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April 23, 2021

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Joint Proposed Order of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and the Public Staff
Docket No. E-100, Sub 167

Dear Ms. Campbell:

Please find enclosed for filing in the above-referenced docket the Joint Proposed Order of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC and the Public Staff Establishing Standard Rates and Contract Terms for Qualifying Facilities. An electronic copy is being emailed to briefs@ncuc.net.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's, Duke Energy Progress, LLC's and the Public Staff's Joint Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, in Docket No. E-100, Sub 167, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 23rd day of April, 2021.

Kendrick C. Fentress

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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 Rates for Electric Utility Purchases from Qualifying Facilities – 2020	**DUKE ENERGY CAROLINAS, LLC'S DUKE ENERGY PROGRESS, LLC'S, AND THE PUBLIC STAFF OF THE NORTH CAROLINA UTILTIES COMMISSION'S JOINT PROPOSED ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES**

BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under North Carolina General Statute (N.C.G.S., G.S. or Gen. Stat.) § 62-156(b) to establish rates for small power producers as that term is defined in 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 prescribe 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. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards and 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 established in accordance with Section 210 of PURPA.

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. The relevant 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 has implemented Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. 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.

This proceeding also results from the mandate of G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that, "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" as used in G.S. § 62-156 is more restrictive than the PURPA definition of that term, in that G.S. § 62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding other types of renewable resources.

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 or the Companies), 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 in Sub 158. 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 Carolinas Clean Energy Business Alliance (CCEBA, formerly North Carolina Clean Energy Business Alliance); 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 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 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 cost rates and avoided capacity rates based on the methodological guidelines and requirements approved in Docket No. E-100, Sub 158 ("2018 Avoided Cost Proceeding" or "2018 Sub 158 Proceeding") in the Commission's *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued on April 15, 2020 ("*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, QFs providing ancillary services, the Performance Adjustment Factor (PAF), and other more controversial "policy" issues (the 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 address the Sub 158 Additional Issues by November 2, 2021; to file by December 7, 2020 a list of the Sub 158 Additional Issues and a timeline for how they intend to address those issues; and to 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 a

Joint 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 filed its first progress report on the Sub 158 Additional Issues, as did DENC.

On December 22, 2020, WCU and New River jointly filed their proposed avoided cost rates.

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 filed its second progress report on the Sub 158 Additional Issues, as did DENC.

On January 25, 2021, the Public Staff filed its Initial Statement, and SACE, CCEBA and NCSEA (Joint Solar Intervenors) filed the Joint Initial Comments of the Southern

Alliance for Clean Energy, North Carolina Clean Energy Business Alliance, and the North Carolina Sustainable Energy Association.

On February 2, 2021, Duke, DENC, CIGFUR, NCSEA, SACE, CCEBA, and 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 filed its third progress report on the Sub 158 Additional Issues, as did DENC.

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 filed its fourth progress report on the Sub 158 Additional Issues, as did DENC.

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

Various filings were made, and orders were issued which are not discussed in this order but are included in the record of the proceeding.

Based on the foregoing, all of the parties' comments and other filings, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

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

2. It is appropriate for DEC and DEP to be required to offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's 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.

Avoided Capacity Costs

3. The Companies' quantification of their avoided capacity costs using the peaker methodology and their resulting avoided capacity rates are reasonable.

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

5. The Companies' respective first years of avoidable capacity need are appropriate and have been determined consistent with the *2018 Sub 158 Order* and the Companies' 2020 Integrated Resource Plans (IRPs).

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

7. 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 weighting capacity value between winter and summer to calculate DEC's and DEP's avoided capacity rates in this proceeding.

8. 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 QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric (hydro) QFs 1 MW and less until they file their next standard offers and proposed avoided cost rates in the 2021 avoided cost proceeding.

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

<u>Avoided Energy Costs</u>

10. 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.

11. It is appropriate for DEC and DEP to rely on fundamental forecasts for Henry Hub prices developed by private firms IHS and ICF, and the Commission will not require the Companies to supplement and average those forecasts with publicly available Henry Hub price forecasts in EIS's *2020 Annual Energy Outlook*.

12. 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, are reasonable for purposes of calculating avoided costs in this proceeding.

13. Duke should 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 to inform future avoided cost proceedings.

14. The Companies' avoided hedging adjustment is reasonable and appropriate for purposes of this proceeding.

15. The Companies' 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.

16. The Companies' 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.

17. The Commission directs 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.

18. The Companies' solar integration decrement to avoided energy rates, as approved by the Commission in the previous biennial avoided cost proceeding, is reasonable and appropriate for purposes of this proceeding.

Rate Design

19. That 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.

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

Standard Offer Terms and Conditions

21. Duke has agreed to delete a provision in Section 6 of their standard offer PPAs that provided that the Companies 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 the respective Company; with this deletion, the Companies' standard offer PPAs are reasonable and appropriate.

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

The evidence supporting these findings of fact is found in Duke's verified Joint Initial Statement and the exhibits attached thereto (JIS). These findings are essentially jurisdictional and administrative and are not contested.

Summary of the Comments

In the JIS, 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).[1]

Discussion and Conclusions

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

[1] JIS at 1; JIS DEC Exhibit 1 and DEP Exhibit 1.

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.[2] 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.

AVOIDED CAPACITY RATES

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

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

Summary of the Comments

In the JIS, Duke stated that for purposes of this proceeding, the Companies continue to base their 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.[3]

The JIS 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

[2] *See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, issued Nov. 11, 2017 ("*2016 Sub 148 Order*") at 38-39.
[3] JIS, at 13-14.

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.[4] According to the Companies, 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.[5]

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. The Companies stated in their JIS, however, that they intend to use the time between the filing of the JIS and their next avoided cost filing in November 2021 to discuss any potential adjustments to the DEC and DEP CT cost data with the Public Staff.[6]

The Public Staff's Initial Comments provided an analysis of Duke's CT cost assumptions. The Public Staff concluded that the assumptions were reasonable.[7]

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

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[4] *2018 Sub 158 Order*, at 32-33.
[5] *Id.* at 33.
[6] JIS, at 14.
[7] Initial Statement of the Public Staff, at 10-15, 21.

cost assumption for its avoided capacity costs."[8] 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.[9] 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.[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-

[8] Joint Solar Intervenors' Joint Initial Comments, at 10-11; Crossborder Report, at 11.
[9] Crossborder Report, at 11-12.
[10] Joint Solar Intervenors' Joint Initial Comments, at 10.

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.[11]

DEC and DEP'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.[12]

Regarding the Crossborder Report's recommendation that Duke use H-class capital

[11] Duke Reply Comments, at 17-18.
[12] Duke Reply Comments, at 17-19.

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.[13]

<u>Discussion and Conclusions</u>

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 Orde*r), 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

[13] *Id*. at 19.

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 JIS 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 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 rejects 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 OF FINDINGS OF FACT NOS. 5 -6

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

Summary of the Comments

DEC and DEP stated in their JIS 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. Gen. Stat. § 62-156(b)(3). The Companies' 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.[14] 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 the Companies' demonstrated need for future capacity reflected in their respective IRPs. Specifically, the Companies' 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,

[14] DEP 2020 Biennial IRP, at 112-114; DEC 2020 Biennial IRP, at 111-113.

pursuant to N.C. Gen. Stat. § 62-156(b)(3).[15] As recently amended by Session Law 2019-132, N.C. Gen. Stat. § 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. Gen. Stat. § 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 that 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

[15] *2018 Sub 158 Order*, at 135 (Ordering ¶ 18).

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.

<u>Discussion and Conclusions</u>

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. 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 the Companies' 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, the Companies have 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 the Companies' first year of need and proposed avoided capacity rates are reasonable, appropriate, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the Companies' JIS and the Initial Comments of the Public Staff.

In their JIS, the Companies 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 its 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.[16]

The Companies further reported in their JIS that, for purposes of this proceeding, they did not update their seasonal allocations based upon their recently filed 2020 Resource

Adequacy Studies, which are being reviewed by the Commission and parties to the 2020 IRP proceeding, Docket No. E-100, Sub 165. The Companies' 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.[17]

No party objected to the Companies' 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 weighting capacity value 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. 8-9

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

<u>Summary of the Comments</u>

The Companies' JIS 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.[18] The *2018 Sub 158*

[17] Initial Statement of the Public Staff, at 21-22.
[18] *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

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 the Companies' 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.[19] In accepting the Companies' 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.

The Companies have 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, the Companies did not recommend any additional adjustments to the Commission-approved EA metric to compute the PAF. They have followed the same methodology of compiling five years of historic equivalent availability data for the entire fleet during the Companies' critical peak season months of January, February, July, and August. This critical peak season reflects the high load periods in which the Companies typically do 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. The

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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).

[19] *2018 Sub 158 Order*, at 41.

Companies also stated in their JIS that they 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.[20] In 2014, the Hydro Stipulation provided that the Companies 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.[21] As the Commission recognized in the *2018 Sub 158 Order*[22] and in the prior *2016 Sub 148 Order*[23], 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 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.[24] The *2018 Sub 158 Order* therefore directed the Companies to address whether the special 2.0 PAF capacity multiplier should continue for the standard offer in this biennial proceeding.[25]

Consistent with the Hydro Stipulation, the Companies have included a 2.0 PAF in

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[20] 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. Gen. Stat. § 62-3(27a).

[21] Hydro Stipulation, at ¶¶ 3(a) and 4.

[22] *2018 Sub 158 Order*, at 42.

[23] *Id.*, at 39.

[24] *See* G.S.. § 62-156(b)(3); (c).

[25] *2018 Sub 158 Order,* at 42.

DEC's and DEP's standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW. The Companies 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.[26]

Additionally, the Companies explained in their JIS that, in the 2018 Sub 158 Proceedings, they 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.[27] In the letter, the Companies stated their intent to honor their commitment under the terms of the Hydro Stipulation to apply a 2.0 PAF capacity 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 the Companies' standard offer due to their contract capacity in excess of 1 MW and that were now eligible to enter into negotiated PPAs with the Companies pursuant to N.C. Gen. Stat.§ 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. The Companies' commitment was expressly subject to any future adverse regulatory decisions by the Commission. The Companies make the same commitment

[26] Hydro Stipulation, at ¶ 3.

[27] *See* DEC and DEP's Joint Letter to Small Hydro Group, Docket No. E-100, Sub 158 (filed July 12, 2019).

here, again subject to the any adverse regulatory decisions by the Commission that they 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 the Companies' PAF.[28] 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 the Companies' next initial statement.

Discussion and Conclusions

Based on the foregoing, the Commission finds and concludes that the Companies' 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.[29] No party contested the Companies' 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

[28] Initial Comments of the Public Staff at 15-16.
[29] 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.

in its JIS, 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. Gen. Stat. § 62-156(b)(3); (c). Under these circumstances, and based on the record in this proceeding, the Commission finds that the Companies' proposal that, with the expiration of the Hydro Stipulation, they are no longer required to offer the 2.0 PAF to run-of-river hydro QFs greater than 1 MW to be reasonable and appropriate. The Commission directs the Companies to 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 the Companies and the Public Staff to address the appropriateness of using the EUOR metric in the next avoided cost proceeding. The Companies' 45-day status updates, filed in this docket, reflect that discussions between the Public Staff and the Companies 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.

AVOIDED ENERGY RATES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence supporting these findings of fact are found in the JIS and the entire record herein.

Summary of the Comments

In their JIS, Duke 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.[30] 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 the Companies' 2020 IRPs to streamline this proceeding.[31]

In its Initial Statement, the Public Staff finds the Companies' 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*.[32]

The Joint Solar Intervenors challenged two aspects of the Companies' approach to fundamental forecasts. First, the Joint Solar Intervenors argued for reducing the Companies' 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[33] and a fundamental forecast-only approach in years 9-10.[34] In support of this proposal, the Joint Solar Intervenors summarized arguments made by the Public Staff and individual intervenors now filing comments as the Joint Solar Intervenors in the 2018 Sub 158

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[30] JIS, at 22.
[31] *Id.*
[32] Initial Statement of the Public Staff, at 40.
[33] The Crossborder Energy Report, attached to the Solar Intervenors' Initial Comments as Exhibit A, Intervenors 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.
[34] Joint Solar Intervenors Initial Comments, at 15; Crossborder Energy Report at 26.

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 the Companies, which rely entirely on forward prices for terms greater than six years.[35] Similarly in the 2018 Sub 158 Proceeding, SACE recommended the Companies use no more than two to three years of forward market data followed by a transition to fundamental forecast pricing, and NCSEA recommended just two years of forward market data before transitioning to an average of a set of recent fundamental forecasts.[36]

According to the Joint Solar Intervenors, using eight years of forward market data raises concerns about the transparency, practical applicability, and liquidity of the Companies' price data.[37] The Crossborder Energy Report asserted 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.[38] 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.[39]

Second, the Joint Solar Intervenors criticized the Companies' use of fundamental forecasts for Henry Hub prices developed by private firms IHS and ICF, because they omit public data.[40] Pointing to the Commission's mention in the *2018 Sub 158 Order* that transparency is an important element of combustion turbine price estimates for an avoided

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[35] *Id.* at 14.
[36] *Id.*
[37] *Id.* at 15; Crossborder Energy Report at 2.
[38] Crossborder Energy Report at 3.
[39] *Id.* at 4.
[40] Joint Solar Intervenors Initial Comments, at 10.

cost filing, the Joint Solar Intervenors argued that the Companies' use of private forecasts should be supplemented and averaged with the EIA *2020 Annual Energy Outlook* public forecast of Henry Hub prices.[41] According to the Joint Solar Intervenors, the addition of a public Henry Hub forecast would serve as a check on the Companies' private forecast, add transparency, and provide the perspective of a second prominent forecaster.[42]

In their Reply Comments, the Companies again noted that they followed the Commission's *2018 Sub 158 Order* directive for the forecasting methodology used in the instant proceeding.[43] In light of the streamlined nature of the proceeding, the Companies refrained from arguing for the longer-term use of forward market pricing used in their most recent IRPs. For the same reason, the Companies argued that the Commission should reject the Joint Solar Intervenors' recommendation that the Companies 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.[44]

The Companies likewise argued that the Commission should reject the Joint Solar Intervenors' recommendation that the Companies supplement and average the long-term natural gas commodity price fundamental forecast utilized in their 2020 IRPs with a publicly available Henry Hub forecast, such as the EIA 2020 Annual Energy Outlook forecast of Henry Hub prices.[45] According to the Companies, their use of Henry Hub prices developed by IHS Markit adhered to the Commission's directive in the *2020 Procedural*

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[41] *Id.*; Crossborder Energy Report at 2.
[42] Joint Solar Intervenors Initial Comments. at 11.
[43] Duke's Reply Comments at 8.
[44] *Id.*
[45] *Id.* at 9.

Order to rely upon updated inputs consistent with the methodological guidelines approved in the *2018 Sub 158 Order*.[46] 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 the Companies' 2020 IRPs relied exclusively on the IHS fundamental forecast while Dominion relies upon ICF.[47]

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.[48] 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*.[49] The Public Staff reserved the right to argue for reliance upon fewer years of such data in a future proceeding.[50]

The Public Staff's Reply Comments also indicated agreement with the Companies regarding the Joint Solar Intervenors' proposal that the Companies 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 the Companies' fundamental forecast is inappropriate.[51] According to the Public Staff, because the Companies'

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[46] *Id.* at 10.
[47] *Id.* at 9, fn. 27.
[48] Public Staff Reply Comments, at 4.
[49] *Id.*
[50] *Id.* at 5.
[51] *Id.* at 2.

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.[52]

<u>Discussion and Conclusions</u>

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 the Companies 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 similarly unpersuaded 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.

Based upon the foregoing and the entire record herein, the Commission finds that

[52] *Id.* at 3.

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. The Commission likewise finds that no change is needed to DEC's and DEP's approach of relying on fundamental forecasts for Henry Hub prices, as developed by IHS, which is consistent with Duke's 2020 IRPs. The Commission will not require the Companies to average those forecasts with EIA's *2020 Annual Energy Outlook* as recommended by the Joint Solar Intervenors.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

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

Summary of the Comments

Duke's JIS 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.[53] This includes natural gas transportation and pricing assumptions during the ten-year forecasted avoided cost rate period that influenced natural gas pricing.[54]

The Initial Comments of the Public Staff raised an issue of concern relating to the Duke's reliance upon forecasted natural gas pricing utilizing the Appalachian basin's lower

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[53] 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.
[54] JIS, at 10.

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.[55]

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.[56] 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 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.[57] 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

[55] Initial Statement of the Public Staff, at 42.
[56] *Id*. at 43-44.
[57] *Id*. at 44.

Appalachian basin is constrained by the lack of available takeaway pipeline capacity to move it to the Southeast markets.[58]

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.[59] The Public Staff stated that Duke should utilize other practical options until a firm supply from the Appalachian basin is available to meet the Company's demands.[60] The Public Staff recommended that Duke in its 2021 avoided cost filing 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.[61]

The Joint Solar Intervenors also raised concerns about the Companies' 2020 IRP gas transportation assumptions used in developing avoided costs in their comments. These parties criticized the Companies' reliance on the lower cost Dominion South hub natural

[58] *Id*. at 45.
[59] *Id.* at 46.
[60] *Id.* at 45.
[61] *Id*. at 46.

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.[62] 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,[63] and 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."[64]

In their Reply Comments, the Companies 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 the Companies' 2020 IRP base planning assumptions.[65] They also agreed with the Public Staff's recommendation for the Companies 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.[66] As circumstances evolve regarding the status of additional interstate pipeline capacity into the Carolinas, the

[62] Joint Solar Intervenors Initial Comments, at 8-9.
[63] *Id*. at 9.
[64] *Id.*
[65] Joint Reply Comments, at 3.
[66] *Id*. at 3.

Companies responded that they are committed to updating the Commission on this topic in either their reply comments in the current 2020 IRP proceeding and/or 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.[67]

In response to the Public Staff's further recommendation for the Companies 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.[68] The Companies also noted that the 2021 IRP is an update that will be based on information that exists this summer as the IRP update is being prepared. 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

[67] Duke's Reply Comments, at 3-4.
[68] *Id*. at 4

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.[69]

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.[70]

Duke also noted that the Joint Solar Intervenors' assertion that the MVP "will not be constructed" was wholly unsupported.[71] Duke noted that the Public Staff made no such definitive conclusion,[72] and that Duke 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 the Commission might assume. Duke explained that it has utilized conservative planning assumptions that the

[69] Duke Reply Comments, at 5.
[70] Duke Reply Comments, at 6, *citing* Initial Statement of the Public Staff, at 41.
[71] Joint Solar Intervenors' Initial Comments, at 9.
[72] Initial Statement of the Public Staff, at 44 (. . . MVP "is now delayed and scheduled to enter service in late 2022.").

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 <u>are the marginal resource</u>, and avoided energy costs will be less than if the natural gas was sourced from Transco Zone 4 or 5.[73] 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 described 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.[74]

<u>Discussion and conclusions</u>

[73] Duke Reply Comments, at 6, *citing* Public Staff Initial Statement, at 41 (emphasis added).
[74] *Id.* at 7.

Longer term resource planning assumptions can have a significant impact on administratively-determined projections of electric public utilities' future avoided capacity and energy costs. North Carolina's traditional approach to calculating fixed-price avoided costs for future periods is necessarily based on models, projections, and assumptions that are subject to increasing uncertainty farther into the future. Although such longer-term uncertainty is largely unavoidable where the QF elects to fix avoided cost at the time the obligates itself to deliver power for a future term versus at the time of delivery under 18 C.F.R. 292.304(d), the Commission has attempted to reduce the uncertainty by emphasizing in recent proceedings the significant interplay between the IRP and avoided cost proceedings and the need for consistency between the studies, models, and assumptions used in these proceedings. The Commission reiterated its expectation less than a year ago in Docket No. E-100, Sub 158 that the same models and analyses should be utilized in both the IRP and avoided cost proceedings to achieve this consistency.[75]

As an initial matter, the Commission rejects 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, the Companies have 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.

Turning now to the reasonableness of Duke's natural gas forecasting transportation assumptions underlying its 2020 IRPs, the Commission finds the Public Staff's stated

[75] *Order Denying Motion for Reconsideration*, at 27, Docket No. E-100, Sub 158 (July 21, 2020).

concerns as well as Duke's responses to be reasonable and appropriate for purposes of this 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 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.

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 in either their reply comments in the current 2020 IRP proceeding and/or in the 2021 IRP update, as appropriate. The Commission also finds that it may be appropriate for Duke, with input from Public Staff, as appropriate, to develop 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, if warranted by continuing regulatory uncertainty around new natural gas pipelines into North Carolina. The Commission acknowledges that this issue has also arisen in the 2020 IRP proceeding. As the IRP proceeding is ongoing, it would be premature for the Commission to decide if and when Duke should develop such an alternative IRP portfolio in this avoided cost proceeding, and will instead address this matter in the IRP docket after considering all evidence presented therein.

Finally, the Commission rejects the Joint Solar Intervenors' argument that Duke must include capacity reservation costs in calculating avoided costs, as not accurate or 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 these proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

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

Summary of the Comments

In its JIS, the Companies explained that, for purposes of this streamlined 2020 standard offer avoided cost rate proceeding, they developed their respective avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the 2018 Sub 158 proceeding. In support of their position, the Companies' JIS recounted that, in the 2018 Sub 158 proceeding, they argued that paying QFs an avoided fuel hedging value for their must-purchase power under 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.[76] After discussing this determination with the Public Staff, the Companies explained in their 2018 Sub 158 compliance filing that they had updated their avoided energy cost rate calculations to include the same hedge value approved for DENC in its Sub 158 avoided cost rates.[77]

In their initial comments, the Joint Solar Intervenors questioned whether the Companies had complied with the Commission's *2018 Sub 158 Order*, arguing that Companies 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 G.S. § 62-156, which states that:

> the expected costs of the additional or generating capacity that could be

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[76] *2018 Sub 158 Order*, at 62.

[77] *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Compliance Filing, Docket No. E-100, Sub 158 (Filed Nov. 1, 2019). The Companies reaffirmed their November 1, 2019 compliance filings after the Commission issued its *2018 Sub 158 Order* in April 2020.

> 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 a 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 the Companies 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 the Companies have 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 rejects 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, the Companies deliberately included the avoided hedging costs consistently with the *2018 Sub 158 Order*, although they have acknowledged that they do not agree with their inclusion. Thus, the Commission concludes that for purposes of this streamlined proceeding, the Companies' 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 FINDING OF FACT NO. 16

The evidence supporting this finding of fact is found in the JIS, the Initial Statement of the Public Staff, the Joint Initial Comments of the Joint Solar Intervenors, the Reply Comments of the Public Staff 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, 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 Joint Solar Intervenors, however, 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 the Companies' Emission Allowance Forecasts, which include assumed costs for NO_x and SO2 through year 2044, but do not include cost allowance assumptions for carbon. Additionally, the Joint Solar Intervenors refer to Duke Energy'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 the Companies' long-term corporate commitment, the avoided energy cost modeling in this avoided cost proceeding should use DEC/DEP's IRPs' 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 insist 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.[78] Moreover, the Joint Solar Intervenors again referred to the Companies' own carbon reduction goals to justify including a carbon emissions cost in calculating avoided cost rates.

In their Reply Comments, the Companies agreed with the Public Staff that carbon

[78] Joint Solar Intervenors Reply Comments at 3.

emissions should not be included in avoided energy costs. In addition to the Commission precedent supporting this conclusion cited by the Public Staff, the Companies cited the FERC's determination that only real costs that are actually 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. The Companies' 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.

Discussion and Conclusions

The Commission agrees with the Public Staff and the Companies that the Companies' calculation of avoided energy rates, using the Companies' 2020 IRP least cost "Portfolio A Base without Carbon Policy" is appropriate. As the Commission has previously concluded, North Carolina ratepayers should not bear speculative or uncertain costs that are not avoided through the purchase of power from a QF through the avoided cost rates that they ultimately pay. Instead, the Companies should base their avoided costs on "known and verifiable" costs, which do not include the costs of carbon emissions. Similarly, the FERC has clarified that if environmental costs are real costs that would be incurred by utilities, they may be accounted for in a determination of avoided cost rates. *Cal. Pub. Utility Comm'n*., 132 FERC ¶ 61,047, 61, 267-68 (July 15, 2010). Under this precedent, the Companies have appropriately calculated avoided energy costs that do not include unknown and unverifiable emissions costs. As the Public Staff noted that, unlike

DENC, neither DEC nor DEP are under any known or verifiable legal or regulatory requirement, which would set a mandatory price on carbon emissions applicable to the Companies. Although the Joint Solar Intervenors are correct that the Companies' IRPs present multiple alternative long-term planning pathways or scenarios that forecast carbon emission costs in the future, these planning scenarios do not mean that these forecasted carbon emission costs are known and verifiable for purposes of including them in avoided cost calculations and, ultimately, passing them along to ratepayers.

Moreover, the Commission does not agree with the Joint Solar Intervenors' assertions that because carbon emission costs now are closer to being "known and verifiable" than they were in Docket No. E-100, Sub 140, the Companies should include them in their avoided cost calculation. They have provided no justification for the Commission to depart from its prior determinations, which are consistent with the FERC's determinations, that unknown and speculative costs should not be included when calculating avoided cost rates that will be passed along to customers. A review of the Commission's conclusion on this issue in 2014 demonstrates that the circumstances in that proceeding do not differ so very much from the economic and regulatory circumstances in this avoided cost proceeding with respect to this issue:

> While the EPA has proposed to regulate CO_2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time. The end result of the proposed regulations is speculative at best, and, as Public Staff Hinton noted, the Commission has previously concluded that "[q]uantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." If and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they

become known and verifiable.

Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, issued Dec. 31, 2014, at 42-44. In sum, the Commission concludes that the Joint Solar Intervenors have not demonstrated that the time is yet ripe for the Commission to depart from its prior conclusions on this matter.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

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

Summary of the Comments

The Companies' JIS explained that their 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 the Companies, 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.

The Companies recounted in their JIS that, in the 2016 Sub 148 proceeding, Dominion filed a study showing that surging distribution interconnected QF solar development was causing power backflow on substations throughout Dominion's North Carolina service territory. Relying upon the Dominion 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 Dominion distribution system, and approved Dominion'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, the Companies undertook a similar line loss study. The Companies determined, however, 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 the Companies' 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."[79] Additionally, the Commission found that the Companies' 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. Gen. § 62-156(c) by taking into consideration the individual characteristics of the QF.[80]

Consistent with this Commission direction,[81] the Companies reported in their JIS that they 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. The Companies' analysis showed that, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding

[79] *2018 Sub 158 Order*, at 36.

[80] *Id*.

[81] This *2020 Scheduling Order* specifically directed the Companies to analyze the "extent of backflow at substations." *2020 Scheduling Order,* at 1.

into the transmission system due to distribution-connected generation. The Companies' 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.[82] The Companies' JIS 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, the Companies 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.[83]

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

[82] 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. Dominion Energy North Carolina Initial Statements and Exhibits, at 35, Docket No. E-100, Sub 158 (filed Nov. 1, 2018).

[83] *See* N.C. Gen. Stat. § 62-156(c) (directing that rates for purchases account for the individual characteristics of the QF).

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 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, the Companies agreed with the Public Staff's recommendations and to work with the Public Staff on this issue prior to the November 2021 filing. The Companies 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 the Companies' proposed distribution line loss adder included in their 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 the Companies to discuss these issues with the Public Staff prior to filing their November 2021 proposed avoided cost rates and 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.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is found in the Companies' JIS.

Summary of the Evidence

The Companies' JIS outlined the background of systems integration services charge from previous biennial avoided cost proceedings. In the 2018 Sub 158 proceeding, the Companies proposed an integration services charge specific to integrating new intermittent solar energy generation into the Companies' systems. The Companies 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. The Companies' 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.

The Companies explained in their JIS that, after reviewing the results of the Astrapé Study in the 2018 Sub 158 proceeding, they 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 the Companies 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 and were based only on the existing plus HB 589 transition solar capacity in DEP (2,950 MW) and DEC (840 MW).[84]

The Companies' JIS 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.[85] 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 the Companies to undertake an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings about the Companies' ancillary service costs associated with intermittent, non-dispatchable generation.[86]

With that background, the Companies' JIS provided that, for purposes of this

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[84] Incremental integration costs identified in the Astrapé Study for solar above the HB 589 mandated procurement requirements would have imposed significantly higher incremental integration cost but would not have needed to be updated as each vintage of solar QF would have been assigned their full incremental integration cost at the time of contracting. The Companies did not recommend this approach in the interest of balancing the impact on new QFs versus existing QFs.

[85] *Id.*

[86] *Id*.

avoided cost proceeding, the Companies have incorporated the same integration services charges into their 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. The Companies stated that they 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. The Companies further reported that they are 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. The Companies also committed to include a report detailing the committee's feedback in their initial filing in the next biennial avoided cost proceeding.

<u>Discussion and Conclusions</u>

For purposes of this proceeding, the Commission approves the solar integration decrement to avoided energy rates as proposed by the Companies. No party disputed their inclusion for purposes of this proceeding. As the Companies note, 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, the Companies 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. 19-20

The evidence supporting these findings of fact is found in the JIS, Duke's Reply

Comments, the Initial Statement of the Public Staff, Joint Solar Intervenors' Initial Comments, and DEC & DEP's Supplemental Filing.

Summary of the Comments

Duke's JIS 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.[87] 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 the Companies' initial proposal was "appropriate and beneficial to North Carolina ratepayers."[88] 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[89]). The JIS explains that the *2018 Sub 158 Order* approved the Sub 158 Rate Design Stipulation and

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[87] JIS, at 29.
[88] JIS, at 29-30 (citing Initial Statements of the Public Staff, at 48, 54, Docket No. E-100, Sub 158 (filed Feb. 12, 2019)).
[89] Agreement and Stipulation of Partial Settlement, Docket No. E-100, Sub 158 (filed April 18, 2019).

found the rate designs included therein to be appropriate for use in calculating DEC and DEP's avoided energy and capacity rates.

The JIS 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.[90] 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. The JIS 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.[91]

The Initial Statement of the Public Staff identified that the avoided energy rates filed by DEC and DEP "exhibited counterintuitive behavior in some schedules" when reviewing Duke's rate design.[92] 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

[90] JIS at 30-32.
[91] *Id*. at 32-33.
[92] Initial Statement of the Public Staff at 47.

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.[93]

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.[94] The Initial Statement of the Public Staff, 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.[95]

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."[96] The Joint Solar Intervenors' Initial Comments contended that this result is "apparently" due to old production cost modeling techniques,

[93] *Id.*
[94] *Id.*
[95] *Id.*
[96] Joint Solar Intervenors Initial Comments at 9.

and requested that the Commission not rely on these "erroneous" results.[97]

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.[98]

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, and therefore requested that the Commission approve the DEC and DEP Supplemental Filing and rate designs included therein.[99]

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

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[97] *Id.* at 9-10.
[98] Duke Supplemental Filing, at 2.
[99] Duke Reply Comments, at 15-16.

the treatment of start costs in production cost modeling with Duke and other parties for further consideration in the November 2021 filing.[100]

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."[101]

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 calculation 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

[100] Public Staff Reply Comments, at 5-6.
[101] Joint Solar Intervenors Reply Comments, at 6.

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, and additionally committed to further discuss this issue with the Public Staff and address any resulting rate design changes in its upcoming 2021 avoided cost finding.[102]

For purposes of this streamlined proceeding, the Commission approves DEC and

[102] Duke Reply Comments, at 15.

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, and 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 will, however, consistent with Duke's commitment made in the DEC and DEP Supplemental Filing, require that Duke and the Public Staff 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. 21

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

In their JIS, Duke also amended Section 6 of the Standard Offer PPA to provide that the Companies 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 the Companies. The Companies 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. The Companies 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 the Companies revise their 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 the Companies 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 the Companies' standard offer contracts to require the forecasted hourly production rates from QFs only from facilities greater than 1 MW in capacity.

IT IS, THEREFORE, ORDERED as follows:

1. 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.

2. 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 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.

3. That the Commission will review and determine whether DEC and DEP should be required to develop 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 in Docket No. E-100, Sub 165.

4. 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.

5. That DEC and DEP shall continue to calculate avoided capacity costs using the Peaker Method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need, consistent with N.C.G.S. § 62-156(b)(3).

6. That DEC and DEP shall use a PAF of 1.06 in their respective avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no

other type of generation.

7. 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 avoided cost proceeding.

8. 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.

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

10. 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, consistent with the conclusions reached in this Order.

11. 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 ___ day of ____ 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk