STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	ORDER ESTABLISHING STANDARD
Rates for Electric Utility Purchases from	)	RATES AND CONTRACT TERMS
Qualifying Facilities – 2020	)	FOR QUALIFYING FACILITIES

BY THE COMMISSION: This is the 2020 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. Gen. Stat. § 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 (House Bill 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On August 13, 2020, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing (Scheduling Order). Pursuant to the Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (collectively, Duke), 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) (collectively, the Utilities) were made parties to the proceeding. In addition to proposed rates and proposed standard forms of contract, the Scheduling Order required Duke to file the resource adequacy studies, together with any additional detail and support for the study inputs and outputs, and the Nexant energy efficiency and demand-side management market potential studies required by the Commission in its July 21, 2020 Order Denying Motion For Reconsideration in the 2018 biennial avoided cost proceeding in Docket No. E-100, Sub 158 (2018 Avoided Cost Proceeding or Sub 158 Proceeding). The 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 January 11, 2021, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; February 12, 2021, as the deadline for reply comments; and March 12, 2021, as the deadline for proposed orders. The Scheduling Order also scheduled a public hearing for February 16, 2021, solely for the purpose of taking non-expert public witness testimony. Finally, the 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 the North Carolina Small Hydro Group. Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On October 20, 2020, DEC, DEP, and DENC filed a Notification of Intended Compliance with N.C.G.S. § 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements, and 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 will update the inputs in their avoided energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Commission's April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the 2018 Avoided Cost Proceeding (2018 Sub 158 Order) and requested that the Commission delay until November 2021 the more comprehensive filings that will address the solar integration services charge methodology, the provision of ancillary services by QFs, the Performance Adjustment Factor (PAF), as well as other additional issues arising out of 2018 Avoided Cost Proceeding (Sub 158 Additional Issues). Additionally, DEC, DEP, and DENC 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 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 November 2, 2020, DENC filed its Initial Statement and Exhibits along with avoided cost information, subsequently amended on December 16, 2020, and December 23, 2020, to correct avoided energy rates. On November 2, 2020, DEC and DEP also filed an Initial Statement and Exhibits, subsequently amended on February 12, 2021, to correct avoided energy rates (Supplemental Filing).

On November 24, 2020, the Commission issued an Order Confirming Public Hearing to be Held Remotely and Requiring Public Notice (Public Hearing Order). The Public Hearing Order required the Utilities to publish notice of the hearing, scheduled to begin on February 16, 2021, solely for the purpose of taking nonexpert public witness testimony, and confirmed that the public hearing would be held remotely via Webex. The Public Hearing Order also required parties to file statements of consent to the remote hearing by February 2, 2021, and notified members of the public that they must register by February 9, 2021, to be allowed to speak at the public hearing.

On December 7, 2020, Duke and DENC each individually filed their first progress reports on the Sub 158 Additional Issues.

On December 22, 2020, WCU and New River jointly filed joint comments and proposed avoided cost rates (Joint Comments), verified by Kevin W. O'Donnell.

On December 29, 2020, the Public Staff filed a Motion for Extension of Time, which the Commission granted on December 30, 2020, making initial comments due January 25, 2021, reply comments due February 26, 2021, and proposed orders due March 26, 2021.

On January 21, 2021, Duke and DENC each individually filed their second progress reports on the Sub 158 Additional Issues.

On January 25, 2021, the Public Staff filed its Initial Statement, and SACE, NCEBA, and NCSEA (Joint Solar Intervenors) filed their Joint Initial Comments.

On February 2, 2021, Duke, DENC, CIGFUR, NCSEA, SACE, NCEBA, and the NC Small Hydro Group filed consent to remote hearing.

On February 10, 2021, the Public Staff filed a motion to cancel the public hearing because no members of the public had registered to speak. On February 11, 2021, the Commission canceled the public hearing.

On or before February 15, 2021, all Utilities filed Affidavits of Publication of the Notice of Hearing.

On February 22, 2021, the Joint Solar Intervenors filed a joint motion for extension of time, which the Commission granted on February 23, 2021, making reply comments due March 5, 2021.

On March 5, 2021, Duke, DENC, and the Public Staff each filed Reply Comments, and the Joint Solar Intervenors filed Joint Reply Comments.

On March 8, 2021, Duke and DENC each individually filed their third progress reports on the Sub 158 Additional Issues.

On March 17, 2021, DEC and DEP filed a Joint Motion for Extension of Time, which the Commission granted on March 19, 2021, making proposed orders due April 9, 2021.

On April 5, 2021, DEC and DEP filed a Joint Motion for Additional Extension of Time, making proposed orders due April 23, 2021.

On April 22, 2021, Duke and DENC each individually filed their fourth progress reports on the Sub 158 Additional Issues.

On April 23, 2021, proposed orders were filed by the parties.

On June 7, 2021, Duke and DENC each individually filed their fifth progress reports on the Sub 158 Additional Issues.

Based on the foregoing and the entire record herein, the Commission now makes the following

FINDINGS OF FACT

1. It is appropriate for Duke and DENC 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 the DEC, DEP, and DENC to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

3. DENC should continue to offer in its Schedule 19-LMP, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on December 19, 2007, in Docket No. E-100, Sub 106 (2006 Sub 106 Order), except as modified by the Commission in its October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 148 (2016 Sub 148 Order).

4. Duke's quantification of its avoided capacity costs using the peaker methodology and the resulting avoided capacity rates are reasonable.

5. Duke's use of a hypothetical single F-Class combustion turbine (CT) constructed at a greenfield site, adjusted to reflect the economies of scale associated with gas pipeline interconnection, is reasonable, based on publicly available Energy Information Association (EIA) data, and appropriate for use in calculating avoided capacity costs in this proceeding.

6. 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 their respective 2020 Integrated Resource Plans (IRPs).

7. DEC's and DEP's standard offer schedules appropriately include provisions recognizing that, in certain circumstances, QFs fueled by swine waste, poultry waste, and hydropower receive capacity payments calculated without incorporating the demonstrated first year of need for future capacity as reflected in their respective IRPs.

8. DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in allocating avoided capacity value between winter months and summer months for the purposes of calculating DEC's and DEP's avoided capacity rates in this proceeding.

9. It is appropriate to require DEC and DEP to utilize a performance adjustment factor (PAF) of 1.06 in their respective avoided cost calculations for all QFs, other than hydroelectric (hydro) QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydro QFs 1 without storage capability MW and less until they file their next standard offers and proposed avoided cost rates in the 2021 avoided cost proceeding.

10. Because the June 24, 2014 Stipulation of Settlement Among DEC, DEP, and North Carolina Hydro Group expired on December 31, 2020 (Hydro Stipulation), Duke is no longer required to offer a 2.0 PAF to hydro QFs greater than 1 MW but less than 5 MW in negotiated power purchase agreements (PPAs).

11. 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.

12. For this proceeding it is appropriate for DEC and DEP to rely on fundamental forecasts for Henry Hub prices developed by private firms IHS and ICF.

13. Duke's use of its 2020 IRP natural gas transportation and pricing assumptions, including longer-term reliance upon the Dominion South hub gas in 2026 and after, is reasonable for purposes of calculating avoided costs in this proceeding.

14. Duke should continue to monitor market developments and to evaluate the continuing reasonableness of its long-term planning assumptions relating to available natural gas transportation infrastructure in future IRPs to inform future avoided cost proceedings.

15. Duke's avoided hedging adjustment is reasonable and appropriate for purposes of this proceeding.

16. Duke's calculation of avoided energy rates, using inputs from their 2020 IRPs that do not reflect a carbon price, is appropriate because the Commission has previously directed that only known and verifiable costs should be considered in calculating avoided cost rates.

17. DENC's revised avoided energy rates based on modelling that excludes the federal CO_2 costs that were reflected in DENC's Alternative Plan B as presented in its 2020 IRP are appropriate because the Commission has previously directed that only known and verifiable costs should be considered in calculating avoided cost rates.

18. Duke'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.

19. It is appropriate for DEC and DEP to evaluate: (i) any geographical concentrations of back-feeding substations, and (ii) whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide more accurate avoided cost rates to QFs regarding the value of the energy at the planned point of interconnection.

20. Duke's solar integration services charge as approved by the Commission in the previous biennial avoided cost proceeding, is reasonable and appropriate for purposes of this proceeding.

21. Duke and the Public Staff shall continue to discuss the treatment of start costs in production cost modeling for purposes of DEC and DEP's avoided cost rate designs.

22. DEC and DEP's Supplemental Filing and avoided cost rates and rate design included therein are approved.

23. Duke should delete a provision in Section 6 of its standard offer PPAs providing that Duke may require standard offer Sellers larger than 100 kW to provide prior notice of annual, monthly, and day-ahead forecast(s) of hourly productions, as specified by either DEC or DEP, as is applicable; with this deletion, Duke's standard offer PPAs are reasonable and appropriate.

24. DENC's proposal to continue to use the avoided energy and avoided capacity rate design approved in the 2018 Sub 158 Order is reasonable and appropriate for purposes of this proceeding.

25. DENC's proposal to continue to use seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons is reasonable and appropriate for purposes of this proceeding.

26. DENC's proposed input assumptions to be used in determining its proposed avoided energy costs, including those related to fuel forecasting, fuel hedging activities, and the location marginal price (LMP) adjustment, are appropriate for use in this proceeding.

27. DENC's proposal to continue to charge $0.78/MWh to recover costs incurred by DENC to integrate intermittent, non-dispatchable QFs in its service territory is reasonable and appropriate for purposes of this proceeding.

28. DENC's proposed re-dispatch charge (RDC) avoidance protocol is reasonable and appropriate and should be approved.

29. The installed cost of a CT used by DENC is appropriate for use in calculating avoided capacity costs in this proceeding.

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

31. It is reasonable and appropriate to continue to require DENC to utilize a PAF of 1.07 in its avoided cost calculations for all QFs.

32. DENC has appropriately identified in its 2020 IRP its first avoidable capacity need as 2023 and has appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

33. It is appropriate that, in calculating avoided capacity rates for swine and poultry QFs avoided capacity cost is recognized in the first year and every year of the standard offer contract term, and that in calculating avoided capacity rates for other QFs

avoided capacity cost is recognized in the first year of DENC's first avoidable capacity need.

34. DENC's proposed modifications to its standard offer contracts to contemplate the incorporation of energy storage components in QF projects are reasonable and should be approved.

35. Duke and DENC have appropriately provided periodic updates to the Commission regarding their progress on the Sub 158 Additional Issues.

36. The DEC, DEP, and DENC should address the Sub 158 Additional Issues in their 2021 filings.

37. It is appropriate to require WCU and New River to offer all QFs contracting to sell 1 MW or less variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year term standard offer.

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

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

Summary of the Comments

In Duke's Initial Statement, Duke 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 2, 2020, but prior to the initial filing in the next biennial avoided cost proceeding in November 2021. 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 further stated 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). Duke Initial Statement at 1; Duke Initial Statement, DEC Exhibit 1 and DEP Exhibit 1.

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

In its Initial Statement DENC proposes to continue to offer Schedule 19-LMP to QFs as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at the avoided cost rates determined by the Commission. Under Schedule 19-LMP, DENC would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kilowatts (kW) would be the PJM Dominion Zone (DOM Zone) Day-Ahead hourly locational marginal prices (LMPs) divided by 10 to convert LMP from $/MWh to cents/kWh, and multiplied by the QF's hourly generation in kWh, while the smaller QFs that elect to supply energy only would be paid the average of the PJM DOM Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DENC used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per megawatt per day from PJM's Base Residual Auction for the DOM Zone. As in prior proceedings, DENC also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations. DENC Initial Statement at 13, Exhibit DENC-4 at 3-7.

In its Initial Statement, the Public Staff reviews and summarizes rate schedules proposed by DEC, DEP, and DENC but does not recommend any changes to the standard offer term and eligibility thresholds proposed by DEC, DEP, and DENC.

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, DEP, and DENC with respect to these issues.

Discussion and Conclusions

In the 2016 Sub 148 Order, the Commission approved changes to the standard offer term and eligibility thresholds as a result of changes in the marketplace for QF-supplied power in North Carolina and as a result of the amendments to N.C.G.S. § 62-156 enacted through House Bill 589. The Commission noted that these changes were appropriate to

> reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs.

2016 Sub 148 Order at 38. The Commission further indicated that it would "continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms." *Id*.

In the 2018 Sub 158 Order, the Commission found it 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. The standard offer term and eligibility thresholds for standard offer avoided cost rates and terms were not issues identified to be addressed in this proceeding and no party raised objections to the approval of the Utilities' proposed schedules with respect to these issues. Therefore, the Commission concludes 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 variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term but shall instead change as determined by the Commission in the next biennial proceeding. 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, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities — 2016*, No. E-100, Sub 148, at 38-39 (N.C.U.C. Oct. 11, 2017) (2016 Sub 148 Order). To date, the Commission has not received a motion, nor issued an order, addressing the exact points when an active solicitation shall be regarded as beginning or ending nor addressed whether the Competitive Procurement of Renewable Energy 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.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for DENC to continue to offer, as an alternative to avoided cost rates derived using the Peaker Method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM RPM, subject to the same conditions as approved in the 2006 Sub 106 Order and restated in the 2016 Sub 148 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence supporting these findings of fact is found in Duke's Initial Statement, and Reply Comments, the Initial Statement of the Public Staff, and Joint Solar Intervenors' Joint Initial Comments.

Summary of the Comments

In Duke's Initial Statement, it stated that for purposes of this proceeding, Duke continues to base DEC and DEP's respective hypothetical avoided CT costs on publicly available EIA data for a single F-Class CT constructed at a greenfield site, adjusted to reflect the economies of scale associated with gas pipeline interconnection. Duke Initial Statement at 13-14.

Duke's Initial Statement further explained that, in the 2018 Sub 158 Order, the Commission concluded that the Utilities should use the installed cost of a CT unit derived from publicly available industry sources, such as the U.S. EIA, tailored to adapt such information to the Carolinas for purposes of calculating their avoided capacity costs. 2018 Sub 158 Order at 32-33. According to Duke, the 2018 Sub 158 Order additionally directed that in the 2020 biennial avoided cost proceeding, 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. *Id.* at 33.

Duke does not identify any additional adjustments to its CT cost data adopting the publicly available CT cost information to North Carolina consistent with the Commission's previous avoided cost orders. Duke stated in its Initial Joint Statement, however, that it intends to use the time between the filing of the JIS and the next avoided cost filing in November 2021 to discuss any potential adjustments to the DEC and DEP CT cost data with the Public Staff. Duke Initial Statement at 14.

The Public Staff's Initial Comments provided an analysis of Duke's CT cost assumptions. The Public Staff concluded that the assumptions were reasonable. Public Staff Initial Statement at 10-15, 21.

The Joint Solar Intervenors' Joint Initial Comments and the Crossborder Report attached to those comments asserted that "[i]t is not entirely clear whether Duke complied with the Commission's [2018 Sub 158 Order]" on the issue of avoided CT assumptions and argues that "DEC and DEP should . . . use the costs of an H-Class Turbine as the CT cost assumption for its avoided capacity costs." Joint Solar Intervenors' Initial Comments at 10-11; Crossborder Report at 11. They stated that capacity prices should be based on up-to-date assumptions about the model of CT that would be used as a peaking resource, and they specifically contested Duke's assumption that the peaking resource would be an F-class turbine. The Joint Solar Intervenors noted that DEC is currently constructing an advanced H-class model CT to bolster their argument that Duke should have relied upon an advanced H-class model CT, as opposed to an F-class CT. In particular, the Crossborder Report recommended that the Commission require Duke to use an H-class capital cost from the PJM CONE Study of $835 per kW for a 2022 on-line date in nominal 2022 dollars (annualized to $98.20 per kW-year), as the basis for DEC's and DEP's avoided capacity costs. Crossborder Report at 11-12. In support of their proposal, Joint Solar Intervenors stated that advanced turbines have lower heat rates, i.e., are more fuel-efficient, and efficiency will become increasingly important over time as CTs compete with clean-energy resources with very low variable costs. Joint Solar Intervenors' Initial Comments at 10.

In Reply Comments, Duke stated that the singular basis for the Joint Solar Intervenors' alternative recommendation to an H-class CT is that DEC is currently constructing an H-class CT at its Lincoln County site. DEC explained, however, that this unit reflects a unique arrangement with Siemens Energy allowing Siemens to build and test its newest H-Class technology at DEC's Lincoln County site. In exchange, DEC's customers realize a significant capital cost savings and will receive all of the H-Class unit's energy during a four-year testing period while only paying a portion of the fuel costs — again, a unique arrangement for this single test project. Thus, Duke contended that this H-class CT is a unique CT that is part of a new demonstration project and not reflective of the DEC and DEP's actual system CT conditions or indicative of future system CT conditions. Duke Reply Comments at 17-18.

Duke's Reply Comments further contrasted the number of F-class units that Duke operates, which is a total of 32 F-class units in either simple-cycle or combined-cycle mode in the Carolinas, to the one new H-class Lincoln #17 CT cited by the Joint Solar Intervenors. Duke also noted that the DEC and DEP 2020 IRPs, as well as prior IRPs, also similarly and consistently reflect F-class CTs as the generic peaking resource addition. Further, Duke stated that the use of a simple-cycle F-class CT unit is appropriate under the peaker methodology as a proxy for pure capacity. The peaker methodology assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine generating unit (a peaker) plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the Peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. From an installed cost perspective, Duke explains that a simple-cycle F-frame peaking unit is typically the least expensive type of traditional resource that Duke can construct to provide capacity for reliability purposes, and, therefore, is appropriate for use in the Peaker methodology for purposes of quantifying avoided costs. Duke Reply Comments at 17-19.

Regarding the Crossborder Report's recommendation that Duke use H-class capital costs from the PJM CONE Study of $835 per kW for a 2022 on-line date, Duke stated that the $835/kW capacity cost is not an overnight cost but rather reflects the total installed cost in nominal dollars (including financing costs) for a 2022 in-service date in the PJM region. Duke further pointed out that, although the PJM CONE data and $835/kW capacity costs looked to be the starting point for DENC's avoided CT cost unit, DENC made numerous adjustments (none of which were opposed by Public Staff or the Joint Solar Intervenors), and actually used a capacity cost of $592.5/kW, which is significantly lower than the PJM CONE study, as well as significantly lower than the Duke's filed overnight CT cost of $712.7/kW. Duke's Reply Comments therefore requested that the Commission reject the Joint Solar Intervenors' recommendation to require DEC and DEP to base their avoided capacity rates on a hypothetical H-class CT. *Id*. at 19.

Discussion and Conclusions

In the Commission's Order Setting Avoided Cost Input Parameters, issued on December 31, 2014, in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available

> industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Sub 140 Phase One Order at 48.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission finds that Duke 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. 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. The Commission also notes Duke's commitment in its Initial Statement to discuss any potential adjustments to the DEC and DEP CT cost data with the Public Staff prior to the next avoided cost filing, and its reporting of developments in this issue in its 45-day status updates filed in this docket. The Commission, therefore, directs Duke to continue its efforts to further these discussions with the Public Staff and other stakeholders, and to propose any necessary CT cost adjustments in its next avoided cost filing.

In addition, the Commission determines that it is not appropriate to require DEC and DEP to use H-class capital cost from the PJM CONE Study of $835 per kW for a 2022 on-line date in nominal 2022 dollars (annualized to $98.20 per kW-year), as the basis for DEC's and DEP's avoided capacity costs. The technology type used as the basis for the Duke's CT capital cost is also consistent with Duke's past and present IRPs and avoided cost filings, as well as appropriate for use under the peaker methodology, in addition to being most reflective of current system conditions at this time. Additionally, Duke's utilization of the F-Class CT is supported by the Public Staff. Accordingly, the Commission is not persuaded by the Joint Solar Intervenors' request to require DEC and DEP to base their avoided capacity rates on a hypothetical H-class CT at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

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

Summary of the Comments

DEC and DEP stated in their Initial Statement that they developed their avoided capacity rates consistent with the methodology the Commission approved in the 2018 Sub 158 Order as appropriately implementing N.C.G.S. § 62-156(b)(3). Duke's recently filed 2020 IRPs showed that DEC's next avoidable undesignated capacity need occurs in 2026, and DEP's next avoidable undesignated capacity need occurs in 2024. DEP 2020 Biennial IRP at 112-114; DEC 2020 Biennial IRP at 111-113. Compared to the standard offer avoided cost rates approved in the 2018 Sub 158 proceeding, DEC's first year of avoidable capacity need shifted forward from 2028 to 2026, while DEP's first year of avoidable capacity need shifted outward from 2020 to 2024.

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, receive capacity payments calculated regardless of Duke's demonstrated need for future capacity reflected in their respective IRPs. Specifically, the Duke's respective standard offer rate schedules recognize that a swine or poultry waste-fueled generator or a hydro facility that has a PPA in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3). 2018 Sub 158 Order at 135 As recently amended by Session Law 2019-132, N.C.G.S. § 62-156(b)(3) now provides that a future capacity need shall only be avoided in a year where the utility's most recent biennial IRP filed with the Commission has identified a projected capacity need to serve system load other than for (i) swine or poultry waste for which a need is established consistent with N.C.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 5 MW.

In its Initial Statement, the Public Staff cited the Commission's 2018 Sub 158 Order directing that, beginning with the 2020 IRP, the utilities shall include a specific statement of undesignated capacity that is avoidable by QFs to remove uncertainty around the exact year of capacity need and to provide a clearer standard for all parties, especially in the next biennial avoided cost proceeding. The Public Staff noted that DEC's first capacity need to be avoided is in 2026, and DEP's first capacity need to be avoided is in 2024. The Public Staff further explained that this meant that QFs located in DEC's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2026. QFs located in DEP's service area that select a 10-year rate will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2024.

The Public Staff also cited the Commission's directive from the 2018 Sub 158 Order that the Utilities shall amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydro facility with a capacity of 5 MW or less in capacity that had a PPA in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types. The Public Staff further explained that this direction means that the avoided capacity credits used to calculate avoided cost rates for swine or poultry QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begin in the first year of a utility's capacity need. The Public Staff reviewed the capacity credits for swine and poultry QFs, as well as other assumptions, incorporated into Duke's proposed rates for swine and poultry QFs and found them reasonable for the determination of Duke's capacity credits.

Discussion and Conclusions

The Commission determines that Duke has calculated its avoided capacity cost rates consistently with the North Carolina General Statutes and the Commission's prior 2018 Sub 158 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 (MW).

No party disputed Duke's proposed first year of need or Duke's 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. As addressed by the Public Staff, Duke has complied with the Commission's requirement in the 2018 Sub 158 Order that standard offer rate schedules reflect these distinctions for swine-waste, poultry-waste, or certain hydro QFs. Accordingly, based on the foregoing, the Commission finds and concludes that Duke's first year of need and proposed avoided capacity rates are reasonable, appropriate, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 8

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

In its Initial Statement, Duke adopted the same seasonal allocation of capacity value approved in the 2018 Sub 158 Order, which is heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and the associated impact on summer versus winter reserves. As approved in the 2018 Sub 158 Order, 100% of DEP's loss of load risk is assigned to the winter while 90% of DEC's loss of load risk is assigned to the winter.

Duke further reported in its Initial Statement that, for purposes of this proceeding, it did not update DEC and DEC's respective seasonal allocations based upon the recently filed 2020 Resource Adequacy Studies, which are being reviewed by the Commission and parties to the 2020 IRP proceeding in Docket No. E-100, Sub 165. Duke's

2020 Resource Adequacy Studies continue to identify 100% of DEP's loss of load risk occurring in the winter, while approximately 97% of DEC's loss of load risk is now projected to occur during the winter.

The Public Staff indicated in its Initial Statement that it has reviewed Duke's seasonal allocations and found them to be reasonable for the determination of Duke's avoided capacity rates. Public Staff Initial Statement at 21-22.

No party objected to Duke's use of the seasonal allocations in this proceeding. Based upon the foregoing, the Commission concludes that DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, are appropriate for use in allocating avoided capacity cost between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

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

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

Summary of the Comments

Duke's Initial Statement recounted that in the 2018 Sub 158 proceeding, the Commission approved DEC's and DEP's continued recognition of a PAF in determining the appropriate calculation of avoided capacity to be paid to QFs. 2018 Sub 158 Order at 40 (describing the history of 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, without any reasonable opportunity to experience outages during each peak period, in order to receive the total available avoided capacity payment. The PAF recognizes that the Utilities' generating units experience outages and do not operate 100% of the time and allows QFs to also experience unplanned outages during peak periods and still receive the utility's full avoided capacity costs). 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." The Commission therefore approved Duke's proposed PAF of 1.05, based upon the equivalent availability (EA) metric and the use of five years of historic outage rate data during Duke's critical peak season months. 2018 Sub 158 Order at 41. In accepting Duke's utilization of the EA metric for purposes of calculating the PAF, the Commission additionally accepted the Public Staff's recommendation for the Utilities to consider other reliability metrics besides the EA. The Commission directed Duke and the Public Staff to address the appropriateness of using the Equivalent Unplanned Outage Rate (EUOR) metric in this docket.

Duke has continued to use the EA metric and to apply the same methodology approved in the 2018 Sub 158 Order to calculate the PAF capacity multiplier. To avoid introducing issues that could result in more lengthy proceedings before the Commission, Duke did not recommend any additional adjustments to the Commission-approved EA metric to compute the PAF. Duke has followed the same methodology of compiling five years of historic equivalent availability data for the entire fleet during Duke's critical peak season months of January, February, July, and August. This critical peak season reflects the high load periods in which Duke typically does not schedule planned maintenance outages for fleet generating facilities. Based upon these calculations, DEC's and DEP's respective equivalent availability during this timeframe averages to approximately 94%, which supported a PAF of 1.06. Duke also stated in its Initial Statement that it planned to discuss the appropriateness of utilizing the EUOR metric with the Public Staff before the 2021 avoided cost proceeding.

North Carolina's legacy implementation of PURPA afforded hydro QFs with unique legislative treatment that, for a number of years, resulted in the Utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[1] In 2014, the Hydro Stipulation provided that Duke would continue to include the previously-approved 2.0 PAF in standard offers filed at the Commission prior to December 31, 2020, to calculate the avoided cost rates for small hydro QFs of 5 MW or less until that expiration date. Hydro Stipulation at Paragraphs 3(a) and 4. As the Commission recognized in the 2018 Sub 158 Order[2] and in the prior 2016 Sub 148 Order[3], the General Assembly has subsequently amended the State's implementation of PURPA through HB 589 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while at the same time establishing flexibility for Utilities 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. *See* N.C.G.S. § 62-156(b)(3) and (c). The 2018 Sub 158 Order therefore directed Duke to address whether the 2.0 PAF should continue for the standard offer in this biennial proceeding. 2018 Sub 158 Order at 42.

Consistent with the Hydro Stipulation, Duke has included a 2.0 PAF in DEC's and DEP's standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW. Duke negotiated the Hydro Stipulation in good faith, and its terms and conditions were based both upon North Carolina's policy of supporting small hydro QFs and the relatively small and finite amount of small hydro capacity in the state. Hydro Stipulation at Paragraph 3.

Additionally, Duke explained in its Initial Statement that, in the 2018 Sub 158 Proceedings, DEC and DEP filed a letter with the Commission that outlined their intentions for the continuing applicability of terms and conditions of the Hydro Stipulation for hydro QFs 5 MW and less. *See* DEC and DEP's Joint Letter to Small Hydro Group, Docket No. E-100, Sub 158 (filed July 12, 2019). In the letter, Duke stated its intent to honor its commitment under the terms of the Hydro Stipulation to apply a 2.0 PAF capacity

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

[2] 2018 Sub 158 Order at 42.

[3] *Id.* at 39.

multiplier for purposes of calculating avoided cost rates for those hydro QFs without storage. DEC and DEP did not agree to extend the 2.0 PAF beyond the current Hydro Stipulation's expiration at the end of 2020 due to intervening changes to PURPA implementation in North Carolina enacted by HB 589. This commitment included hydro QFs that were no longer eligible for Duke's standard offer due to their contract capacity in excess of 1 MW and that were now eligible to enter into negotiated PPAs with Duke pursuant to N.C.G.S. § 62-156(c). As noted in the letter, and for the avoidance of doubt, DEC and DEP will continue to honor the 2.0 PAF for purposes of calculating avoided cost rates in those negotiated PPAs through December 31, 2020, and have included a 2.0 PAF multiplier in the calculation of avoided capacity rates for hydro QFs without storage eligible for the standard offer. Duke's commitment was expressly subject to any future adverse regulatory decisions by the Commission. Duke makes the same commitment here, again subject to the any adverse regulatory decisions by the Commission, that it should not offer a 2.0 PAF to hydro QFs 1 MW and less (standard offer) or to hydro QFs greater than 1 MW but equal to or less than 5 MW.

In its Initial Statement, the Public Staff discussed its review of Duke's PAF. Initial Comments of the Public Staff at 15-16. Specifically, the Public Staff highlighted that run-of-river hydro QFs receiving a 2.0 PAF through the standard offer while all of the QFs receive the 1.06 PAF results in an 89% higher annual capacity cost for those hydro QFs compared to all other QFs. The Public Staff noted the Hydro Stipulation and further indicated that the Public Staff did not recommend further changes to what the Companies had proposed with respect to the PAF for hydro QFs with no storage capacity. With respect to the upcoming avoided cost proceeding, however, the Public Staff recommended that Duke address the issue of the appropriate PAF to apply when calculating capacity rates available to run-of-river QFs in Duke's next initial statement.

Discussion and Conclusions

Based on the foregoing, the Commission finds and concludes that Duke's proposed PAFs for QFs and for hydro QFs 1 MW and less are reasonable and appropriate. The Commission further finds and concludes that, with the expiration of the Hydro Stipulation, the Companies are no longer required to offer a 2.0 PAF to run-of-river hydro QFs greater than 1 MW but less than 5 MW.[4] No party contested Duke's proposed PAFs in this proceeding. Moreover, no party produced any justification for continuing the 2.0 PAF for run-of-river hydro QFs greater than 1 MW. As Duke recounts in its Initial Statement, the General Assembly has subsequently amended the State's implementation of PURPA to no longer designate hydroelectric generating facilities as unique small power producers, while at the same time establishing flexibility for the Companies to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in calculating future avoided cost rates. N.C.G.S. § 62-156(b)(3) and (c). Under these circumstances, and based on the record in this proceeding, the Commission finds that Duke's proposal no longer to offer the 2.0 PAF to run-of-river hydro QFs greater than 1 MW upon the with the expiration of the Hydro Stipulation to be reasonable and appropriate. The Commission directs DEC and DEP to

[4] For clarity, these run-of-river QFs would be the QFs that are no longer subject to the standard offer but were included in the Hydro Stipulation.

address the issue of the appropriate PAF for calculating avoided capacity rates available to run-of-river hydro QFs in their initial statements filed in the next avoided cost proceeding in November 2021.

With respect to the PAF in general, the Commission directs Duke and the Public Staff to address the appropriateness of using the EUOR metric in the next avoided cost proceeding. Duke's 45-day status updates, filed in this docket, reflect that discussions between the Public Staff and Duke have already begun on this issue, and the Commission urges them to try to reach consensus on the issue of the PAF in advance of the next avoided cost proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

The evidence supporting these findings of fact are found in Duke's Initial Statement the Public Staff's Initial Statement, the Joint Solar Intervenors' Initial Comments, Duke's Reply Comments, and the entire record herein.

Summary of the Comments

In Duke's Initial Statement, it acknowledged that the Commission's 2018 Sub 158 Order directed DEC and DEP 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. Duke Initial Statement at 22. While DEC's and DEP's recently-filed 2020 IRPs rely upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived based upon fundamental forecasts over the remaining planning period, Duke stated that they developed their respective avoided energy rates by relying on the methodology identified by the Commission in the 2018 Sub 158 Order, rather than the methodology underlying Duke's 2020 IRPs to streamline this proceeding. *Id.*

In its Initial Statement, the Public Staff found Duke's natural gas commodity price forecasting methodology to be reasonable and appropriate for the purposes of this proceeding and consistent with the Commission's 2018 Sub 158 Order. Public Staff Initial Statement at 40.

The Joint Solar Intervenors challenged two aspects of Duke's approach to fundamental forecasts. First, the Joint Solar Intervenors argued for reducing Duke's reliance on forward natural gas market price data from eight years to five years before transitioning to a forecast blending market prices with fundamentals in years 5-8[5] and a fundamental forecast-only approach in years 9-10. Joint Solar Intervenors Initial Comments at 15; Crossborder Energy Report at 26. In support of this proposal, the Joint Solar Intervenors summarized arguments made by the Public Staff and individual

[5] The Crossborder Energy Report, attached to the Solar Intervenors' Initial Comments as Exhibit A, Joint Solar Intervenors recommend for the following blended transition from market-based pricing to fundamental forecasts in years 5-8: "80% forwards/20% fundamentals in year 5, 60% forwards/40% fundamentals in year 7, and 20% forwards/80% fundamentals in year 8, before moving to 100% fundamentals in year 9." Crossborder Energy Report at 4.

intervenors now filing comments as the Joint Solar Intervenors in the 2018 Sub 158 proceeding. The Joint Solar Intervenors noted that the Public Staff argued at that time for using no more than five years of forward market data because they were unable to identify any utilities other than Duke that rely entirely on forward prices for terms greater than six years. *Id*. at 14. Similarly in the 2018 Sub 158 Proceeding, SACE recommended that Duke use no more than two to three years of forward market data followed by a transition to fundamental forecast pricing. In the 2018 Sub 158 Proceeding, NCSEA recommended just two years of forward market data before transitioning to an average of a set of recent fundamental forecasts. *Id.*

The Joint Solar Intervenors assert that using eight years of forward market data raises concerns about the transparency, practical applicability, and liquidity of Duke's price data. *Id*. at 15; Crossborder Energy Report at 2. The Crossborder Energy Report states that no evidence shows that forward price data is superior to forecasts that examine the fundamentals of natural gas supply and demand over periods longer than two years in the future. Crossborder Energy Report at 3. The Crossborder Energy Report also suggested a transition period in years 5-8 proposed by the Joint Solar Intervenors would more closely parallel DENC's approach of transitioning to fundamental forecasts. *Id.* at 4.

Second, the Joint Solar Intervenors criticized Duke's use of fundamental forecasts for Henry Hub prices developed by private firms IHS and ICF, because they omit public data. Joint Solar Intervenors Initial Comments at 10. Based on the Commission's mention in the 2018 Sub 158 Order that transparency is an important element of combustion turbine price estimates for an avoided cost filing, the Joint Solar Intervenors argued that Duke's use of private forecasts should be supplemented and averaged with the EIA *2020 Annual Energy Outlook* public forecast of Henry Hub prices. According to the Joint Solar Intervenors, the addition of a public Henry Hub forecast would serve as a check on Duke's private forecast, add transparency, and provide the perspective of a second prominent forecaster. Joint Solar Intervenors Initial Comments at 11.

In their Reply Comments, Duke noted that it followed the Commission's 2018 Sub 158 Order directive for the forecasting methodology used in the instant proceeding. Duke's Reply Comments at 8. In light of the streamlined nature of the proceeding, Duke refrained from arguing for the longer-term use of forward market pricing used in their most recent IRPs. For the same reason, Duke argued that the Commission should reject the Joint Solar Intervenors' recommendation that Duke rely on fewer than eight years of forward natural gas market price data before transitioning to a fundamentals forecast, suggesting that the Joint Solar Intervenors would be free to raise that argument again in a future avoided cost proceeding that is not streamlined. *Id.*

Duke likewise argued that the Commission should reject the Joint Solar Intervenors' recommendation that Duke supplement and average the long-term natural gas commodity price fundamental forecast utilized in the 2020 IRPs with a publicly available Henry Hub forecast, such as the EIA 2020 Annual Energy Outlook forecast of Henry Hub prices. *Id*. at 9. According to Duke, their use of Henry Hub prices developed by IHS Markit adhered to the Commission's directive in the 2020 Procedural Order to rely upon updated inputs consistent with the methodological guidelines approved in the 2018

Sub 158 Order. *Id*. at 10. Duke also pointed out that the Joint Solar Intervenors wrongly assumed that Duke currently averages fundamentals forecasts for Henry Hub prices from the private consultancies IHS and ICF, noting that Duke's 2020 IRPs relied exclusively on the IHS fundamental forecast while Dominion relies upon ICF. *Id*. at 9 n.27.

In their Reply Comments, the Public Staff agreed with the Joint Solar Intervenors that Duke should rely on fewer than eight years of forward natural gas price data before transitioning to a fundamentals forecast in both the avoided cost proceeding and the IRP proceeding. Public Staff Reply Comments at 4. However, the Public Staff also agreed that for the purpose of this streamlined proceeding, the Companies' reliance on eight years of forward natural gas market price data should be accepted as consistent with the methodology adopted in the Commission's 2018 Sub 158 Order. *Id*. The Public Staff reserved the right to argue for reliance upon fewer years of such data in a future proceeding. *Id*. at 5.

The Public Staff's Reply Comments also indicated agreement with Duke regarding the Joint Solar Intervenors' proposal that Duke supplement and average their Henry Hub prices with the publicly available Henry Hub forecast set forth in EIA's *2020 Annual Energy Outlook*. The Public Staff stated that the suggested supplement is unnecessary, noting that other parties can cite publicly available forecasts and provide supporting evidence in their comments if they believe that Duke's fundamental forecast is inappropriate. *Id*. at 2. According to the Public Staff, because Duke's fundamental price forecasts are "reasonably comparable" to the EIA's 2020 Annual Energy Outlook gas price forecast and no intervenors provided persuasive evidence that the Companies' fundamental forecasts are inappropriate, the Commission-mandated use of publicly available forecasts is not currently warranted. *Id*. at 3.

Discussion and Conclusions

As a threshold matter, the Commission acknowledges that the streamlined nature of this proceeding is not targeted to allow for a thorough vetting of the Joint Solar Intervenors' proposal to reduce the number of years a utility may rely upon market prices before transitioning to fundamental forecast-based commodity pricing assumptions. Both the Public Staff and Duke have expressed their view that this issue is not appropriate for the Commission's consideration in the current truncated proceeding. Accordingly, after careful consideration, the Commission is not persuaded that a change in the fuel forecasting methodology approved in 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 Joint Solar Intervenors' recommendation that the Commission require utilities who use Henry Hub prices developed by private firms to modify their assumptions by averaging such forecasts based upon Henry Hub price forecasts that are publicly available, such as the EIA 2020 *Annual Energy Outlook* forecast. The Commission agrees with the Public Staff that any intervenor who believes a utility's fundamental forecast is inappropriate may freely and persuasively make that point in comments by citing to publicly available forecasts as a comparison. However, the Commission is open to revisiting this decision in the 2021 biennial proceeding.

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 DEC's and DEP's approach of relying on fundamental forecasts for Henry Hub prices, as developed by IHS, is appropriate for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

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

Summary of the Comments

Duke's Initial Statement identified that DEC and DEP have used modeling and planning assumptions consistent with their most recent 2020 biennial IRPs for purposes of quantifying DEC's and DEP's avoided costs.[6] This includes natural gas transportation and pricing assumptions during the ten-year forecasted avoided cost rate period that influenced natural gas pricing. Duke Initial Statement at 10.

The Initial Comments of the Public Staff raised an issue of concern relating to Duke's reliance upon forecasted natural gas pricing utilizing the Appalachian basin's lower cost Dominion South Hub starting in year 2026, as opposed to continued utilization of the Transco Zones 4 and 5 pricing through and past year 2026. The Public Staff explained that DEC's and DEP's current forecast plans reflect an increased volume of firm natural gas transportation service from the Dominion South hub to some of their existing and all of their future CC fleet starting in 2026. Public Staff Initial Statement at 42.

The Public Staff's stated concern is based on the recent unfavorable regulatory landscape for building newer natural gas pipelines in the region and the lack of pipeline takeaway capacity from the Appalachian region to the Transco Zone 5 region. The Public Staff specifically highlighted the current lack of operating gas pipeline infrastructure near the Dominion South hub due to the recent cancellation of the Atlantic Coast Pipeline (ACP), as well as the uncertain future regulatory landscape for the construction of new gas pipelines, specifically the Mountain Valley Pipeline (MVP), in this region. *Id*. at 43-44. The Public Staff identified that, in prior IRP proceedings, Duke planned to rely on the ACP to transport natural gas into North Carolina. According to the Public Staff, the cancellation of the ACP in July 2020 has cast doubt on Duke's assumptions that it would have

[6] As discussed elsewhere in this Order, for purposes of forecasting avoided energy costs over the future 10-year rate period, the Companies have relied upon forward market price data out eight years (2021-2028) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies' avoided energy cost rates before transitioning to fundamental forecast data starting in year nine.

additional increased interstate pipeline capacity from the Appalachian basin by 2026, especially given the political and economic issues surrounding the construction of new natural gas pipelines. *Id*. at 44. The Public Staff notes that while Duke has put forward what Duke considers to be a conservative timeline to obtain natural gas from the Dominion South trading hub to some of its existing CC fleet starting in 2026, the Public Staff has reservations about the underlying assumptions because, currently, growth of natural gas production in the Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast markets. *Id*. at 45.

Despite this concern, the Public Staff commented that it "accepts the Dominion South trading hub price assumption as reasonable for this proceeding" while stating its concerns that this pricing assumption may cause the capacity expansion models to overly rely on natural gas. *Id.* at 46. The Public Staff stated that Duke should utilize other practical options until a firm supply from the Appalachian basin is available to meet its demands. *Id.* at 45. The Public Staff recommended that, in the 2021 avoided cost proceeding, Duke re-evaluate its assumptions regarding the availability of additional interstate pipeline capacity. If Duke continues to assert that adequate capacity will be available, the Public Staff recommended that Duke should provide the Commission and stakeholders with a detailed narrative that identifies expected actions by various pipeline developers and other parties with expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential new interstate pipelines. Consistent with the Public Staff's comments filed in the 2020 IRP proceeding, the Public Staff also recommended that Duke should consider developing an IRP portfolio or sensitivity in the 2021 IRP Update that is similar to its base cases, but which includes natural gas import restrictions or less reliance on Dominion South trading hub gas. *Id*. at 46.

The Joint Solar Intervenors also raised concerns about Duke's 2020 IRP gas transportation assumptions used in developing avoided costs in their Initial Comments. These parties criticized Duke's reliance on the lower cost Dominion South hub natural gas assumptions in their 2020 IRPs and suggested that Duke failed to comply with the Commission's 2018 Sub 158 Order by relying upon these IRP planning assumptions in calculating their avoided energy cost rates. Joint Solar Intervenors Initial Comments at 8-9. The Joint Solar Intervenors argued that it is not reasonable or appropriate for Duke to change several of the combined-cycle plants to the Dominion South zone beginning in 2026, *Id*. at 9. They further requested that the Commission require Duke to use the Transco Zones 4 and 5 for the entire applicable forecast period.

In addition, the Joint Solar Intervenors argued that "updated differential basis does not appear to incorporate capacity reservation costs," which they claimed "must be considered when determining the economics of a prospective new pipeline." *Id*.

In its Reply Comments, Duke agreed with the Public Staff that, for purposes of this proceeding, DEC's and DEP's natural gas forecasting assumptions, including longer-term reliance on lower-cost gas at the Dominion South trading hub, are reasonable and should be utilized, as they align with Duke's 2020 IRP base planning assumptions. Duke's Reply Comments at 3. They also agreed with the Public Staff's recommendation for Duke to further evaluate their assumptions regarding the availability of additional interstate pipeline capacity, to provide the Commission and stakeholders with updated information on expected actions by various pipeline developers and other parties, and to address expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential pipelines. *Id*. at 3. As circumstances evolve regarding the status of additional interstate pipeline capacity into the Carolinas, Duke responded that it is committed to updating the Commission on this topic in either their reply comments in the current 2020 IRP proceeding as well as in the 2021 IRP update and avoided cost filings, as appropriate, and also emphasize that this is first and foremost an IRP issue that will then influence subsequent valuations of avoided costs. Duke's Reply Comments at 3-4.

In response to the Public Staff's further recommendation for Duke to consider developing an IRP portfolio or sensitivity in the 2021 IRP Update that is similar to their base case, but which includes natural gas import restrictions or less reliance on Dominion South trading hub gas, Duke stated in Reply Comments that they generally accepted the Public Staff's recommendation to consider developing an IRP portfolio or sensitivity in their future IRPs that is similar to their base case, but which includes natural gas import restrictions or less reliance on Dominion South trading hub gas. However, Duke believed the next comprehensive IRP filing in 2022 is more appropriate for developing this type of sensitivity analysis, as it will provide a more informed view on this issue than can be provided in the 2021 IRP update filing. Duke explained that changing the assumption of natural gas availability has fundamental implications for many aspects of the IRP such as the timing of coal generation retirements and the selection of resources that could reliably replace coal and reliably meet load growth. *Id*. at 4. Duke also noted that the 2021 IRP is an update that will be based on information from the summer of 2021 as the IRP update is prepared at that point in time. Given the potential for new policy mandates at the state and federal level as a result of the change in the administration and the recent events in the Electric Reliability Council of Texas (ERCOT), it may be premature to analyze the potential impacts of interstate gas supply and the consequences it would have on a future resource plan. Duke also reiterated the Public Staff's statements regarding the difficulties in forecasting long-range prices of natural gas and other fuels, citing the historically declining price of natural gas. Duke Reply Comments at 5.

In response to the Joint Solar Intervenors, Duke disagreed with their assertion that reliance in this proceeding on the gas forecasting assumptions presented in their 2020 IRPs failed to comply with the 2018 Sub 158 Order. Duke also explained that they generally relied upon the natural gas forecasting transportation assumptions presented in DEC's and DEP's 2020 IRPs, as confirmed by the Public Staff. Duke Reply Comments at 6, *citing* Public Staff Initial Statement at 41.

Duke also noted that the Joint Solar Intervenors' assertion that the MVP "will not be constructed" was wholly unsupported. Joint Solar Intervenors' Initial Comments, at 9. Duke further noted that the Public Staff made no such definitive conclusion. Public Staff Initial Statement at 44 (MVP "is now delayed and scheduled to enter service in late 2022."). Duke also stated that it was not aware of any decision by MVP to cancel its plans for construction. As addressed in its response to the Public Staff, Duke explained that it generally agrees it is appropriate to continue to monitor market developments and to evaluate the continuing reasonableness of its long-term planning assumptions relating to available natural gas transportation infrastructure in future IRPs in order to inform future avoided cost proceedings.

Duke also pointed out that these longer-term natural gas transportation assumptions for providing natural gas to the Companies' combined cycle fleets and potential future CT may not have as material of an impact on avoided cost rates as might be assumed. Duke explained that it has utilized conservative planning assumptions that the Dominion South trading hub would not be available to provide gas to certain of DEC's and DEP's existing combined cycle (CC) fleets until 2026. This means that this gas transportation hub assumption will only impact resource planning and avoided costs beginning in year six of the current planning period (as well as year six of the avoided cost rate calculation). Duke emphasized the Public Staff's comment that this lower priced gas will only have an impact when Duke's natural gas units that receive gas from the Dominion South hub are the marginal resource and avoided energy costs will be less than if the natural gas was sourced from Transco Zone 4 or 5. Duke Reply Comments at 6, *citing* Public Staff Initial Statement at 41. Duke explained that the IRP's reliance on Dominion South hub gas beginning in 2026 only impacts the avoided cost in the 2026 to 2030 period when CCs are on the margin.

Duke also disputed the Joint Solar Intervenors' assertion that capacity reservation costs must be considered when determining the economics of prospective new pipeline as inaccurate for purposes of calculating the DEC's and DEP's avoided capacity costs under the peaker methodology. Duke pointed out that the Companies' avoided CT cost assumptions have consistently assumed #2 fuel oil as the backup fuel source as opposed to relying upon firm gas capacity reservations, and, as such, the Companies did not include the cost to reserve firm upstream capacity for the avoided CT. Therefore, Duke concluded that although this issue may be appropriate to consider in the broader resource planning context, it would be improper for Duke to accept the Joint Solar Intervenors' recommendation to incorporate capacity reservation costs into their avoided cost calculations. *Id.* at 7.

Discussion and Conclusions

As an initial matter, the Commission is not persuaded by the Joint Solar Intervenors' assertion that Duke's reliance in this proceeding on the gas forecasting assumptions presented in their 2020 IRPs failed to comply with the 2018 Sub 158 Order. As explained by Duke and confirmed by the Public Staff, Duke has relied upon the same natural gas forecasting transportation assumptions presented in DEC's and DEP's 2020 IRPs to develop their avoided costs in this proceeding. This was appropriate and consistent with the Commission's prior guidance.

Regarding the reasonableness of Duke's natural gas forecasting transportation assumptions underlying its 2020 IRPs, the Commission finds the Public Staff's stated concerns as well as Duke's responses to be reasonable and appropriate for purposes of this streamlined proceeding. At the highest level, the Public Staff is identifying the planning uncertainties around needed new natural gas transportation capacity into North Carolina in light of the recent ACP cancellation as well as the challenging recent regulatory landscape for building newer natural gas pipelines, such as the MVP. Duke does not dispute that those planning uncertainties exist, but instead highlighted that Duke supports the Public Staff's recommendations to continue to evaluate the reasonableness of its long-term planning assumptions relating to available natural gas transportation infrastructure in its future IRPs and, as appropriate, avoided cost proceedings. The Commission agrees with Duke's assertion that this issue is first and foremost an IRP issue that will then influence subsequent valuations of avoided costs, 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.

The Commission also notes that the Public Staff finds that Duke's natural gas resource and availability assumptions are reasonable and should be utilized in calculating DEC's and DEP's avoided costs for the purposes of this streamlined proceeding, as they align with the Companies' 2020 IRP base planning assumptions. Moreover, the Commission accepts Duke's commitment to provide the Commission and stakeholders with updated information on expected actions by various pipeline developers and other parties and to address expected timelines that are needed for project completion, as well as identification of major challenges associated with planned or potential pipelines, either in the current 2020 IRP proceeding or in future IRP proceedings, as appropriate.

Finally, the Commission is not persuaded by the Joint Solar Intervenors' argument that Duke must include capacity reservation costs in calculating avoided costs and concludes instead that such costs are neither accurate nor appropriate for purposes of calculating the Companies' avoided capacity costs under the peaker methodology, for the reasons explained by Duke in this proceeding.

In summary, the Commission accepts Duke's use of its 2020 IRP natural gas transportation and pricing assumptions as reasonable for purposes of calculating avoided costs in this proceeding. In its pending review of the two Duke 2020 IRPs the Commission may give further consideration to the appropriateness of these assumptions for purposes of resource planning and other future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 15

The evidence supporting this finding of fact is found in Duke's Initial Statement, the Public Staff's Initial Statement, and the Joint Solar Intervenors' Initial Comments.

Summary of the Comments

Duke's Initial Comments explained that, for purposes of this streamlined 2020 standard offer avoided cost rate proceeding, it developed its respective avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the 2018 Sub 158 proceeding. In support of its position, Duke's Initial Comments recounted that, in the 2018 Sub 158 proceeding, Duke argued that paying QFs an avoided fuel hedging value for their must-purchase power was not appropriate under PURPA. Therefore, they did not include a hedge value in their proposed avoided energy cost calculations. The Commission's 2018 Sub 158 Order, however, determined that renewable generation is capable of providing fuel price hedging benefits; accordingly, the Commission directed DEC and DEP to recalculate their avoided energy rates to include a fuel hedging value utilizing the Black-Scholes Model to determine the hedging value of renewable generation. 2018 Sub 158 Order at 62. After discussing this determination with the Public Staff, Duke explained in its 2018 Sub 158 compliance filing that it had updated its avoided energy cost rate calculations to include the same hedge value approved for DENC in its Sub 158 avoided cost rates. *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Compliance Filing, Docket No. E-100, Sub 158 (Nov. 1, 2019). Duke reaffirmed its November 1, 2019 compliance filings after the Commission issued its 2018 Sub 158 Order in April 2020.

In their initial comments, the Joint Solar Intervenors questioned whether Duke had complied with the Commission's 2018 Sub 158 Order, arguing that Duke should have included an appropriate fuel hedging value using the Black-Scholes Model or a similar model to determine the hedging value of renewable generation. Additionally, according to the Joint Solar Intervenors, the Commission had directed that the fuel hedge value should be included for each year of the entire term of the QF PPA. In support, the Joint Solar Intervenors cited N.C.G.S. § 62-156, which states:

> the expected costs of the additional or generating capacity that could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources.

The Joint Solar Intervenors then promoted a "more accurate methodology" than Black-Scholes to determine the fuel hedging value and comply with the statute, because, they argued, Black-Scholes undervalues the long-term physical hedge against natural gas volatility provided by a long-term, fixed price PPA with a renewable QF. Black-Scholes simulates buying sequential options to purchase an 8-month supply of natural gas at a fixed price, over a 10-year period. Black-Scholes updates the price of natural gas fuel 15 times over the course of that 10-year period because the price of each successive option depends on the then-prevailing market price. Therefore, the Joint Solar Intervenors concluded, the Black-Scholes method did not accurately reflect the added fuel price stability gained through each year of the long-term, fixed-price PPA with a renewable QF. The Joint Solar Intervenors urged the Commission to direct Duke to investigate and apply a more accurate model that better conforms to the Commission's prior orders, or, in the alternative, to revisit the methodology used to calculate fuel hedging in the full proceeding beginning in November 2021.

In Reply Comments, Duke contested the Joint Solar Intervenors' assertion that the hedge value used in this proceeding, which was accepted in the 2018 Sub 158 Proceeding, was a "compliance issue." The method that Duke used to calculate the fuel hedge applicable to QFs was just that, a methodological issue that the parties and the

Commission have agreed to address in future proceedings rather than at this time. Duke asserted that it disagreed with the Joint Solar Intervenors' allegations and will likely continue to oppose the inclusion of any avoided hedging costs in future proceedings. Nevertheless, Duke agreed that this issue should be addressed in the Companies' November 2021 avoided cost filing.

Discussion and Conclusions

Based on the foregoing, the Commission determines that Duke has included avoided hedging costs consistent with the 2018 Sub 158 Order and that these costs are reasonable and should be approved. In so doing, the Commission notes that the Public Staff did not comment specifically on the avoided hedging values, but it supported the overall reasonableness of the inputs to the Commission's avoided energy cost rates.

The Commission is not persuaded by the Joint Solar Intervenors' recommendation to consider a new methodology in this proceeding. The issue of avoided hedging costs has been contentious in the past, and this proceeding has been streamlined so that the parties and the Commission could have more time to address more complex issues in the November 2021 filing. To better achieve that goal, Duke deliberately included the avoided hedging costs consistently with the 2018 Sub 158 Order, although it has acknowledged that it does not agree with their inclusion. Thus, the Commission concludes that for purposes of this streamlined proceeding, Duke's avoided hedging costs are reasonable. The Commission, however, directs the interested parties to address this issue in the next avoided cost proceeding.

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

The evidence supporting this finding of fact is found in Duke's Initial Statement, the Public Staff's Initial Statement, the Joint Solar Intervenors' Initial Comments, the Public Staff's Reply Comments, and Duke's Reply Comments.

Summary of the Comments

In its Initial Statement, the Public Staff cited the Commission's previous determinations from the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, holding that the calculation of avoided costs should be based on "known and verifiable" costs and that the costs of carbon emissions were not sufficiently certain to be included in avoided costs. The Public Staff additionally noted that the Commission had previously directed that the generation expansion plans used to calculate avoided energy should be based on IRP expansion plans that account for only known and quantifiable costs.

The Public Staff confirmed that in calculating their avoided energy rates, DEC and DEP utilized their Portfolio A from their 2020 IRP, which is the base case without carbon policy. Accordingly, the production cost model inputs DEC and DEP used to calculate avoided energy rates do not include a carbon price, consistent with Portfolio A. Because neither DEC nor DEP are currently subject to any regulations imposing a carbon price, there is no known and verifiable carbon cost. Therefore, the Public Staff agreed that

DEC's and DEP's calculation of avoided energy cost rates that did not reflect any carbon price were appropriate and consistent with the prior Commission precedent to consider only known and verifiable costs in calculating avoided cost rates.

The Public Staff notes that DENC calculated its proposed avoided energy rates using its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165, and that Alternative Plan B is the least-cost plan that complies with all applicable state law, including the Virginia Clean Economy Act and Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI), effective January 1, 2021. The Public Staff states that while there is some uncertainty regarding the projected future cost of RGGI carbon allowances, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law. Therefore, the Public Staff concludes that it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates. The Public Staff also finds DENC's explanation for the difference between the CO_2 price included in DENC's avoided energy rates and the RGGI CO_2 price forecasts included in DENC's 2020 IRP to be reasonable. Public Staff Initial Statement at 38-39.

The Public Staff notes further that the CO_2 price utilized by DENC to calculate its proposed avoided energy rates also includes a federal CO_2 price in addition to the RGGI CO_2 price in years 2026 and beyond. The Public Staff argues that the inclusion of a federal CO_2 price is inconsistent with prior Public Staff positions and the Commission's Sub 140 Phase One Order that the avoided energy rate should only include "known and verifiable" costs. The Public Staff asserts that as no federal CO_2 price currently exists, such costs should not be included in the calculation of avoided energy rates. The Public Staff recommends that DENC calculate its production cost model using a RGGI price forecast without a federal CO_2 price, and file revised avoided energy rates. *Id*. at 39-40.

The Joint Solar Intervenors recommended that DEC and DEP include carbon emission costs in their avoided energy costs. In support of their recommendation, they note that the inputs for the cost production runs used by DEC and DEP do not include CO_2 emission costs over the 10-year forecast period. The Joint Solar Intervenors then referenced Duke's Emission Allowance Forecasts, which include assumed costs for NO_x and SO_2 through year 2044, but do not include cost allowance assumptions for carbon. Additionally, the Joint Solar Intervenors refer to Duke Energy Corporation's corporate commitment to achieve a 50% reduction in carbon emissions by 2030 and to be carbon-neutral by 2050, which is reflected in the Companies' 2020 IRPs. The Joint Solar Intervenors assert that the Companies' 2020 IRPs include carbon pricing in most of their modeling scenarios and, furthermore, include a non-zero price for carbon in the IRP scenarios that put DEC and DEP on trajectories to meet their long-term carbon commitments. In the Joint Solar Intervenors' opinion, because DEC and DEP use a forecast of increasing CO_2 emission costs in their respective IRPs, and assume that non-zero carbon emission costs are necessary to meet Duke's long-term corporate commitment, the avoided energy cost modeling in this avoided cost proceeding should use the 2020 Duke IRP base scenario for carbon emission costs starting in 2025. In the alternative, the Joint Solar Intervenors note that the Commission should consider this point with respect to its review of the 2020 IRPs and the subsequent 2021 avoided cost proceeding.

In their Reply Comments, the Joint Solar Intervenors urge the Commission to reconsider its application of the “known and verifiable” standard, as set forth in the Sub 140 Phase One Order, with respect to carbon costs. They argue that the likelihood of a carbon price in the near term is “substantially greater” than at the time the Commission issued its Sub 140 Phase One Order through either federal regulation or state policy. Joint Solar Intervenors Reply Comments at 3. Finally, the Joint Solar Intervenors referred to the Duke Energy Corporation’s carbon reduction goals to justify including a carbon emissions cost in calculating avoided cost rates.

In their Reply Comments, the Joint Intervenors state that they do not oppose DENC’s revised rates to remove the federal CO_2 costs, but maintaining the RGGI costs. Joint Intervenors Reply Comments at 2.

In Duke’s Reply Comments, it agreed with the Public Staff that carbon emissions should not be included in avoided energy costs. In addition to the Commission precedent supporting this conclusion cited by the Public Staff, Duke cited the FERC’s determination that only real costs, costs that are avoidable by a utility and its customers when a utility purchases from a QF, should be accounted for and included in a utility’s avoided costs. Duke’s use of inputs from their 2020 IRPs that do not include carbon costs to calculate their respective avoided energy rates is consistent with the Commission’s directives. The Companies acknowledged that their IRPs present multiple alternative long-term planning pathways that do forecast carbon emission costs in the future, but they asserted that these forecasts do not mean that they are known and verifiable costs today.

In its reply comments DENC states that it calculated its initially filed avoided energy rates including a federal CO_2 price because doing so was consistent with Alternative Plan B in the 2020 IRP. However, considering the precedent cited by the Public Staff, DENC states that it does not object to the Public Staff’s recommendation and presents the results of running the PLEXOS model using the RGGI price forecast but no federal CO_2 price. DENC states that it shared the revised rates and supporting data with the Public Staff and the Joint Intervenors, and that if the Commission agrees with the Public Staff on this issue, DENC does not object to using these revised avoided energy rates. DENC reiterates the Public Staff’s recognition that the RGGI Only price used in the IRP is a price forecast made under the influence of a federal CO_2 price, and the RGGI Only price decline in years 2026 through 2030 is due to downward pressure on emissions resulting from the federal CO_2 price. As a result, the RGGI Only price forecast in absence of the federal CO_2 price will actually slightly increase in years 2026 through 2030. DENC Reply Comments at 7-8.

In its Reply Comments the Public Staff states that it has further discussed the federal CO_2 issue with DENC, that DENC shared with the Public Staff revised rate schedules consistent with the Public Staff’s recommendation, and that the Public Staff agrees that those rates are appropriate for use in this proceeding. Public Staff’s Reply Comments at 6.

Discussion and Conclusions

In the Sub 140 Phase One Order the Commission 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, the Companies should base their avoided costs on “known and verifiable” costs, which do not include the costs of carbon emissions. The Commission is not persuaded by the Joint Solar Intervenors’ assertions that this streamlined process is the appropriate time to revisit the “known and verifiable” cost standard at this time.

The Commission finds persuasive the Public Staff and Duke’s position that Duke’s calculation of avoided energy rates, using the Companies’ 2020 IRP least cost “Portfolio A Base without Carbon Policy,” is appropriate for this proceeding.

Given the streamlined nature of this proceeding as provided for in the Continuance Order, the Commission concludes that it is reasonable, for purposes of this proceeding, to approve DENC’s revised avoided energy rates based on modelling that uses the RGGI price forecast but that excludes the federal CO_2 costs that were reflected in DENC’s Alternative Plan B as presented in its 2020 IRP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

The evidence supporting this finding of fact is found in Duke’s Initial Comments, the Public Staff’s Initial Comments, and the Duke’s Reply Comments.

Summary of the Comments

Duke’s Initial Statement explained that its Schedule PP rates offer different avoided energy credits depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. This approach, according to Duke, accurately reflects 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.

Duke recounted in its Initial Statement that, in the 2016 Sub 148 proceeding, DENC filed a study showing that surging distribution interconnected QF solar development was causing power backflow on substations throughout DENC’s service territory. Relying upon the DENC study, the Commission determined that the previously recognized “avoided line loss benefits associated with distributed generation have been reduced or negated” for future QFs requesting to interconnect to the DENC distribution system, and approved DENC’s request to eliminate the line loss adder from its standard offer avoided energy payments for QFs interconnecting on its distribution network.

In the 2018 Sub 158 proceeding, Duke undertook a similar line loss study. However, Duke determined that it was appropriate for DEC and DEP to continue offering a line loss adder, as their studies showed that the number of substations on their respective systems where backflow was reducing or negating the avoided line loss benefits of distribution-connected QFs was not substantial enough to eliminate the line loss adder for relatively small 1 MW or less standard offer QFs. The Commission approved Duke's determination and further concluded that it was appropriate for 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 next biennial avoided cost proceeding." 2018 Sub 158 Order at 36. Additionally, the Commission found that Duke'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.*

Consistent with this Commission direction,[7] Duke reported in their Initial Statement that it 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 currently are or are expected to experience backfeed in the near future because of the recent growth in utility-scale QF growth. Duke's analysis showed that, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding into the transmission system due to distribution-connected generation. Duke's analysis further indicated that despite the high number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 132 out of 408 substations, or 32% of DEP's substations, were estimated to experience backfeed before the projects being addressed by this avoided cost proceeding start connecting.[8] Duke's Initial Statement continued that, for DEC, the percentages of substation banks currently experiencing backfeed due to distribution-connected projects is significantly less – only 4.2%. Even accounting for the estimated impact of queued projects requesting to interconnect to the DEC distribution system, this number only grows to 7.7%.

Based upon their analysis, Duke determined that retaining a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP at this time is appropriate. For proposed distribution-connected QFs that are not eligible for Schedule PP, and in accordance with the 2018 Sub 158 Order, the Companies stated their intent to continue considering whether the QF's energy output would backfeed the substation and inject energy onto the transmission system. Consistent with HB 589, the Companies will 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. *See* N.C.G.S. § 62-156(c) (directing that rates for purchases account for the individual characteristics of the QF).

In their Initial Statement, the Public Staff agreed it was appropriate for DEC and DEP to continue to have its line loss adder removed from their standard offer. Having reviewed the information submitted by DEC and DEP, the Public Staff noted that they continue to have a level of unsubscribed substation capacity that would allow the line loss

[7] The 2020 Scheduling Order specifically directed the Companies to analyze the "extent of backflow at substations." 2020 Scheduling Order at 1.

[8] For comparison, DENC's study presented in the Sub 158 proceeding identified that out of 38 transformers with solar distributed generation, 16 were realizing consistent backflow, and only two had positive flow or additional capacity for load reduction capability. DENC Initial Statements and Exhibits at 35, Docket No. E-100, Sub 158 (Nov. 1, 2018).

adders to be included. The Public Staff committed to continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings and recommended that the Commission direct the utilities to continue to file information to support the removal/inclusion of the line loss adder in future proposed avoided cost rates. With respect to the next avoided cost proceeding, the Public Staff recommended that DEC and DEP evaluate and report on: (i) any geographical concentrations of back-feeding substations, and (ii) whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide market-based rate signals to QFs regarding the value of the energy at the selection location.

In their Reply Comments, Duke agreed with the Public Staff's recommendations and to work with the Public Staff on this issue prior to the November 2021 filing. Duke then requested that the Commission approve their respective proposed distribution line loss adder included in the standard offer Schedule PP rates for purposes of this proceeding.

Discussion and Conclusion

The Commission approves Duke's proposed distribution line loss adder included in its standard offer Schedule PP rates for purposes of this proceeding. No party objected to the inclusion of these adders. The Commission further approves the Public Staff's recommendations that in the next avoided cost proceeding, currently commencing in November 2021, DEC and DEP evaluate and report on: (i) any geographical concentrations of back-feeding substations, and (ii) whether a rate design with and without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide a more accurate avoided cost rate to QFs regarding the value of the energy at the selection location. The Commission directs Duke to discuss these issues with the Public Staff and other stakeholders prior to filing their November 2021 proposed avoided cost rates and address in Duke's initial statement whether it would be appropriate to offer an enhanced rate design that calculates avoided costs with and without a line loss adder based on the amount of back-feeding at a substation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding of fact is found in Duke's Initial Statement.

Summary of the Evidence

Duke's Initial Statement outlined the background of systems integration services charge from previous biennial avoided cost proceedings. In the 2018 Sub 158 Proceeding, Duke proposed an integration services charge specific to integrating new intermittent solar energy generation into Duke's system. Duke designed the charge to recognize the impact on operating reserves, or increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity. Duke's ongoing evaluation of integration costs as well as the Astrapé Study filed in the 2018 Sub 158 proceeding showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases.

In Duke's Initial Statement it explained that after reviewing the results of the Astrapé Study in the 2018 Sub 158 proceeding, it requested approval of an integration services charge designed to reflect the average integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources. The charge would only apply to solar QF generators contracting to sell prospectively (whether new solar QFs or new PPAs with operating QFs after the term of the current agreement terminates), and Duke would update this average charge every two years in future biennial avoided cost proceedings. The solar integration services charges presented in the 2018 Sub 158 proceeding were $1.10/MWh for DEC and $2.39/MWh for DEP. These charges were based only on the existing plus HB 589 transition solar capacity in DEP (2,950 MW) and DEC (840 MW).

Duke's Initial Statement further recounted that in the 2018 Sub 158 Order, the Commission approved the integration charge amounts calculated in the Astrapé Study and approved the exemption for Controlled Solar Generators from being assigned the charge. *Id.* The Commission, however, determined that to remain consistent with FERC's regulations implementing PURPA, the charge should remain fixed during the term of a new QF's contract, as opposed to being subject to biennial adjustments throughout the term of the contract. The Commission also directed Duke to undertake an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings about Duke's ancillary service costs associated with intermittent, non-dispatchable generation. *Id.*

With that background, Duke's Initial Statement provided that, for purposes of this avoided cost proceeding, Duke has incorporated the same integration services charges into its avoided energy rates as approved in the 2018 Sub 158 Order. Accordingly, the Companies did not propose any modifications to the integration charge amounts or to the rate design approved in the 2018 Sub 158 Order, which currently assigns new solar generators the average versus incremental integration charge. Duke stated that it planned to evaluate these methodological and rate design issues for the next biennial avoided cost proceeding and to engage with the Public Staff and other interested stakeholders. Duke further reported that it is also undertaking the formation of the independent technical review committee, as directed in the 2018 Sub 158 Order, to review the Astrapé Study methodology and the model used for system simulations. Duke states that it is also committed to include a report detailing the committee's feedback in their initial filing in the next biennial avoided cost proceeding.

Discussion and Conclusions

For purposes of this proceeding, the Commission approves the solar integration decrement to avoided energy rates as proposed by Duke. No party disputed its inclusion for purposes of this proceeding. As Duke notes, however, with respect to future avoided cost proceedings, an independent technical review committee is currently reviewing the Astrapé Study methodology and the model used for system simulations. As the Commission has previously directed, Duke shall include a report detailing the independent technical review committee's feedback on the methodology and model in their next biennial avoided cost initial filing.

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

The evidence supporting these findings of fact is found in the Duke's Initial Statement, Duke's Reply Comments, the Public Staff's Initial Statement, the Joint Solar Intervenors' Initial Comments, and Duke's Supplemental Filing.

Summary of the Comments

Duke's Initial Statement explains how 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. Duke Initial Statement at 29.

In the 2018 Sub 158 proceeding, the Public Staff's initial comments on Duke's Schedule PP rate design concluded that the DEC and DEP proposed rate design "compl[ies] with the Commission's [Sub 148 Order] directive to propose more granular rates," but suggested that additional granularity, beyond Duke's initial proposal was "appropriate and beneficial to North Carolina ratepayers." Duke Initial Statement at 29-30 (*citing* Public Staff Initial Statements at 48, 54, Docket No. E-100, Sub 158 (Feb. 12, 2019)). The Public Staff therefore proposed that Duke implement a three-step methodology expanding DEC and DEP's initial rate design and focusing on more granularly defined premium peak hours and additional shoulder month periods to further distinguish rates in more critical summer and winter seasons as compared to DEC and DEP's initially proposed rate design.

After engaging with the Public Staff on rate design issues, Duke and Public Staff filed a Partial Settlement on April 18, 2019, in the Sub 158 Proceeding, 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's Initial Statement 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's Initial Statement states that DEC and DEP are continuing to utilize the Commission-approved avoided energy and capacity rate designs outlined in the Sub 158 Rate Design Stipulation. Duke Initial Statement at 30-32. Specifically, as approved in the 2018 Sub 158 Order, the Schedule PP capacity rate design offers three distinct pricing periods to most accurately reflect the marginal capacity value to customers during each period. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December, January, February, and March. No capacity payments apply during the remaining months. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The seasonal months and three capacity pricing periods are the same for DEC and DEP. Duke's Initial Statement concludes by stating that DEC and DEP have designed their avoided capacity and energy rates in accordance with the stipulated rate design approved in the 2018

Sub 158 Proceeding, and that Duke plans to continue to discuss the accuracy and appropriateness of the rate design with the Public Staff between now and the next biennial avoided cost proceeding. *Id*. at 32-33.

The Public Staff's Initial Statement identified that the avoided energy rates filed by DEC and DEP "exhibited counterintuitive behavior in some schedules" when reviewing Duke's rate design. Public Staff Initial Statement at 47. For example, the variable rate for both DEP and DEC, and the 10-year fixed rate for DEP, all have a winter AM-peak rate that is actually lower than the winter off-peak rate; and the 10-year fixed rate for DEC has a shoulder on-peak rate that is lower than the shoulder off-peak rate. The Public Staff's Initial Statement provided that that this behavior is not reflective of actual avoided costs, and, in fact, this behavior might be an artifact of the production cost modeling. In that case, the time variant rates would not incentivize the appropriate operational behavior from dispatchable QFs. *Id.*

Upon investigation, the Public Staff determined that the primary driver for these counterintuitive rates was due to a change in the way the Duke has treated start-up costs in the production cost model that is used to determine avoided energy costs. *Id*. The Public Staff's Initial Statement, however, further explained that Duke had notified the Public Staff that it intends to re-run its production cost models using the Sub 158 methodology of spreading the start costs over each unit's run time. The Public Staff's Initial Statement also noted how Duke indicated that it plans to continue to evaluate the most accurate method to allocate unit start costs for both integrated resource planning and avoided cost modeling purposes and that the Public Staff anticipates working with Duke on this issue prior to the November 2021 avoided cost filing. *Id*.

In the Joint Solar Intervenors' Initial Comments, they noted that Duke's proposed avoided energy costs for the winter morning peak period included in the DEC and DEP rate designs are "unreasonably low — much lower, in fact, than the avoided energy prices for surrounding off-peak hours." Joint Solar Intervenors Initial Comments at 9. The Joint Solar Intervenors' Initial Comments contended that this result is "apparently" due to old production cost modeling techniques, and requested that the Commission not rely on these "erroneous" results. *Id.* at 9-10.

Prior to filing Reply Comments, DEC and DEP made their Supplemental Filing. DEC and DEP's Supplemental Filing agreed with the Public Staff and Joint Solar Intervenors that Duke's initially proposed avoided energy costs result in counterintuitive energy pricing periods, which included on-peak rates being lower than off-peak rates in certain periods. The DEC and DEP Supplemental Filing also explained that this result was due to a change in Duke's production cost modeling's treatment of unit start costs as compared to the 2018 Sub 158 proceeding. The DEC and DEP Supplemental filing explained that, having discussed the issue with the Public Staff, Duke has reverted to modeling unit start costs in the same manner as was done in the 2018 Sub 158 Proceeding and has committed to further discussing this issue with the Public Staff and addressing any resulting rate design changes in the upcoming 2021 filing. Duke Supplemental Filing at 2.

In Reply Comments, Duke stated that based on the DEC and DEP Supplemental Filing and updated avoided energy credits filed therein, Duke believed that the Public Staff's and the Joint Solar Intervenors' stated concerns regarding the initially filed rate designs are now resolved. Therefore, Duke requested that the Commission approve the DEC and DEP Supplemental Filing and rate designs included therein. Duke Reply Comments at 15-16.

The Public Staff's Reply Comments stated that the Public Staff has reviewed the DEC and DEP's Supplemental Filing and found that the revisions appear to resolve the anomalies previously identified, and the Public Staff believed that the revised rates are appropriate for use in this proceeding. The Public Staff also agreed to continue to discuss the treatment of start costs in production cost modeling with Duke and other parties for further consideration in the November 2021 filing. Public Staff Reply Comments at 5-6.

The Joint Solar Intervenors' Reply Comments stated that Duke's Supplemental Filing and revisions included therein "appear reasonable" and that Joint Solar Intervenors "do not object to the revisions that Duke made for purposes of calculating avoided cost rates in this proceeding." Joint Solar Intervenors Reply Comments at 6.

Discussion and Conclusions

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." The Commission therefore required the Utilities to consider refinements to the avoided capacity rate and to address these refinements in the Sub 158 proceeding. 2016 Sub 148 Order at 56. 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 and the Public Staff worked together through the course of the Sub 158 Proceeding to reach the Rate Design Stipulation, which was approved by the Commission. 2018 Sub 158 Order at 25. 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'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 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's avoided energy costs. *Id*.

In this proceeding, the Commission finds that Duke has adhered to the Sub 158 Rate Design Stipulation in proposing its avoided energy and avoided capacity rate design. However, as explained above, Duke's initially proposed rate design modeling methodology differed from the methodology approved in the Sub 158 proceeding in that Duke's underlying production cost modeling's treatment of unit start costs had been adjusted for purposes of developing the 2020 IRP. After discussions with the Public Staff, Duke reverted to modeling unit start costs in same manner as was done in the 2018 Sub 158 proceeding. Duke also committed to further discuss this issue with the Public Staff and address any resulting rate design changes in its upcoming 2021 avoided cost finding. Duke Reply Comments at 15.

For purposes of this streamlined proceeding, the Commission approves DEC and DEP's revised rate design and resulting avoided energy and capacity rates as presented in the DEC and DEP Supplemental Filing made on February 12, 2021. The Commission finds that the revised rates are more appropriate than those originally filed, with premium peak prices higher than on-peak prices and on-peak prices higher than off-peak prices. No parties take issue with DEC and DEP's Supplemental Filing. Further, the Public Staff's investigation of the Supplemental Filing indicates that Duke's revisions resolve the issues previously identified in the rate design by both the Public Staff and Joint Solar Intervenors. Moreover, both the Public Staff and Joint Solar Intervenors support the revised rates and rate design included in the DEC and DEP Supplemental Filing as appropriate for use in this proceeding. The Commission directs Duke and the Public Staff to continue to discuss the treatment of start costs in production cost modeling for further consideration in the November 2021 filing, as well as other general rate design issues.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is found in Duke's Initial Statement, the Public Staff's Initial Statement, the Reply Comments of the Joint Solar Intervenors and Duke's Reply Comments.

In Duke's Initial Statement, it proposed an amendment to Section 6 of the Standard Offer PPA to provide that it may require standard offer Sellers above 100 kW to provide prior notice of annual, monthly, and day-ahead forecasts of hourly production, as specified by either DEC or DEP as is applicable. Duke did not intend to require such information from small standard offer QFs, but believed this change was appropriate to better align Section 6 with the revised standard offer eligibility under HB 589. Duke also recognized that requesting operational data from smaller QFs during the terms of these PPAs, as increasing penetrations of distributed energy resources are installed on the Companies' systems, may become more appropriate in the future.

In its Initial Statement, the Public Staff recommended that Duke revise its standard offer contracts to require the forecasted hourly production rates from QFs greater than 1 MW in capacity. The Public Staff commented that lowering the reporting threshold from

3 MW to 100 kW may be onerous and costly for some small QFs and noted that Duke had not requested operational forecast information from any QFs less than 5 MW in the past five years. The Public Staff concluded that a facility greater than 5 MW may be better situated to agree to certain production forecasting reporting requirements as part of the negotiated PPA with DEC or DEP.

In their Reply Comments, the Joint Solar Intervenors agreed with the Public Staff's position of lowering the threshold for requiring prior notice of annual, monthly, and day-ahead forecasted hourly production from 3 MW to 100 kW would be onerous and costly for some small QFs. Thus, they supported the Public Staff's recommendation to delete that provision of the Companies' PPAs.

In Reply Comments, Duke agreed to revise the standard offer PPA to delete the provision and to prospectively limit the production forecast reporting requirements to QFs greater than 1 MW entering into the negotiated PPAs.

Based on the foregoing, and the agreement of the parties, the Commission approves the Public Staff's recommendation to revise Duke's standard offer contracts to require the forecasted hourly production rates from QFs only from facilities greater than 1 MW in capacity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 24-25

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

Summary of the Comments

DENC describes in its Initial Statement the methodology it used for purposes of calculating energy rates. That rate design, which was approved in the 2018 Sub 158 Order, comprised nine pricing periods: summer off-peak; summer on-peak; summer premium peak; winter off-peak; winter on-peak am; winter on-peak pm; winter premium peak; and shoulder on- and off-peak periods. DENC has maintained these pricing periods in calculating avoided energy cost rates for purposes of this proceeding. DENC also explains that it continues to allocate its CT costs using the seasonal allocation weighting approved in the 2018 Sub 158 Order of 45% summer, 40% winter, and 15% shoulder. DENC Initial Statement at 4.

In its Initial Statement, the Public Staff acknowledges that DENC's energy pricing periods remain consistent with the 2018 Sub 158 Order and does not raise any concerns with maintaining this rate design. Public Staff Initial Statement at 27. The Public Staff also acknowledges that DENC's weighting capacity value between seasons remains consistent with the 2018 Sub 158 Order and does not raise any concerns with maintaining this weighting. *Id*. at 22.

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

Discussion and Conclusions

In the 2018 Sub 158 Order, the Commission found it appropriate to require DENC to use the rate design agreed upon by DENC and the Public Staff as presented in the rebuttal testimony of DENC witness Bruce Petrie in calculating avoided energy and capacity rates in that proceeding. The Commission found that the revised rate design was responsive to the directives in prior Commission orders by providing QFs with more granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further found that DENC's revised proposed seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons were appropriate for use in weighting capacity value between seasons, as these weightings continue to reflect DENC's participation in PJM and the recent strong winter peak loads, as well as the shift of May from summer to shoulder capacity. 2018 Sub 158 Order at Finding of Fact No. 43, at 98.

Based upon the foregoing and the entire record herein, and in light of the streamlined nature of this proceeding, the Commission concludes that DENC's proposed rate design, unchanged from the rate design approved in the 2018 Sub 158 Order, is appropriate for continued use for the purpose of calculating rates for DENC's nine pricing periods for purposes of this proceeding. The Commission further concludes that DENC's continued use of the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons, also unchanged from the seasonal allocations approved in the 2018 Sub 158 Order, are appropriate for use in weighting capacity value between seasons for purposes of this proceeding.

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

The evidence supporting these findings of fact is found DENC's Initial Statement and Reply Comments, the Public Staff's Initial Statement and Reply Comments, and the Joint Intervenors' initial and reply comments.

Summary of the Comments

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC explains that since the 2018 Sub 158 Proceeding, it moved from using the PROMOD utility production cost model to the PLEXOS model, which incorporates an 8,760 hourly load profile, an improvement from the PROMOD model used previously, which incorporated a "typical week by month" profile. DENC states that compared to PROMOD, the dispatch from the PLEXOS model utilizing the short-term module better accounts for dispatch constraints on thermal generating units. DENC notes that while it has changed production costing models, the process for developing the avoided energy costs is the same as in previous filings. DENC states that the PLEXOS production cost model is used to derive avoided energy costs for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in DENC's service area where QFs are located, plus a fuel hedging benefit and the RDC. DENC states that it used the PLEXOS output results to calculate the levelized on-peak and off-peak long-term fixed energy rates under Schedule 19-FP. DENC Initial Statement at 4-6.

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International (ICF) prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the Sub 158 Proceeding. *Id*. at 6.

DENC explains that consistent with the Commission's conclusions in the 2016 Sub 148 Order and the 2018 Sub 158 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that locational marginal prices (LMPs) in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs and states that it included the historical average congestion differentials for all periods in its calculation of proposed energy rates. *Id*. at 6-8.

DENC also notes that 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 explains that in the December 17, 2015 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in Docket No. E-100, Sub 140 (Sub 140 Phase Two Order) the Commission 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 Proceeding and the Sub 158 Proceeding , 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 the 2014 Sub 140 Case, 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.

Finally, DENC recalls that in the Sub 158 Proceeding, it proposed to adjust avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs — specifically, re-dispatch costs — caused by these generators, and that the Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff, to be $0.78/MWh. DENC proposes to continue to apply the $0.78/MWh RDC that was approved in the 2018 Sub 158 Order for purposes of Schedule 19-FP in this proceeding. *Id*. at 10.

In its Initial Statement the Public Staff states that based on its review of the PLEXOS inputs it believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs. The Public Staff confirms that DENC's calculation of avoided energy rates is consistent with the 2018 Sub 158 Order, as is DENC's inclusion of avoided fuel hedging values based on the Black-Scholes option pricing model. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices and states that DENC's calculation of the fuel hedge value is reasonable. Public Staff Initial Statement at 27-28.

In their initial comments the Joint Intervenors do not make any recommendations specific to DENC. The Joint Intervenors include, however, with their initial comments a report by Crossborder Energy (Crossborder Report), which makes two recommendations for the "utilities." First, the Crossborder Report recommends that the utilities supplement the fundamental forecasts for Henry Hub prices from private consultancies IHS and ICF with a public Henry Hub forecast, and that the IHS/ICF forecasts be averaged with the Energy Information Administration's (EIA) 2020 Annual Energy Outlook forecast of Henry Hub prices. With regard to DENC, this means that DENC would use the average of the EIA and ICF forecasts as its fundamental forecast. Joint Intervenor's Initial Comments, Exhibit A: Crossborder Report at 2. Second, the Crossborder Report recommends that the utilities use a fuel hedging model other than the Black-Scholes method. *Id.* at 6-10.

DENC also states that, to the extent that the Crossborder Report's recommendation with regard to fuel forecasts is considered to apply to DENC, it believes its current approach of using the ICF fundamental forecast is appropriate. DENC notes that its use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136), most recently in the 2018 Sub 158 Order, and that DENC continues to believe that the ICF forecast of commodity prices is, on its own, appropriate for estimating avoided energy cost rates. DENC explains that ICF forecasts are reputable and respected in the industry and points out that Joint Intervenors have not presented a convincing reason why continued use of the ICF forecast on its own is not reasonable, particularly given the Commission's consistent decisions accepting that approach. Moreover, DENC indicates that ICF conducts regional forecasts for electricity as well as natural gas and other commodities, which allows DENC to use relevant and correlated forecasts for system modeling purposes. In contrast, DENC explains, using uncorrelated forecasts, by for example mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, would skew the dispatch and economic value of DENC's natural gas-fired units. *Id.* at 9-10.

DENC also states that to the extent that the Crossborder Report's fuel hedging recommendation is considered to apply to DENC, the alternative methods suggested by the Crossborder Report are not reasonable approaches to calculating avoided hedging costs for North Carolina. DENC explains that this is due to several factors, including but not limited to the fact that both of the methods discussed in the Crossborder Report are based on outdated data and would result in inappropriately inflated hedging values, thereby drastically and unreasonably increasing avoided energy cost rates. In addition, DENC notes that the Commission concluded in the 2014 Sub 140 Proceeding and again in the 2018 Sub 158 Order that hedging benefits should only be valued over the hedging terms actually used by the Utilities. Consistent with this determination, DENC indicates that the use of ten- or 20-year hedging periods as suggested by the Crossborder Report is far in excess of what is appropriate. Since DENC's typical natural gas financial hedge program could extend approximately 18 to 24 months in the future, DENC finds it appropriate to calculate assumed avoided hedging costs using this time frame. *Id*. at 10-11.

With regard to natural gas forecasting, the Public Staff notes that other parties have the ability to cite publicly available forecasts and provide supporting evidence in their comments if they believe that that Utilities' fundamental forecast is inappropriate. Given that the Utilities' long-term fundamental price forecasts are reasonably comparable to EIA's 2020 Annual Energy Outlook (AEO) gas price forecast and no intervenors have provided persuasive evidence that the Utilities' fundamental forecasts are inappropriate, the Public Staff does not believe that the mandated use of publicly available forecasts is warranted at this time. *Id*. at 2-3.

No party objected to DENC's continued application of the LMP adjustment to its avoided energy rates or continued application of the RDC as approved in the 2018 Sub 158 Order.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed avoided energy inputs, as modified by DENC's reply comments, are reasonable for the purposes of this proceeding.

With respect to the fuel forecast DENC used in its modeling, the Commission agrees that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings, which the Commission has accepted since the 2012 Sub 136 Proceeding, continues to be appropriate. No party raised specific objections to DENC's approach. The Commission declines to accept Joint Intervenors' recommendation regarding fuel forecasts for the reasons discussed in the Public Staff's Reply Comments and DENC's Reply Comments.

With regard to hedging, in the Sub 140 Phase One Order the Commission concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. Sub 140 Phase One Order at Findings of Fact 12 & 13, at 8. In the Sub 140 Phase Two Order, the Commission found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. Sub 140 Phase Two Order at Finding of Fact 11, at 7.

Based on the record in this proceeding, the Commission concludes that DENC has calculated avoided hedging costs appropriately for purposes of this proceeding, and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.02/MWh, which it assumed constant for all years of the Schedule 19-FP contract. The Commission declines to accept Joint Intervenors' recommendation regarding the hedging value calculation model. DENC's use of the Black-Scholes model to calculate hedging value is consistent with the Sub 140 Phase Two Order and the 2018 Sub 158 Order, and given the streamlined nature of this proceeding, the Commission declines to reevaluate this precedent at this time.

Additionally, based on the evidence presented by DENC updating the continued disparity in LMPs in its service territory, which no party contested here, the Commission concludes that it continues to be appropriate for DENC to include the historical average congestion differentials for all periods in its calculation of proposed energy costs for purposes of this proceeding.

Finally, in the Sub 158 Proceeding, DENC proposed to adjust the avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs — specifically, redispatch costs — caused by these generators. The Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff to be $0.78/MWh. No party contested DENC's proposal to continue to apply the same RDC for purposes of this proceeding. The Commission therefore concludes that it is appropriate for DENC to continue to apply the RDC as agreed upon in Sub 158 Proceeding for purposes of Schedule 19-FP in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

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

Summary of the Comments

In its Initial Statement, DENC acknowledges that in the 2018 Sub 158 Order the Commission directed DENC to file a proposed protocol for avoidance of the RDC. DENC proposes that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD). DENC defines an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage.

DENC proposes to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. The output for the case without storage will be the actual metered output of the facility excluding the impact of storage, and the output for the case with storage will be the actual metered output for the facility including the impact of storage. DENC notes that determining the impact of storage will require that the storage device is separately metered. For each case, on a calendar year basis, DENC will calculate variability as the sum of the hourly absolute output variance from a QF-provided generation forecast. The percent reduction in variability will be calculated by subtracting the ratio of the variability of the case with storage to the variability of the case without storage from one. DENC will then calculate a credit to the RDC as follows: (1) the percent reduction multiplied by (2) the RDC rate multiplied by (3) the total calendar year output (MWh) of the case with storage. DENC Initial Statement at 10-11.

DENC explains that to be eligible for the redispatch cost reduction, a QF must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date (COD). For subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract; if no updated forecast is provided, DENC will utilize the previously provided forecast to calculate the RDC reduction credit. Every April, DENC will calculate the redispatch cost reduction using the prior calendar year forecast and metered data. DENC will provide the RDC reduction as a line item credit with the first payment following the April calculation. *Id*.

In its Initial Statement, the Public Staff states that it does not object to DENC's proposed RDC avoidance protocol, although it notes that the proposed methodology is a "reasonable 'third best' proxy for estimating the reduction in re-dispatch costs" Public Staff Initial Statement at 34. The Public Staff states that the proposed protocol is a reasonable proxy largely because DENC's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a controlled solar generator (CSG) consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. *Id*. at 34-35. The Public Staff also presents two preferred options for RDC Avoidance Protocol, while opining on the reasons that they are impracticable at this time or infeasible due to data availability issues. *Id*. at 33-35.

The Public Staff adds, however, that the RDC credit depends on the type of forecast the CSG provides as well as how the CSG dispatches the ESD, and notes that a CSG could provide different types of forecasts depending on whether it wants to use its ESD to "smooth" its output profile or to shift energy from off-peak to on-peak hours. The Public Staff questions whether ratepayers would actually benefit more from energy shifting dispatch than from smoothing dispatch, even though a CSG that is shifting energy would qualify for a higher RDC credit than a CSG that is seeking to smooth output. In order to address its concerns, the Public Staff recommends that DENC monitor the types of forecasts and the ESD dispatch behavior for CSGs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of CSGs in DENC's service territory, in its future avoided cost filings. The Public Staff states that these biennial reports would be similar to the Solar Integration Services Charge (SISC) Avoidance reports recommended by NCSEA, NCCEBA, and the Public Staff for Duke in the Sub 158 Case. The Public Staff also recommends that DENC specifically address CSGs seeking RDC avoidance in each future fuel rider proceeding, providing the specific facility(ies) and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on CSGs seeking to avoid the RDC. The Public Staff further notes that it made the same request of DEP and DEC in the Sub 158 Case. The Public Staff suggests that should evidence emerge that CSGs are able to game their forecasts and output to obtain excessive RDC credits, or if a large number of QFs install an ESD to smooth volatility, the Public Staff may recommend that DENC take measures to address those issues in future avoided cost proceedings. *Id*. at 35-37.

In their reply comments, the Joint Intervenors disagree with the Public Staff's suggestion that there is a risk that CSGs might game the RDC and also disagree with the Public Staff's comments on CSGs engaging in energy-shifting receiving higher RDC credits than CSGs engaging solely in energy smoothing. Joint Intervenors did not raise any objection to the proposed RDC avoidance protocol. Joint Intervenors Reply Comments at 5-6.

In its reply comments, DENC states that its proposed RDC Avoidance Protocol is a reasonable proxy for estimating the reduction in redispatch costs incurred by CSGs. DENC explains that the proposed Protocol can decrease the costs to customers by improving the load forecasts; as CSGs consistently deliver more predictable output, DENC's forecasting tools will incorporate the data in the load forecast process. DENC does not object to the Public Staff's recommendation of monitoring, for CSGs that attempt to avoid the RDC, such CSG's forecasts and behavior and including that information and an analysis of actual solar volatility of CSGs in DENC's service territory in its future biennial avoided cost filings. DENC clarifies that its monitoring and reporting obligation would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. DENC also notes that, if the Commission adopts this recommendation, DENC plans to monitor this information on an annual basis, consistent with the RDC avoidance protocol structure of using annual forecasts. DENC also does not object to the Public Staff's recommendation that DENC monitor CSGs seeking RDC avoidance in future fuel rider proceedings, subject to the same clarification that this obligation would be limited to CSGs seeking to avail themselves of the RDC avoidance protocol that are actually paired with ESDs. DENC Reply Comments at 2-6.

Discussion and Conclusions

In the 2018 Sub 158 Order, in addition to accepting the RDC, the Commission noted the potential for a QF to justify an exception from the RDC and directed DENC to file a proposed protocol for avoidance of the RDC similar to protocols that the Commission directed Duke to file with regard to its integration services charge. 2018 Sub 158 Order at 113.

Based on the evidence presented, the Commission concludes that DENC's proposed RDC avoidance protocol is appropriate for use in this proceeding. The Commission finds reasonable DENC's proposal that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an ESD and that the proposed protocol is a reasonable proxy for estimating the reduction in redispatch costs incurred by CSGs. The Commission also relies on the Public Staff's determination that the protocol is reasonable in part because DENC's QF load reduction estimates incorporate QF output from the prior day (in addition to other variables), such that over time, as a CSG consistently delivers more predictable output in an attempt to adhere to its forecast, DENC's QF load reduction estimate takes that predictability into account. For these reasons the Commission concludes that DENC has complied with the Sub 158 Order directive to file a proposed protocol for avoidance of the RDC.

The Commission concludes that, if any CSGs seek to avail themselves of the RDC avoidance protocol, the information that the Public Staff requests DENC to monitor and provide may be helpful for purposes of evaluating the results of the protocol in the future. The Commission encourages DENC and the Public Staff to continue to discuss the information requested by the Public Staff with regard to the RDC avoidance and, to the extent appropriate, DENC should address the proposed monitoring and reporting of this information in its November 1, 2021 avoided cost filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

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

Summary of the Evidence

In its Initial Statement DENC indicates that consistent with the method used in its compliance filing in the 2018 Sub 158 Case, it used the applicable costs of the Greensville combined cycle power plant as the basis for the CT equipment costs. DENC states that these costs are current and verifiable and represent DENC's actual procurement costs of CT equipment related to a power plant that came online in December 2018. DENC states further that for the remaining costs, including construction and owner costs, it utilized the PJM cost of new entry estimates, based primarily on the "PJM Cost of New Entry for Combustion Turbine and Combined Cycle Plants with June 1, 2022 Online Date" report prepared by The Brattle Group and Sargent & Lundy, dated April 19, 2018. DENC indicates that it also made several adjustments to the Brattle Study results to tailor those results to meet the requirements of the Sub 140 Phase One Order. DENC Initial Statement at 14-15.

In its Initial Comments the Public Staff indicates that it reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates and finds them reasonable. Public Staff Initial Comments at 21.

Discussion and Conclusions

In the Sub 140 Phase One Order, the Commission determined:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

Sub 140 Phase One Order at 48.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission concludes that DENC appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that its source information was tailored in a manner consistent with the guidance previously provided by the Commission. The Commission therefore also concludes that the CT cost information used by DENC is reasonable and appropriate for purposes of calculating avoided capacity costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

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

Summary of the Comments

In its Initial Statement, DENC explains that in the 2016 Sub 148 Order, the Commission approved DENC's proposal to eliminate from its avoided energy rates the 3% adder that had historically been included in avoided energy rates. DENC also explains that in the 2018 Sub 158 Order, the Commission found that power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continued to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated, and that it was appropriate that DENC continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network. For purposes of this proceeding, DENC's avoided energy rates continue to reflect the elimination of the line loss adder. DENC Initial Statement at 9. In its initial status update on the Sub 158 Additional Issues filed on December 7, 2020, DENC states that prior to joining with Duke in the October 20, 2020, joint request, DENC had updated its evaluation of the amount of backflow on the North Carolina portion of its service area, but did not include the updated study with the streamlined filing submitted on November 2, 2020, based on its determination that the analysis was included in the "Sub 158 Additional Issues" to be included in the November 2021 filing. DENC states that the updated study shows that the number of transformers experiencing backflow has increased as more distributed solar generation has become operational. Specifically, of the 41 transformers with connected distributed solar, the study shows 24 realizing consistent backflow (58.5%), an increase from the 16 out of 38 transformers (42%) consistently experiencing backflow in the 2018 study. DENC notes that it plans to update the backflow study again during the third quarter of 2021 for purposes of the November 2021 biennial avoided cost filing.

In its Initial Statement the Public Staff states that for the reasons articulated in the 2016 Sub 148 Order, it is appropriate for DENC to continue to have its line loss adder removed from its standard offer avoided costs rates. The Public Staff explains that DENC demonstrated that the amount of "back feed" from renewable generation occurring and expected to continue to occur on the DENC system justifies the removal of a line loss adder. The Public Staff also states that it will continue to evaluate the appropriateness of line loss adders in future avoided cost proceedings and recommends that the Commission direct the Utilities to continue to file information to support the removal or inclusion of the line loss adder in proposed avoided cost rates in future avoided cost proceedings. Public Staff Initial Statement at 48-49.

Discussion and Conclusions

Pursuant to 18 C.F.R. § 292.304(e)(4), in determining avoided costs "the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity," shall, to the extent practicable, be taken into account. In the 2016 Sub 148 Order, the Commission concluded that line losses may not exist if power purchased from a distribution-connected QF is backfeeding to the substation, and the Commission directed the Utilities to further evaluate this issue in the Sub 158 Case. In the 2018 Sub 158 Order, the Commission determined that backflows are continuing to occur with regularity on a number of DENC's distribution system circuits and that backflows will continue to increase over time. The Commission decided that this greatly reduces or eliminates the benefits of the solar QFs' line loss avoidances, and that it was appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer. Sub 158 Order at 35-36.

Based on the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer for the purposes of this streamlined proceeding. The Commission also accepts the Public Staff's recommendation that the Utilities continue to file information to support the removal or inclusion of the line loss adder in proposed avoided cost rates in future avoided cost proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

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

Summary of the Comments

In its Initial Statement, DENC explains that in the 2016 Sub 148 Order, the Commission ruled that it would "require the Utilities to address the PAF and to support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total in [their] initial filings" in the next biennial avoided cost proceeding. In its 2018 initial statement, DENC proposed to use the metric EA to determine the PAF. As DENC explained, EA represents the availability of the unit(s) during the defined period, and accounts for unit unavailability caused by planned, maintenance, and forced outages. In the 2018 Sub 158 Order, the Commission approved DENC's resulting proposed PAF of 1.07. DENC has continued to apply the 1.07 PAF that was approved in the 2018 Sub 158 Order for purposes of this filing. DENC Initial Statement at 19-20. In its Initial Statement, the Public Staff acknowledges that DENC proposes to continue to use a PAF of 1.07.

In its Sub 158 Additional Issues updates filed on December 7, 2020, January 21, 2021, and March 8, 2021, DENC reports that it has met with the Public Staff to discuss indices to support development of the PAF and that it plans to continue coordinating with the Public Staff on this issue.

Discussion and Conclusions

As discussed in the 2018 Sub 158 Order, the Commission has consistently recognized that because standard avoided capacity rates are paid on a per-kWh basis, 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, without any reasonable opportunity to experience outages during each peak period, to receive the total available avoided capacity payment. Recognizing that the Utilities' generating units experience outages and do not operate 100% of the time, the Commission therefore has ordered the Utilities to apply a PAF, or a simple capacity multiplier, in calculating avoided capacity rates paid to QFs in previous avoided cost proceedings. In the 2016 Sub 148 Order the Commission found that the methodology used to calculate the PAF should include greater precision than in past proceedings and required the Utilities to calculate the PAF using a system availability metric representing the reliability of the Utilities' respective systems during peak periods. The Commission determined in the Sub 158 Case that the evidence supported calculating the PAF based upon a metric or metrics that assess generating unit "availability" and that the methodology used to calculate generating unit availability should be based upon an informed discussion of utility system planning and load forecasting.

In the 2018 Sub 158 Order, the Commission found that the PAFs proposed in the Utilities' respective initial statements were appropriate based on this standard. The Commission also directed the Utilities, with Public Staff input, to evaluate the appropriateness of using other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support development of the PAF prior to the next biennial avoided cost filing. The Commission also adopted the Public Staff's recommendation to require the Utilities to continue to use three (as used by DENC) to five (as used by Duke) years of historic outage rate data to support the PAF. Finally, the Commission acknowledged that there is no possibility that a run-of-river hydroelectric QF will seek to avail itself of the opportunity to sell electric power from its facility to DENC, and therefore, the Commission concluded that DENC was not required to address related issues in the next avoided cost proceeding. 2018 Sub 158 Order at 40-42.

In its Scheduling Order in this proceeding, the Commission set forth a number of issues to be addressed by the Utilities in their Initial Statements, including the use of other reliability indices, specifically the EUOR metric, to support development of the PAF. In its Order Granting Continuance, however, the Commission permitted the Utilities to address this issue in their next biennial full avoided cost proceeding initial statements to be filed on November 1, 2021.

Based upon the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to use a PAF of 1.07 in its avoided cost calculations for all QFs and to address the appropriateness of other reliability indices in its initial statement to be filed on November 1, 2021.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

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

Summary of the Comments

In its Initial Statement, DENC states that on September 1, 2020, in Docket No. E 100, Sub 165, DENC filed an addendum to its 2020 IRP that was submitted in that docket on May 1, 2020, stating that the next year of undesignated capacity need for DENC is 2023. DENC explains that consistent with the Commission's findings in the Sub 158 Order and DENC's statement of capacity need, its calculation of the seasonal levelized rates therefore includes no avoided capacity costs through 2022 since DENC's 2020 IRP shows the first avoidable capacity in 2023. DENC Initial Statement at 18.

In the Public Staff's Initial Statement, the Public Staff notes that in the 2018 Sub 158 Order, the Commission found that it is appropriate for an electric utility to update its avoided capacity calculations to reflect any changes in the utility's first year of avoidable capacity need for negotiated contracts beginning with the 2020 IRP and that DENC's IRP shows the first deferrable capacity need in 2023. The Public Staff explains that, therefore, QFs located in DENC's service area that select a 10-year contract will receive avoided capacity rates that reflect the present value of avoided capacity costs beginning in 2023.

Discussion and Conclusions

Section 62-156(b)(3) provides that a future capacity need "shall only be avoided in a year where the utility's most recent biennial [IRP] 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 . . . ." In the 2018 Sub 158 Order, the Commission explained that in its August 27, 2019 Order on the 2018 IRPs in Docket No. E-100, Sub 157, the Commission found the IRPs of DEC, DEP, and DENC to be reasonable for planning purposes, and found that the Utilities appropriately identified their first avoidable capacity needs in their 2018 IRPs, and therefore, complied with N.C.G.S. § 62-153(b)(3). The Commission also determined that, beginning with the 2020 IRP, it was appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding. 2018 Sub 158 Order at 46.

Based on the foregoing, the Commission concludes that DENC's addendum to its 2020 IRP submitted on September 1, 2020, in Docket No. E-100, Sub 165 serves this purpose, that DENC's next year of undesignated capacity need is 2023, and that DENC appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

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

Summary of the Comments

In its Initial Statement, DENC acknowledges the Commission's directive in the 2018 Sub 158 Order for the Utilities to "amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended. For other types of QF generation, the Utilities shall recognize a QF's commitment to sell and deliver energy and capacity over a future fixed term as avoiding an undesignated future capacity need beginning only in the first year when there is an avoidable capacity need identified" in each Utilities' respective most recent IRP." DENC states that its standard offer rate schedules have been revised to include these recognitions. DENC Initial Statement at 19.

In its Initial Statement, the Public Staff explains that the avoided capacity credits used to calculate avoided cost rates for swine or poultry QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begins in the first year of a utility's capacity need. The Public Staff states that based on its review the capacity credits and other assumptions incorporated in Duke's and DENC's proposed rates for swine and poultry QFs are reasonable for the determination of Duke's and DENC's avoided capacity credits. Public Staff Initial Statement at 23.

Discussion and Conclusions

In its 2018 Sub 158 Order, the Commission found House Bill 589's and House Bill 329's recent amendments to N.C.G.S. § 62-156(b)(3) to be controlling on the issue of when renewing QFs can be considered to provide capacity value to the Utilities. As discussed above, House Bill 589 provides that "[a] future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] 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 QF resource based upon its availability and reliability of power . . . ," but expressly carves out swine and poultry waste generation from this requirement based upon their designated need to meet REPS compliance. Section 3(a) of House Bill 589 adds to N.C.G.S. § 62-156(b)(3) an additional carve-out for "legacy" hydroelectric QFs of 5 MW or less selling and delivering power under QF PPAs in effect as of July 27, 2017. The Commission noted the further direction provided by Section 3(b) of House Bill 329, which emphasized this distinction by stating that "the exception for hydropower small power producers from limitations on capacity payments established in N.C.G.S. § 62-156(b)(3), as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer." 2018 Sub 158 Order at 50-52.

The Commission found that the clear intent of the General Assembly as shown through House Bill 589 and House Bill 329 is to treat swine and poultry waste QF resources and legacy small hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period. The Commission concluded that it is appropriate for the Utilities to recognize any new commitment by a swine or poultry waste QF generator or a legacy small hydroelectric facility 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, obligating itself to sell and deliver its full energy and capacity output over a future contract term as helping the Utilities avoid a designated future capacity need beginning in the first year of the new QF PPA, pursuant to the N.C.G.S. § 62-156(b)(3), as amended by House Bill 329. *Id*.

Based upon the evidence herein, the Commission concludes that DENC's Schedule 19-FP and Schedule 19-LMP contain language to appropriately reflect the requirements in House Bill 589 and House Bill 329 with respect to capacity payments for a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less with a PPA in effect as of July 27, 2017, and that DENC has therefore complied with this directive from the 2018 Sub 158 Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

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

Summary of the Comments

In its Initial Statement, DENC proposes limited additional provisions for its Schedule 19-FP and Schedule 19-LMP standard contracts and terms and conditions that contemplate the incorporation of energy storage components in QF projects. DENC explains that it is proposing these limited changes at this time, even though it made no such proposals in the Sub 158 Case, as it recognizes the increased likelihood that new QF projects eligible for rates and terms under this biennial proceeding may choose to incorporate an energy storage component in their project designs. DENC notes that it relied on the Commission's approval in the 2018 Sub 158 Order of similar provisions in the Duke standard offer contracts in making these proposals, which are intended to provide guidance to QFs as to how DENC will address projects with energy storage components.

First, for both of its standard contracts, DENC proposes to include at a new Exhibit G, an Energy Storage Device Addendum. DENC explains that the Energy Storage Device Addendum will provide basic information about the storage component of a QF project that proposes to include a battery or other storage component in its design, as well as basic requirements for such storage components that are associated with a QF facility eligible for compensation under these agreements.

Second, DENC proposes to add a provision to Article 7 of its standard offer contracts to provide that any material alteration to a QF facility shall require its prior written consent. As stated in the new provision, “Material Alteration” means a modification to the QF facility that renders the facility description specified in the contract inaccurate in any material sense as determined by the DENC in a commercially reasonable manner, including but not limited to the addition of an Energy Storage Device or a modification that increases the output of the facility. The new provision also states that the repair or replacement of equipment (including solar panels) with like-kind equipment, which does not increase the facility’s capacity or decrease its capacity by more than five percent, shall not be considered a Material Alteration. DENC notes that this provision was approved by the Commission in the 2018 Sub 158 Order for use in Duke’s standard avoided cost contracts, and that DENC is proposing to include it in its standard contracts to provide the same guidance regarding how modifications to QF facilities will be addressed under those agreements. DENC Initial Statement at 20-21.

The Public Staff and Joint Intervenors did not raise any issues with DENC’s proposed changes to its standard offer PPA Terms and Conditions.

Discussion and Conclusions

In the 2018 Sub 158 Order, the Commission discussed proposed changes in the terms and conditions of Duke’s standard offer contracts to address modifications to a QF that seeks to install battery storage or otherwise increase its energy output. The Commission determined that for existing PPAs, material changes to the capacity of the QF should be authorized by the utility, although the evaluation of such change should be treated in a commercially reasonable manner. The Commission agreed that regular maintenance and repair of a facility after a storm, or similar instances that occur on a normal basis, should be treated within the normal course of operations and should not be considered a change that would allow the utility to void the existing PPA. The Commission also found that QFs often complete maintenance on their facilities that could increase the energy or capacity such as replacing existing solar panels with newer panels, or re-paneling, without first obtaining the consent of the utility, and that this type of maintenance should not trigger a default of the existing PPA. The Commission concluded that the newly defined term “Material Alteration” added to Duke’s standard offer contract terms and conditions appropriately defined the instances of what is a material change that requires the utility’s consent, and that without consent may lead to default of an existing PPA. The Commission noted that the term expressly allows replacement of “like-kind” equipment and provides that material alterations will be evaluated by DEC and DEP in a “commercially reasonable manner.” 2018 Sub 158 Order at 129-130.[9]

[9] The 2018 Sub 158 Order also discussed in detail the issue of how to compensate existing QFs for new storage capacity and energy and directed the Utilities to engage in a stakeholder process on that issue and submit a report. The Utilities submitted their report in September 2020, and comments were exchanged on the report. The Commission continues to consider those pleadings along with those received in response to the March 29, 2021, Order Requiring Additional Information (Docket No. E-100, Subs 101 and 158). That issue is separate from the limited proposals that DENC made in this proceeding.

The proposed changes to DENC's standard offer PPAs terms and conditions largely mirror the same proposed changes to Duke's standard offer PPAs in the Sub 158 Case that the Commission approved in the 2018 Sub 158 Order. Specifically, DENC's new proposed provision to Article 7 of its standard offer contracts provides that any material alteration to a QF facility shall require DENC's prior written consent. "Material Alteration" is defined similarly to Duke's definition in the Sub 158 Case and would include the addition of an Energy Storage Device or a modification that increases the output of the facility. The new provision also states that the repair or replacement of equipment (including solar panels) with like-kind equipment, which does not increase the facility's capacity or decrease its capacity by more than five percent, shall not be considered a Material Alteration. No party has raised any concern with this proposed revision to DENC's standard offer contracts.

DENC's Energy Storage Device Addendum will provide DENC and QFs seeking to sell their output to DENC with basic information regarding an ESD that a QF proposes to include in its facility's design. No party has raised any concern with DENC's proposed addition of the Energy Storage Device Addendum as Exhibit G to its standard offer contracts.

Based upon the evidence herein, the Commission concludes that DENC's proposed modifications to its Schedule 19-FP and Schedule 19-LMP standard offer PPAs are reasonable and appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-36

The evidence supporting these findings of fact is found in DENC's Initial Statement, the Sub 158 Additional Issue progress reports filed by DENC and jointly by DEC and DEP and the entire record herein.

Summary of the Comments

DENC, DEC, and DEP have filed six status updates on its progress with regard to the Sub 158 Additional Issues since December of 2020. In the status updates, DEC, DEP and DENC provide updates to the Commission on its progress with discussions with the Public Staff and other stakeholders regarding the Sub 158 Additional Issues.

Discussion and Conclusions

In the 2018 Sub 158 Order, the Commission set forth a number of additional issues (the Sub 158 Additional Issues) to be addressed by the utilities in their initial filings in the next biennial avoided cost proceeding. In the Scheduling Order, the Commission directed the DEC, DEP, and DENC to address those issues in their initial filings in this docket. In addition, the Commission noted that FERC issued Order No. 872 on July 16, 2020, in Docket Nos. RM19-15-000 and AD16-16-000, potentially driving additional changes to PURPA implementation and the determination of avoided cost rates in North Carolina.

In the Continuance Order, the Commission acknowledged the intention of DEC, DEP, and DENC to comply with N.C.G.S. § 62-156(b) by filing "streamlined" 2020 avoided cost filings, and directed that (1) the Utilities address the Sub 158 Additional Issues by November 1, 2021, (2) on or by December 7, 2020, the Utilities file a list of the Sub 158 Additional Issues and a timeline for how they intend to address those issues by November 1, 2021, and (3) the Utilities file updates on their progress on the Sub 158 Additional Issues at least every 45 days afterward until the issues are fully addressed (Progress Update).

Based on the evidence contained herein, the Commission determines that DEC, DEP, and DENC have complied with the requirements of the 2018 Sub 158 Order in filing its Progress Updates on the Sub 158 Additional Issues to date. Consistent with the Continuance Order, DEC, DEP, and DENC shall continue filing its Progress Updates until the issues are fully addressed or until the filing of proposed rates and terms on November 1, 2021, whichever is earlier and, to the extent relevant to DENC, address the Sub 158 Additional Issues in its November 2021 filing. As contemplated by the Scheduling Order, the Commission recognizes that the Utilities may make proposals stemming from FERC Order No. 872 and its potential effect on PURPA implementation in North Carolina, and the Commission will consider any such proposals in the next biennial proceeding as appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting these findings of fact is found in the joint comments filed by WCU and New River, the comments of the Public Staff, and the entire record herein.

In the Joint Comments WCU proposes to continue to pay variable rates based on its wholesale cost of power; New River proposes to continue to offer variable rates based on DEC's Schedule PP, but will not recover the administrative charge to suppliers found in Schedule PP. WCU and New River each further propose to offer long-term fixed price rates approved for DEC's Schedule PP, but again, New River will not recover the administrative charge found in Schedule PP. DEC is WCU's all requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation (Blue Ridge). The Joint Comments note that both WCU and New River will change their power suppliers on January 1, 2022, to Carolina Power Partners (CPP). Joint Comments at 6.

The Public Staff noted that it does not object to the proposed rates for WCU and New River, but recommends if the Commission recommends changes to the DEC rates, those changes should be reflected in the rates of WCU and New River. Public Staff Initial Statement at 30.

For both WCU and New River this is the same approach approved by the Commission in prior proceedings. No parties filed objections to WCU's and New River's proposals.

The Commission therefore concludes, based upon the foregoing and the entire record herein, that WCU's and New River's proposed rates should be approved.

IT IS, THEREFORE, ORDERED as follows:

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

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

3. That DEC, DEP, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding;

4. That DEC's and DEP's Schedule PP and Schedule PP-5, as presented in DEC's and DEP's Supplemental Filing and discussed in this Order, are approved to be offered to QFs eligible for DEC's and DEP's standard offer tariffs;

5. That DEC and DEP shall treat the evaluation of geographical concentrations of back-feeding substations as an "additional issue" to be evaluated prior to the Companies' next avoided cost filing planned for November 2021 and shall discuss these issues with the Public Staff and other stakeholders prior to filing their November 2021 proposed avoided cost rates and shall address in the Companies' initial statements whether it would be appropriate to offer an enhanced rate design that calculates

avoided costs with and without a line loss adder based on the amount of back-feeding at a substation;

6. That DENC shall continue to calculate rates that reflect the elimination of the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

7. That, for the purposes of calculating avoided capacity rates in this proceeding, DEC should use seasonal allocation weightings of 90% for winter and 10% for summer, and DEP should use seasonal allocation weightings of 100% for winter;

8. That DEC, DEP, and DENC 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 to QFs other than those using swine or poultry resources, or hydroelectric resources greater than 5 MW, in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3);

9. That DENC shall continue to use a PAF of 1.07 in its avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

10. That DEC and DEP shall continue to use a PAF of 1.06 in its avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

11. That DEC and DEP shall use a PAF of 2.0 in their avoided cost calculations for hydroelectric QFs 1 MW and less with no storage capability and no other type of generation, and shall address the issue of whether continuation of the 2.0 PAF for hydroelectric QFs 1 MW and less with no storage capability in their initial statements in the next biennial proceeding;

12. That DEC and DEP shall continue to calculate their avoided energy costs using forward natural gas prices for no more than eight years before using the fundamental forecast data for the remainder of the planning period, and DENC shall use its proposed fuel forecasting methodology in calculating avoided energy costs in this proceeding;

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

14. That the integration services charges proposed by DEC ($1.10/MWh) and DEP ($2.39/MWh) shall be used in calculating rates in this proceeding as a decrement to DEC and DEP's avoided energy rates, which shall apply prospectively for the duration of the contract;

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

16. That DENC shall continue to use the seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons that were approved in Sub 158 Case in calculating rates in this proceeding;

17. That DENC's proposed input assumptions to be used in determining its proposed energy rates, including those related to fuel forecasting methodology, fuel hedging activities, and the LMP adjustment shall be used in calculating DENC's rates in this proceeding;

18. That the redispatch charge proposed by DENC ($0.78/MWh) shall be used in calculating DENC's rates in this proceeding as a decrement to DENC's avoided energy rates;

19. That DENC's proposed redispatch charge avoidance protocol is approved;

20. That DENC's proposed modifications to its standard offer contracts to add an energy storage device addendum and material alteration provisions are approved; and

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

ISSUED BY ORDER OF THE COMMISSION.

This the 13th day of August, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Joann R. Snyder, Deputy Clerk