the management of the grid. Accordingly, NCSEA recommends that the Commission direct Duke to develop new predetermined ESS Retrofit Rates to be considered in the next avoided cost proceeding. NCSEA Reply Comments at 2-3.

CCEBA's Reply Comments indicate support for NCSEA's recommendation to develop updated predetermined ESS rates for consideration in the next avoided cost proceeding. CCEBA further supports amending the current ESS Retrofit rate structure to encourage addition of storage by offering these rates to QFs that agree to renew their PPA and co-locate a battery energy storage system. CCEBA believes that offering standard ESS Retrofit rates is a more efficient contracting mechanism for QFs than engaging in PPA negotiations. CCEBA Reply Comments at 5.

SACE also supports NCSEA's proposal regarding ESS Retrofit Rates. In its Reply Comments, SACE notes that a standard ESS retrofit rate will streamline the process for adding storage to the Companies' significant existing solar fleet, which will improve capacity value and help meet peak demand at lower cost. SACE Reply Comments at 5.

<u>Discussion and Conclusion</u>

As a threshold matter, under the existing Commission-approved framework, DEC's and DEP's ESS Retrofit Rates expired as of November 1, 2023. Duke Energy's September 29, 2021 Compliance filing in Docket Nos. E-100, Sub 101 and E-100, Sub 158 and approved by the Commission on May 12, 2022 clearly provided that DEC's and DEP's predetermined ESS Retrofit Rates would be available to eligible QFs that submitted a Notice of Commitment Form prior to November 1, 2023 and would remain available until "the earlier of November 1, 2023 or when 100 MW of incremental ESS retrofit additions have submitted Notice of Commitment forms under the new rates."[30] Because no QFs submitted a Notice of Commitment Form in the prescribed time period, DEC's and DEP's ESS Retrofit Rates expired on November 1, 2023.

Despite discontinuation of the predetermined rate, however, QFs interested in adding battery energy storage may still obtain avoided cost rates from DEC or DEP, consistent with North Carolina's framework for implementing PURPA, and would be eligible for a negotiated rate based on the most recent Commission-

[30] *Id*. at 5.

approved avoided cost methodology. Accordingly, the Commission declines to require Duke Energy to develop new ESS retrofit rates as recommended by NCSEA and CCEBA.

<u>NET ENERGY METERING</u>

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-28

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

<u>Summary of the Comments</u>

In its Initial Statement, Duke Energy explains that Net Energy Metering (NEM) customers who export power are compensated at a Net Excess Energy Credit (NEEC) pursuant to DEC's and DEP's revised NEM Tariffs approved by the Commission in Docket No. E-100, Sub 180. Duke Energy explains that in the 2021 Sub 175 proceeding, the Public Staff proposed that calculation of the NEEC should be determined in the Companies' biennial avoided cost proceedings. Duke Energy did not object to this proposal, and the Commission subsequently directed the Companies to file for Commission approval their respective NEECs and calculation methodology in future biennial avoided cost proceedings.[31] Duke Energy Initial Statement at 41-42.

Duke Energy explains that the Commission first approved DEC's and DEP's' proposed NEECs in its August 3, 2023 Order Establishing Net Excess Energy Credit for NEM Tariff in Docket No. E-100, Sub 175 (the "2023 NEEC Order"). Those rates became effective October 1, 2023. Duke Energy explains that DEC's and DEP's proposed updated NEECs are calculated based on a five-year term in a consistent manner with the two- and 10-year fixed term rates shown on Schedule PPs. The five-year rates are then weighted based on a typical rooftop solar production profile to determine an annual value. The annual value includes an energy component, and a capacity component when applicable. For this docket, Duke Energy explains that 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.* at 42. In its February 15, 2024 letter to the Commission, Duke Energy explains that it updated DEC's and DEP's NEEC to reflect CPIRP reference Portfolio P3 Fall Base.

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[31] Order Establishing Net Excess Energy Credit for NEM Tariff, Docket No. E-100, Sub 175 at 4 (Aug. 4, 2023); Sub 180 NEM Order at 41.

In its Initial Statement, the Public Staff explains that the NEEC is used to compensate net metered customers for excess generation in avoided cost proceedings, recognizing that net metered customers sometimes generate excess energy credit that is based on avoided costs. The Public Staff explains that the NEEC reflects avoided energy and avoided capacity calculated over a five-year term, inclusive of the distribution line-loss adder and fuel hedging value, with energy rates weighted to a generic rooftop solar output profile. The Public Staff recommends that the Commission approve DEC's and DEP's NEECs as reflected in their February 15, 2024 update filing. Public Staff Initial Statement at 14.

SACE attaches to its Initial Comments the Comments of Justin Barnes, President of EQ Research. On behalf of SACE, Mr. Barnes recommends several refinements to the calculation of the NEEC that he recommends will properly value electricity exported to the grid by net metered generation. First, Mr. Barnes argues that Duke Energy should utilize a 10-year NEEC calculation term. Mr. Barnes notes that the Commission approved the use of a 5-year time horizon to calculate the NEEC based on the recommendation of the Public Staff, which expressed concern that a 10-year term may be too long since there is no contractual obligation for a net metered facility to operate for that term. Mr. Barnes argues that even in the absence of a contract, a net metered solar system can reasonably be expected to operate for at least 20 years. According to Mr. Barnes, this assumption is consistent with Duke Energy's CPIRP, which assumes that a new net metering system installed in 2023 will continue to operate through 2050. Mr. Barnes further notes that since the NEEC rate will be updated every 2 years rather than being locked in for a longer amount of time, there is no danger that the NEEC will become outdated. Accordingly, on behalf of SACE, Mr. Barnes recommends that the NEEC calculation use a minimum term of 10 years consistent with the term offered under standard offer QF contracts. Mr. Barnes further recommends that the Commission consider using a longer-term time horizon (e.g., 20-25 years) that would be most consistent with the typical lifetime of a customer-sited solar facility. SACE Initial Comments, Attachment 4 (Refining the NEEC to Improve Accuracy) at 1-2.

On behalf of SACE, Mr. Barnes also recommends that Duke Energy adjust its NEEC calculations to include gross-ups for line losses varied by the avoided cost pricing periods using the same amounts applied for distribution-interconnected QFs. Mr. Barnes notes that Duke Energy does not currently calculate line losses for distribution lines. According to Mr. Barnes, this is appropriate for in front of the meter QFs that export substantial quantities of energy to the distribution grid since that electricity would serve demand at locations remote from the generating facility. In contrast, Mr. Barnes states that the exports of net metered systems are more likely to serve loads close in proximity to the system (e.g., next door neighbors) and therefore incur minimal distribution line losses. *Id.* at 2-3.

Finally, Mr. Barnes recommends that Duke Energy should include avoided transmission and distribution costs in its NEEC calculation. With respect to transmission Mr. Barnes states that Duke Energy can calculate a reasonable estimate of avoided transmission costs by examining how their forecasts of transmission costs under the preferred portfolio would change under sensitivities for low, base, and high forecasts of customer-sited generation. Recommends a time horizon of 10 years and using an average of the low-to-base and base-to-high scenarios. With respect to distribution, Mr. Barnes recommends calculating avoided distribution costs by assessing the effective capacity determination using analyzing the timing of circuit-level peaks throughout the year varied by month and time of day as a starting point for further discussion. Specifically, Mr. Barnes suggests that the methodological framework could be further refined by (1) using multiple years of distribution peak data; (2) using forecasted distribution peak data rather than historic data; and (3) developing a further weighting factor based on the capacity of net metered systems on individual distribution circuits. *Id.* at 3-4.

The AGO's Comments argue that the NEEC undervalues rooftop solar. Because NEEC is based on avoided cost rates, it does not fully reflect carbon emission reductions that rooftop solar provides to Duke. Therefore, customers are not being fully incentivized to provide the maximum value to the system. AGO Comments at 7.

In its Reply Comments, Duke Energy supports maintaining its methodology for calculating the NEEC, which the Commission approved in 2023. First, Duke Energy explains that with respect to the calculation term, DEC's and DEP's initially-proposed NEEC rates in the 2021 Sub 175 Proceeding were based on a 2-year avoided cost calculation term.[32] Duke Energy believed the 2-year calculation term to be the most appropriate time horizon for calculating the NEEC because NEM facilities do not enter into long-term contractual relationships and, consequently, the rates they receive are updated every two years. Duke Energy explains that it agreed to the Public Staff's proposed 5-year time horizon in a good faith attempt to compromise and reach consensus. Duke Energy Reply Comments at 29-30.

Consistent with their position in the 2021 Sub 175 Proceeding, Duke Energy explains that it continues to believe it would be inappropriate and potentially risk a cross-subsidization from non-participating customers to calculate the NEEC based on a 10-year avoided cost time horizon. Duke Energy explains that in establishing NEM rates, the Commission recognized that such rates, by law, should be "nondiscriminatory" and that "cross-subsidization should be avoided by holding harmless electric public utilities' customers that do not participate" in NEM

[32] *See* Joint Initial Statement, Exhibit 11, Docket No. E-100, Sub 175 (Nov. 1, 2021).

programs.[33] According to Duke Energy, utilizing a 10-year calculation term would incorporate longer-term forecasts and introduce increased risk of inaccurate pricing signals to NEM customers and the potential for over-payments for QF power. For example, Duke Energy explains that its avoided energy pricing is based upon forecasted natural gas pricing using five years of market prices followed by three years of blending before transitioning to fundamental forecasts in years nine (9) and ten (10). Duke Energy explains that fundamental forecasts used in later years tend to be higher than current market prices. Accordingly calculating the NEEC based on a 10-year time horizon unnecessarily risks overpayment to NEM participants based on the gas forecast. Duke Energy explains that because the NEEC is updated regularly, NEM participants receive a rate that more accurately reflects DEC's and DEP's actual avoided costs. *Id.* at 30-31

Duke Energy further explains that the CPIRP modeling assumes energy from rooftop solar facilities, in the aggregate, increases over time but—recognizing that the CPIRP is a generic modeling exercise—do not make explicit assumptions that third-party owned facilities will operate for any specified term absent a contractual obligation to do so. Absent a contractual obligation, Duke Energy explains, there is no certainty that a specific rooftop solar customer will continue to deliver power for any specified term. Duke Energy notes that the solar facility may already be nearing the end of its useful life, it may become damaged or inoperable, or the homeowner may move and a new owner may elect not to continue to operate the rooftop solar array. *Id.* at 31-32.

Regarding Mr. Barnes' recommendation the Duke Energy should add avoided transmission and distribution costs to the NEEC calculation, Duke Energy notes that the retail rate charged to the customer includes distribution and transmission fixed cost recovery, thus the customer who pays a lower bill as a result of self-consuming energy from the solar system (or exporting generated energy and offsetting imports at a different time) is actually already receiving benefits associated with avoided distribution and transmission costs. By reducing their costs associated with the core tariff charges, such distribution and transmission costs are being reduced by the solar system owner. *Id.* at 32-33.

Duke Energy further explains that distribution and transmission values are random and unpredictable, thus resulting in no such avoidable distribution and transmission planning benefits. For example, Duke Energy states that if a customer installed a solar facility that generated 1,100 kWh in a given month, and the customer's consumption was 1,000 kWh in the same month, the customer would receive the distribution and transmission value associated with the 1,000

[33] *See Order Approving Revised Net Metering Tariffs* at 4, Docket No. E-100, Sub 180 (March 23, 2023) citing N.C.G.S. § 62-126.2; 62-126.4.

kWh, assuming it was never exported to the grid but rather directly self-consumed, by virtue of the fact that their core bills would go down, and those charges include fixed cost recovery for T&D assets. However, Duke Energy explains, the 100 kWh constituting the net exports could come from excess generation at any time across that month. For these reasons, Duke Energy maintains that the net exports should receive only the avoided energy costs presently included in the Companies' avoided costs calculations—such unpredictable deliveries of energy (in terms of quantity and timing) are insufficient to create any planning or investment benefits in terms of transmission and distribution assets. *Id.* at 33-34.

Finally, Duke Energy disagrees with the AGO that an incremental carbon benefit should be added to the NEEC because it is not presently being passed to solar customers. Duke Energy explains that while it is true that solar resources have zero carbon emissions when generating electricity, the energy not generated from other facilities is not directly attributable to the solar resources and therefore cannot be included in the NEEC. Additionally, from a Cost of Service (COS) perspective, carbon emissions have no cost (as no state or federal financial benefits are presently created associated with carbon reduction and therefore COS is not impacted). Accordingly, Duke Energy explains, COS analysis that governs utility rate-making has no means by which to flow such supposed carbon reduction benefits to owners of solar facilities. *Id.* at 34-35.

In its Reply Comments, the Public Staff agrees with Duke Energy that a 5-year, rather than 10-year, avoided cost time horizon is more appropriate for calculating the NEEC. The Public Staff explains that using levelized 10-year rates to calculate the NEEC will likely result in overpayment and subsidization of NEM participants by other customers. Public Staff Reply Comments at 10-11.

In addition, the Public Staff recommends that Duke Energy analyze potential avoided T&D costs that can be avoided by behind-the-meter generation and discuss their potential inclusion in the next avoided cost proceeding. The Public Staff also recommends that Duke Energy update its NEEC to include an incremental line loss factor to account for the secondary distribution losses avoided when a net metering customer's exports flow directly to meet the load of nearby customers, which can avoid the need to pass through local distribution transformers. Public Staff Reply Comments at 11-12.

In their respective Reply Comments, the NCSEA and CCEBA support SACE's recommendations for adjustments to the NEEC. NCSEA Reply Comments at 8-9; CCEBA Reply Comments at 15.

Discussion and Conclusions

The Commission most recently considered and approved DEC's and DEP's NEEC calculation methodology in its March 23, 2023 *Order Revising Net Metering Tariff* (the "NEM Order") issued in Docket No. E-100, Sub 180 and August 2, 2023 *Order Establishing Net Excess Energy Credit for NEM Tariff* (the "NEEC Order") issued in Docket No. E-100, Sub 175. Based on the evidence and entire record herein, the Commission does not find any compelling reason to order adjustments to DEC's and DEP's recently-approved NEEC calculation methodology at this time.

Specifically, the Commission finds that it is reasonable and appropriate for DEC and DEP to calculate their respective NEEC using a 5-year time horizon. Since the NEEC is updated every two years for all NEM facilities, the Commission finds that a time horizon longer than 5 years may unnecessarily exceed the utility's actual avoided cost and risk a cross-subsidization from non-participating customers. Sections 62-126.2 & 62-126.4 of the North Carolina General Statutes provide that NEM rates should be "nondiscriminatory" and that "cross-subsidization should be avoided by holding harmless electric public utilities' customers that do not participate" in NEM programs. Utilizing a 10-year calculation term, as SACE recommends, would necessarily require Duke Energy to incorporate longer-term forecasts and introduce increased risk of inaccurate pricing signals to NEM customers along with the potential for over-payments to NEM participants by customers that do not participate in the NEM program. The Commission further agrees with Duke Energy and the Public Staff that, absent a contractual obligation, there is no certainty that an NEM customer will continue to deliver power for any specified term and notes that NEM customers have the option to sell power at avoided cost rates as an alternative to participating in NEM.

The Commission further will not require DEC and DEP to incorporate avoided transmission and distribution benefits into their respective NEECs. The Commission reiterates its position that only known and measurable benefits and costs should be included in the determination of the NEEC. The Commission is persuaded by Duke Energy's comments that the potential for transmission and distribution system value associated with NEM generation is random and unpredictable and does not create any generically avoidable costs. As the Commission noted in the NEM Order, the Commission cannot speculate on future deferrals of transmission and distribution costs, and the costs and benefits of NEM facilities will continue to change in the future. Accordingly, the Commission finds and concludes that it is appropriate for Duke Energy to calculate its NEECs without incorporating any cost for potentially-avoided transmission and distribution system costs.

Finally, the Commission notes that Duke Energy's May 20, 2024 letter in this docket indicates that it reached a compromise with the Public Staff such that

DEC and DEP will recalculate their respective NEECs to incorporate a residential-only distribution line loss factor into their respective NEECs. The Commission finds this approach to be reasonable and appropriate and directs Duke Energy to file updated NEECs incorporating a distribution line loss factor as part of its compliance filing in this docket.

Timing of Future Biennial Avoided Cost Proceedings

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 29

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

Discussion of the Comments

In its Comments, the AGO argues that avoided cost rates should align with approved, rather than proposed, CPIRPs and requests that the Commission direct Duke Energy to recalculate its avoided cost calculations within 90 days of Commission approval of its next and subsequent CPIRPs. AGO Initial Comments at 19-20.

In its Reply Comments, Duke Energy notes that the Commission has never required utilities to file updated standard avoided cost rates following issuance of a final IRP ruling and between biennial proceedings. According to Duke, doing so would cause unnecessary administrative inefficiency that is unnecessary given the biennial cadence of avoided cost proceedings. Duke Energy notes that the short lag period between approval of a CPIRP in late December and filing of the next avoided cost proceeding the following November would only impact small QFs 1 MW or less selling pursuant to the standard offer as Duke Energy updates its large QF rates on a quarterly basis. DEC/DEP Reply Comments at 9-10.

In its Reply Comments, the Public Staff states that it sees no reason to depart from the precedent of setting avoided cost rates based on the utility's most recently filed IRP. However, the Public Staff states that if the Commission's final CPIRP Order in Docket No. E-100, Sub 190 would significantly impact avoided cost rates, then the Commission could consider whether it is appropriate to require Duke Energy to update its avoided cost rates. Public Staff Reply Comments at 13-14. SACE argues the Commission should require Duke Energy to calculate avoided cost rates using the Commission's most recently approved CPIRP rather than Duke Energy's preferred portfolio from a subsequent unapproved CPIRP filing. SACE Reply Comments at 4. Finally, NCSEA recommends that Duke Energy should make its biennial avoided cost filing 90 days after the Commission issues an order approving a CPIRP, moving its initial statement filing date from November

1 to approximately April 1. NCSEA Reply Comments at 5. NCSEA explains that doing so will ensure that avoided cost rates are based on Commission-approved portfolios and avoid mid-proceeding filings. NCSEA Reply Comments at 6.

Discussion and Conclusions

Based upon the foregoing and the entire record, the Commission concludes that it is reasonable and appropriate to maintain the longstanding practice of filing updated avoided cost rates in November of odd years. This practice ensures that avoided cost rates are updated close in time to the refreshed inputs used to develop a utility's IRP, which are generally filed on September 1 of the same year. Basing a utility's avoided cost rates on the most recently approved IRP would introduce additional staleness to a utility's avoided cost rates since IRPs are generally approved many months (in the case of the CPIRP, more than a year) after the initial filing. Accordingly, the Commission declines to accept the AGO's recommendation that Duke Energy be required to recalculate its avoided cost calculations within 90 days of the Commission's approval of its next and subsequent CPIRP proceedings.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC and DEP shall offer long-term levelized capacity payments and energy payments for ten-year periods as standard options to all non-hydroelectric QFs with a design capacity up to and including one megawatt (MW). 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 DEP and DEC 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 As-Available 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 or not there is an active solicitation underway, 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 As-Available 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. That DEC's and DEP's Schedule PP, as presented in DEC Updated Exhibit 1 and DEP Updated Exhibit 1 to Duke Energy's Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs.

4. That DEC and DEP shall continue to calculate avoided capacity costs using the peaker method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C. Gen. Stat. 62-156(b)(3) and shall evaluate, before the next biennial avoided cost proceeding, whether to propose an alternative method to calculate avoided costs under PURPA;

5. That DEC and DEP shall evaluate using an advanced class CT to calculate avoided capacity payments under the peaker method, at least as an alternative, in the next avoided cost proceeding and shall also assess in future avoided cost dockets potential least cost capacity resources other than a CT unit, as they become available, and shall address in the next biennial avoided cost proceeding whether any changes to the avoidable resource used in the peaker method are appropriate;

6. That DEC shall use a PAF of 1.05 and DEP shall use a PAF of 1.07 in their respective avoided cost calculations for all QFs;

7. That DEC and DEP shall address the inclusion of solar and wind generator outage data in the PAF calculation in future avoided cost proceedings;

8. That DEC and DEP shall calculate their avoided energy costs using five years of forward market natural gas forecast pricing followed by three years of blending before transitioning to fundamental forecasts;

9. That DEC and DEP shall utilize the fuel hedging adjustment as proposed for the purposes of this proceeding;

10. That the solar integration services charges proposed by DEC ($1.09 per MWh) and DEP ($1.62 per MWh) shall be used in calculating rates in this proceeding as a decrement to DEC's and DEP's avoided energy rates, which shall

apply prospectively for the duration of the contract, consistent with the conclusions reached in this Order;

11. That Duke Energy shall file a report on QFs that attempt to avoid the SISC and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in Duke Energy's service territories in future fuel rider proceedings, providing the specific facilities and amount of SISC credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC;

12. That DEC and DEP shall continue to evaluate the operating characteristics of inverter-based resources to provide ancillary services and shall update the Commission regarding any ongoing testing or evaluation in the first biennial CPIRP following the interconnection of large-scale battery energy storage systems to the Duke Energy transmission system;

13. That for the purposes of calculating avoided capacity rates in this proceeding, DEC and DEP should use seasonal allocation weightings of 100% for winter;

14. That DEC's and DEP's standard offer PPA, as presented in DEC Exhibit 3 and DEP Exhibit 3 to Duke Energy's Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

15. That DEC's and DEP's Terms and Conditions, as presented in DEC Exhibit 4 and DEP Exhibit 4 to Duke Energy's Initial Statement and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

16. That DEC's and DEP's Notice of Commitment Forms, as presented in DEC Exhibit 6 and DEP Exhibit 6 to Duke Energy's Initial Statement, is approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

17. That DEC and DEP shall consult with the Public Staff and address, in the next biennial avoided cost proceeding, (1) the number of QFs with expiring PPAs over the next five years and (2) the process for existing QFs with expiring PPAs to obligate themselves to sell power for a new term; and (3) whether designing and offering a competitive solicitation process open to QFs with expiring PPAs would be reasonable and in the public interest;

18. That DEC's and DEP's ESS retrofit avoided cost rates expired effective November 1, 2023 and QFs interested in adding battery energy storage may obtain avoided cost rates from DEC or DEP, consistent with North Carolina's

framework for implementing PURPA, through a negotiated rate based on the most recent Commission-approved avoided cost methodology;

19. That DEC and DEP shall update their respective NEECs to incorporate a distribution line loss factor and that DEC's and DEP's calculation of their NEECs, as presented in DEC Updated Exhibit 11 and DEP Updated Exhibit 11 to Duke Energy's Initial Statement and discussed in this Order, is otherwise approved;

20. That within 30 days after the date of this Order, the Utilities shall file final 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 as to the accuracy of the calculations are raised.

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 Duke Energy Carolinas, LLC's, Duke Energy Progress, LLC's, and the Public Staff's *Joint Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* 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/E. Brett Breitschwerdt

E. Brett Breitschwerdt
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601
Telephone: (919) 755-6563
bbreitschwerdt@mcguirewoods.com

Attorney for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC