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July 1, 2022

VIA Electronic Filing

Ms. A. Shonta Dunston, Interim 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
Docket No. E-100, Sub 175

Dear Ms. Dunston:

Enclosed for filing in the above-referenced proceeding on behalf of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and the Public Staff is their *Joint Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*.

Please do not hesitate to contact me should you have any questions. Thank you for your assistance with this matter.

Very truly yours,

/s/E. Brett Breitschwerdt

EBB:sbc
Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 175

In the Matter of

Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	)))))))	**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**

BY THE COMMISSION: This is the 2021 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegates responsibilities in that regard to this 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 public utilities for power purchased from small power producers, as defined in N.C.G.S. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the 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 the 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, the FERC stated:

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

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), order on reh'g, Order No. 69-A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983).

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state regulation, the FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the 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 public 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 recently amended N.C.G.S. § 62-156 in 2017 through enactment of Session Law 2017-192 (HB 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On April 15, 2020, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 158

(Sub 158 Order), in which it (1) approved the payment by QF owners for costs of the utility's ancillary services used to integrate the QF's solar generation onto the grid, continued reliance on significant forward natural gas prices in establishing avoided energy costs, and ongoing use of the peaker methodology in calculating avoided costs; and (2) posed a series of additional issues (Sub 158 Additional Issues) to be addressed by the utilities involved in that docket.[1]

On August 13, 2020, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (2020 Scheduling Order). Pursuant to the 2020 Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (collectively, Duke Energy), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DENC), Western Carolina University (WCU), and Appalachian State University d/b/a New River Light and Power Company (New River) were made parties to the proceeding.

On October 20, 2020, DEC, DEP, and DENC filed a Notification of Intended Compliance with N.C.G.S. § 62-156(b), a Request for Continuance of Compliance with Certain 2020 Filing Requirements, and a Request to Prospectively Modify Timing of Biennial Proceedings (Notice of Intended Compliance). In the Notice of Intended Compliance, DEC, DEP, and DENC notified the Commission of their intention to file streamlined 2020 avoided cost filings that would update the inputs in their avoided energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Commission's Sub 158 Order and requested that the Commission delay until November 2021 the more comprehensive filings that would address the solar integration services charge methodology, the provision of ancillary services by QFs, the Performance Adjustment Factor (PAF), and other Sub 158 Additional Issues. DEC, DEP, and DENC also proposed that, going forward, the Commission modify the timing of biennial avoided cost proceedings by starting the next full biennial proceeding in 2021 and shifting all future proceedings to odd calendar years.

On October 30, 2020, the Commission granted the continuance (2020 Continuance Order) and directed DEC, DEP, and DENC to (1) address the Sub 158 Additional Issues by November 2, 2021; (2) file a list of the Sub 158 Additional Issues and a timeline for how they intend to address those issues by December 7, 2020; and (3) file updates on their progress on the Sub 158 Additional Issues at least every 45 days after the December 7, 2020 filing.

On August 13, 2021, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 167 (Sub 167 Order), in which it determined that DEC, DEP, and DENC had complied with the requirements of the 2018 Sub 158 Order in filing their Progress

[1] The utilities involved in Docket No. E-100, Sub 158 included Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, Western Carolina University, and Appalachian State University d/b/a New River Light and Power Company.

Updates on the Sub 158 Additional Issues to date, and, consistent with the 2020 Continuance Order, directed DEC, DEP, and DENC to continue filing their Progress Updates until the issues were fully addressed or until the filing of proposed rates and terms on November 1, 2021, whichever was earlier and, to the extent relevant to DENC, address the Sub 158 Additional Issues in its November 2021 filing.

Also on August 13, 2021, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (2021 Scheduling Order). Pursuant to the 2021 Scheduling Order, Duke Energy, DENC, WCU, and New River (collectively, the Utilities) were made parties to the proceeding. The 2021 Scheduling Order stated that 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 9, 2022, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings and March 11, 2022, as the deadline for reply comments. The 2021 Scheduling Order also scheduled a public hearing for February 22, 2022, solely for the purpose of taking non-expert public witness testimony. Finally, the 2021 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 no later than the date of the hearing.

The following parties filed timely petitions to intervene that were granted by the Commission: the North Carolina Sustainable Energy Association (NCSEA); the North Carolina Clean Energy Business Alliance (NCCEBA); the Carolina Industrial Customers for Fair Utility Rates I, II, and III (CIGFUR); Southern Alliance for Clean Energy (SACE); and Appalachian Voices. 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, 2021, Duke Energy and DENC filed their proposed avoided cost rates, standard power purchase agreements (PPAs), and terms and conditions, consistent with the 2021 Scheduling Order. On December 21, 2021, WCU jointly with New River also made their avoided cost filings in this docket.

On February 2, 2022, NCCEBA, NCSEA, and SACE filed a Joint Motion requesting an extension of time to February 24, 2022, to file initial comments and to March 28, 2022, to file reply comments. The Commission granted the extension.

On February 24, 2022, the Public Staff, SACE, and Appalachian Voices filed comments. On the same day, NCCEBA and NCSEA (Joint Commenters) filed Joint Initial Comments.

On March 1, 2022, New River filed amended proposed rates and contracts. On March 11, 2022, Appalachian Voices filed a response to New River's amended filing.

On March 24, 2022, Duke Energy filed a Motion for Extension of Time, asking that the deadline for reply comments be extended to April 1, 2022. The Commission granted the request on March 25, 2022.

On March 31, 2022, SACE filed its Reply Comments. The following day, New River, NCSEA, the Joint Commenters, Duke Energy, DENC, and the Public Staff each filed their Reply Comments.

On May 16, 2022, the Commission issued its Order Requiring the Filing of Proposed Orders and Briefs, setting forth a deadline of June 17, 2022, to do so, and determining that no full evidentiary hearing was required.

On June 10, Duke Energy requested an extension of three weeks for the date by which proposed orders and briefs should be filed. The Commission issued an Order on June 14, 2022, granting an extension to July 1, 2022, by which proposed orders and briefs should be filed.

On July 1, 2022, proposed orders were filed by the parties.

Based upon the foregoing and the entire record herein, 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 contracting to sell one megawatt (MW) or less capacity. 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 Marginal Cost Rate or 2-year contractual Variable Rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the

Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the Marginal Cost 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.

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 is 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 the economies of scale associated with gas pipeline interconnection, are reasonable, based on publicly available United States Energy Information Administration (EIA) data, and appropriate for use in calculating avoided capacity costs in this proceeding.

5. DEC's and DEP's respective first years of avoidable capacity need are appropriate and have been determined consistent with the 2018 Sub 158 Order and the 2021 Sub 167 Order and DEC's and DEP's 2020 Integrated Resource Plans (IRPs) with updated assumptions to reflect the Commission's March 31, 2021 Orders in Docket Nos. E-7, Sub 1214 and E-2, Sub 1146 approving aspects of DEC's and DEP's Grid Improvement Plan.

6. DEC's and DEP's standard offer schedules have also appropriately included 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 DEC's and DEP's 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 1.04 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), DEC and DEP are no longer required to offer a 2.0 PAF to hydro QFs in standard power purchase agreements (PPAs).

Avoided Energy Costs

9. It is appropriate in this proceeding to require DEC and DEP to continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period.

10. It is appropriate for DEC and DEP to rely on fundamental forecasts for Henry Hub prices developed by private firm IHS, and the Commission will not require DEC and DEP to supplement and average those forecasts with publicly available Henry Hub price forecasts in EIA's *2021 Reference Case*.

11. DEC's and DEP's use of their respective 2020 IRP natural gas transportation and pricing assumptions are reasonable for purposes of calculating avoided costs in this proceeding.

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

13. DEC's and DEP's calculation of avoided energy rates, using inputs from their 2020 IRPs 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.

14. 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.

15. 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.

16. DEC's and DEP's solar integration decrements of $1.05 per MWh for DEC and $2.26 per MWh for DEP, based on the analysis in the 2021 Solar Integration Services Charge Study prepared by Astrapé Consulting which incorporated the findings in the independent technical report of the Technical Review Committee, are reasonable and appropriate for purposes of this proceeding.

17. 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*.

18. 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

19. 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 DEC and DEP on an "as-available" basis.

Schedule PP Rate Design

20. DEC's proposed seasonal allocation weightings of 96% for winter and 4% for summer, and DEP's proposed seasonal allocation weighting 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.

21. DEC's and DEP's updated start cost modeling is reasonable and appropriate for 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 revisions to the Notice of Commitment form appropriately incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872, align the LEO process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from a Notice of Commitment Form to a PPA.

Energy Storage System Retrofit Rates

26. DEC's and DEP's Energy Storage System (ESS) Retrofit avoided cost rates are reasonable and appropriate.

27. The Public Staff's bifurcated rate proposal reflects a compromise consensus among stakeholders and is reasonable and appropriate.

Net Energy Metering

28. DEC's and DEP's Net Excess Energy Credit (NEEC) calculation methodology for use in setting Net Energy Metering (NEM) tariffs should be discussed and approved in the avoided costs docket going forward.

29. DEC's and DEP's annualized NEEC rates, as set forth in DEC and DEP Reply Comments Exhibit 2, are reasonable and appropriate.

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

The evidence supporting these findings of fact is found in Duke Energy's verified Joint Initial Statement and the exhibits attached thereto (JIS), 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>

As attachments DEC Exhibit 1 and DEP Exhibit 1 to the JIS, 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, 2021, but prior to the initial filing in the next biennial avoided cost proceeding in November 2023. 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). In its Initial Statement, the Public Staff reviews and summarizes the rate schedules proposed by DEC and DEP, but 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.

<u>Discussion and Conclusions</u>

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

In past biennial avoided cost proceedings, the Commission 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 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 Marginal Cost Rate or 2-year contractual Variable 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.

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 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 Marginal Cost Rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding. The Commission again recognizes the enactment of N.C.G.S. § 62-110.8, providing for a competitive procurement option for renewable energy facilities, *see* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 148, at 38-39 (Nov. 11, 2017) (Sub 148 Order). as well as the ongoing competitive procurement of solar resources pursuant to HB 951. *See* 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). 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 the Competitive Procurement of Renewable Energy program or 2022 Solar Procurement Program may be considered an active solicitation 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.

AVOIDED CAPACITY RATES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

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

Summary of the Comments

In the JIS, 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 JIS 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. JIS at 13-14.

In its Initial Statement, the Public Staff likewise notes the Commission's consistent approval of the peaker method and indicates that it continues to support the use of the peaker methodology for both Duke Energy and DENC in this proceeding. Nevertheless, the Public Staff observes that the peaker methodology may not always be appropriate for use in developing avoided costs in North Carolina as the utilities pursue decarbonization and increase reliance on generation from renewable resources. Public Staff Initial Statement at 24. SACE likewise argues in its Initial Comments that the Commission should begin to reconsider the appropriateness of the peaker method for avoided cost determinations, and CCEBA/NCSEA recommend that the Commission and interested stakeholders should re-evaluate the peaker methodology given the development and implementation of the Carbon Plan. SACE Initial Comments at 3-5.

In Reply Comments, Duke Energy argues that the peaker methodology remains a reasonable and well-accepted methodology by which to calculate avoided energy and capacity costs. They further note that, while intervenors have raised a potential need to reevaluate the peaker methodology in the future, no party has directly challenged its use in this proceeding. Nevertheless, given the ongoing development of the Carbon Plan, DEC and DEP commit to continue evaluating the appropriateness of the peaker methodology in the future and state that they will address this topic in their next biennial avoided cost proceeding in 2024. DEC and DEP further point out that FERC's recent PURPA rulemaking Order, Order Nos. 872 and 872-A, approved a number of new approaches that rely upon competitive pricing methodologies by which a utility may compensate QFs for their output in lieu of traditional administratively-forecasted avoided costs methodologies. Duke Energy further explains that, although Order No. 872 implementation was a topic of discussion with stakeholders in advance of Duke Energy's November 2022 avoided costs filing, stakeholders did not express support for further evaluation of competitive price methodologies or further consideration of new methodologies that provide for more accurate avoided energy calculations based on rates calculated as of the time energy is delivered. DEC/DEP Reply Comments at 35-36.

SACE reiterates its underlying criticism of the peaker methodology in its Reply Comments, noting that the calculation methodology might soon be inappropriate. SACE Reply Comments at 4-5, 9. CCEBA/NCSEA state in their Reply Comments that they agree with the arguments of SACE and the Public Staff and recommend that the Commission carefully study the role of the peaker method in the Carbon Plan and future avoided cost proceedings. CCEBA/NCSEA Reply Comments at 4.

Discussion and Conclusions

Based upon the foregoing evidence and the entire record, the Commission finds that the peaker methodology remains a reasonable and well-accepted methodology by which to calculate avoided energy and capacity costs at this time. The Commission has consistently approved Duke Energy's continued use of the peaker method as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs in the 2020 Sub 167 proceeding and a number of prior biennial avoided cost proceedings. *See* Sub 167 Order at 60 (Ordering Paragraph 8); *2018 Sub 158 Order*, at 134 (Ordering Paragraph 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). As recognized in these prior avoided cost proceedings, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)."[2] 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 avoided cost framework—which the

[2] *See* Sub 140 Phase One Order at 30 (explaining that the Commission "has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided cost"). Applying the peaker method, "the cost of peaking capacity is utilized as the cost basis for the capacity credits, and energy credits are calculated by simulating DEC's and DEP's respective system operations with and without 100 MW of no cost energy in each hour and determining the energy cost difference between the simulations." *Id*.

Utilities and Public Staff continue to support and no party provides a specific alternative—at this time.

For all of the foregoing reasons, the Commission finds that the peaker methodology remains the appropriate method by which to calculate avoided costs in this proceeding. The Commission remains open to evolving the avoided cost methodology in the future as long as PURPA's requirements are achieved—specifically, ensuring that avoided cost rates do not exceed the utility's actual avoided costs for QF purchases and that avoided cost rates are calculated in a manner that ensures rates paid by customers are just and reasonable, in the public interest, and do not discriminate against QFs. Utilities, the Public Staff and other parties may evaluate in future biennial proceedings, taking into account the approved Carbon Plan, whether to propose an alternative methodology to calculate avoided costs, including those recently determined by FERC to be reasonable and appropriate for calculating avoided costs in Order No. 872 and now included in 18 C.F.R. 292.304(b).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

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

<u>Summary of the Comments</u>

In the JIS, Duke Energy states that it used the installed cost of a CT unit derived from publicly available industry sources, such as the EIA, tailored to adapt such information to the Carolinas for purposes of calculating their avoided capacity costs. As Duke Energy explains, this approach is consistent with the Commission's directives in prior avoided cost proceedings. In addition, Duke Energy notes that the 2018 Sub 158 Order directed, as one of the Sub 158 Additional Issues, that the Utilities should evaluate and apply cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility. Consistent with this directive, Duke Energy explains that it worked with the Public Staff and DENC to develop the methodology for calculating CT cost estimates, arriving at a consensus approach to streamline the determination of the avoided CT capacity cost that fairly values the avoided capacity cost for QFs while ensuring customers do not overpay for capacity. JIS at 17.

Duke Energy explains that while construction of replacement generation at brownfield sites could potentially offer higher cost savings (thereby lowering avoided CT cost), any such savings likely would be site-specific. According to Duke Energy, calculating CT costs using a greenfield economies of scale adjustment reflects the generic nature of the avoided CT under the peaker method and also results in a smaller adjustment to the publicly available CT capacity cost which benefits the QF. Duke Energy explains that the greenfield economies of scale methodology uses the avoided capacity cost based upon the EIA's most current published overnight cost of a CT unit, and applies a percentage decrement to reflect the economies of scale associated with a 4-unit CT site in the Carolinas resulting in an overnight CT capital cost of $619/kW (2021$) for use in setting avoided capacity rates in this proceeding. For the fixed operations and maintenance (FOM) cost component, DEC and DEP used the publicly available FOM data from the same EIA data source and made adjustments using internal data to reflect the FOM economies associated with a four-unit CT project. JIS at 18-19.

For these reasons, Duke Energy states, a standardized greenfield economies of scale adjustment for the purpose of calculating avoided CT costs is appropriate at this time and consistent with the methodology approved by the Commission in its 2020 Sub 167 Order. Duke Energy further states that additional information supporting these calculations is set forth in DEC/DEP Exhibit 8 to the JIS. JIS at 18-19.

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

For this proceeding, based on the agreement with Duke Energy, DENC utilized the 2021 EIA Annual Energy outlook costs for an F class turbine and did not make any adjustments to the CT equipment costs. DENC did make adjustments to reflect economies of scale and the cost benefits associated with building four CTs at a single site. DENC Initial Statement 20-21.

In its Initial Statement, the Public Staff states that it agrees with Duke Energy's and DENC's utilization of publicly available CT costs and the economy of scale adjustments, finding them both to be reasonable. The Public Staff notes that in the Sub 167 proceeding, it observed that a brownfield site cost decrement should be applied given the historic build out of more recent CTs at brownfield sites. However, after multiple discussions with the Utilities, the Public Staff states that its current understanding is that there is no certainty as to where future CTs may be built, and the peaker method relies upon the concept of a “hypothetical” CT. While it is likely that new CT generation may be built at a brownfield site, the Public Staff states that a brownfield cost decrement is not appropriate for inclusion in the calculation of avoided capacity rates at this time. Public Staff Initial Statement at 14-15.

In addition, the Public Staff notes that in developing the CT costs to be used as the basis for the calculation of avoided capacity rates, both Duke Energy and DENC independently calculated adjustments to the published EIA data. Duke Energy’s calculations yielded a 6.7% adjustment, and DENC’s calculations yielded a 7.5% adjustment. The Public Staff notes that both Duke Energy and DENC recommend using an average adjustment of 7.0% to determine the appropriate CT costs, and the Public Staff finds this adjustment to be reasonable. Public Staff Initial Statement at 15.

SACE’s Initial Comments state that Duke Energy’s selection of the CT as its projected avoided peaking resource is inconsistent with future procurement and instead proposes that the Commission should direct Duke Energy to use an aeroderivative gas turbine as the peaking unit in this proceeding. SACE notes that compliance with HB 951 will require Duke Energy to procure large quantities of zero-emitting resources, including solar and wind generation. According to SACE, the flexibility and other operating characteristics of an aeroderivative gas turbine would better match the needs of the changing grid while also providing the same basic generating capacity services as a CT. SACE further notes that because the up-front capital cost of a CT is lower than aeroderivative gas turbines, Duke Energy’s use of a CT artificially reduces the avoided capacity cost. SACE Initial Comments at 4.

In the longer term, SACE states that peaking resources will need to be zero-carbon and notes that Duke Energy has proposed to procure both hydrogen-powered combustion turbines and batteries. SACE argues that Duke Energy’s avoided cost inputs and assumptions should match its plans—if hydrogen powered combustion turbines or batteries will be the avoided peaking resources then they should be the measure of avoided capacity cost. SACE Initial Comments at 4-5.

SACE argues that state law requires system flexibility enhancements going forward. Specifically, SACE cites the carbon reduction goals of HB 951—70% by 2030 and carbon neutrality by 2050—as evidence that Duke Energy will be required to procure large amounts of additional zero-carbon resources starting immediately that will eventually require that future peaking resources are no longer any form of carbon-emitting resource but instead zero-carbon resources such as battery energy storage or demand-side management. SACE Initial Comments at 5-6.

In addition, SACE notes that Portfolios D and E to Duke Energy's South Carolina IRPs show that to achieve 70% carbon reduction by 2035, Duke Energy would need approximately 14 GW of new solar, as well as other zero-carbon resources forced into the model. SACE states that it commissioned Synapse to prepare a report for the 2020 IRPs, re-running Duke Energy's modeling with different assumptions that SACE believes to be more reasonable. SACE reports that Synapse findings indicate that North Carolina will transition from 7.96 GW of renewables in 2021 to 40.5 GW of renewables in 2035, including approximately 22 GW of new solar and many GW of battery energy storage. SACE Initial Comments at 6-7. According to SACE, the substantial additions of renewable resources in these analyses further underscore existing indications of the value of system flexibility on the Duke grid, greatly strengthening the likelihood that Duke's future procurement of peakers will target highly flexible technologies. SACE Initial Comments at 8.

SACE next argues that an aeroderivative gas turbine is the appropriate avoided capacity resource in the near term. SACE states that an aeroderivative gas turbine is the most economical highly flexible CT technology at present, making it a more appropriate resource to use in calculating avoided capacity costs in this proceeding. According to SACE, a simple CT cannot offer the same flexibility and operational efficiencies. SACE explains that an aeroderivative gas turbine is a modified aviation turbine of the kind used to propel a jumbo jet with characteristics such as faster start-up times and ramp rates, and higher efficiencies compared to industrial frame CTs. SACE states that aeroderivatives are the leading CT technology recently deployed in PJM, and another highly flexible generation technology—reciprocating engines—has proliferated in Texas. SACE further notes that Dominion Energy South Carolina recently proposed and received approval to use aeroderivative CTs as the avoided resources for avoided capacity rate calculations in South Carolina. SACE Initial Comments at 8-10.

SACE next argues that Duke Energy's IRPs indicate a need for peaking resources with advanced flexibility capabilities. SACE notes that DEC's 2018 IRP concluded that F-frame CTs would be the most economical peaking resources unless there is a special application that requires the fast start capability of the aero-derivative CTs or reciprocating engines. Similarly in the Sub 167 docket, SACE states that Duke Energy acknowledged that H class or other more advanced aeroderivative CTs could be a future way for DEC and DEP to manage intermittent output of must-take solar generation. SACE further notes that Duke Energy continues to develop an advanced combustion turbine unit at the Lincoln CT Plant. SACE Initial Comments at 10-12.

Finally, SACE notes that capital and fixed operation and maintenance (O&M) costs to construct an aeroderivative gas turbine are much higher than those of a CT, and argues the Commission should not allow Duke Energy to base its avoided capacity cost calculation on an outdated peaking resource. SACE argues the Commission should require Duke Energy to recalculate its avoided capacity costs using an aeroderivative gas turbine as the avoided peaking resources or, at a minimum, require Duke Energy to explain how continued construction of CTs for peaking capacity would be consistent with changing system need, the requirements of HB 951, and the forthcoming Carbon Plan. SACE Initial Comments at 13.

Next, SACE argues that hydrogen-capable turbines and associated infrastructure upgrade costs should be used to calculate avoided capacity costs in the near future. Specifically, SACE argues that the avoided peaker of the near future will not be fossil fuel-burning at all. SACE states that, under the Carbon Plan, future peaking resources will be either battery storage or hydrogen powered combustion turbines, and these zero-carbon peaking resources would, according to SACE, most accurately represent the capacity cost avoided by a QF in the near future. SACE Initial Comments at 13-14.

SACE notes that, like the aeroderivative gas turbine, future avoided capacity costs defined by these resources are likely to be higher than those defined by a CT. SACE states that it does not recommend using hydrogen-powered turbines or batteries to calculate avoided capacity costs in this proceeding, but states that doing so might be appropriate in a future proceeding. SACE Initial Comments at 15-16.

In their Initial Comments, CCEBA/NCSEA state that they agree with SACE that an aeroderivative gas turbine is the appropriate avoided capacity resource in the near term. CCEBA/NCSEA Initial Comments at 4.

Through Reply Comments, Duke Energy states that SACE proposes to significantly increase DEC's and DEP's avoided capacity cost by asking the Commission to reject DEC's and DEP's continued use of a F-frame CT in applying the peaker methodology and, instead, to require use of the significantly more expensive aeroderivative turbine unit. Duke Energy reiterates that it worked with the Public Staff and DENC to develop the proposed methodology for calculating CT cost estimates, which is based on publicly available data from the EIA for an F-frame CT. Duke Energy further notes that it has used an F-frame CT as the avoided unit in at least the last four avoided cost proceedings dating back to 2014. Duke Energy states that its continued use of CTs as a peaking resource remains accurate and appropriate under the peaker methodology to determine the avoided cost of capacity. Duke Energy Reply Comments at 7-8.

Addressing SACE's arguments, Duke Energy states that although an aeroderivative turbine may provide greater flexibility attributes than an F-frame CT, an F-frame CT provides fast start and ramping capabilities at an installed cost approximately 60% below the cost of an aeroderivative CT. Duke Energy explains that, 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. According to Duke Energy, even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology still accurately represents a valid estimate of the utility's avoided costs as a simple cycle F-frame peaking unit is typically the least expensive type of traditional resource that DEC and DEP can construct to provide capacity for reliability purposes. Duke Energy explains that building incremental peakers for capacity and relying on the remaining system for marginal energy is always an option within the resource planning process. Duke Energy Reply Comments at 10-11.

In addition, Duke Energy states that DEC's and DEP's 2020 IRPs and Supplemental Portfolio B filed in Docket No. E-100, Sub 165 demonstrate the need for F-frame CTs and do not show any need for aeroderivative CTs. Duke Energy states that it explained in its Reply Comments in the Sub 167 proceeding (which also relied upon the 2020 IRP) that H-class or other more advanced aeroderivative CTs could be a future way for DEC and DEP to manage the intermittent output of must-take solar generators. According to Duke Energy, these units provide greater flexibility and operational capability to integrate variable and intermittent renewable energy production, which comes at a markedly higher cost. In that event, however, Duke Energy states that the cost causer for the more expensive CT unit would be the solar providers themselves and, thus, the incremental cost of constructing H-class or aeroderivative CTs versus F-class CTs should not also be paid for by customers to the solar providers as avoided costs. According to Duke Energy, its use of the F-frame CT to calculate avoided capacity costs in this proceeding is consistent with past and present IRPs and avoided cost filings, appropriate under the peaker methodology, most reflective of current system conditions at this time, as well as supported by the Public Staff. Duke Energy Reply Comments at 10.

Next, Duke Energy explains that while hydrogen-capable turbines may be an important potential enabler to achieve the carbon reductions mandated by Session Law 2021-165, they will likely play only a minor role in meeting the goal of 70% carbon emissions reduction by 2030 because hydrogen fuel is a developing technology that has several potential pathways to deployment. Finally, Duke Energy notes that while the Carbon Plan developed in compliance with Session Law 2021-165 will necessarily require high levels of renewable resources, it is unknown at this time what thermal resources will be needed to produce a least cost plan that satisfies the law's resource planning and carbon emission reduction targets and provides an adequate level of reliability. Because of the current uncertainty regarding the resource mix that will result from the Carbon Plan and the likelihood that CTs will remain a critical part of the resource portfolio in the near term, Duke Energy believes, and the Public Staff supports, that CTs are the appropriate peaking unit for use in this proceeding. Duke Energy Reply Comments at 11-12.

With regard to CT costs, DENC responds in its Reply Comments that the use of an aeroderivative CT, batteries, or a 100% green hydrogen-powered turbine is not appropriate to use for purposes of determining avoided capacity costs under the peaker method. DENC first explains that the peaker method provides a hypothetical exercise to value capacity and that it was appropriate to use an F-class CT because a higher proportion of its value is derived from the capacity it provides with less value derived from its other attributes. In contrast, aeroderivatives provide additional benefits beyond simple capacity such as faster start-up time, faster ramping, and higher efficiency. DENC notes that batteries and green hydrogen also offer benefits beyond pure capacity and these added benefits bring value to energy and ancillary markets and would need to be netted from the avoided capacity cost if any of these three resources were used to model capacity for use with the peaker method. DENC Reply Comments at 6-7.

DENC explains further that a primary driver in considering whether to implement aeroderivative CTs in particular is the need to effectively integrate intermittent resources, like solar, that cause a greater need for quick-start flexible units. DENC notes that the growing use of aeroderivatives by some Southeastern utilities with increasing solar penetration is evidence of the need for utilities to invest in higher cost resources to manage the growing intermittency on their systems. While more Southeastern utilities are using aeroderivative CTs to help with solar integration, DENC disagrees that this means aeroderivative CTs should be used to calculate avoided capacity costs in North Carolina. DENC Reply Comments at 8-9.

DENC points out that it would be illogical to pay intermittent resources higher capacity rates to account for those resources' creation of the need to add expensive quick-start units to make up for distributed solar resources' intermittency and lack of dispatchability. Such an approach would reward these QFs with the increased capacity costs caused by those same QFs. DENC states that it does not currently need aeroderivatives to integrate the level of intermittent resources on its system, but if it does require them in the future then the energy and ancillary value of the aeroderivative will need to be netted from the avoided capacity cost. Moreover, if aeroderivatives are used to value capacity in future avoided cost proceedings, DENC will need to reconsider the capacity value seasonal allocations and hours of capacity need according to the forward market projections at the time. DENC Reply Comments at 10.

Discussion and Conclusions

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that Duke Energy appropriately relied on publicly-available industry sources for determining the installed per-kW cost of a CT, a hypothetical F-class CT, and that DEC and DEP's respective source information was developed in a manner consistent with the guidance previously provided by the Commission. Recognizing that the utilities typically plan to build multiple CTs at a single site, the Commission further finds that the Utilities' 7.0% economies of scale adjustment is reasonable and appropriate for this proceeding. Finally, the Commission is persuaded by the comments of Duke Energy, DENC, and the Public Staff—and the lack of any opposition from intervenors—that a brownfield cost decrement is not appropriate for inclusion in the calculation of avoided capacity rates at this time. The Commission therefore finds that the CT cost information used by DEC and DEP is reasonable and appropriate for purposes of calculating avoided capacity costs in this proceeding.

In addition, the Commission determines that it is not appropriate to require DEC and DEP to recalculate their avoided capacity rates using an aeroderivative gas turbine as the peaking resource. The F-frame CT unit Duke Energy used as the basis for DEC's and DEP's avoided capacity costs is consistent with Duke Energy's past and present IRPs and avoided cost filings, appropriate for use under the peaker methodology, and the peaking resource that is most reflective of current system condition at this time. The Commission further notes that Duke Energy's utilization of the F-Class CT is supported by the Public Staff. While the Commission recognizes that Duke Energy's generation mix will evolve as it takes steps to implement the Carbon Plan that that this Commission will approve on or before December 31, 2022, the Commission rejects the request of SACE and CCEBA/NCSEA to require DEC and DEP to base their avoided capacity rates on an aeroderivative gas turbine at this time.

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

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

Summary of the Comments

Duke Energy's JIS explains that DEC and DEP developed respective avoided capacity rates consistent with the methodology the Commission approved in the 2018 Sub 158 Order and the 2020 Sub 167 Order as appropriately implementing N.C.G.S. § 62-156(b)(3). As background, Duke Energy explains that 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. *Id.* at 10 (Finding of Fact Nos. 19, 22). Duke Energy followed this directive, identifying each utility's next year of avoidable undesignated capacity in their 2020 IRPs and using those dates to determine avoided capacity costs in the 2020 Sub 167 proceeding.

Duke Energy's JIS 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 annual updates to their IRPs. JIS at 15-16; JIS DEC/DEP Exhibit 8 at 2. Duke Energy explains that DEC and DEP last filed their identified first resource needs with the Commission in September 2020 as part of their 2020 IRPs. Because the Commission's June 29, 2021 Order in Docket No. E-100, Sub 165 waived DEC's and DEP's obligation to file 2021 IRP updates under Rule R8-60(h)(2), DEC and DEP did not file 2021 IRP updates presenting an updated assessment of their respective first year of undesignated capacity need in 2021. Accordingly, Exhibit 8 to Duke Energy's JIS presents DEC's and DEP's updated first years of undesignated capacity need, calculated as of October 2021. *Id.*

Compared to the standard offer avoided cost rates approved in the 2020 Sub 167 proceeding, DEC's first year of avoidable undesignated capacity need shifts outward from 2026 to 2028. DEC explains that the shift to 2028 reflects the additional approximately 175 MW of designated capacity that will be added to the DEC system through the Integrated Volt/Var Control (IVVC) program, which the Commission approved in March 2021. DEP's first year of avoidable undesignated capacity need remains the same at 2024. Due to the passage of time, for DEP, this represents an earlier capacity need than used in the prior 2020 Sub 167 avoided cost rates.

Finally, Duke Energy explains in its JIS that, consistent with the 2020 Sub 167 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 MW, are assigned immediate capacity value.

In its Initial Statement, the Public Staff sets out the procedural history of the Commission's directive that utilities should develop avoided capacity rates, taking into account the utility's next year of identified avoidable undesignated capacity need. After analyzing DEC's and DEP's updated first years of need, the Public Staff finds 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 and based upon the most recently filed IRP. No other parties commented on this issue.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission determines that Duke Energy has calculated DEC's and DEP's avoided capacity cost rates consistently with the North Carolina General Statutes and the Commission's prior *2018 Sub 158 Order* and *2020 Sub 167 Order* on this matter. N.C.G.S. § 62-156(a)(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. Further, the Commission finds DEC's and DEP's updated calculation of their respective first years of unavoidable capacity need to be reasonable. DEC has appropriately adjusted its first year of need to 2028 to reflect the additional approximately 175 MW of designated capacity that will be added to the DEC system through the IVVC program approved by the Commission in March 2021. Accordingly, based on the foregoing, the Commission finds and concludes that DEC's and DEP's first year of need and proposed avoided capacity rates are reasonable, appropriate, and should be approved.

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

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

<u>Summary of the Comments</u>

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. Specifically, Duke Energy explains, in the 2018 Sub 158 proceeding, the Commission approved the continued recognition of a PAF in determining the appropriate calculation of avoided capacity to be paid to QFs. The 2018 Sub 158 Order reiterated the 2016 Sub 148 Order's finding that inclusion of a PAF in avoided capacity rates is appropriate and should be based upon a metric or metrics that assess generating unit "availability." As Duke Energy explains, the Commission approved Duke Energy's proposed PAF of 1.05 in the

2018 Sub 158 proceeding based upon the equivalent availability EA metric and the use of five years of historic outage rate data during Duke Energy's critical peak season months. Sub 158 Order at 41. In accepting Duke Energy's utilization of the EA metric for calculating the PAF, Duke Energy explains, the Commission additionally accepted the Public Staff's recommendation for the utilities to consider other reliability metrics besides the EA. The Commission directed Duke Energy and the Public Staff to address the appropriateness of using the Equivalent Unplanned Outage Rate ("EUOR") metric in the following 2020 Sub 167 proceeding.

Duke Energy explains that DEC and DEP continued to utilize the EA metric to calculate the PAF in the 2020 Sub 167 proceeding in an effort to "streamline" the 2020 avoided cost proceeding. Nevertheless, Duke Energy states that it committed to discussing the appropriateness of utilizing the EUOR metric with the Public Staff prior to this avoided cost proceeding. Based on that commitment, Duke Energy explains, the Commission urged the parties to try to reach consensus on the appropriateness of using the EUOR metric prior to their initial filing in the present docket.

In preparation for this avoided cost proceeding, Duke Energy states that it worked with the Public Staff and DENC to consider the use of the EUOR metric and other reliability metrics for developing the PAF. Based on these discussions, Duke Energy explains, Duke Energy, the Public Staff and DENC reached a consensus to adopt the Equivalent Unplanned Outage Factor ("EUOF") metric for developing the PAF. Similar to the EUOR metric, the EUOF metric includes the impact of maintenance outages that can also occur during peak demand periods and appropriately excludes planned outages from the calculation. Duke Energy explains that it compiled five years (2016-2020) of Generating Availability Data System ("GADS") data and calculated EUOF for the entire generation fleet, excluding DEC and DEP-owned solar resources, which is consistent with the practice of using five years of GADS data in Duke Energy's planning models. According to Duke Energy, use of the EUOF metric also allowed it to align calculation of the PAF with the actual periods that DEC and DEP pay for capacity. For DEC, Duke Energy states, this includes the winter months of December-March and summer months of July-August. To align with DEP's actual capacity payment period, Duke Energy explains that the DEP data was based only on the winter months of December-March and does not include any summer months. Based upon these calculations and the agreed-upon methodology, Duke Energy states that DEC's and DEP's respective system weighted EUOF (WEUOF) during this timeframe averages to approximately 4%, which results in a PAF of 1.04 for both DEC and DEP.

The JIS also explains Duke Energy's position on continuing the PAF for hydroelectric ("hydro") QFs that are eligible for the standard offer (1 MW and less). In past biennial avoided cost proceedings, Duke Energy notes, North Carolina's legacy implementation of PURPA afforded hydro QFs with unique legislative treatment that resulted in the Utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[3] JIS at 21. As Duke Energy notes, the Commission approved a 2.0 PAF for run-of-river hydro QFs more than two decades ago in the 1996 avoided cost proceedings in Docket No. E-100, Sub 79. JIS at 22 (*citing* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 79, at 19 (issued June 19, 1997)). Based in part on that unique legislative treatment and the Commission's then-existing 2.0 PAF for run-of-river hydro QFs, Duke Energy explains that DEC, DEP and the NC Hydro Group entered into a stipulation in Docket No. E-100, Sub 140 (Hydro Stipulation), agreeing that, among other things, Duke Energy would continue to include the previously-approved 2.0 PAF in standard offers, to calculate the avoided cost rates for small hydro QFs of 5 MW or less through December 31, 2020. JIS at 22 (*citing* Hydro Stipulation, at ¶¶ 3(a), 4)).

Duke Energy explains that the General Assembly amended the State's implementation of PURPA through HB 589 in 2017 and HB 329 in 2019 to no longer designate hydroelectric generating facilities as unique small power producers, while, at the same time, establishing flexibility for Duke Energy 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. JIS at 22 (*citing* N.C.G.S. §§ 62-156(b)(3), (c)). Because of these 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." JIS at 22 (*citing* Sub 158 Order at 42)).

Duke Energy next explains that in the 2020 Sub 167 proceedings, when the expiration of the Hydro Stipulation was imminent, Duke Energy stated that it would retain the 2.0 PAF for run-of-river hydro QFs 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 December 31, 2020. Accordingly, Duke Energy explains, it indicated that it would include the 2.0 PAF for negotiated PPAs with hydro QFs greater than 1 MW but less than 5 MW until December 31, 2020. JIS at 23 (*citing* Joint Initial Statement, Docket No. E-100 Sub 167, at 17-18 (filed November 2, 2020)). In the 2020 Sub 167 Order, Duke Energy notes, the Commission cited the expiration of the Hydro Stipulation and agreed with Duke Energy's conclusion 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." Sub 167 Order at 20. As Duke Energy explains, the Commission also directed Duke Energy to address the appropriate PAF for run-of-river hydro QFs 1 MW and less in this avoided cost proceeding. JIS at 23.

[3] Prior to HB 589's enactment in 2017, 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)).

In addressing this issue for this avoided cost proceeding, Duke Energy explains that it is now appropriate to also discontinue the elevated PAF for run-of-river hydro QFs with capacity of 1 MW or less. Both the Hydro Stipulation and the 2020 Sub 167 standard offer have expired. Thus, in this first avoided cost proceeding following the expiration of the Hydro Stipulation, Duke Energy proposes standard offer avoided cost rates for run-of-river hydro QFs that reflect the same standard PAF of 1.04 for all QFs, not the elevated and outdated PAF of 2.0 for only run-of-river QFs with capacity at or under 1 MW. JIS at 23.

In its Initial Statement, DENC explains that for the purposes of the streamlined 2020 Avoided Cost Case, it continued to apply the PAF that was approved in the Sub 158 Order and the Commission approved this proposal in the Sub 167 Order. DENC notes that the Sub 158 Order directive regarding PAF became one of the Sub 158 Additional Issues that DENC discussed with Public Staff on multiple occasions. For purposes of this proceeding, DENC reached consensus with the Public Staff that DENC will use the Weighted Equivalent Unforced Outage Factor (WEUOF), which accounts for unit unavailability caused by maintenance and forced outages, to determine the PAF. DENC agreed with the Public Staff to use a 5-year average, instead of the previously used 3-year average, to calculate the WEUOF. DENC and Public Staff also agreed that DENC will have the flexibility to determine the months to be used in the overall PAF calculation, and would provide support for use of those months in DENC's Initial Statement. As a result, for this proceeding, DENC calculated a PAF of 1.07 using 5 years of history for the months January, February, June, July, and August and it utilized these months for consistency with PJM's "Peak Period Months" in the PJM Manual 10. DENC Initial Statement at 23-24.

In its Initial Statement, the Public Staff agrees with DEC's, DEP's, and DENC's proposed PAF adjustments and supported the use of the WEUOF metric for each utility's respective generation fleet. The Public Staff notes, however, that the WEUOF is calculated using data from GADs, which does not currently require solar generation reporting. Because neither Duke Energy nor DENC report outages from their solar generation facilities into GADs, the Public Staff notes that solar outage data is excluded from the WEUOF. The Public Staff recognizes that solar outage data at this time would be unlikely to impact the WEUOF and the PAF, but Duke Energy and DENC are now subject to carbon reduction legislation requiring the construction or acquisition of utility-owned solar assets. Therefore, the Public Staff recommends that Duke Energy and DENC address the inclusion of solar and wind generator outage data in calculating the PAF in their next avoided cost filing and the current status of outage reporting requirements set by the North American Electric Reliability Corporation ("NERC"), which maintains GADS.

In their Reply Comments, Duke Energy agrees with the Public Staff's recommendation to address solar and wind generator outage data in calculating the PAF in DEC's and DEP's next avoided cost filing. According to Duke Energy's Reply Comments, at that time, the 2021 NERC GADS Section 1600 Data Request and public comment, proposed mandatory reporting to GADs for solar facilities: (1)

50 MW or more to GADS is scheduled to begin in 2023 and (2) total installed capacity of 20 MW or more is scheduled to begin in 2024. However, Duke Energy notes that NERC plans to issue a revised data request and second comment period this summer; thus, the mandatory reporting duties may be delayed. With the expected growth in in utility-owned solar and potential wind facilities, Duke Energy believes that including these facilities in the determination of the PAF once the GADs data becomes available is appropriate. Therefore, Duke Energy agrees agreed to address inclusion of the solar and wind generator outage data in the PAF calculation in future avoided cost filings.

In its reply comments, DENC does not oppose the Public Staff's recommendation, and if the Commission agrees with the Public Staff, will address the appropriateness of including solar and wind generator outage data in the calculation of the PAF in its initial filing for the next biennial avoided cost proceeding. DENC also states that it does not oppose providing the status of NERC outage report requirements in the next biennial proceeding, should the Commission find that to be appropriate. DENC states that when the NERC reporting requirements, outage coding protocols, and any updated WEOUF calculation definitions are known, it will be best able to address the appropriateness of including solar outage data in the calculation of its PAF, including whether incorporation of such data could be accomplished in a manner consistent with the peaker method. (DENC Reply Comments at 4-5.)

Discussion and Conclusions

Based on the foregoing, the Commission finds and concludes that Duke's proposed PAFs of 1.04 for all QFs, including hydro QFs, is reasonable and appropriate. As directed by the Commission, Duke Energy, DENC, and the Public Staff worked together prior to the filing of Duke Energy's JIS to consider the use of other reliability metrics for developing the PAF. These discussions resulted in a consensus to adopt the WEUOF metric for each utility's respective generation fleet. No party contested this methodology. Accordingly, the Commission finds and concludes that the WEUOF metric is a reasonable and appropriate to use in this avoided cost proceeding and future avoided cost proceedings to calculate the PAF.

At this time, the system WEUOF calculation is based on the performance of the respective DEC and DEP generation fleets, excluding the Company-owned solar facilities. The Commission agrees with the Public Staff that solar outage data, at this time, is unlikely to impact the WEUOF and the PAF. The carbon reduction legislation that explicitly directs Duke Energy to build or acquire utility-owned solar assets, however, will result in growth in Duke Energy-owned solar and potential wind facilities. Duke Energy and the Public Staff agreed that including these facilities in the determination of the PAF once the GADS data for these facilities becomes available is reasonable and appropriate. The Commission likewise agrees and, therefore, directs Duke Energy to address the inclusion of solar and wind generator outage data in the PAF calculation in future avoided cost proceedings.

The Commission also 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. The Hydro Stipulation has expired, and no party offered any justification for extending the 2.0 PAF any longer. The General Assembly has amended the unique legislation that supported the smaller, run-of-river hydro receiving a 2.0 PAF. Moreover, for the reasons set forth above, a 2.0 PAF is excessive and outdated. Accordingly, the Commission approves Duke Energy's proposed 1.04 PAF for all QFs eligible for the standard offer.

AVOIDED ENERGY COSTS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

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

Summary of the Comments

The JIS states that DEC and DEP began relying upon ten years of forward contract natural gas market price data in 2014 to forecast commodity prices and have continued to use this same methodology in the IRP proceedings in 2016, 2018, and 2020. Duke Energy notes, however, that for avoided cost purposes the Commission determined in the 2016 Sub 148 Order, 2018 Sub 158 Order, and 2020 Sub 167 Order, that DEC and DEP should be required to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period. 2016 Sub 148 Order at 109 (Ordering Paragraphs 5-6); 2018 Sub 158 Order at 136 (Ordering Paragraph 20); 2020 Sub 167 Order at 60 (Ordering Paragraph 12). Duke Energy explains that, in a good faith effort to reduce the number of potential contested issues for the Commission's determination, it has elected to extend that approach in this proceeding. Duke Energy specifies that it is relying upon forward market price data for eight years (2022-2029) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating its avoided energy cost rates before transitioning to fundamental forecast data starting in year nine (2030-2031). Duke Energy explains that the market prices were obtained from an actual forward purchase to determine the market price of gas and forward market liquidity. Duke Energy notes that this approach is consistent with the 2018 Sub 158 Order and the 2020 Sub 167 Order, and it achieved consensus with the Public Staff on this approach. JIS at 25-26.

In its Initial Statement, the Public Staff explains that it has reviewed Duke Energy's Prosym inputs for the price forecasts for delivered natural gas and found them to be reasonably consistent with the 2020 Sub 167 Proceeding and appropriate for this proceeding. Public Staff Initial Statement at 40.

In its Initial Comments, SACE states that Duke Energy's natural gas commodity price forecast methodology should be revised, and an eight-year-forward-contract methodology inherently produces inaccurate results for the same reasons SACE presented in the 2016 Sub 148 Proceeding, 2018 Sub 158 Proceeding, and 2020 Sub 167 Proceeding. SACE states that two recent developments indicate that Duke Energy's natural gas commodity price forecast methodology is ripe for revisions. First, SACE notes that Duke Energy's Carbon Plan will replace Duke Energy's 2022 biennial IRP. For the Carbon Plan, Duke Energy proposed to replace the ten-year-forward-contract methodology used in its prior IRPs with five years of market gas followed by a three-year blend to fundamentals. SACE also notes that in the Carbon Plan, for its market fundamentals forecast, Duke Energy plans to use an average of "EIA, EVA, HIS and Wood MacKenzie" in an effort to decrease volatility from year to year, and SACE explains that this is consistent with SACE's and other intervenors' recommendation in the 2020 Sub 167 Proceeding to average fundamental forecasts. SACE criticizes Duke Energy's reliance in this proceeding on IHS, alone, for its fundamental forecast because it is a private forecast with, according to SACE, opaque methodology. To remedy this, SACE recommends that the Commission require Duke Energy to blend IHS forecasts with the public, more transparent EIA data for purposes of the fundamental forecast in this proceeding. SACE Initial Comments at 18-21.

SACE states that the increase in natural gas prices over the past year shows the potential inaccuracy of forward market prices and the benefit of blending multiple fundamental forecasts to reduce inaccuracies due to commodity volatility. SACE states that the Commission should require Duke Energy to adopt the basic methodology applied by DENC using 18 months of forward market prices, 18 months of blended prices, before switching fully to fundamental forecasts, averaging the Spring 2021 IHS and EIA 2021 Reference Case data for purposes of the fundamental forecast. SACE states that this approach is essentially identical to the approach required by the South Carolina Public Service Commission in Duke Energy's recent IRP proceeding. SACE Initial Comments at 22-23.

CCEBA/NCSEA state in their Initial Comments that the Commission has previously found that it is appropriate for Duke Energy to apply the same natural gas forecast methodology in its IRP proceeding that it uses to calculate avoided cost rates. CCEBA/NCSEA recommend that the Commission require Duke Energy to use fewer years of forward market prices, with a transition to fundamental forecasts for the remainder of the applicable planning period. Specifically, Joint Intervenors recommend that the Commission require Duke Energy to adopt the recommendations of Witness Lucas as presented in the 2020 IRP Proceeding, which would require Duke Energy to utilize 18 months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period. CCEBA/NCSEA Initial Comments at 21-22.

In its Reply Comments, Duke Energy notes that its natural gas forecasting methodology is consistent with the Commission's orders in the past three avoided cost dockets, all of which direct Duke Energy to use no more than eight years of forward natural gas market prices before transitioning to fundamental forecasts. In addition, Duke Energy notes the Commission's November 19, 2021 Order Accepting Integrating Resource Plans, REPS and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning (Sub 165 IRP Order) directed Duke Energy to follow this same forecasting methodology—eight years of forward market prices before transitioning to fundamentals—in the development of its Carbon Plan filing. Duke Energy Reply Comments at 14-16. Duke Energy states that SACE and CCEBA/NCSEA's comments largely reiterate the same points that each party made in past proceedings on the issue of natural gas forecasting methodology. Duke Energy states that the Commission should reject SACE's and CCEBA/NCSEA's recommendations in this proceeding and instead find that Duke Energy's proposed methodology is reasonable and appropriate for use in this proceeding and consistent with the Commission's recent orders on this issue. Duke Energy Reply Comments at 14-16.

In its Reply Comments, the Public Staff states that it does not recommend Duke Energy recalculate its avoided energy rates in this proceeding using a different natural gas forecasting methodology because the current methodology technically complies with past Commission orders and is in alignment with the natural gas forecasting methodology in the 2020 IRP Supplemental Portfolio B. The Public Staff believes that the natural gas forecasting methodology should remain consistent between the IRP and avoided cost determinations. In addition, the Public Staff notes that, in stakeholder meetings related to the 2022 Carbon Plan, Duke Energy has indicated it intends to use five years of forward market prices followed by a three-year period blending forward market prices with a fundamental price forecast. While the Public Staff states that it supports this approach and recommends that Duke Energy use this forecasting methodology in future avoided cost filings, it does not recommend adoption of the new methodology at this time given that Duke Energy had not yet filed its Carbon Plan at the time of its avoided costs filing. Public Staff Reply Comments at 3-4.

Discussion and Conclusions

As a threshold matter, the Commission acknowledges that this issue has been contentious in the last three avoided cost proceedings. Duke Energy's proposed natural gas forecasting methodology in this proceeding is consistent with the methodology approved by the Commission in the last three avoided cost proceedings as well as recent in the Sub 165 IRP Order, and the Public Staff has agreed that Duke Energy's proposed methodology is appropriate for use in this proceeding. Accordingly, after careful consideration, the Commission is not persuaded that a change in the fuel forecasting methodology approved in the 2020

Sub 167 Order, the 2018 Sub 158 Order, and the 2016 Sub 148 Order is appropriate at this time.

The Commission is not persuaded, at this time, by the SACE's and CCEBA/NCSEA's recommendation that the Commission require Duke Energy to use 18 months of forward market prices then transition to at least 18 months of blended prices (and then, in the case of SACE, switch fully to a fundamental forecast). However, the Commission is open to revisiting this decision in the 2023 biennial avoided costs proceeding, which will take place after the Commission has approved an initial Carbon Plan and, with it, a likely updated natural gas forecasting methodology. The Commission further notes that Duke Energy's natural gas forecasting methodology proposed in its Carbon Plan may be more appropriate for use in the subsequent avoided cost biennial proceeding.

The Commission is likewise unpersuaded by SACE's recommendation that the Commission require Duke Energy to modify its assumptions by averaging the Spring 2021 IHS Henry Hub prices with the publicly available EIA 2021 Reference case. The Commission notes that the Public Staff supports Duke Energy's use of IHS price forecasts in this proceeding, and any intervenor who believes Duke Energy's fundamental forecast is inappropriate may freely and persuasively make that point in comments by citing to publicly available forecasts as a comparison.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to approve Duke's methodological approach of calculating avoided energy costs using market-based forward contract natural gas prices for no more than eight years before using 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 that no change is needed to DEC's and DEP's approach of relying on fundamental forecasts for Henry Hub prices, as developed by IHS, which is consistent with Duke's 2020 IRPs. The Commission will not require the DEC and DEP to average those forecasts with EIA's 2021 Reference case as recommended by the SACE.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

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

<u>Summary of the Comments</u>

The Public Staff's Initial Statement summarizes its general concern regarding Duke Energy's reliance on forecasted lower cost natural gas pricing utilizing the Appalachian basin's lower cost Dominion South hub (DS Hub), which the Public Staff addressed in its Initial Comments in the 2020 Sub 165 IRP Proceeding. The Public Staff explains that the Commission's Sub 165 IRP Order required Duke Energy to file a Supplemental 2020 IRP Limited DS Hub Gas portfolio, which Duke Energy filed on February 9, 2022 (Supplemental Portfolio B). Public Staff explains that relative to Duke Energy's Portfolio B which had no limits on gas transportation access assumptions, Supplemental Portfolio B contained 2,448 MW fewer natural-gas fired combined cycle generation in the 15-year plan, and this reduction was replaced with CTs, solar and solar plus storage, and onshore wind. Public Staff explains that this shift increased projected total system costs through 2050 by 5.2 billion, or 6.3%. The Public Staff states that it does not recommend the use of Supplemental Portfolio B as the basis for calculating avoided energy rates, but states that it would address this issue, the appropriate level of reliance on current gas transportation assumptions, and its concerns with the Mountain Valley Pipeline's (MVP) construction delays in its supplemental IRP comments and its comments on Duke Energy's 2022 Carbon Plan. Public Staff Initial Statement at 41-42.

In Reply Comments, SACE states that it shares the Public Staff's concern that Duke Energy's longer-term projections of avoided energy costs may be inaccurate due to potential overreliance on lower-priced shale gas, which depends on the assumption that certain gas pipelines will be constructed. Nevertheless, SACE agrees with the Public Staff's recommendation not to use the Supplemental Portfolio B as the basis for calculating avoided energy rates in this proceeding. SACE recommends close scrutiny of avoided energy calculations in future proceedings to ensure that they are based on accurate assumptions about gas transport. SACE Reply Comments, at 6.

In its Reply Comments, Duke Energy acknowledges the concerns raised by the Public Staff regarding DEC's and DEP's reliance upon forecasted lower cost natural gas pricing utilizing the DS hub. Duke Energy notes that despite these concerns and the uncertain regulatory future for the MVP pipeline, the Public Staff does not recommend the use of Supplemental Portfolio B as the basis for calculating avoided energy rates at this time. Duke Energy also notes that on March 30, 2022, the Public Staff filed its comments on Supplemental Portfolio B in the 2020 Sub 165 IRP proceeding and recommended that DEC and DEP limit their reliance on Appalachian Gas in modeling the Carbon Plan. Supplemental Reply Comments of the Public Staff, Docket No. E-100, Sub 165 at 6-7. Duke Energy explains, however, that the Public Staff did not propose any recommended modifications to avoided costs in this proceeding. Duke Energy finally states that the extent of its reliance on DS Hub gas is an issue that will be further considered as part of the 2022 Carbon Plan and updated as regulatory circumstances surrounding the MVP pipeline provide more clarity regarding its eventual viability. Duke Energy Reply Comments at 16-17.

Discussion and Conclusions

Similar to the issues raised in the 2020 Sub 167 Proceeding, the Public Staff in this proceeding is identifying the planning uncertainties around needed new natural gas transportation capacity into North Carolina in light of the recent Atlantic Coast Pipeline cancellation as well as the challenging recent regulatory landscape for building newer natural gas pipelines, such as the MVP. Duke Energy continues to not dispute that those planning uncertainties exist. After analysis of Duke Energy's supplemental filing in the 2020 IRP Proceeding and Supplemental Portfolio B, however, the Public Staff and SACE ultimately do not recommend any revisions to Duke Energy's methodology or reliance on existing gas transportation assumptions for the purposes of this proceeding. As a result, regarding the reasonableness of Duke Energy's natural gas forecasting transportation assumptions in this proceeding, the Commission finds the Public Staff's and SACE's stated concerns as well as Duke Energy's responses to be reasonable and appropriate for purposes of this proceeding. The Commission agrees that this issue is best addressed in the IRP context and, this year, through the 2022 Carbon Plan proceeding, as changing natural gas availability assumptions have fundamental implications for many aspects of the IRP, including the timing of coal generation retirements and the selection of resources that could reliably replace coal units while also reliably meeting load growth.

In summary, the Commission accepts Duke Energy's use of its natural gas transportation and pricing assumptions as reasonable for purposes of calculating avoided costs in this proceeding. In its review of the 2022 Carbon Plan in Docket No. E-100, Sub 179, the Commission may give further consideration to the appropriateness of Duke Energy's gas transportation assumptions for purposes of resource planning and other future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

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

<u>Summary of the Comments</u>

Duke Energy's JIS notes that the issue of whether to pay QFs an avoided fuel hedging value for their must-purchase power under PURPA has been contested in prior avoided cost proceedings. In the 2018 Sub 158 Order, Duke Energy explains, the Commission determined that renewable generation is capable of providing fuel price hedging benefits and, accordingly, required DEC and DEP to recalculate their avoided energy rates to include a fuel hedging adjustment utilizing the Black-Scholes Model to determine the hedging value of renewable generation. After conferring with the Public Staff, Duke Energy states that DEC and DEP updated their avoided energy rate calculations to incorporate the same hedge value that the Commission approved for DENC in the 2018 Sub 158 Order. For purposes of the streamlined 2020 Sub 167 proceeding, Duke Energy explains that DEC and DEP developed their respective avoided energy rates to again incorporate the same avoided fuel hedge value accepted for DENC in the 2018 Sub 158 proceeding, while continuing to question the appropriateness of this adjustment. As Duke Energy notes, the 2020 Sub 167 Order directed all interested parties to address the issue in this 2021 avoided cost proceeding. JIS at 26-27.

Duke Energy states that after discussing this issue with the Public Staff and, continuing to try to reduce the number of potential contested issues for the Commission's determination, DEC and DEP have used the Black-Scholes option pricing method to calculate a fuel hedging adjustment that aligns with the methodology used by DENC and accepted by the Public Staff and the Commission in recent avoided cost proceedings. According to Duke Energy, DEC's and DEP's Black-Scholes calculation results in a fuel hedge value of $0.02 per MWh, and DEC and DEP incorporated that value in their avoided energy rates in this docket. JIS at 27.

DENC recalls in its Initial Statement that in the December 31, 2014 Order Setting Avoided Cost Input Parameters issued in the Sub 140 Phase One Order, the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC also recalls that in Phase Two of that proceeding, the Commission's December 17, 2015 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities required the Utilities to utilize the Black-Scholes Model, or a similar model, to determine the fuel price hedging value of renewable generation. Consistent with its proposal in the Sub 148, Sub 158, and Sub 167 Avoided Cost Cases, DENC proposes to continue to use the same Black-Scholes Option Pricing Model to determine fuel hedging benefits that was proposed by the Public Staff in Docket No. E-100, Sub 140, with a resulting fuel price hedging value of $0.02/MWh, which was assumed constant for all years of the Schedule 19-FP contract. *Id*. at 9-10.

The Public Staff reports on its review of Duke Energy's hedging value in its Initial Statement. The Public Staff notes that Duke Energy included fuel hedging benefits in avoided energy calculations, based on the Black-Scholes option pricing model, using an estimate for gas volatility, risk-free interest rates, and a strike price, which yielded a fuel hedging value of $0.02 per MWh to supplement its avoided energy rates. The Public Staff agrees that this was consistent with the Commission's 2018 Sub 158 Order, and it recommended no changes or modifications to Duke Energy's fuel hedging value. Public Staff Initial Statement at 47-48.

Other than DEC's and DEP's acknowledgement that the fuel hedging value was an area that they and the Public Staff had come to agreement on prior to November 1, 2021 filing of the JIS, no party raised the issue of the fuel hedging value in reply comments.

Discussion and Conclusions

To reduce the number of contested issues before the Commission in biennial avoided cost cases, Duke Energy and the Public Staff have worked to develop reasonable, standardized, and repeatable methodologies to resolve avoided cost issues that are typically contentious. The Commission recognizes that the issue of the appropriate hedging value to use when calculating avoided energy cost rates has been one of those contested issues in past proceedings. In this proceeding, however, Duke Energy and the Public Staff have agreed upon an appropriate hedging value and methodology for calculating that value. In fact, no party contested Duke Energy's methodology for calculating the fuel hedging value or the fuel hedging value of \$0.02 per MWh itself. The Commission agrees with the Public Staff that the calculation was consistent with the 2018 Sub 158 Order. Therefore, based on the foregoing, the Commission concludes that Duke Energy's fuel hedging value is reasonable and should be approved. In addition, the Commission finds and concludes that the methodology that Duke energyused to calculate the hedging value is reasonable and appropriate for use in future avoided cost proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

<u>Summary of the Comments</u>

DEC's and DEP's avoided costs calculation methodology does not include an assumed avoided cost of carbon emissions, and Duke Energy's JIS is silent on the issue. In its Initial Statement, the Public Staff notes that Duke Energy calculated avoided energy rates using Portfolio A from DEC's and DEP's 2020 IRPs, which is the base case without carbon policy. The Public Staff acknowledges that HB 951 imposes a limit on total CO_2 emissions (mass cap), but notes that it does not impose a direct price on CO_2 emissions. Further, while setting a mass cap in capacity expansion models will yield a model result with an implied cost of carbon, the Public Staff notes that not all of the total cost of carbon abatement is avoidable in the context of calculating avoided costs. *Id.* at 8-9. By way of example, the Public Staff explains that a portion of the implied cost of carbon derived from the Carbon Plan may include higher capital costs associated with the purchase or construction of new renewable generation facilities, but that some of those costs may not be avoided when purchasing incremental renewable energy from QFs. Accordingly, the Public Staff takes the position that the implied cost of carbon resulting from HB 951 cannot be accurately determined until a Carbon Plan is approved and recommends that the Commission approve DEC's and DEP's avoided costs rates using Portfolio A without a carbon price at this time. Once a Carbon Plan is approved and an avoidable cost of carbon, if any, is determined within those proceedings or in subsequent proceedings, the Public Staff recommends that the Commission direct DEC and DEP to use the Carbon Plan as the expansion portfolio and include any Commission-approved avoidable cost of carbon in its calculation of rates in the next avoided cost filing. Public Staff Initial Statement at 6-9.

SACE argues that the carbon reduction mandates of HB 951 are "self-executing" and make it possible to calculate a known and verifiable cost of carbon appropriate to be factored into avoided cost rates in this proceeding and in advance of a Commission-approved Carbon Plan. Recognizing that the Carbon Plan has not yet been finalized and approved by the Commission, SACE argues that the Commission could look to Duke Energy's base case with carbon policy in their respective 2020 IRPs as a reasonable proxy for the price of carbon. SACE further argues that HB 951's mandate to "take all reasonable steps" to achieve the stated carbon reduction mandates "arguably requires the Commission to include a cost of carbon in avoided cost rates" since establishing a cost of carbon in avoided cost rates would increase the cost of carbon-emitting generation and encourage zero-emitting generation and reduce emissions. For all of these reasons, SACE argues that the Commission should order Duke to recalculate its avoided costs using Duke's 2020 IRP base case with carbon policy or the Regional Greenhouse Gas Initiative (RGGI) allowance cost as a reasonable proxy for the applicable cost of carbon, starting at $5/ton in 2025 and escalating at a rate of $5/ton per year thereafter. SACE Initial Comments at 33-34.

Duke Energy addresses SACE's argument in Reply Comments. Similar to the Public Staff, DEC and DEP note that the Commission has previously determined—including most recently in the 2020 Sub 167 Order—that carbon emission-related cost would only be avoidable where such costs are "known and verifiable,"[4] and that the FERC has held 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. *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," the costs "may be accounted for in a determination of avoided cost rates"). Duke Energy argues that SACE fails to explain how incorporation of a hypothetical backward-looking carbon cost adder that is not based on any known or measurable carbon price or tax into the avoidable costs to be paid by ratepayers to QFs contracting under the Schedule PP is reasonable—let alone needed—to achieve HB 951's carbon reduction goals. Instead, Duke Energy states that it is amenable and agrees to the solution proposed by the Public Staff—that the future base portfolio selected from the Carbon Plan should be used to calculate avoided cost rates in the next biennial avoided cost proceeding. Duke Energy notes that because the Commission will formally approve the Carbon Plan, the modeled cost of the resources identified to

[4] *2020 Sub 167 Order*, at 7, 33 (recognizing that "ratepayers should not bear speculative or uncertain costs that are not avoided through purchase of power from a QF through the avoided cost rates that they ultimately pay"); *see also Sub 140 Phase One Order* at 8 (Finding of Fact 14), 42–44 .

meet HB 951's carbon reduction goals will then be known and verifiable. DEC/DEP Reply Comments, at 17-21.

Duke Energy further recommends that the Commission consider whether renewable energy credits and environmental attributes should be credited to customers if customers are paying QFs for avoided carbon benefits of generation. It explains that, in conjunction with mandating CO_2 emission reduction targets in North Carolina, HB 951 also ensures that all environmental attributes associated with new generation selected by the Commission in the Carbon Plan are conveyed to the utility for the benefit of its customers, *see* Session Law 2021-165. Part I, §. 2.b., while the traditional standard PURPA contract does not convey such attributes. To the extent that avoidable cost of carbon emissions reductions are to be included in any fashion as part of future avoided energy costs for QF purchases, the utility and customers should obtain all environmental and renewable attributes in the same manner as utility-owned and third-party solar resources procured under the Carbon Plan. DEC/DEP Reply Comments at 21.

In its Reply Comments, SACE opposes the Public Staff's proposal that the Commission should wait until after the Carbon Plan is approved to include an implied cost of avoided carbon emissions in DEC's and DEP's avoided costs calculations, arguing that the Carbon Plan will continue to evolve, and suggest that the Commission should not wait until all inputs are absolutely certain before it includes an avoided cost of carbon in avoided cost rates. SACE Reply Comments at 2-3. CCEBA/NCSEA, in their Reply Comments, agree with SACE that it would not be appropriate to delay the modeling of Carbon Plan compliance for avoided cost purposes until 2030 when the 70% reduction mandate is required. CCEBA/NCSEA do not object to the Public Staff's proposal to further evaluate the appropriate application of the Carbon Plan in the calculation of avoided cost rates after approval of the Carbon Plan. However, CCEBA/NCSEA propose that it would be appropriate for the parties to address this issue *before* DEC and DEP make their 2023 avoided cost filings, in either this proceeding, the Carbon Plan proceeding, or in some other docket in the Commission's discretion. CCEBA/NCSEA Reply Comments at 4.

Discussion and Conclusions

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that it is not appropriate to include an implied cost of avoided carbon emissions in DEC's and DEP's avoided costs calculations at this time. As the Commission has previously concluded, North Carolina ratepayers should not bear speculative or uncertain costs that are not avoided through the purchase of power from a QF through the avoided cost rates that they ultimately pay. Instead, DEC and DEP should base their avoided costs on "known and verifiable" costs, which do not include the costs of carbon emissions. The Commission's 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. Similarly, the FERC has explained that, if environmental costs are real costs that would be incurred by utilities, they may be accounted for in a determination of avoided cost rates. Cal. Pub. Utility Comm'n., 132 FERC ¶ 61,047, 61, 267-68 (July 15, 2010). Under this precedent, DEC and DEP have appropriately calculated avoided energy costs that do not include carbon emissions-related costs in this proceeding.

The Commission does not agree with SACE's assertions that carbon emission costs now are "known and verifiable" in light of the North Carolina General Assembly's passage of HB 951. As both Duke Energy and the Public Staff note, there is no certainty regarding the resources to be developed or any future implied cost of carbon to be included in the approved Carbon Plan and, therefore, there are no real or known and verifiable costs associated with future carbon emission reductions under the Carbon Plan that should be avoidable at this time. The Commission similarly rejects SACE's argument that Duke Energy's 2020 IRP base case with carbon policy portfolios could serve as a reasonable proxy for an implied cost of carbon in advance of developing the Carbon Plan.

In sum, CCEBA/NCSEA and SACE have provided no justification for the Commission to depart from its prior determinations—, which are consistent with the FERC's determinations—, that unknown and speculative costs should not be included when calculating avoided cost rates that will be passed along to customers. A review of the Commission's conclusion on this issue in 2014 demonstrates that the circumstances in that proceeding do not differ so very much from the economic and regulatory circumstances in this avoided cost proceeding with respect to this issue:

> While the EPA has proposed to regulate CO2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time. The end result of the proposed regulations is speculative at best, and, as Public Staff Hinton noted, the Commission has previously concluded that "[q]uantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." If and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable.

Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, at 42-44 (Dec. 31, 2014).

In sum, the Commission concludes that SACE has not demonstrated that the time is yet ripe for the Commission to depart from its prior conclusions on this matter. The Commission agrees with the Public Staff that the implied cost of carbon resulting from HB 951 cannot be accurately determined until a Carbon Plan is approved and therefore finds the DEC's and DEP's avoided costs rate calculation's use of DEC's and DEP's 2020 IRP Portfolio A without a carbon price appropriate at this time. Further, the Commission declines to order, as SACE recommends, that the parties address this recommendation before the DEC and DEP make their next comprehensive avoided cost filing in 2023. The Commission notes that the Carbon Plan must be approved no later than December 31, 2022, and that DEC's and DEP's next biennial avoided cost filings will be due in November 2023. Accordingly, the Commission finds that there is insufficient time to address this issue in a separate filing before DEC and DEP make their next biennial avoided costs filing.

The Commission does, however, expect and hereby directs the DEC and DEP to explain in their next biennial avoided cost filings how the Commission's then-approved Carbon Plan expansion portfolio has been incorporated into avoided cost rates and to address how any Commission-approved avoidable cost of carbon is factored into Duke Energy's calculation of avoided cost rates. Duke Energy and the Public Staff should also further address whether renewable energy credits and environmental attributes should be credited to customers if customers are paying QFs for avoided carbon benefits of generation in the next biennial avoided costs proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGs OF FACT NO. 14-15

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

<u>Summary of the Comments</u>

Duke Energy's JIS notes that DEC's and DEP's Schedule PP rates, as approved in the 2020 Sub 167 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. JIS at 27.

In addition, Duke Energy further reports on the line loss studies undertaken in the 2018 Sub 158 proceeding. According to Duke Energy, these studies showed that the number of substations on DEC's and DEP's respective systems where backflow was reducing or negating avoided line loss benefits of distribution-connected QFs was not substantial enough to eliminate the line loss adder for relatively small one MW or less standard offer QFs. Accordingly, Duke Energy explains that in that proceeding, DEC and DEP each determined that it was appropriate to continue offering a line loss adder. As Duke Energy explains, the Commission then approved the DEC's and DEP's inclusion of a line loss adjustment in Schedule PP and further directed the Utilities to continue to "study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the 2020 Sub 167 avoided cost proceeding." 2018 Sub 158 Order, at 36.[5] JIS at 28.

The JIS notes that in the 2020 Sub 167 proceeding, DEC and DEP again analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of substations that were then currently experiencing or expected to experience significant backfeed in the near future because of the recent growth in utility-scale QF capacity. Based upon this analysis, Duke Energy explains that it determined retaining a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP was appropriate. For proposed distribution-connected QFs not eligible for Schedule PP, Duke Energy explains, it committed to continue considering whether the QF's energy output would continue to backfeed at the substation and inject energy onto the transmission system. The Sub 167 Order approved DEC's and DEP's proposed distribution line loss adder for standard offer-eligible QFs contracting under Schedule PP. 2020 Sub 167 Order at 35, 59-60 (Ordering Paragraphs 5-6). The Commission, at the Public Staff's recommendation, directed DEC and DEP to evaluate and report on (1) any geographical concentrations of back-feeding substations; and (2) whether a rate design with or without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide a more accurate avoided costs rate to QFs regarding the value of energy at the selected station. *Id.* at 35. Duke Energy explains that the Commission further directed DEC and DEP to discuss these issues with the Public Staff and other stakeholders prior to filing in the 2021 avoided cost rate proceeding. JIS at 29.

The JIS also refers to Duke Energy's 45-day reports, filed in 2020 Sub 167 proceeding, which detailed the progress that DEC and DEP were making in reaching consensus with other stakeholders on certain issues prior to filing this avoided cost proceeding. Duke Energy explains that its seventh 45-day report 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. JIS at 29 (*citing Seventh Joint 45-Day Progress Report of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC*, Docket No. E-100, Sub 167 (filed Sept. 7, 2021)). Duke Energy states that its updated analysis showed that for DEP, 106 out of 407 substation banks, or 26%, are backfeeding into the transmission system due to

[5] The Commission also found in this order that Duke Energy's proposal to assess the individual characteristics of QFs that are not eligible for Schedule PP standard offer rates and to address the line loss adder analysis as part of the PPA negotiation process was consistent with N.C.G.S. § 62-156(c) by taking into consideration the individual characteristics of the QF. *Id.*

distribution-connected generation. For DEC, Duke Energy states that the percentages of substation banks experiencing backfeed due to distribution-connected projects continues to be significantly less—only 48 out of 1048 banks analyzed, or 4.6%, are backfeeding. JIS at 29.

In addition, the JIS includes a map showing the concentrated nature of QF solar development in more rural areas, especially in the DEP eastern North Carolina service territory. However, Duke Energy explains that distribution-connected QFs continue to not be as geographically concentrated in DEC or DEP territory as compared to DENC. JIS at 30. While a certain level of backflow into the transmission system is not likely to offset the line loss benefits of distributed generation, Duke Energy states that its analysis suggested that additional generation will start to increase substation losses at some point in the future. Specifically, Duke Energy states that the near-term contribution or impact of adding one or more 1 MW standard offer QFs on substation backflow would not be sufficiently substantial to offset the line loss benefit, while more significant concentrations of larger distribution-connected QFs may increase backflow to the point where the line loss adder is no longer appropriate. JIS at 29.

Based upon Duke Energy's most recent analysis, both DEC and DEP propose to maintain the line loss adder for standard offer-eligible QFs contracting under Schedule PP at this time. Duke Energy states that for QFs greater than one MW that are not eligible for the standard offer, which could backflow a more significant amount of energy into the transmission system, Duke Energy proposes 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 is appropriate on a case-by-case basis. Specifically, Duke Energy indicates that DEC and DEP would assess the amount of potential backflow from distribution-connected QFs greater than one MW against the following criteria to determine if the line loss adder is appropriate: (1) the substation bank that serves the distribution point-of-interconnection has distributed energy resources (DER) backflow of greater than or equal to 50% or (2) the addition of the QF would cause the DER backflow to become greater than or equal to 50%. If these criteria are met, Duke Energy states that the QF will receive the transmission rates that exclude marginal loss factors for capacity and energy. JIS at 29.

The Public Staff supports Duke Energy's continued inclusion of the line loss adder for the standard offer avoided cost rate, given the current subscription ratio of distribution connected generation to Duke Energy's distribution system. After its review, the Public Staff also found Duke Energy's proposed objective methodology to evaluate the potential for backflow from distribution-connected QFs greater than 1 MW (and the inclusion or exclusion of the line loss adder) to be reasonable. Public Staff Initial Statement at 16-17.

Discussion and Conclusions

Other than the Public Staff, which agreed with Duke Energy's position and proposed methodology, no other party commented on this issue with respect to Duke Energy. The Commission understands that Duke Energy committed time and resources in discussing this issue prior to filing with both the Public Staff and other stakeholders. Therefore, 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 proposed, objective methodology for evaluating the potential for backflow from distribution-connected QFs greater than one MW (and the inclusion or exclusion of the line loss adder) to be reasonable and appropriate for use in this proceeding and in future biennial avoided cost proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-17

The evidence supporting these findings of fact is found in Duke Energy's JIS 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 JIS, 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 in North Carolina. Duke Energy explains that it first proposed an integration services charge in the 2018 Sub 158 proceeding in response to the Commission's 2016 Sub 148 Order. Duke Energy explains that these charges were calculated based upon a solar integration cost study by Astrapé Consulting (2018 Astrapé SISC Study) and were designed to quantify the impact on operating reserves, or increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity into the DEC and DEP systems. JIS at 31. Duke Energy notes that the 2018 Astrapé SISC Study showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases. JIS at 32.

In the 2018 Sub 158 Order, Duke Energy explains, the Commission approved Duke Energy's proposed solar integration services charge values, which were supported by the 2018 Astrapé Study, to be included as a component of each utility's avoided energy costs. JIS at 32. Duke Energy explains that the 2018 Sub 158 Order also directed DEC and DEP to undertake an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings about the DEC's and DEP's ancillary services costs associated with integrating intermittent, non-dispatchable generation. As detailed in each of the eight 45-Day progress reports filed with the Commission in the Sub 167 docket, Duke Energy initiated the independent technical review of the Astrapé Study's methodology and modeling used for system simulations. Duke Energy explains that Brattle Consulting led the review as principal consultant with the involvement of technical experts from three national renewable energy laboratories (the Technical Review Committee) as well as participation by the Public Staff and the South Carolina Office of Regulatory Staff as regulatory observers.[6] Taking into account input from the TRC and at the Duke Energy's direction, Astrapé Consulting developed an updated 2021 SISC Study that incorporates the TRC Report's findings and updates its modeling and analysis of the integration costs associated with integrating incremental solar into the DEC and DEP systems.[7] Duke Energy explains that based upon Astrapé's updated analysis, DEC and DEP have incorporated solar integration cost decrements of $1.05 per MWh (DEC) and $2.26 per MWh (DEP) into the uncontrolled solar avoided energy rates. JIS at 33-34.

In its Initial Statement, the Public Staff states that it reviewed both the TRC Report and the 2021 Astrapé Study. The Public Staff notes that in addition to addressing methodology and inputs, the TRC also addressed matters raised by intervenors in the Sub 158 proceeding and submitted to the TRC on March 30, 2021, by the Southern Environmental Law Center on behalf of SACE, NCSEA, and CCEBA. Public Staff Initial Statement at 20. According to the Public Staff, the TRC Report provides an in-depth discussion of the specific issues discussed during the TRC meetings and addresses how each recommendation from the TRC is incorporated into the 2021 Astrapé Study. Overall, the Public Staff notes that the TRC found the estimate cost of reserves to be reasonable given the size of DEC and DEP relative to PJM Interconnection, L.L.C. and given the relative inflexibility of Duke Energy's generation fleet. Public Staff Initial Statement at 20-21.

The Public Staff additionally highlights several changes to the SISC methodology adopted based upon the input of the TRC and stakeholders. First, the Public Staff notes that a major criticism of Duke Energy's proposed SISC methodology in the Sub 158 proceeding was that DEC and DEP were modeled separately. Because the Joint Dispatch Agreement (JDA) allows DEC and DEP to share load following reserves at least cost in the event of intra-hour net load variations, the Public Staff explains that the 2021 Astrapé SISC Report includes a SISC calculated under the JDA assumptions at the TRC's recommendation. The Public Staff states that it finds the SISC derived under the JDA assumptions to be reasonable and appropriate, and it supports Duke Energy's proposal to utilize the SISC with those assumptions. Public Staff Initial Statement at 21-22.

Similarly, the Public Staff notes that Astrapé's use of the Loss of Load Expectation (LOLE) flexibility standard (which was an approximation of NERC reliability standards) was another contested issue in the Sub 158 proceeding. The

[6] A copy of the TRC Report is attached as DEC/DEP Exhibit 10 to the JIS.

[7] The 2021 Astrapé SISC Study is attached as DEC/DEP Exhibit 11 to the JIS.

Public Staff notes that the 2021 Astrapé SISC Report focuses on returning the system to pre-solar levels of reliability rather than on incorporating the NERC reliability standards into the model. The Public Staff agrees with this approach and notes that the TRC also supports the approach. Public Staff Initial Statement at 22.

Next, the Public Staff notes that the 2021 Astrapé SISC Study employed a targeted approach to adding load following reserves, adding reserves when they are most likely to be needed (i.e., in hours of high solar volatility). The Public Staff agrees with this approach and notes that the TRC also support the change, finding that adding load following reserves only when solar volatility is a factor better represents actual system conditions and operations. Public Staff Initial Statement at 22-23.

Finally, the Public Staff notes that the TRC considered whether it was appropriate to include the effects of the proposed Southeastern Energy Exchange Market (SEEM) in calculating the SISC. According to the Public Staff, the TRC found that incorporating SEEM would be at least partially speculative since the design, implementation, and actual operations of the SEEM are still uncertain. Accordingly, the Public Staff recommends that Duke Energy consider the effect of the SEEM on the calculation of the SISC in any avoided cost filings that occur six months or more after SEEM operations commence. Public Staff Initial Statement at 24.

In contrast to Public Staff's support for the TRC's findings and the updated SISC methodology and rate inputs, as calculated in the 2021 Astrapé SISC Study, SACE identifies three purported "flaws" in the proposed methodology that SACE contends inflate the value of the SISC and therefore artificially depress avoided energy costs paid to solar QFs. SACE Initial Comments at 23. In particular, SACE argues that (1) the assumption that solar load-following reserves are required before sunrise and after sunset—hours during which there is no solar generation—results in an overcharge to solar QFs for reserves; (2) Astrapé's "combined case" failed to account for the reduction in solar load-following reserves that are required under JDA operations, leading to an overstatement of load-following reserve requirements and an artificial increase to the SISC; and (3) the five-minute "flexibility violation" metric is unnecessarily stringent and inappropriate for the SISC analysis. SACE Initial Comments at 23.

In its Reply Comments, Duke Energy reaffirms that the 2021 Astrapé SISC Study appropriately considered and tested Duke Energy's load following requirements iteratively to determine the least cost way to resolve flexibility excursions and highlight a number of improvements to the 2021 Astrapé SISC Study over the 2018 study that were recognized by the TRC. DEC/DEP Reply Comments at 40. Duke Energy also addresses each of SACE's three criticisms.

First, Duke Energy notes that the 2021 Astrapé SISC Study appropriately considered and tested Duke Energy's solar incremental load-following reserve requirements iteratively to determine the least cost way to resolve flexibility excursions. According to Duke Energy, Astrapé examined the 12x24 flexibility excursions from the cases with solar and added reserves to remove the aforementioned excursions. Based on this assessment, Astrapé removed some of the flexibility excursions in the pre-solar and post-solar hours. Using this methodology, Duke Energy explains that the overall excursions are still reduced to the level of the no solar Base Case, and the TRC found Astrapé's approach to be a "significant improvement" over the approach used in the previous study.

Second, Duke Energy asserts that SACE fundamentally misunderstood Duke Energy's operational obligations under the JDA in arguing that the "combined case" failed to account for the reduction in solar load-following reserves that are required under DEC's and DEP's JDA. Duke Energy states that SACE's claim that "the JDA nets the DEC and DEP systems' dispatch needs to meet real-time balancing requirements" is an oversimplification. According to Duke Energy, while the JDA allows economic exchanges to reduce the costs of additional load following requirements, each Balancing Authority (BA) *must continue to plan for and maintain its own operating reserves. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct,* Docket Nos. E-2, Sub 998 and E-7, Sub 986, at Appendix A, Regulatory Conditions Section 4.1 (June 29, 2012).[8] Accordingly, Duke Energy explains that any model that simply "netted" DEC's and DEP's system dispatch needs would not accurately reflect the relationship between the two utilities under the JDA. Instead, Duke Energy explains that it used input from both the TRC and Duke Energy subject matter experts to ensure its model accurately reflected the true operation of the JDA, Astrapé's "combined case." DEC/DEP Reply Comments at 41. Duke Energy notes that the TRC found this methodology to be appropriate to ensure resources in DEC and DEP are jointly committed and dispatched. In this way, Duke Energy explains, the 2021 Astrapé SISC Study thus successfully models the JDA through lower fuel and operations costs, while ensuring each Balancing Authority maintains its respective operating reserves.

Finally, Duke Energy explains that the 2021 Astrapé Study's modeling approach to address flexibility violations was accepted by the TRC and is not unreasonably stringent. In particular, Duke Energy notes that the TRC supported Astrapé's approach to assessing flexibility violations, finding that increasing the length of the flexibility violations to ten (10) minutes would result in higher—not

[8] Regulatory Condition 4.1 conditions the approval of Duke Energy Corporation's and Progress Energy, Inc.'s merger upon "the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA [Balancing Authority Area], control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or [Progress Energy Carolinas, LLC] to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates."

lower—integration costs.[9] In direct contrast to SACE's contention, the TRC found that the five-minute flexibility violation "results in a lower SISC relative to using a longer flexibility violation." Id. As the TRC found, "adjusting the modeling assumptions to reduce the level of reliability to exactly the amount needed to avoid NERC standards implies eliminating any potential reliability cushion that has historically been provided to customers and giving all the benefit of eliminating that cushion entirely to solar resources." See id. Accordingly, Duke Energy recommends that the Commission reject SACE's recommendation to modify the SISC methodology.

Discussion and Conclusions

In the 2018 Sub 158 Order, the Commission directed Duke Energy to assemble a technical review committee to provide a review of the Astrapé Study. 2018 Sub 158 Order at 95. In doing so, the Commission further directed that the review committee should be comprised of individuals not otherwise affiliated with Duke Energy or any of its affiliates or organizations in which Duke Energy or its affiliates is a member, including at least one personnel employed by the National Laboratories with relevant experience and expertise. With respect to scope, the Commission directed that the purpose of the work is to provide an in-depth review of the study methodology and the model used for system simulations. Id. The Commission has been following the work of the TRC through eight 45-day reports filed by Duke Energy in the Sub 158 docket documenting the progress on this issue among others. Based on its review of both the 2021 Astrapé SISC Report and the TRC Report, in addition to the comments and filings of parties to this docket, the Commission finds that the 2021 Astrapé SISC Report contains a number of improvements over the 2018 Astrapé SISC Study, and the Commission agrees with the TRC and the Public Staff that the 2021 Astrapé Study reasonably quantified solar integration costs for DEC and DEP.

Accordingly, the Commission approves Duke Energy's SISC as presented in the 2021 Astrapé Report and declines to accept the critiques presented by SACE. The Commission further directs Duke Energy to continue to evaluate the appropriate methodology for quantifying integration costs based on the methodology supported by the TRC and used to develop the 2021 Astrapé SISC Report determined to be reasonable in this proceeding.

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[9] Duke Energy JIS, DEC/DEP Exhibit 10, TRC Report, Section I(1) ("Astrapé provided information on the length of flexibility violations (5-min vs. 10-min) to inform whether having the model match historical 10-min flexibility violations, instead of 5- min violations, would significantly alter the results. The addition of solar resources increases the share of longer flexibility violations, which implies the integration costs would be higher if the modeling was forced to match historical 10-minute flexibility violations. Therefore, the approach used by Astrapé results in a lower SISC relative to using a longer flexibility violation").

Based upon the foregoing and the entire record, the Commission finds the solar integration cost decrements of $1.05 per MWh (DEC) and $2.26 per MWh (DEP) to be reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

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

Summary of the Comments

Duke Energy's JIS explains that it considered the potential for QFs to provide positive ancillary services pursuant to the Commission's direction to do so in the Sub 158 Order. In particular, as the JIS explains, Duke Energy assessed needed changes to their respective system operations to incorporate third-party QF ancillary services into the DEC and DEP systems in a way that would maintain system reliability, analyzing approaches taken in other states, and engaging with the Public Staff and interested stakeholders. JIS at 34. Duke Energy notes that FERC defines ancillary services as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." JIS at 35. The JIS explains that ancillary services are functions that allow a utility to maintain the reliability of the system and provide flexibility needed to respond to disruptive events by re-balancing the system. Some of the more prominent types of ancillary services include: (1) regulating reserves, which are used to manage the active power volatility of a balancing authority's ("BA") load and generation resources; (2) contingency reserves, which are resources that can respond in fifteen minutes to a disturbance event; (3) balancing reserves, which are unused MW that can be called upon to re-balance the system as needed; and (4) black start, which are resources that have the ability to bring resources back online following an outage. According to the JIS and with the exception of black start services, the avoided peaker—for which the QF is being compensated—is capable of providing all of those services. JIS at 35.

The JIS explains that a fundamental aspect of ancillary services is that system operators must have operational control over the assets to dispatch them quickly as need arises. Because DEC and DEP system operators do not have such control over third-party QF resources, the JIS explains, QFs do not have the ability to provide positive ancillary services benefits at a lower cost than utilities' own resources at this time. Further, Duke Energy argues that transitioning the BAs' modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would require a fundamental (and costly) change in how the grid is operated, along with major technical and financial investments. JIS at 36.

Finally, Duke Energy argues in its JIS that the “must-take” PURPA framework is not compatible with the concept of QFs providing positive ancillary services. Duke Energy notes that the “must-take” payment structure is based on an assumption that QFs will provide all of their energy and capacity to DEC or DEP, but providing ancillary services to DEC and DEP would inherently require QFs to produce less than their maximum energy and capacity. The JIS additionally argues that integration of QFs has historically increased the need for ancillaries on the system as solar QF output is variable, intermittent, and dependent on somewhat unpredictable environmental factors.

For all of these reasons, the JIS concludes that a QF selling “must take” energy under PURPA cannot provide incremental positive ancillary services value under current system operations. JIS at 36.

In both their Initial and Reply Comments, the Public Staff expresses agreement with Duke Energy that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke’s SISC by smoothing their volatility. The Public Staff states that it has had numerous discussions with intervenors and Duke Energy to discuss what, if any, ancillary services might be provided by QFs and whether it is reasonable and cost effective for Duke to procure these services from QFs within the context of PURPA. In addition, the Public Staff notes that it is not aware of any other regulated utility in the country, operating outside of an RTO or Independent System Operator, that procures ancillary services from a third party power supplier. Nevertheless, the Public Staff notes that while PURPA’s mandatory purchase obligation does not extend to ancillary services, it also does not prohibit the procurement of ancillary services from QFs. Public Staff Initial Statement at 17.

The Public Staff believes that as DEC and DEP procure additional renewable generation to comply with the Carbon Plan, some ancillary services may be provided at least cost from inverter-based resources (IBRs) such as solar PV—spinning reserve, frequency regulation, and Volt-VAR support. Public Staff Initial Statement at 17. However, the Public Staff also acknowledges concerns with implementation of such a program particularly given the relatively small amount of ancillary services required at any given time. In addition, the Public Staff believes it is unlikely a QF would choose to provide ancillary services during most times of the year since QFs must hold back energy and capacity to maintain the ability to ramp up to provide ancillary services, and the rates for ancillary services purchased by RTOs and ISOs are generally much lower than PURPA rates for energy and capacity. Public Staff Initial Statement at 18-19.

Given these uncertainties, the Public Staff, in its Initial Statement asked for feedback from Duke Energy, DENC, as well as other intervenors, on the potential benefits of initiating a proceeding to investigate the ability of QFs to provide ancillary services and potential benefits, if any, to customers and potentially establishing a pilot program to procure a small amount of ancillary services from IBRs. Public Staff Initial Statement at 19.

CCEBA/NCSEA and SACE each argue that QFs should be compensated for the provision of ancillary services. First, CCEBA/NCSEA argue that Duke Energy's characterization of operational control of QFs is incomplete, and that the changes required to facilitate the provision of ancillary services from QFs are easily attainable. In CCEBA/NCSEA's view, many existing QFs may already be equipped with automatic generation control (AGC) capability that would allow them to currently, or with limited modification, provide ancillary services. CCEBA/NCSEA believe that upgrades to existing QFs to allow them to provide ancillary services could be completed without substantial cost and that benefits to the grid outweigh the costs to facilitate their availability. CCEBA/NCSEA Initial Comments at 6-7. In addition, CCEBA/NCSEA argue that QF operations could be modified to incentivize the provision of ancillary services, noting that QFs may agree to amend their PPAs to sell less than their full output to DEC and DEP and should be given the option to do so. CCEBA/NCSEA Initial Comments at 9-10.

CCEBA/NCSEA next state that QFs already provide reactive power—which, they contend, is a type of ancillary service—to DEC and DEP without compensation. In particular, CCEBA/NCSEA argue that the Interconnection Agreement (IA) between DEC/DEP and QFs requires Interconnection Customers to maintain a composite power delivery at a prescribed power factor, for which they are not compensated. CCEBA/NCSEA also allege that DEC and DEP provide reactive power from their own renewable facilities in other jurisdictions, pointing to comments filed by Duke Energy in FERC's ongoing proposed rulemaking on reactive power compensation. CCEBA/NCSEA Comments at 7-8. CCEBA/NCSEA also argue that the peaker method does not incorporate the provision of, and compensation for ancillary services. According to CCEBA/NCSEA, neither avoided energy nor avoided capacity costs under North Carolina's peaker methodology expressly include ancillary services. CCEBA/NCSEA Initial Comments at 11-12.

For all of these reasons, CCEBA/NCSEA recommend that the Commission initiate a stakeholder proceeding to evaluate how new and existing solar and solar plus storage facilities can provide and be compensated for providing ancillary services. In particular, CCEBA/NCSEA note that stakeholder could work collaboratively to devise a contract and commercial structure for new solar and solar plus storage that allows for QF provision of and compensation for ancillary services. CCEBA/NCSEA point to a dispatchable PPA as one option to allow a solar generator to provide ancillary services to the utility for compensation. CCEBA/NCSEA Initial Comments at 15-16.

For its part, SACE reiterates and adopts CCEBA/NCSEA's position that QFs already provide positive ancillary services and could provide more. In addition, SACE argues that QFs are entitled to compensation for ancillary services under PURPA. SACE Initial Comments at 25.

Duke Energy addresses each of these positions in its Reply Comments, reiterating that no action is needed or appropriate to compensate QFs for ancillary services in this proceeding. First, Duke Energy explains that its avoided cost rates fully compensate QFs for delivering energy and capacity. Specifically, Duke Energy explains that the peaker methodology inherently provides the operational capacity value of the avoided CT unit, which would include any value of ancillary services the hypothetical CT is capable of providing. Duke Energy describes the theory of peaker methodology, explaining that while there is not a discrete adjustment or "adder" for operating the avoided CT unit to provide ancillary services, avoiding the capital and operating cost of the peaker unit and marginal running costs of the system fully represents the capacity and energy value that can be avoided by purchasing power from a QF. Duke Energy further points out that, under PURPA, QFs may not lawfully be paid at rates above the utility's full avoided capacity and energy costs. Accordingly, while a QF could technically enter into some agreement to provide ancillary services, such costs are only recoverable under PURPA to the extent they are actually avoided. Duke Energy further comments that because the DEC and DEP systems have no present incremental need for ancillary services, payment to QFs for ancillary services would not be appropriate under PURPA. Duke Energy Reply Comments at 25-26.

Next, Duke Energy's Reply Comments note that no intervenor has identified any precedent for procuring ancillary services under a State's implementation of PURPA. Recognizing that ancillary services are FERC-jurisdictional transmission services regulated under each Transmission Provider's OATT, Duke Energy argues that it is unsurprising that other States have not pursued (and it is questionable whether State regulatory authorities would have jurisdiction under PURPA to establish) a compensation scheme or "pilot ancillary services market" as recommended by NCSEA/CCEBA. Duke Energy Reply Comments at 28-30.

Duke Energy also refutes CCEBA/NCSEA's claim that solar QFs are providing grid services today without compensation. Acknowledging the novelty of this argument in North Carolina PURPA proceedings, Duke Energy points out that the FERC considered and rejected generally the same argument in establishing the pro forma Large Generator Interconnection Procedures and Large Generator Interconnection Agreement in Order No. 2003, finding that an 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. Duke Energy Reply Comments at 29-30; see also Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546 (2003). Duke Energy also clarifies that DEC and DEP do not compensate their own fleet generators or affiliated generators for reactive power to service, contrary to the claim made by CCEBA/NCSEA. Duke Energy Reply Comments at 30.

Finally, Duke Energy urges the Commission that no new proceeding is needed to further evaluate procuring ancillary services from QFs and no further action from the Commission on this issue is needed at this time. In support of this position, Duke Energy's Reply Comments reiterate that transitioning DEC's and DEP's modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would create costs rather than avoid costs and would require a fundamental change in how the grid is operated, along with major technical and financial investments. Duke Energy Reply Comments at 31. Duke Energy further notes that the only way to provide regulation up capability would be to curtail solar across the day and then release some of that curtailment to provide upward regulation when needed. According to Duke Energy, no QFs have opted to mitigate their output to avoid the Solar Integration Service Charge, indicating that the ancillaries quantified to date in the SISC are not high enough value to forego the energy value. Duke Energy Reply Comments at 33.

In their Joint Reply Comments, CCEBA/NCSEA argue that Duke Energy should be required to provide detailed information on how DEC and DEP procure and compensate ancillary services. CCEBA/NCSEA then reiterate their recommendation for a stakeholder process to discuss the technical, contractual, and legal questions related to QFs' ability to provide and be compensated for ancillary services and, further, express support for the pilot program proposed by the Public Staff. CCEBA/NCSEA Reply Comments, at 7. SACE's Reply Comments likewise express support for the stakeholder proceeding and pilot program proposed by the Public Staff, arguing that all interested parties would benefit from a more detailed understanding of the technical ability of QFs to provide ancillary services and the associate costs. SACE Reply Comments at 4-5.

The Public Staff's Reply Comments state that the issue of ancillary services has expanded beyond a strictly avoided cost issue, particularly as procurement of IBRs is increasingly occurring outside of PURPA contracts. Accordingly, the Public Staff recommends that the Commission open a separate docket to solicit comments specifically related to the proposed pilot or, more broadly, utilization of IBRs to provide ancillary services. Public Staff Reply Comments, at 4-5. To supports its proposal for a new docket, the Public Staff notes that the energy landscape in North Carolina is shifting, with fewer third-party projects selling power through standard offer and negotiated contracts under PURPA. Instead, large-scale competitive procurements for renewable energy are increasingly responsible for much of the new solar interconnected to Duke Energy's grid. Accordingly, to minimize the amount of regulatory attention that would be diverted by a pilot program, the Public Staff suggests that it may be more beneficial for Duke Energy and stakeholder to focus on potential revisions to future competitive procurements triggered by need identified within the Carbon Plan. Public Staff Reply Comments at 6-7.

<u>Discussion and Conclusions</u>

The potential for QFs to provide ancillary services and appropriate compensation is one of the Sub 158 Additional Issues the Commission's Sub 158 Order directed the utilities to address in their November 2020 avoided cost filings. Specifically, the Commission instructed that the utilities should evaluate:

> [W]hether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides

positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide[.]

2018 Sub 158 Order at 136 (Ordering Paragraph 24). After investigating this complex issue and engaging with the Public Staff and stakeholders as described in its JIS, Duke Energy concludes that QFs selling energy and capacity under PURPA cannot provide incremental positive ancillary services value under current system operations. The Public Staff, for its part, recommends that the Commission open a new docket for the purpose of further investigating ancillary services, including considering the merits of a potential pilot program and potential revisions to future competitive procurements to facilitate QF provisions of ancillary services. CCEBA/NCSEA and SACE each argue that QFs have the capacity to provide valuable ancillary services and should be compensated for doing so now and support the Public Staff's stakeholder proceeding proposal. While there appears to be alignment among the intervenors that further investigation into ancillary services is warranted, the Commission is persuaded by Duke Energy that opening a docket to formally begin an inquiry is not necessary or appropriate at this time.

FERC defines ancillary services as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." *See* FERC Order No. 890, App'x A (Pro Forma Open Access Transmission Tariff), at I.1.2; *see also* Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC (Joint OATT), at I.1.2, accessible at http://www.oatioasis.com/duk/index.html. FERC has recognized that rates for purchasing "'energy' from QFs under Section 210 of PURPA includes the entire output of the QF, including capacity, energy and ancillary services." *See Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, 123 FERC ¶ 61,055, n. 869, 2008 FERC LEXIS 788 (Apr. 21, 2008). This statement—made in the context of clarifying the scope of QF exemptions from FERC oversight of market-based rates under sections 205 and 206 of the Federal Power Act—recognizes that utilities are required to purchase a QF's entire capacity and energy output, which may include some ancillary services related to that capacity and energy.[10] Importantly, PURPA is a "must purchase" construct where all "electric power generated by the Facility" delivered and made available by the QF seller to the utility is purchased at DEC's or DEP's avoided

[10] FERC has also recently disclaimed jurisdiction under Section 205 of the Federal Power Act to determine whether compensation for "reactive service" should be authorized where a QF's PPA selling capacity and energy exclusively to its interconnected utility was subject to state PURPA implementation. *See Cherokee Cty. Cogeneration Partners, LLC*, 1 76 FERC ¶ 61,069, at P. 16 (2021).

costs. JIS at DEC/DEP Exhibit 1, DEC/DEP Exhibit 3.[11] The Commission notes that it has long approved the peaker methodology to forecast DEC's and DEP's full avoided costs, and the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)." JIS at 13–14 (citing Sub 140 Phase One Order at 30). For these reasons, the Commission finds persuasive Duke Energy's argument that the Commission-approved methodology for calculating DEC's and DEP's avoided costs rates fully compensate QFs for delivering energy and capacity.

In addition, the Commission agrees with Duke Energy that the provision of ancillary services by QFs is inconsistent with PURPA's must-take structure. As all parties appear to acknowledge, a QF's provision of ancillary services would require both utility dispatch and operational control of the QF's generating facility and require the QF to produce *less than* its maximum energy and capacity. The Commission acknowledges that HB 951 requires third party solar and solar plus storage resources procured pursuant to the Carbon Plan to be dispatched, operated, and controlled in the same manner as the utility's own generation resources, which could potentially mitigate those concerns and provide Duke the operational control required. However, the commercial and operational terms applied to these resources will likely be determined through the Carbon Plan and a competitive solicitation process, and would not apply to QFs seeking to sell power under PURPA standard offer or negotiated rates. The Commission is further persuaded by the argument that procuring ancillary services from a large number of third-party generators would introduce untenable complexity to Duke's system operations. Finally, the Commission notes that no party has identified precedent for procuring ancillary services under a State's implementation of PURPA.

The Commission is likewise not persuaded by CCEBA/NCSEA's argument that QFs are currently providing certain ancillary services for which they are not being compensated. CCEBA/NCSEA assert that QFs are capable of providing voltage support given the requirement in Section 1.8 of the IA that solar QFs are obligated to "maintain a constant voltage level." 2018 Sub 158 Order at 48–49. 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." *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007). This is because "an 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

[11]Schedule PP provides that Seller and Company shall agree to the Contract Capacity of the QF facility committing to sell power to DEC or DEP, and DEC's and DEP's standard Purchase Power Agreement by a Qualifying Cogenerator or Small Power Producer provides that the QF "shall sell and deliver exclusively to Company all of the electric power generated by the Facility."

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." *Id.* at P 29. Contrary to CCEBA/NCSEA's assertions, Duke Energy does not compensate its fleet or affiliated generators for reactive power service, and the Commission is therefore persuaded that QFs are not going uncompensated for services provided under PURPA.

Finally, the Commission is not persuaded that a new docket should be opened at this time for the purpose of further investigating the ability of QFs to provide ancillary services. Nevertheless, the Commission agrees with the Public Staff that the energy landscape in North Carolina is changing such that fewer third party QFs are selling power through standard offer PPAs and are instead participating in competitive procurements like the CPRE and, going forward, Duke will be procuring new solar resources and solar plus storage resources selected in the Carbon Plan. The Commission further agrees with Public Staff that studying the ability of IBRs to provide ancillary services is a worthwhile exercise. Recognizing the limited size of DEC's and DEP's ancillary service requirement and HB 951's mandates for utility ownership of new generating facilities selected in the Carbon Plan and operational control of third-party owned solar and solar plus storage IBRs in the same manner as Duke Energy's own generating facilities, the Commission directs Duke Energy to conduct a preliminary investigatory study of the operating characteristics of IBR at certain of its own IBR facilities to understand which ancillary services can be provided by each resource or combination or resources. Duke Energy should report on the results of the study to the Public Staff and other interested stakeholders and address the results of the study in the next Carbon Plan update proceeding in 2024.

For all of these reasons, the Commission finds that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility. The Commission additionally directs Duke Energy to commence a study of Duke Energy's needs for ancillary services and the capability of IBRs to cost-effectively provide ancillary services as described in this section.

Duke Energy's JIS explains that DEC and DEP considered the potential for QFs to provide positive ancillary services pursuant to the Commission's direction to do so in the Sub 158 Order. In particular, as the JIS explains, Duke Energy needed changes to their respective system operations to incorporate third-party QF ancillary services into the DEC and DEP systems in a way that would maintain system reliability, analyzing approaches taken in other states, and engaging with the Public Staff and interested stakeholders. JIS at 34. Duke Energy notes that FERC defines ancillary services as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." JIS at 35. The JIS explains that ancillary services are functions that allow a utility to maintain the reliability of the system and provide flexibility needed to respond to disruptive events by re-balancing the system. Some of the more prominent types of ancillary services include: (1) regulating reserves, which are used to manage the active power volatility of a balancing authority's ("BA") load and generation resources; (2) contingency reserves, which are resources that can respond in fifteen minutes to a disturbance event; (3) balancing reserves, which are unused MW that can be called upon to re-balance the system as needed; and (4) black start, which are resources that have the ability to bring resources back online following an outage. According to the JIS and with the exception of black start services, the avoided peaker—for which the QF is being compensated—is capable of providing all of those services. JIS at 35.

The JIS explains that a fundamental aspect of ancillary services is that system operators must have operational control over the assets to dispatch them quickly as need arises. Because DEC and DEP system operators do not have such control over third-party QF resources, the JIS explains, QFs do not have the ability to provide positive ancillary services benefits at a lower cost than utilities' own resources at this time. Further, Duke Energy explains that transitioning the BAs' modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would require a fundamental (and costly) change in how the grid is operated, along with major technical and financial investments. JIS at 36.

Finally, Duke Energy states that the "must-take" PURPA framework is not compatible with the concept of QFs providing positive ancillary services. Duke Energy notes that the "must-take" payment structure is based on an assumption that QFs will provide all of their energy and capacity to DEC or DEP, but providing ancillary services to DEC and DEP would inherently require QFs to produce *less than* their maximum energy and capacity. The JIS additionally argues that integration of QFs has historically *increased* the need for ancillaries on the system as solar QF output is variable, intermittent, and dependent on somewhat unpredictable environmental factors.

For all of these reasons, the JIS concludes that a QF selling "must take" energy under PURPA cannot provide incremental positive ancillary services value under current system operations. JIS at 36.

In both its Initial Statement and Reply Comments, the Public Staff expresses agreement with Duke Energy that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility. The Public Staff states that it has had numerous discussions with intervenors and Duke Energy to discuss what, if any, ancillary services might be provided by QFs and whether it is reasonable and cost effective for Duke to procure these services from QFs within the context of PURPA. In addition, the Public Staff notes that it is not aware of any other regulated utility in the country, operating outside of an RTO or Independent System Operator, that procures ancillary services from a third-party power supplier. Nevertheless, the Public Staff notes that while PURPA's mandatory purchase obligation does not extend to ancillary services, it also does not prohibit the procurement of ancillary services from QFs. Public Staff Initial Statement at 17.

The Public Staff believes that as DEC and DEP procure additional renewable generation to comply with the Carbon Plan, some ancillary services may be provided at least cost from IBRs such as solar PV—spinning reserve, frequency regulation, and Volt-VAR support. Public Staff Initial Statement at 17. However, the Public Staff also acknowledges concerns with implementation of such a program particularly given the relatively small amount of ancillary services required at any given time. In addition, the Public Staff believes it is unlikely a QF would choose to provide ancillary services during most times of the year since QFs must hold back energy and capacity to maintain the ability to ramp up to provide ancillary services, and the rates for ancillary services purchased by RTOs and ISOs are generally much lower than PURPA rates for energy and capacity. Public Staff Initial Statement at 18-19.

Given these uncertainties, the Public Staff, in its Initial Statement asks for feedback from Duke Energy, DENC, and other intervenors on the potential benefits of initiating a proceeding to investigate the ability of QFs to provide ancillary services and potential benefits, if any, to customers and potentially establishing a pilot program to procure a small amount of ancillary services from IBRs. Public Staff Initial Statement at 19.

CCEBA/NCSEA and SACE each argue that QFs should be compensated for the provision of ancillary services. First, CCEBA/NCSEA argue that Duke Energy's operational control of QFs is incomplete, and that the changes required to facilitate the provision of ancillary services from QFs are easily attainable. In CCEBA/NCSEA's view, many existing QFs may already be equipped with automatic generation control (AGC) capability that would allow them to currently, or with limited modification, provide ancillary services. CCEBA/NCSEA believe that upgrades to existing QFs to allow them to provide ancillary services could be completed without substantial cost and that benefits to the grid outweigh the costs to facilitate their availability. CCEBA/NCSEA Initial Comments at 6-7. In addition, CCEBA/NCSEA argue that QF operations could be modified to incentivize the provision of ancillary services, noting that QFs may agree to amend their PPAs to sell less than their full output to DEC and DEP and should be given the option to do so. CCEBA/NCSEA Initial Comments at 9-10.

CCEBA/NCSEA next state that QFs already provide reactive power—which, they contend, is a type of ancillary service—to DEC and DEP without compensation. In particular, CCEBA/NCSEA argue that the IA between DEC/DEP and QFs requires Interconnection Customers to maintain a composite power delivery at a prescribed power factor, for which they are not compensated. CCEBA/NCSEA also allege that DEC and DEP provide reactive power from their own renewable facilities in other jurisdictions, pointing to comments filed by Duke

Energy in FERC's ongoing proposed rulemaking on reactive power compensation. CCEBA/NCSEA Comments at 7-8. CCEBA/ NCSEA also argue that the peaker method does not incorporate the provision of, and compensation for ancillary services. According to CCEBA/NCSEA, neither avoided energy nor avoided capacity costs under North Carolina's peaker methodology expressly include ancillary services. CCEBA/NCSEA Initial Comments at 11-12.

For all of these reasons, CCEBA/NCSEA recommend that the Commission initiate a stakeholder proceeding to evaluate how new and existing solar and solar plus storage facilities can provide and be compensated for providing ancillary services. In particular, CCEBA/NCSEA note that stakeholder could work collaboratively to devise a contract and commercial structure for new solar and solar plus storage that allows for QF provision of and compensation for ancillary services. CCEBA/NCSEA point to a dispatchable PPA as one option to allow a solar generator to provide ancillary services to the utility for compensation. CCEBA/NCSEA Initial Comments at 15-16.

For its part, SACE reiterates and adopts CCEBA/NCSEA's position that QFs already provide positive ancillary services and could provide more. In addition, SACE argues that QFs are entitled to compensation for ancillary services under PURPA. SACE Initial Comments at 25.

Duke Energy addresses each of these positions in its Reply Comments, reiterating that no action is needed or appropriate to compensate QFs for ancillary services in this proceeding. First, Duke Energy's Reply Comments explain that DEC's and DEP's avoided cost rates fully compensate QFs for delivering energy and capacity. Specifically, Duke Energy explains that the peaker methodology inherently provides the operational capacity value of the avoided CT unit, which would include any value of ancillary services the hypothetical CT is capable of providing. Duke Energy describes the theory of peaker methodology, explaining that while there is not a discrete adjustment or "adder" for operating the avoided CT unit to provide ancillary services, avoiding the capital and operating cost of the peaker unit and marginal running costs of the system fully represents the capacity and energy value that can be avoided by purchasing power from a QF. Duke Energy further points out that, under PURPA, QFs may not lawfully be paid at rates above the utility's full avoided capacity and energy costs. Accordingly, while a QF could technically enter into some agreement to provide ancillary services, such costs are only recoverable under PURPA to the extent they are actually avoided. Duke Energy further comments that because the DEC and DEP systems have no present incremental need for ancillary services, payment to QFs for ancillary services would not be appropriate under PURPA. Duke Energy Reply Comments at 25-26.

Next, Duke Energy's Reply Comments note that no intervenor has identified any precedent for procuring ancillary services under a State's implementation of PURPA. Recognizing that ancillary services are FERC-jurisdictional transmission services regulated under each Transmission Provider's OATT, Duke Energy argues that it is unsurprising that other States have not pursued (and it is questionable whether State regulatory authorities would have jurisdiction under PURPA to establish) a compensation scheme or "pilot ancillary services market" as recommended by NCSEA/CCEBA. Duke Energy Reply Comments at 28-30.

Duke Energy's Reply Comments also refute CCEBA/NCSEA's claim that solar QFs are providing grid services today without compensation. Acknowledging the novelty of this argument in North Carolina PURPA proceedings, Duke Energy points out that the FERC considered and rejected generally the same argument in establishing the *pro forma* Large Generator Interconnection Procedures and Large Generator Interconnection Agreement in Order No. 2003, finding that an 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. Duke Energy Reply Comments at 29-30; *see also* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546 (2003). Duke Energy also clarified that DEC and DEP do not compensate their own fleet generators or affiliated generators for reactive power to service, contrary to the claim made by CCEBA/NCSEA. Duke Energy Reply Comments at 30.

Finally, Duke Energy urges the Commission that no new proceeding is needed to further evaluate procuring ancillary services from QFs and no further action from the Commission on this issue is needed at this time. In support of this position, Duke Energy's Reply Comments reiterate that transitioning the DEC's and DEP's modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would create costs rather than avoid costs and would require a fundamental change in how the grid is operated, along with major technical and financial investments. Duke Energy Reply Comments at 31. Duke Energy further notes that the only way to provide regulation up capability would be to curtail solar across the day and then release some of that curtailment to provide upward regulation when needed. According to Duke Energy, no QFs have opted to mitigate their output to avoid the Solar Integration Service Charge, indicating that the ancillaries quantified to date in the SISC are not high enough value to forego the energy value. Duke Energy Reply Comments at 33.

In their Joint Reply Comments, CCEBA/NCSEA argue that Duke Energy should be required to provide detailed information on how DEC and DEP procure and compensate ancillary services. CCEBA/NCSEA then reiterate their recommendation for a stakeholder process to discuss the technical, contractual, and legal questions related to QFs' ability to provide and be compensated for ancillary services and, further, express support for the pilot program proposed by the Public Staff. CCEBA/NCSEA Reply Comments, at 7. SACE's Reply Comments likewise express support for the stakeholder proceeding and pilot program proposed by the Public Staff, arguing that all interested parties would benefit from a more detailed understanding of the technical ability of QFs to provide ancillary services and the associate costs. SACE Reply Comments at 4-5.

The Public Staff's Reply Comments state that the issue of ancillary services has expanded beyond a strictly avoided cost issue, particularly as procurement of IBRs is increasingly occurring outside of PURPA contracts. Accordingly, the Public Staff recommends that the Commission open a separate docket to solicit comments specifically related to the proposed pilot or, more broadly, utilization of IBRs to provide ancillary services. Public Staff Reply Comments, at 4-5. To supports its proposal for a new docket, the Public Staff notes that the energy landscape in North Carolina is shifting, with fewer third-party projects selling power through standard offer and negotiated contracts under PURPA. Instead, large-scale competitive procurements for renewable energy are increasingly responsible for much of the new solar interconnected to Duke Energy's grid. Accordingly, to minimize the amount of regulatory attention that would be diverted by a pilot program, the Public Staff suggests that it may be more beneficial for Duke Energy and stakeholders to focus on potential revisions to future competitive procurements triggered by need identified within the Carbon Plan. Public Staff Reply Comments at 6-7.

<u>Discussion and Conclusions</u>

The potential for QFs to provide ancillary services and appropriate compensation is one of the Sub 158 Additional Issues the Commission's Sub 158 Order directed the utilities to address in their November 2020 avoided cost filings. Specifically, the Commission instructed that the utilities should evaluate:

> [W]hether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide[.]

2018 Sub 158 Order at 136 (Ordering Paragraph 24). After investigating this complex issue and engaging with the Public Staff and stakeholders as described in their JIS, Duke Energy concludes that QFs selling energy and capacity under PURPA cannot provide incremental positive ancillary services value under current system operations. The Public Staff, for its part, recommends that the Commission open a new docket for the purpose of further investigating ancillary services, including considering the merits of a potential pilot program and potential revisions to future competitive procurements to facilitate QF provisions of ancillary services. CCEBA/NCSEA and SACE each argue that QFs have the capacity to provide valuable ancillary services and should be compensated for doing so now and support the Public Staff's stakeholder proceeding proposal. While there appears to be alignment among the intervenors that further investigation into ancillary services is warranted, the Commission is persuaded by Duke Energy that opening a docket to formally begin an inquiry is not necessary or appropriate at this time.

FERC defines ancillary services as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." *See* FERC Order No. 890, App'x A (Pro Forma Open Access Transmission Tariff), at I.1.2; *see also* Joint OATT at I.1.2. FERC has recognized that rates for purchasing "'energy' from QFs under Section 210 of PURPA includes the entire output of the QF, including capacity, energy and ancillary services." *See Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, 123 FERC ¶ 61,055, n. 869, 2008 FERC LEXIS 788 (Apr. 21, 2008). This statement—made in the context of clarifying the scope of QF exemptions from FERC oversight of market-based rates under sections 205 and 206 of the Federal Power Act—recognizes that utilities are required to purchase a QF's entire capacity and energy output, which may include some ancillary services related to that capacity and energy.[12] Importantly, PURPA is a "must purchase" construct where all "electric power generated by the Facility" delivered and made available by the QF seller to the utility is purchased at DEC's or DEP's avoided costs. JIS at DEC/DEP Exhibit 1, DEC/DEP Exhibit 3. The Commission notes that it has long approved the peaker methodology to forecast DEC's and DEP's full avoided costs, and the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)." JIS at 13–14 (citing Sub 140 Phase One Order at 30). For these reasons, the Commission finds persuasive Duke Energy's argument that the Commission-approved methodology for calculating Duke Energy's avoided costs rates fully compensate QFs for delivering energy and capacity.

In addition, the Commission agrees with Duke Energy that the provision of ancillary services by QFs is inconsistent with PURPA's must-take structure. As all parties appear to acknowledge, a QF's provision of ancillary services would require both utility dispatch and operational control of the QF's generating facility and require the QF to produce *less than* its maximum energy and capacity. The Commission acknowledges that HB 951 requires third party solar and solar plus storage resources procured pursuant to the Carbon Plan to be dispatched, operated, and controlled in the same manner as the utility's own generation resources, which could potentially mitigate those concerns and provide Duke the operational control required. However, the commercial and operational terms applied to these resources will likely be determined through the Carbon Plan and a competitive solicitation process and would not apply to QFs seeking to sell power under PURPA standard offer or negotiated rates. The Commission is further

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[12] FERC has also recently disclaimed jurisdiction under Section 205 of the Federal Power Act to determine whether compensation for "reactive service" should be authorized where a QF's PPA selling capacity and energy exclusively to its interconnected utility was subject to state PURPA implementation. *See Cherokee Cty. Cogeneration Partners, LLC*, 1 76 FERC ¶ 61,069, at P. 16 (2021).

persuaded by the argument that procuring ancillary services from a large number of third party generators would introduce untenable complexity to Duke's system operations. Finally, the Commission notes that no party has identified precedent for procuring ancillary services under a State's implementation of PURPA.

The Commission is likewise not persuaded by CCEBA/NCSEA's argument that QFs are currently providing certain ancillary services for which they are not being compensated. CCEBA/NCSEA assert that QFs are capable of providing voltage support given the requirement in Section 1.8 of the IA that solar QFs are obligated to "maintain a constant voltage level." 2018 Sub 158 Order at 48–49. 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." *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 30 (2007). This is because "an 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." *Id.* at P 29. Contrary to CCEBA/NCSEA's assertions, Duke Energy does not compensate its fleet or affiliated generators for reactive power service, and the Commission is therefore persuaded that QFs are not going uncompensated for services provided under PURPA.

Finally, the Commission is not persuaded that a new docket should be opened at this time for the purpose of further investigating the ability of QFs to provide ancillary services. Nevertheless, the Commission agrees with the Public Staff that the energy landscape in North Carolina is changing such that fewer third party QFs are selling power through standard offer PPAs and are instead participating in competitive procurements like the CPRE and, going forward, Duke will be procuring new solar resources and solar plus storage resources selected in the Carbon Plan. The Commission further agrees with Public Staff that studying the ability of IBRs to provide ancillary services is a worthwhile exercise. Recognizing the limited size of DEC's and DEP's ancillary service requirement and HB 951's mandates for utility ownership of new generating facilities selected in the Carbon Plan and operational control of third-party owned solar and solar plus storage IBRs in the same manner as Duke Energy's own generating facilities, the Commission directs Duke Energy to conduct a preliminary investigatory study of the operating characteristics of IBR at certain of its own IBR facilities to understand which ancillary services can be provided by each resource or combination or resources. Duke Energy should report on the results of the study to the Public Staff and other interested stakeholders and address the results of the study in the next Carbon Plan update proceeding in 2024.

For all of these reasons, the Commission finds that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility. The Commission additionally directs Duke Energy to commence a study of Duke Energy's needs for ancillary services and the capability of IBRs to cost-effectively provide ancillary services as described in this section.

AS-AVAILABLE RATES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

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

Summary of the Comments

In its JIS, Duke Energy explains that the Commission directed it, as one of the Sub 158 Additional Issues, to evaluate real-time pricing tariff options for QFs selling under Schedule PP, specifically focusing on the new rate options prescribed under FERC Order No. 872. Duke Energy explains that in Order No. 872, FERC amended its regulations to provide states greater flexibility to (1) utilize locational marginal prices (where available) or competitive prices to set rates for as available QF energy sales and (2) mandate that variable avoided energy rates calculated at time of delivery could also be used to set the energy rates for QFs electing to sell energy pursuant to a LEO. 18 C.F.R. §§ 292.304(b)(6-7), (d)(1)(iii). With respect to the latter, Duke Energy quotes Order No. 872 for the proposition that "flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility's as available avoided costs at the time the energy is delivered." *Id*. at § 292.304(d)(2). Duke Energy also states that FERC recognized that such as-available rates ensure that QF rates do not exceed the avoided cost rate cap imposed by PURPA, which balances the risk allocation between QFs and utility customers and allows rates to automatically adjust as avoided costs change. Finally, with respect to Order No. 872, Duke Energy states that FERC's revised regulations permit state regulatory authorities to set as-available rates using either pricing established through a liquid market hub or "Combined Cycle Prices" established by a state-approved formula incorporating "published natural gas price indices, a proxy heat rate, and variable operations and management costs." JIS at 38-39.

Consistent with FERC's policy goals and analysis in Order No. 872, Duke Energy proposes to update its Schedule PP tariff to use the hourly marginal cost of producing energy (Marginal Cost Rates) to calculate avoided costs for QFs that elect to sell energy to Duke Energy on an as-available basis. Duke Energy explains that the Marginal Cost Rates will be calculated ex-post at the end of the month for each hour in a given month based on the joint dispatch outcomes for DEC and DEP during that month using the incremental cost of production of the next megawatt hour. Duke Energy also explains that because the Marginal Cost Rates are calculated at the end of each calendar month, QF compensation will be based on actual marginal costs rather than market forecasts. Duke Energy states that under this methodology, the "as-available" rates will accurately compensate QFs for the energy they provide based upon the utility's avoided costs calculated "at the time of delivery" in accordance with PURPA, while protecting DEC and DEP's customers from potential overpayment. Duke Energy notes that it currently uses this methodology to calculate transmission and wholesale imbalance billing rates. JIS at 40.

Duke Energy explains that it investigated developing a projection of avoided energy cost on a day-ahead basis but determined that QFs putting power to the utility and its customers under the as-available rate already have the option to sell to Duke Energy or other markets, such as PJM, Southern Company, or DENC, in the forward day-ahead market based on the projected wholesale need and value of purchased power at that point in time. If the QF does not sell its output to Duke or other market participants, it can put its power to DEC or DEP under the "as-available" rate and receive the value of the avoided energy created for DEC and DEP's customers at the time of delivery using the ex-post pricing described in the rate. Duke Energy also explains that QFs that commit to sell their full output to Duke Energy, under a LEO, have other PURPA-guaranteed rate options for fixed price power sales of various terms, but for those QFs that elect to sell and deliver power "as-available" and maintain the option to sell off-system to another entity, the ex post methodology most accurately reflects the utility's actual avoided cost at the time of delivery and will best protect customers from over- or under-estimations of the actual costs avoided when the energy is delivered. *Id.* at 40-41.

Duke Energy also explains that it is retaining the 2-year Variable Rates contract option that exists under the Schedule PP approved in the 2020 Sub 167 Order, but this rate option will now require a QF to contractually obligate itself to sell and deliver power for at least a two-year term to reflect that DEC and DEP are forecasting avoided costs over this period. *Id.* at 41.

Finally, Duke Energy notes that, after discussion with the Public Staff and other stakeholders, for this proceeding, it is not proposing to offer a long-term fixed capacity rate and variable energy rate option based upon DEC's and DEP's avoided energy cost calculated at the time of delivery, as now allowed under 18 C.F.R. 292.304(d)(2). Duke Energy states that in future biennial proceedings, it will continue to evaluate this concept along with the other new options for establishing avoided cost rates under FERC's implementing regulations, as updated in Order No. 872. *Id.* at 41.

In its Initial Statement, the Public Staff states that it has worked with Duke Energy to develop the as-available rates that Duke Energy proposed in its JIS and notes that because DEP and DEC are not members of a Regional Transmission Organization, developing a real-time pricing tariff is more complex. The Public Staff explains that it supports Duke Energy's proposal because it will reduce overpayment risk to QFs that do not contractually obligate themselves to sell and deliver power to Duke for a fixed term. The Public Staff also notes that as of December 2021, only three small hydro QFs are selling power to Duke Energy under "as-available" rates, so the anticipated impact of this proposal will be minimal. Public Staff Initial Statement at 13-14.

In its Initial Comments, SACE argues that Duke Energy's proposal to calculate rates ex-post at the end of the month is not appropriate. SACE explains that in Order No. 872, FERC rationalized allowing states to shift to avoided cost rates with variable energy components while maintaining a fixed capacity component because it determined this was a construct found elsewhere in the electric industry. SACE argues, however, that calculation a month after the fact is not standard in the industry. According to SACE, ex-post calculation creates additional uncertainty and imposes a cost and inflates QF overall project costs which effectively imposes a decrement on the rates a QF receives. SACE notes that this will make QF financing more difficult and weaken the PURPA market. SACE argues that a price set ex-ante and adjustment more frequently should be used. SACE Initial Comments at 31-32.

Duke Energy's Reply Comments note the Public Staff's support for its as-available rates and responds to SACE's comments. Duke Energy explains that SACE's comments focus on the changes Order No. 872 implemented to the LEO option under 18 CFR § 292.304(d)(1)(ii) that recognized the benefits of more accurate avoided energy rates over the term of the QF contract, but DEC's and DEP's Marginal Cost Rates are intended to meet the "as available" requirements under 18 CFR § 292.304(d)(1)(i) for QFs that elect not to contract to sell their capacity and energy over a specified term. Duke Energy also states that SACE's claim that the ex-post calculation methodology will make QF financing more difficult misses the point that the DEC and DEP' Marginal Cost Rates are "as available" rates where the QF is not contracting to sell its capacity and energy to DEC or DEP for any specified future term. Duke Energy notes that for a QF that desires a short-term rate but seeks a fixed price and commits to deliver capacity and energy over a future term, DEC and DEP offer other PURPA-guaranteed rate options for fixed price power sales of various terms, including the short-term 2-year Variable Rates contract option approved by the Commission in the 2020 Sub 167 Order. Duke Reply Comments at 33-34.

Duke Energy also states that SACE is incorrect that DEC's and DEP's proposed methodology to calculate the Marginal Cost Rates is not utilized in the industry today. Duke Energy notes that the Public Staff acknowledges that DEC and DEP use this same methodology to calculate transmission and wholesale imbalance billing rates. In addition, Duke Energy explains that Duke Energy Florida uses a similar ex-post methodology to calculate as-available avoided energy cost rates to meet its PURPA rate obligations in that jurisdiction. Duke reiterates that the Marginal Cost Rate should be adopted and offered to QFs that elect only to sell as-available energy versus contracting to sell power to DEC or DEP for a specified future term. Duke Reply Comments at 34-35.

Discussion and Conclusions

FERC Order No. 872, updating FERC's regulations implementing PURPA, was issued on July 16, 2020, and this Commission acknowledged in its 2020 Sub 167 Order that FERC Order No. 872 may "driv[e] additional changes to PURPA implementation and the determination of avoided cost rates in North Carolina." The Commission also recognized that it would consider proposals stemming from Order No. 872 and its potential effect on PURPA implementation in North Carolina in this proceeding. 2020 Sub 167 Order at 57-58. Order No. 872 ultimately gives states more flexibility to set rates for as-available energy sales and also requires that variable avoided energy rates calculated at the time of delivery be used to set energy rates for QFs electing to sell energy pursuant to a LEO. 18 C.F.R. §§ 292.304(b)(6-7), (d)(1)(iii). Any rates set, however, still must not exceed the avoided cost rate cap imposed by PURPA.

The Commission acknowledges Duke Energy's attention to Order No. 872 and its impact on this proceeding as shown by multiple stakeholder meetings conducted by Duke Energy and its proposal to update its Schedule PP tariff to use the Marginal Cost Rates to calculate avoided costs for QFs that elect to sell energy to DEC and DEP on an as-available basis. The Commission also finds Duke Energy's proposal, as supported by the Public Staff, to calculate the Marginal Cost Rates ex-post at the end of the month for each hour based on the joint dispatch outcomes for DEC and DEP and the incremental cost of production of the next megawatt hour to be reasonable. This methodology ensures that QFs are accurately compensated based on the time they provide the energy while also protecting DEC and DEP's customers from overpayment.

The Commission is not persuaded by SACE's argument that Duke Energy's ex-post calculation will make QF financing more difficult because Duke Energy's as-available rates do not require a QF to contract with DEC or DEP to sell its capacity and energy for any specified future term. Instead, if QFs desire a short-term rate, but seek a fixed price while committing to sell capacity and energy over a future term, they can select other PURPA-guaranteed rate options for fixed price power sales of capacity an energy over a specified term as provided for in 18 C.F.R. 292.304(d)(1)(ii). The Commission also notes, as highlighted by Duke Energy, that SACE's contention that Duke Energy's Marginal Cost Rates calculation methodology is not utilized in the industry today is inaccurate as Duke Energy notes (and the Public Staff acknowledges) that DEC and DEC use this same methodology to calculate transmission and wholesale imbalance billing rates.

The Commission further finds reasonable Duke Energy's proposal to retain its 2-year Variable Rates contract option under Schedule PP, as approved in the 2020 Sub 167 Order, and add a requirement that a QF must contractually obligate itself to sell and delivery power for at least a two-year term.

In summary, based upon the foregoing and the entire record, the Commission accepts Duke Energy's use of Marginal Cost Rates to calculate avoided cost rates on an as-available basis and accepts its added fixed term requirement to its two-year Variable Rates contract option under Schedule PP as reasonable for purposes of this proceeding. In future biennial avoided cost proceedings, Duke Energy should continue to evaluate pursuant to 18 C.F.R. 292.304(d) the potential of offering a long-term fixed capacity rate and variable energy rate option based upon DEC and DEP's avoided energy cost calculated at the time of delivery.

SCHEDULE PP RATE DESIGN

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

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

Summary of the Comments

In the JIS, Duke Energy explains that Schedule PP pays QFs on a volumetric rate basis where both avoided energy and capacity is paid on a $/kWh basis versus a separate fixed payment for capacity. DEC and DEP note that the Schedule PP rates are designed to credit QFs for avoided energy supplied during pre-designated on-peak and off-peak hours. JIS at 41-42.

Duke Energy's JIS 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 Public Staff filed a Partial Settlement on April 18, 2019, to achieve these goals, recommending an avoided energy and avoided capacity rate design methodology for use in the Sub 158 Proceeding and in future proceedings (Sub 158 Rate Design Stipulation). Agreement and Stipulation of Partial Settlement, Docket No. E-100, Sub 158 (Apr. 18, 2019). Duke Energy's JIS explains that the 2018 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 and DEP's avoided energy and capacity rates. Duke Energy states that, for the purposes of this proceeding, it is continuing to use the Commission-approved avoided energy rates designs as outlined in the Sub 158 Rate Design Stipulation and as approved by the Commission in the 2018 Sub 158 Order and 2020 Sub 167 Order. JIS at 41-42.

Duke Energy also notes that, pursuant to the Commission's directive in the 2020 Sub 167 Order, Duke Energy worked with the Public Staff to review DEC's and DEP's approach to inclusion of CT start costs used in production cost modeling. In Exhibit 8 to the JIS, Duke Energy explains that DEC and DEP modified their start cost modeling to resolve unintended impacts on the avoided energy pricing periods. Specifically, Duke Energy explains that start-up and shut-down costs are distributed over the anticipated operation and added to the per MWh and per Hour cost components. Total O&M costs, including start costs, are captured in this approach while providing intuitive and appropriate avoided energy price signals. Duke Energy explains that this methodology is consistent with the modeling approach utilized in the approved 2018 Sub 158 and 2020 Sub 167 avoided energy rates, and the Public Staff has indicated that it supports Duke Energy's approach to this calculation. JIS at 42-43, Exhibit 8; Sub 167 Order at 40.

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 representing the hours most likely to have capacity value. Duke Energy states that this is consistent with the approach it has historically utilized with respect to QF rate design under prior vintages of Schedule PP. Duke Energy explains that it developed DEC's and DEP's seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the 2020 resource adequacy study by Astrapé Consulting as inputs to the avoided capacity rate design in this proceeding. JIS at 44. Duke Energy notes that all of the inputs were updated in the new study, the solar projections were increased compared to the previous study, and Astrapé incorporated an enhancement for modeling load during extreme cold weather which shifted some of the winter loss of load risk from PM hours to AM hours. *Id.*

Duke Energy explains that the Schedule PP capacity rate design in this proceeding reflects updated pricing periods to most accurately reflect the marginal capacity value to customers during each period. Duke Energy specifies that, for DEC, the updated pricing periods include capacity payments during the PM hours in the summer months of July and August and during the AM hours in the winter months of December, January, February, and March. For DEP, the updated pricing periods include AM hours during the winter months of December, January, February, and March and do not include a summer pricing period. Duke Energy notes that no capacity payments apply during the remaining months for either DEC or DEP and that the highest prices are paid in the early morning winter hours in order to recognize the greater loss of load risk and greater value of capacity during those hours. JIS at 44-45.

Duke Energy also explains that the seasonal allocation of capacity value remains heavily weighted to winter based on the impact of summer versus winter loss of load risk. Specifically, Duke Energy states that DEP's loss of load risk is 100% winter—unchanged from the approved allocation in the 2018 Sub 158 Order and 2020 Sub 167 Order—and DEC's loss of load risk is 96% winter —an increase from the approved 90% allocation in the 2018 Sub 158 Order and 2020 Sub 167 Order—based on the 2020 Resource Adequacy Study. JIS at 45.

Finally, Duke Energy notes that it engaged with the Public Staff prior to filing its JIS in this proceeding and that it plans to continue discussing the accuracy and appropriateness of the rate design with the Public Staff in advance of the next biennial avoided cost proceeding in 2023. JIS at 45.

In its Initial Statement, the Public Staff states that it reviewed Duke Energy's seasonal allocations and other assumptions incorporated into DEC's and DEP's avoided costs, finds the avoided capacity rates reflected in Schedule PP to be reasonable, and recommends that the Commission approve them. The Public Staff also states that it finds Duke Energy's revised approach for modeling start costs to be reasonable for this proceeding because Duke Energy has produced rates that generally align with the purpose of the Sub 158 Rate Design Stipulation approved in the Sub 158 Proceeding. Public Staff Initial Statement at 37-39, 46-47.

No other party commented on Duke Energy's rate design, start costs, or use of seasonal allocations in this proceeding, or otherwise raises objections with respect to these issues.

<u>Discussions 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 2020 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 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 2020 Solar Resource Adequacy Study for updating the avoided capacity rate design in this proceeding. The Commission also finds that Duke Energy and the Public Staff have reasonably addressed the Commission's directive in the Sub 167 Order to address the issues associated with modeling start costs in the production cost model by spreading these costs over all hours that the individual unit operates.

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 2020 Resource Adequacy Study and as presented in Duke Energy's JIS. The Commission also approves DEC's seasonal allocation of capacity value of 100% to winter and DEP's seasonal allocation of capacity value of 96% to winter. The Public Staff supports, and no other parties take issue with, Duke Energy's JIS on these issues.

STANDARD OFFER TERMS AND CONDITIONS

EVIDENCE AND CONCLUSIONS TO SUPPORT FINDINGS OF FACT NOS. 23-24

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

Summary of the Comments

In their JIS, DEC and DEP explain the minor modifications made to their Schedule PP Tariff to reflect the updated avoided cost rates and the revised as-available rate structure. These modifications include administrative revisions for improved clarity and consistency, ensuring that references to rates accurately and clearly distinguish between Long-Term Rates, Variable Rates, and new Marginal Cost Rates. Regarding Marginal Cost Rates, Duke Energy explains that in the 2002 avoided cost proceeding, the Commission directed that the two-year variable rate acted as the "as available" rate for purposes of the standard offer. Because Duke Energy has proposed an updated methodology for determining the "as available" rates that is consistent with FERC's recent Order No. 872, as well as maintained the two-year variable rate offer, Duke Energy is amending its tariffs to reflect the distinct rate offers. JIS at 46.

Further, Duke Energy explains that it updated and simplified the Capacity Credit schedule to reflect that hydroelectric generation QFs receive the same capacity credits as other QFs. The Capacity Credit schedule reflects that there are two applicable categories for hydro QFs depending upon whether they are a legacy hydro QF or a hydro QF that does not qualify for the statutory exemption and that are eligible for capacity credits beginning in the first year of a utility's capacity need. *Id*.

Duke Energy also explains that it added a new Marginal Cost Rates section to Schedule PP which discusses how such rates are developed and calculated at the end of each calendar month, for each hour of the month, and how eligible QFs may receive the rates after executing a non-disclosure agreement. JIS at 47.

Finally, Duke Energy proposes to reduce the monthly Administrative Charge (DEC) or Monthly Seller Charge (DEP) ("seller charges") to $3.00 per month for QFs with capacity of 15 kW (AC) or less. Duke Energy notes in its JIS that it has not proposed an associated increase in seller charges for other QFs to make up for the revenue loss. *Id.*

In the Terms and Conditions for the Purchase of Electric Power, Duke Energy states that it has revised Section 6 to use the Marginal Cost Rates as the benchmark for calculating early termination payments for the period on and after November 1, 2021, which replaces the use of Variable Rates for this purpose. Duke Energy has also modified Section 9 to reflect the new service regulation standard that a "Month" for billing purposes is 26-34 days. *Id.*

The JIS also explains that Duke Energy has made limited revisions to its standard offer PPA forms presented in DEC's and DEP's respective Exhibit 3. The revised standard PPA forms now refer to the new Marginal Cost Rates and clarify that any automatic extension of the Agreement would use the as-available rates, which, in DEC's and DEP's proposal is now the Marginal Cost Rates. For the sake of clarity, because it does not apply to Eligible QFs of 1,000 kW (1MW) and under, Duke Energy has also removed a reporting requirement provision (Section 6 of the PPA form). Duke Energy clarifies in its JIS that the Section 6 requirement will continue to be used in non-standard offer PPAs for larger QFs. Additionally, Duke Energy makes limited clarifying revisions to the Capacity Hour Windows concept in the Exhibit A Energy Storage Protocol. JIS at 48.

No other party to this proceeding commented on Duke Energy's proposed revisions to its Standard Offer documents, including minor revisions to DEC's and DEP's respective Schedule PPs, Standard Offer Terms and Conditions, and Standard Offer PPA.

Discussion and Conclusions

Based on the foregoing and the entire record herein, and given that no party expressed any objection to the revisions proposed by Duke Energy, the

Commission finds that the revisions to DEC's and DEP's respective Schedule PPs, Standard Offer Terms and Conditions, and Standard Offer PPA are reasonable and appropriate.

EVIDENCE AND CONCLUSIONS TO SUPPORT FINDING OF FACT NO. 25

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

Summary of the Comments

Duke Energy presents DEC's and DEP's updated Notice of Commitment Forms in DEC/DEP Exhibit 6 (for QFs up to 1 MW eligible for Schedule PP) and DEC/DEP Exhibit 7 (for large QFs). In its JIS, Duke Energy explains that it is proposing to update DEC's and DEP's Notice of Commitment Forms to accomplish three primary objectives: (1) incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872; (2) align the Notice of Commitment Form with the now-approved queue reform process under the North Carolina Interconnection procedures; and (3) update the non-standard offer Notice of Commitment Form to establish a more standardized and efficient process for QFs to proceed from Notice of Commitment Form to PPA. JIS at 49.

With respect to FERC Order No. 872, Duke Energy explains that FERC adopted 18 C.F.R. 292.304(d)(3), which now requires new QFs to "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a legally enforceable obligation." FERC Order No. 872, at ¶¶ 684-696. Duke Energy explains that FERC identified several examples of factors that could reasonably demonstrate a QF's commercial viability and financial commitment, including that the QF (1) is taking meaningful steps to obtain site control adequate to commence construction; (2) has filed an interconnection application with the appropriate entity; (3) has submitted applications, including filing fees, to obtain all necessary local permitting and zoning approvals; and (4) has met objective and reasonable milestone in development that can demonstrate financial commitment. JIS at 49-50 (citing FERC Order No. 872, at ¶¶ 685-690.

In line with this guidance, Duke Energy explains that Attachment C to the Notice of Commitment Form requires the QF to show that it (1) has obtained a CPCN; (2) for new QFs requesting to interconnect to the utility's system, the QF has met all requirement to enter the Definitive Interconnection Study Process under NCIP Section 4.4.1. and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5; (3) has site control for the entire proposed term of delivery under a future PPA; and (4) provides reasonable evidence and documentation of the QF's commitment to develop the project by including a status update on permitting, procurement of any long lead-time materials, execution of third-party engineering, procurement and construction contracts to construct the facility, and executing of any third-party transmission agreements, if applicable. Duke Energy asserts in its JIS that each of these requirements are reasonable, objective and are within the control of the QF Developer. JIS at 51.

In addition, Duke Energy states that it has modified DEC's and DEP's Notice of Commitment Forms to align with the new Definitive Interconnection Study Process, which restructures the traditional North Carolina Interconnection Procedures (NCIP) Section 4.3 serial System Impact Study into a multi-step Cluster Study process under NCIP Section 4.4.7. Duke Energy explains that a key objective of queue reform—which aligns with FERC's new commercial viability standards—is to reduce the number of speculative projects entering the interconnection process through increasing study deposits, commercial readiness requirements and financial commitments for non-ready project as they progress through the interconnection study process. Duke Energy explains that a new QF proposing to interconnect and sell and deliver power to DEC or DEP, must demonstrate that it has (1) submitted an interconnection request to become an Interconnection Customer of the Company; (2) provided initial security requirements under NCIP Section 4.4.1; and (3) executed a Definitive Interconnection System Impact Study (DISIS) Agreement pursuant to NCIP Section 4.4.5. DEC and DEP assert that their updated Notice of Commitment Forms align with the DISIS process as a binding Notice of Commitment and can be used to demonstrate project readiness at both the M1 and M2 milestones JIS at 52-53.

Finally, Duke Energy also proposes to update the Notice of Commitment Form to provide a more standardized and streamlined process for QFs to progress from a Notice of Commitment Form to a mutually binding PPA. Specifically, Duke Energy has updated Section 3 and Attachment B of the Large QF (those not eligible for Standard Tariff) Notice Commitment Form to now establish a standardized process for the QF to provide all information that DEC and DEP require to develop a negotiated QF PPA and commits that DEC and DEP will deliver an executable PPA back to the QF within 30 days. The QF would then have a period of 90 days to work with the utility to finalize and execute the PPA, with this period being automatically extended to no earlier than 30 days after receiving a Facilities Study Agreement from the Company.

In its Initial Statement, the Public Staff states that it generally supports Duke Energy's revisions to DEC's and DEP's Notice of Commitment Forms. Moreover, the Public Staff agrees with Duke Energy that the revisions incorporate the new commercial viability and financial commitment requirements established in Order No. 872, align the LEO process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from the Notice of Commitment to PPA. Public Staff Initial Statement at 56. The Public Staff states that Duke Energy needs assurances that projects entering into the DISIS study process are commercially viable and progressing toward construction and the sale of the project's output to the utility in order to rely on those projects in Duke

Energy's planning process. The Notice of Commitment form, as the Public Staff explains, is designed to provide a more efficient path for QFs to commit themselves to deliver capacity by executing a PPA and imposing a hard deadline for the QFs to do so after receiving a Facilities Study Agreement. Finally, the Public Staff notes that obtaining a LEO allows QFs to show readiness in the DISIS process and to submit a smaller financial commitment to enter and continue through the early stages of the DISIS process. Public Staff Initial Statement at 56.

In their Joint Initial Comments, CCEBA/NCSEA state that they are "generally comfortable" with Duke Energy's proposed changes to its Notice of Commitment form for QFs larger than 1 MW (AC). However, CCEBA/NCSEA express concern that proposed Section 4 of the Large QF Notice of Commitment Form may make it difficult for QFs to obtain financing. CCEBA/NCSEA explain that Section 4 requires the QF to represent that it will begin delivering output to Duke Energy no later than 365 days after the Notice of Commitment form Submittal Date. CCEBA/NCSEA point out that, given Duke Energy's expected time to complete interconnection studies and construct interconnection facilities is approximately four years, Section 4 would prevent a QF from forming a LEO and securing pricing until approximately three years into the interconnection study and construction process. CCEBA/NCSEA Initial Comments at 22. According to CCEBA/NCSEA, no QF has been financed or built with such a lack of price certainty and none would be in the future. CCEBA/NCSEA further note that Duke Energy's proposed work-around—a day-for-day extension of the 365-day deadline for any days by which Duke Energy's completion of the interconnection facilities and network upgrades exceeds the QF's requested interconnection date is insufficient to remedy the issue. CCEBA/NCSEA Initial Comments at 23.

To remedy the issue, CCEBA/NCSEA propose that Duke Energy revise Section 4 to instead require such new QFs seeking interconnection to the DEC or DEP systems to begin delivering energy output within 90 days of DEC's or DEP's completion of all required interconnection facilities and network upgrades. CCEBA/NCSEA Initial Comments at 24.

As Exhibit 1 to its Reply Comments, Duke Energy filed an updated Large QF Notice of Commitment Form. According to Duke Energy, these revisions address the concerns raised by CCEBA/NCSEA. First, Duke Energy explains that the revised Notice of Commitment Form now distinguishes between existing QFs (with existing interconnection agreements) that are already interconnected to DEC's or DEP's system and new QFs seeking interconnection that have not yet achieved commercial operation. Pursuant to the revisions, Duke Energy explains, existing QFs must commence delivery of its output within 365 days after submitting a Notice of Commitment Form; new QFs, however must only commence delivery no later than 90 days after its in-service date. DEC/DEP Reply Comments at 45; Exhibit 1 at 11.

Also, in response to CCEBA/NCSEA's stated concerns, Duke Energy's Exhibit 1 modifies Section 4 to allow further extension of the in-service date- where the Seller is making a good faith effort to advance the project but is delayed due to circumstances beyond its control and which do not result from its fault or negligence. DEC/DEP Reply Comments at 44-45. In their Reply Comments, CCEBA/NCSEA note that they reached agreement with Duke Energy on revisions to the Notice of Commitment Forms. CCEBA/NCSEA Reply Comments at 1-2. The Public Staff's Reply Comments acknowledge that Duke Energy shared a draft of the revised Notice of Commitment Form before filing it with the Commission. The Public Staff states that it supports the revisions and commends the parties in coming to an agreement. Public Staff Reply Comments, at 7-8.

SACE's Reply Comments state that SACE agrees with CCEBA/NCSEA's critique and recommended revisions to Section 4 of Duke Energy's proposed Notice of Commitment Forms. SACE Reply Comments at 10.

<u>Discussion and Conclusions</u>

In Order No. 872, FERC adopted 18 C.F.R. 292.304(d)(3), which now requires new QFs to "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a legally enforceable obligation." FERC Order No. 872, at ¶¶ 684-696. The new regulations task State Commissions with determining the objective and reasonable criteria QFs must use to demonstrate commercial viability and financial commitment. FERC emphasized that these new requirements were "raising the bar to prevent speculative QFs from obtaining LEOs, and the associated burden on purchasing utilities, [while] not establishing a barrier for financially committed developers seeking to develop commercially viable QFs." *Id.* at ¶ 688. The new standard is also designed to ensure that that no electric utility obligation is triggered for those QF projects that are not sufficiently advanced in their development, and therefore, for which it would be unreasonable for a utility to include in its resource planning. *Id.* at ¶ 684. As FERC notes, utilities must be able to "reasonably rely on the LEO in planning for system resource adequacy." *Id*. at ¶ 687.

FERC also explained in Order No. 872 that the criteria or factors established by State Commissions for QFs to demonstrate commercial viability and financial commitment should be in the control of the QF, and identified a number of examples of factors that a state could reasonably require, including requiring the QF to: (1) demonstrate it is taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location; (2) demonstrate it has filed an interconnection application with the appropriate entity; (3) demonstrate that it has submitted all applications, including filing fees, to obtain all necessary local permitting and zoning approvals; and (4) meet objective and reasonable milestones in the QF's development that can sufficiently demonstrate the QF developers' financial commitment in the QF development and allows utilities to reasonably rely on the LEO in planning for system resource adequacy. According to FERC, these factors "provide a reasonable balance between providing QFs with objective and transparent milestones up front that are needed to obtain a LEO, allowing states the flexibility to establish factors that address the individual circumstances of each state, and increasing utilities ability to accurately plan their systems."[13] FERC also emphasized that states are in the best position to determine what specific factors would best suit the specific circumstances of that state, so long as they are objective and reasonable. *Id.* at ¶¶ 685-690.

As a threshold matter the Commission commends Duke Energy, CCEBA/NCSEA and the Public Staff for working together to address identified issues and develop an amended Large QF Notice of Commitment Form. In addition to the fact that all parties appear to be in agreement regarding the terms of the Notice of Commitment Forms,[14] the Commission finds that Duke Energy's proposed revisions appropriately incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872. The revised Notice of Commitment Forms further balance Duke Energy's need for assurance that projects entering into the DISIS study process are commercially viable and progressing toward construction and sale of the project's output with QFs' need for reasonable opportunities to obtain financing. Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to approve Duke Energy's Notice of Commitment Forms as presented in DEC/DEP Exhibit 6 (for QFs up to 1 MW eligible for Schedule PP) and DEC/DEP Reply Comments Exhibit 1 (for large QFs not eligible for the standard offer).

ENERGY STORAGE SYSTEM RETROFIT RATES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

The evidence supporting these findings of fact is found in Duke Energy's JIS, the Initial Statement of the Public Staff, Duke Energy's Reply Comments, the Reply Comments of NCSEA on Net Excess Energy Credit Rate Revision Proposal (NCSEA NEEC Reply Comments), and the entire record herein.

Summary of the Comments

The JIS presents DEC's and DEP's proposed new ESS Retrofit avoided cost rates in DEC Exhibit 12 and DEP Exhibit 12. As Duke Energy explains, the forecast data used to calculate each published levelized New ESS Retrofit avoided cost rate will begin January 1, 2023 and span the length of time specified for the

[13] FERC states that the factors articulated will "limit the number of unviable QFs obtaining LEOs and unnecessarily burdening utilities that currently have to plan for QFs that obtain a LEO very early in the process but ultimately are never developed." Order No. 872, at ¶ 688.

[14] The Commission notes that, unlike the other commenting parties, SACE had not reviewed the revised Large QF Notice of Commitment Form at the time of filing its Reply Comments. Nevertheless, SACE has not sought leave to file sur-reply comments in response to the revisions and adopted the position of CCEBA/NCSEA, which now support Duke Energy's revised Notice of Commitment Forms.

particular year term of the New ESS Retrofit avoided cost rate. These rates will be available until November 1, 2023. JIS, at 54.

Duke Energy explains that DEC and DEP are filing their respective 2, 3, 4, 5, 6, 7, 8, 9, and 10-year ESS Retrofit avoided cost rates in this proceeding pursuant to a commitment Duke Energy made in the Sub 158 and Sub 101 dockets. JIS, at 4.

In its Initial Statement, the Public Staff explains that Duke Energy's ESS Retrofit avoided cost rates would be made available to QFs that (1) are currently selling power to DEC or DEP; and (2) established a LEO or entered into a PPA prior to November 15, 2016, and wish to retrofit their facilities with energy storage. Public Staff Initial Statement at 57. The Public Staff notes that Duke Energy used forecast data beginning on January 1, 2023 to calculate the new ESS retrofit avoided cost rates to reflect that QFs retrofitting their facilities with energy storage will proceed through the DISIS, and pursuant to DISIS timelines, will not be online until 2023 at the earliest. Public Staff Initial Statement at 58.

Ultimately, the Public Staff finds the proposed ESS Retrofit rates and eligibility requirements to be reasonable. The Public Staff also recommends the Commission adopt the bifurcated rate proposal originally raised in the Public Staff's Initial Comments in the Sub 158 avoided costs proceeding. According to the Public Staff, the bifurcated rate proposal would balance the need to incentivize new technologies with establishing appropriate rates by separately metering any additional output at the then-current Commission-approved avoided cost rates. The Public Staff recommends the Commission approve both DEC's and DEP's proposed New ESS Retrofit avoided cost rates and the Public Staff's bifurcated rate proposal. Public Staff Initial Statement at 59.

In their Reply Comments, DEC and DEP agree with the Public Staff that their New ESS Retrofit avoided cost rates are reasonable and should be approved, and additionally note that no other intervenor submitted comments on this issue. DEC/DEP Reply Comments at 47. With respect to the Public Staff's bifurcated rate proposal, Duke Energy explains that the proposal would require utilities to separately meter any additional energy output from the original facility and compensate the additional output at the then-current Commission-approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of the pre-existing PPA. Duke Energy states that it opposed this proposal in the Sub 158 proceeding, and all parties, including the Public Staff, acknowledged potential challenges to implementation. Duke Energy explains that the Commission's Sub 158 Order found that it was "premature" to rule on the Public Staff's proposal absent further "investigation" into the issues." DEC/DEP Reply Comments, at 47-48. Accordingly, Duke Energy explains, beginning in May 2020, Duke Energy worked in good faith with stakeholders to achieve technical and regulatory solutions for modifying existing facilities to add energy storage and reached a compromise consensus regarding the Public Staff's proposed bifurcated rate proposal. Specifically, Duke Energy explains, the parties agreed that (1) the addition of storage to an existing facility will be accomplished through amendment of the existing PPA, rather than negotiating a new PPA; and (2) metering of the storage addition will be covered by an AC-connected configuration, although integration of DC connected systems will be allowed once DC revenue-grade meters are available and tested. The addition of a 2^{nd} meter will allow Duke to implement a bifurcated rate as proposed by the Public Staff. Accordingly, subject to the caveat that only AC-connected configurations can currently be metered, Duke Energy supports the Public Staff's request for the Commission to approve the bifurcated rate proposal. DEC/DEP Reply Comments at 48.

Discussion and Conclusions

In both the 2018 Sub 158 Order and the Commission's June 14, 2019 Order Approving Revised Interconnection Standard and Requiring Reports and Testimony in Docket No. E-100, Sub 101, the Commission directed the parties to address issues related to the addition of energy storage at an existing QF, including, but not limited to, developing a streamlined process for interconnecting ESS to existing generation sites and organizing a stakeholder proceeding to address other related issues. 2018 Sub 158 Order, at 137 (Ordering Paragraph 31); 2019 Sub 101 Order, at 65 (Ordering Paragraph 7). Through the stakeholder process, DEC and DEP subsequently developed their ESS Retrofit Study Process and filed it with the Commission.

On August 17, 2021, the Commission ordered DEC and DEP to, among other things, establish and file "the procedure for how a QF establishes eligibility for the avoided cost rate or methodology applicable to the output of the energy storage addition." Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations, Docket No. E-100, Sub 101 (issued Aug. 17, 2021). DEC and DEP set out their proposal for this process in their September 29, 2021 Compliance Filing filed in both the Sub 158 and Sub 101 dockets. ESS Retrofit Compliance Filing, Attachment C (Procedure for Energy Storage System Retrofit at an Existing QF Generation Site to Establish Eligibility for Avoided Cost Rates), Docket. Nos. E-100, Sub 101 and E-100, Sub 158 (N.C.U.C. Sept. 29, 2021). The Commission approved the Duke Energy's proposal on May 12, 2022 in Docket Nos. E-100, Sub 101 and E-100, Sub 158. Order Granting Waivers to Implement Energy Storage System Expedited Study Process and Approving Process to Establish Eligibility of Avoided Cost Rates for Retrofit Energy Storage Systems, Nos. E-100, Sub 101, E-100, Sub 158 (N.C.U.C. May 12, 2022). Accordingly, Duke Energy's new ESS retrofit avoided cost rates as well as the Public Staff's bifurcated rate proposal are ripe for Commission consideration in this docket.

Based on the foregoing evidence and the entire record, the Commission finds that DEC's and DEP's respective 2, 3, 4, 5, 6, 7, 8, 9, and 10-year New ESS Retrofit avoided cost rates available to Interconnection Customers proposing to retrofit an ESS at an existing generation site, as set forth in DEC Exhibit 12 and DEP Exhibit 12, are reasonable and hereby approved. The Commission also commends the parties for working together to reach agreement regarding the Public Staff's bifurcated rate proposal and finds the proposal to be reasonable for the purposes of this proceeding. Accordingly, the Commission approves the Public Staff's bifurcated rate proposal and finds that (1) the addition of storage to an existing facility will be accomplished through amendment of the existing PPA, rather than negotiating a new PPA; and (2) metering of the storage addition will be covered by an AC-connected configuration, although integration of DC connected systems will be allowed once DC revenue-grade meters are available and tested. The Commission further recognizes that, at this time, only AC-connected configurations can currently be metered.

NET ENERGY METERING

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-29

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

Summary of the Comments

In its Initial Statement, the Public Staff addresses Duke Energy's proposed calculation of the NEEC, which was presented in DEC's and DEP's Joint Application for Approval of Revised Net Energy Metering Tariffs in Docket Nos. E-7, Sub 1214, E-2, Sub 1219, and E-2, Sub 1076 and which the Commission directed the parties to file comments addressing in Docket No. E-100, Sub 180. The Public Staff explains that Duke Energy's filing proposes that customers who export power are compensated at a Net Excess Energy Credit—a two-year annualized rate, at the distribution level, for Uncontrolled Solar Generators, which is based upon avoided costs. To avoid the need for an avoided cost determination in the NEM Tariff proceeding, the Public Staff recommends that the appropriate methodology for calculating the avoided cost rate used for the NEEC should be decided in the instant docket. In addition, the Public Staff makes three recommendations with respect to Duke Energy's calculation of the NEEC. Public Staff Initial Statement at 3.

First, the Public Staff proposes that it may be appropriate to apply a solar profile, rather than a constant profile to the annualized rate. Although the Public Staff acknowledges that this change will have only a minor impact on the NEEC rate, it nonetheless recommends the change to reflect that solar does not deliver constant energy in all hours of the year. Public Staff Initial Statement at 4.

Second, the Public Staff recommends that the Commission require Duke Energy to calculate seasonal NEEC rates—as opposed to the average annual rate calculation proposed by Duke Energy—for the summer and non-summer seasons to reflect the difference in value associated with net metering exports and to align with the seasons in the time of use rates schedules applicable to all NEM customers taking services under the proposed NEM Tariffs. The Public Staff acknowledges that this, too, would have a minor impact on the NEEC rate. Public Staff Initial Statement at 4.

Finally, the Public Staff notes that the two-year variable rate Duke Energy has proposed to set the NEEC does not include any capacity credits. The Public Staff suggests that it may be appropriate to use a longer-term rate, as net metered solar is included in DEC's and DEP's IRPs as a reduction to their respective load forecasts. Acknowledging that a 10-year term may be too long, as there is no contractual obligation for the net metered facility to operate for that term, the Public Staff proposes to utilize a 5-year rate as the basis for future NEEC calculations. The Public Staff recommends that in future avoided cost filings, Duke Energy calculate the NEEC for NEM Tariffs pursuant to this methodology. Public Staff Initial Statement at 4-5.

In their Reply Comments, DEC and DEP agree with the Public Staff's recommendation to determine the NEEC in the avoided cost docket. DEC and DEP state that they support modifying their proposed methodology for calculation of the NEEC to reflect annualized NEEC rates based on a 5-year term, including both energy and capacity credits where applicable, and weighted using a typical rooftop solar production profile. DEC/DEP Reply Comments at 49. Duke Energy's Reply Comments Exhibit 2 presents re-calculated NEEC rates consistent with the adoption of these recommendations.

With respect to the Public Staff's recommendation to calculate seasonal rates, however, Duke Energy states that it determined implementing seasonal rates would have a negligible impact on the NEEC avoided cost credit. In particular, Duke Energy states that Table 1 to its Reply Comments demonstrates that there is only a 5% differentiation between summer and non-summer rates. Duke Energy further notes that other parties to a Memorandum of Understanding (MOU) filed in Docket No. E-100, Sub 180 on November 29, 2021, have raised concerns to Duke Energy about adding further complexity to the proposed NEM Tariffs.[15] Duke Energy states that it shares this concern. Given the negligible impact and the concerns of Duke Energy and the parties to the MOU regarding the added complexity of the proposal, Duke Energy recommends that the Commission adopt the annualized, rather than seasonal, rate option. Nevertheless, Duke Energy agrees to calculate seasonal NEEC rates within future avoided cost proceedings for analytical purposes and to consider switching to seasonal NEEC rates if the differentiation between summer and non-summer seasons becomes sufficiently impactful to outweigh the added complexity. DEC/DEP Reply Comments at 50.

[15] These settling parties include NCSEA, the Southern Environmental Law Center on behalf of Vote Solar and SACE, Sunrun, Inc., and Solar Energy Industries Association.

NCSEA filed independent Reply Comments on NEEC credit rate proposal. First, NCSEA states that it would be premature to approve revisions to the NEEC rate design because the Commission has not yet approved Duke Energy's NEM proposal. NCSEA Reply Comments on NEEC at 2. In addition, NCSEA notes that under the MOU, Duke Energy has flexibility to propose a solar energy profile and different monthly rates, if and when prudent. NCSEA further notes that Duke Energy has not yet requested a solar profile, and many critics of the NEM Proposal have pointed to the increased complexity of this new net metering paradigm as being an obstacle to broad adoption. NCSEA Reply Comments on NEEC at 3. NCSEA states that it believes, in the near term, that the NEEC rates, as originally envisioned in the MOU, will be appropriate. NCSEA recommends that the Commission instruct interested parties to work together on future NEEC rate parameters to improve the accuracy of compensation to solar customers. NCSEA Reply Comments on NEEC at 4. Finally, NCSEA recommends that if the Commission agree with the Public Staff on the need to use a longer-term rate and a seasonally changing rate upon initial adoption of Duke Energy's NEM Proposal, the Commission should order the use of a 10-year rate, at least. NCSEA disagrees with the Public Staff's position that a 10-year rate may be too long, noting that the Public Staff did not provide any evidence that a net metered facility would operate longer than 5 years. In particular, NCSEA notes that most residential solar equipment manufacturer warranties are good for at least 10 years, solar panel performance warranties are often for 25 years, and net metered systems have a strong financial motivation to operate longer than 10 years to realize enough electricity bill savings to offset the initial investment. NCSEA Reply Comments on NEEC at 4-5.

<u>Discussion and Conclusions</u>

As a threshold matter, the Commission agrees with the Public Staff and other parties that calculation of the NEEC is an avoided costs issue that should be decided in the avoided costs docket. Accordingly, the Commission will consider in this docket the NEEC rate and corresponding calculation methodology that DEC and DEP filed with their respective Joint Application for Approval of Revised Net Energy Metering Tariffs in Docket Nos. E-7, Sub 1214, E-2, Sub 1219, and E-2, Sub 1076. The Commission further orders that should file for Commission approval of their respective NEEC rate and calculation methodology in future biennial avoided cost proceeding.

Addressing the issue of the NEEC rate calculation methodology presented for Commission approval in this case, the Commission finds based on the evidence that it is appropriate to calculation the NEEC to reflect annualized NEEC rates based on a 5-year term, including both energy and capacity credits where applicable, and weighted using a typical rooftop solar production profile. The Commission notes that the parties disagree regarding whether it is appropriate to implement seasonal rates at this time to the NEEC rates. Nevertheless, all parties to file comments on this issue agree that the impact of implementing seasonal rates would be minimal at this time. Accordingly, the Commission approves the

NEEC rates presented in DEC/DEP Reply Comments Exhibit 2 and further orders Duke Energy to address in future avoided cost filings whether it is appropriate to switch to seasonal NEEC rates and whether the output profile used for weighting should be modified.

IT IS, THEREFORE, ORDERED as follows:

1. DEC's and DEP's Schedule PP, as presented in DEC Exhibit 1 and DEP Exhibit 1 to the JIS and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs.

2. 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.G.S. 62-156(b)(3) and shall evaluate continued use of the Peaker Method in the next biennial avoided cost proceeding.

3. DEC and DEP shall use a PAF of 1.04 in their respective avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation.

4. DEC and DEP shall calculate their avoided energy costs using forward natural gas prices for no more than 8 years before transitioning to fundamental forecasts.

5. DEC and DEP shall utilize the avoided hedging adjustment as proposed for the purposes of this proceeding.

6. The solar integration services charges proposed by DEC ($1.05 per MWh) and DEP ($2.26 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.

7. For the purposes of calculating avoided capacity rates in this proceeding, DEC should use seasonal allocation weightings of 96% for winter and 4% for summer, and DEP should use seasonal allocation weightings of 100% for winter.

8. DEC's and DEP's standard offer PPA, as presented in DEC Exhibit 3 and DEP Exhibit 3 to the JIS and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs.

9. DEC's and DEP's Terms and Conditions, as presented in DEC Exhibit 4 and DEP Exhibit 4 to the JIS and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs.

10. DEC's and DEP's Notice of Commitment Form, as presented in DEC Exhibit 6 and DEP Exhibit 6 to the JIS and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs.

11. DEC's and DEP's ESS retrofit avoided cost rates, as presented in DEC Exhibit 12 and DEP Exhibit 12 to the JIS and discussed in this Order, are approved to be offered to QFs that commit to retrofit their existing generating facility to co-locate an ESS.

12. DEC's and DEP's NEEC rates, as presented in Duke Energy's Reply Comments, Exhibit 2 and based on a 5-year term, including both energy and capacity credits where applicable, and weighted using a typical rooftop solar production profile are approved.

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

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ____ 2022.

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 175 was served via electronic delivery or mailed, first-class, postage prepaid, upon all parties of record.

This, the 1st day of July, 2022.

<u>/s/ E. Brett Breitschwerdt</u>

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