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July 1, 2022

VIA Electronic Filing

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

Re: Docket No. E-100, Sub 175
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021

Dear Ms. Dunston:

Enclosed for filing in the above-captioned proceeding on behalf of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or the "Company"), is the Company's *Proposed Order*.

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

Very truly yours,

/s/Andrea R. Kells

ARK:kjg

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	)))	PROPOSED ORDER OF DOMINION ENERGY NORTH CAROLINA

BY THE COMMISSION: This is the 2021 biennial proceeding held by the North Carolina Utilities Commission (Commission) pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegate responsibilities in that regard to this Commission. This proceeding is also held pursuant to N.C.G.S. § 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers, as defined in N.C. Gen. Stat. § 62-3(27a).

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

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

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

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

With respect to electric utilities subject to state regulation, FERC delegated the implementation of these rules to the state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings as required by N.C.G.S. § 62-156. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

As noted above, this proceeding also results from the mandate of N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The General Assembly amended N.C.G.S. § 62-156 in 2017 through enactment of Session Law 2017-192 (House Bill 589) and again in 2019 through enactment of Session Law 2019-132 (House Bill 329).

On August 13, 2021, the Commission issued in this docket an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing (Scheduling Order). Pursuant to the Scheduling Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke Energy), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC, and together with DEC and DEP, the Utilities), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (New River) were made parties to the proceeding.

In the Scheduling Order, the Commission explained that in its April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in the 2018 proceeding (Docket No. E-100, Sub 158, hereinafter the Sub 158 Avoided Cost Case), the Commission required the Utilities to address a number of additional issues (Sub 158 Additional Issues) in their initial filings in the 2020 proceeding (Docket No. E-100, Sub 167, hereinafter the Sub 167 Avoided Cost Case). The Sub 158 Additional Issues included:

- Real-time pricing tariffs;

- Cost increments and decrements to the publicly available combustion turbine cost estimates;

- The use of other reliability indices, specifically the Equivalent Unplanned Outage Rate (EUOR) metric, to support development of the performance adjustment factor (PAF);

- The extent of backflow at substations;

- The potential for qualifying facilities to provide ancillary services and appropriate compensation; and

- The results of an independent technical review of the Astrape Study solar integration services (SISC) methodology.

On October 30, 2020, in the Sub 167 Avoided Cost Case, the Commission granted a continuance for the Utilities to address the Sub 158 Additional Issues by no later than November 1, 2021, in this 2021 biennial proceeding (Sub 175 Avoided Cost Case).

The Scheduling Order stated that given the recurring nature of the issues and decisions that have traditionally arisen in these proceedings, the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules rather than a full evidentiary hearing. The Commission established February 9, 2022, as the deadline for interventions by interested persons and also for initial comments and exhibits on the Utilities' filings; March 11, 2022, as the deadline for reply comments; and the deadlines for additional comments, additional reply comments and proposed orders to be established by further order of the Commission. The Scheduling Order also scheduled a public hearing for February 22, 2022, 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 to the Commission 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

Carolina's Clean Energy Business Alliance (CCEBA), the Southern Alliance for Clean Energy (SACE), the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR), and Appalachian Voices. Participation of the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On November 1, 2021, DENC filed its Initial Statement and Exhibits (DENC Initial Statement), along with DENC's avoided cost information as required by 18 C.F.R § 292.302(b)(1)-(3). DENC subsequently filed corrected standard avoided capacity rates on January 7, 2022.

On December 16, 2021, WCU and New River filed a Notice of Appearance and Motion for Extension of Time to file their initial statements and exhibits, which was granted by Commission Order issued on December 20, 2021.

On December 21, 2021, WCU and New River filed their Joint Comments, Proposed Rates and Contracts.

On February 2, 2022, NCSEA, CCEBA, and SACE filed a Joint Motion for Extension of Time through and including February 24, 2022, for the parties to file their initial comments and through and including March 28, 2022, for parties to file their reply comments, which was granted by Commission order issued on February 7, 2022.

On February 14, 2022, DENC filed Proof of Publication of the notice of hearing. On February 21, 2022, Duke Energy filed affidavits of publication of notice.

On February 22, 2022, the public witness hearing portion of the proceeding was held as scheduled, and no witnesses appeared to testify.

On February 24, 2022, the Public Staff, SACE, and Appalachian Voices filed Initial Comments and CCEBA and NCSEA (Joint Intervenors) filed Joint Initial Comments.

On March 24, 2022, Duke Energy filed a Joint Motion for Extension of Time to file reply comments through and including April 1, 2022, which was granted by Commission order on March 25, 2022.

On March 31, 2022, SACE filed Reply Comments.

On April 1, 2022, reply comments were filed by DENC, Duke Energy, the Public Staff, New River, and the Joint Intervenors. NCSEA filed additional reply comments on Duke Energy's net excess energy credit rate revision (NEEC) proposal.

On June 29, 2022, DENC filed a letter and exhibits presenting modifications to its updated LEO forms.

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

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

FINDINGS OF FACT

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

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

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

4. DENC's proposal to continue to use the energy and capacity rate design approved in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on August 13, 2021, in Docket No. E-100, Sub 167 (Sub 167 Order) is reasonable and appropriate for purposes of this proceeding.

5. DENC's proposal to continue to use seasonal allocation weightings of 45% for summer, 40% for winter, and 15% for shoulder seasons that were approved in the Sub 167 Order is reasonable and appropriate for purposes of this proceeding.

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

7. DENC's proposal to charge $1.87/MWh to recover costs incurred to integrate intermittent, non-dispatchable QFs in its service territory is reasonable and appropriate for purposes of this proceeding.

8. It is reasonable and appropriate for DENC to maintain its proposed re-dispatch charge (RDC) avoidance protocol as approved in the Sub 167 Order.

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

10. The installed cost of a CT used by DENC that uses cost increments and decrements as directed in the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued on April 15, 2020, in Docket No. E-100, Sub 158 (Sub 158 Order), and based on the consensus reached with Duke Energy, is appropriate for use in calculating avoided capacity costs in this proceeding.

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

12. It is reasonable and appropriate for DENC to use a 5-year average Weighted Equivalent Unforced Outage Factor (WEUOF) to determine the Performance Adjustment Factor (PAF) in its avoided cost calculations for all QFs. DENC's calculation of a PAF of 1.07 for this proceeding is reasonable and appropriate.

13. DENC has appropriately identified in its 2021 Integrated Resource Plan Update (IRP Update) its first avoidable capacity need as 2026, and relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

14. DENC's proposed process for determining how and the point in time at which a facility secures eligibility for a specific avoided cost rate or methodology when adding energy storage is reasonable and appropriate, and DENC has otherwise satisfied the directives of the Commission's August 17, 2021 Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations issued in Docket No. E-100, Sub 158 (Retrofit Storage Order).

15. DENC's proposed Retrofit Storage Legally Enforceable Obligation (LEO) Forms are reasonable and appropriate for use by QFs seeking to secure eligibility for a specific avoided cost rate or methodology when adding storage to an existing facility.

16. DENC has reasonably and appropriately revised its LEO Forms to implement FERC Order No. 872.

17. No further action or analysis by or relating to DENC is needed at this time with regard to the potential for QFs to provide and receive compensation for ancillary services.

18. DENC has adequately addressed the applicable Sub 158 Additional Issues in this proceeding.

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

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

Summary of the Evidence

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

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

In its Initial Statement the Public Staff reviews and summarizes DENC's proposed rate schedules, including the methods for calculation of rates under Schedule 19-LMP.

Discussion and Conclusions

In the Sub 148 Order, the Commission approved changes to the standard offer term and eligibility thresholds as a result of changes in the marketplace for QF-supplied power in North Carolina and as a result of the amendments to N.C.G.S. § 62-156 enacted through House Bill 589. The Commission noted that these changes were appropriate to reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs. Sub 148 Order at 38.

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

In the Sub 158 Order and the Sub 167 Order, the Commission found it appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity. The standard offer term and eligibility thresholds for standard offer avoided cost rates and terms were not issues identified to be addressed in this proceeding and no party raised objections to the approval of the Utilities' proposed schedules with respect to these issues. Therefore, the Commission concludes that it is appropriate to require the Utilities to continue to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell 1 MW or less capacity.

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

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

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

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

Summary of the Evidence

In its Initial Statement, DENC describes the methodology it used for purposes of calculating energy rates. That rate design, which was approved in the Sub 167 Order, comprises nine pricing periods: summer off-peak; summer on-peak; summer premium peak; winter off-peak; winter on-peak am; winter on-peak pm; winter premium peak; and shoulder on- and off-peak periods. DENC has maintained these pricing periods in calculating avoided energy cost rates for purposes of this proceeding. DENC has continued to allocate its CT costs using the seasonal allocation weighting approved in the Sub 167 Order of 45% summer, 40% winter, and 15% shoulder. (DENC Initial Statement at 4-5, 22.)

In its Initial Statement, the Public Staff states that DENC's method for calculating avoided energy costs for Schedule 19-FP is largely consistent with methods employed in the 2020 Avoided Cost Case and does not raise any concerns with maintaining this rate design. (Public Staff Initial Statement at 47-48.) The Public Staff also acknowledges that DENC's weighting capacity value between seasons remains consistent with the Sub 158 Order and does not raise any concerns with maintaining this weighting. (Id. at 39.)

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

Discussion and Conclusions

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

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed rate design, unchanged from the rate design approved in the Sub 158 and Sub 167 Orders, is appropriate to continue using to calculate rates for DENC's nine pricing periods for purposes of this proceeding. No party has raised any concern with DENC's rate design, which continues to provide QFs with granular price signals to incentivize QFs to better match DENC's generation needs. The Commission further concludes that DENC's continued use of the seasonal allocation weightings of 45% for summer, 40% for winter, and 15%

for shoulder seasons, also unchanged from the seasonal allocations approved in the Sub 158 and Sub 167 Orders and without objection in this proceeding, are appropriate for use in weighting capacity value between seasons for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

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

Summary of the Evidence

DENC describes in its Initial Statement the methodology it used to calculate avoided energy costs under its proposed Schedule 19-FP. DENC used the PLEXOS model for the calculation and used its generation expansion plan "B" from its most recent IRP Updated filed on September 1, 2021, in Docket No. E-100, Sub 165 (2021 IRP Update) as the starting point for its analysis as the "without QF case." DENC ran a second PLEXOS case, the "with QF" case, with an additional QF resource. DENC explains that the input assumptions in this modeling process falls into three categories: (1) assumptions regarding generating unit operating characteristics, (2) purchase power assumptions and non-utility generator sources, and (3) the variable (or dispatch) costs of generating units (including fuel, variable O&M, and emission and start-up costs). DENC notes that, consistent with the Sub 167 Order, the third category does include RGGI costs but does not include federal carbon costs. With these inputs, the resulting PLEXOS output was used to calculate the levelized long-term fixed energy rates under Schedule 19-FP for each of the nine pricing periods approved in the Sub 167 Order. (DENC Initial Statement at 5-6.)

Regarding forward commodity prices, DENC states that consistent with past practice it developed its avoided energy costs using 18 months of forward market prices, 18 months of blended prices, and then ICF International (ICF) prices exclusively starting in month 37 of the forecast period. DENC notes that the Commission found this approach to be reasonable in the Sub 167 Avoided Cost Case. (Id. at 7.)

DENC explains that consistent with the Commission's conclusions in the Sub 148 Order, the Sub 158 Order, and the Sub 167 Order, it adjusted the avoided energy costs proposed in this proceeding to reflect the fact that locational marginal prices (LMPs) in the North Carolina area of its service territory continue to be lower than the LMPs for the PJM DOM Zone. DENC provides updated data showing the continued disparity in LMPs in support of its adjustment of the avoided energy cost rate proposed in this proceeding to reflect the fact that LMPs in the North Carolina area of its service territory continue to be lower than the LMPs for the DOM Zone. (Id. at 7-8.)

DENC recalls that in the December 31, 2014 Order Setting Avoided Cost Input Parameters issued in Docket No. E-100, Sub 140 (Sub 140 Phase One Order), the Commission determined that it is appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. DENC also recalls that in Phase 2 of that proceeding, the Commission's December 17, 2015 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 140 Phase Two Order) required the Utilities to utilize the Black-Scholes Option Pricing Model (Black-Scholes Model), or a similar model, to determine the fuel price hedging value of renewable generation. Consistent with its proposal in the Sub 148, Sub 158, and Sub 167 Avoided Cost Cases, DENC proposes to continue to use the same Black-Scholes Model to determine fuel hedging benefits that was proposed by the Public Staff in Docket No. E-100, Sub 140, with a resulting fuel price hedging value of $0.02/MWh, which was assumed constant for all years of the Schedule 19-FP contract. (Id. at 9-10.)

In its Initial Statement the Public Staff states that based on its review of the PLEXOS inputs, the inputs into the model, and the output data from the model are reasonable for the determination of DENC's avoided energy costs. The Public Staff confirms that DENC's calculation of avoided energy rates is consistent with the Sub 158 Order, as is DENC's inclusion of avoided fuel hedging values based on the Black-Scholes Model. The Public Staff does not raise any concerns with DENC's forecasted natural gas prices or DENC's calculation of the fuel hedge value. (Public Staff Initial Statement at 47-48.)

The Public Staff notes that DENC calculated its proposed avoided energy rates using its generation expansion Plan B from its 2021 IRP Update in Docket No. E-100, Sub 165, and that Plan B is the least-cost plan that complies with all applicable state law, including the Virginia Clean Economy Act and Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI), effective January 1, 2021. The Public Staff states that while there is some uncertainty regarding the projected future cost of RGGI carbon allowances as well as whether Virginia will remain a member of RGGI, the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law. The Public Staff concludes that therefore it is appropriate for DENC to utilize generation expansion Plan B and to include the cost of RGGI carbon allowances in the production cost models that are used to calculate avoided energy rates. (Id. at 10.)

In its initial comments, SACE states that DENC's approach to fuel forecasting is reasonable for combining forward prices and fundamental forecast components of an overall price forecast in this proceeding, but asserts that DENC should average multiple fundamental price forecasts rather than use its private ICF fundamentals forecast to calculate its natural gas forecasting. Specifically, SACE argues that DENC should be required to average its ICF fundamentals forecast with the 2021 EIA annual energy outlook reference case. (SACE Initial Comments at 38.)

In their Initial Comments, Joint Intervenors note that they have previously not objected to DENC's fuel forecast and do not object to the fuel forecast approach in this case. (Joint Intervenors Comments at 4.)

In its Reply Comments, DENC states that its current approach of using the ICF fundamental forecast, on its own, continues to be appropriate for estimating avoided energy cost rates. DENC notes that its use of the ICF forecast to forecast energy prices in avoided cost proceedings has been accepted by the Commission since the 2012 avoided cost proceeding (Docket No. E-100, Sub 136) and most recently in the Sub 167 Order. DENC notes further that the ICF forecasts are reputable and respected in the industry and SACE has not presented a convincing reason why continued use of the ICF forecast on its own is not reasonable, particularly given the Commission's consistent decisions accepting that approach. With respect to transparency, DENC reports that through both the IRP process and this avoided cost proceeding it has responded to all of SACE's requests, including questions about the ICF forecast. Finally, DENC explains that ICF conducts regional forecasts for electricity as well as natural gas and other commodities that allow DENC to use relevant and correlated forecasts versus mixing ICF price forecasts for energy and other commodities with an EIA forecast for Henry Hub, which would skew the dispatch and economic value of DENC's natural gas-fired units. (DENC Reply Comments at 11-12.)

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission concludes that DENC's proposed avoided energy inputs are reasonable for the purposes of this proceeding and should be approved.

As explained in the Sub 167 Order and in the Sub 140 Phase One Order, the Commission concluded that the calculation of avoided costs should be based on "known and verifiable" costs, finding that the costs of carbon emissions were not sufficiently certain to be included in avoided costs. (Sub 140 Phase One Order at 42-44.) Further, the Commission ruled that the generation expansion plans used in the calculation of avoided energy should be based on IRP expansion plans that take into account only known and quantifiable costs. (Id.) In the Sub 158 Order, the Commission reiterated that costs that are sufficiently known and quantifiable to impact the value of QF-supplied energy and capacity must be reflected in the avoided energy and capacity costs in these proceedings. (Sub 158 Order at 93.) Here, the Commission concludes that it is reasonable for purposes of this proceeding to approve DENC's avoided energy rates based on modelling that includes RGGI costs and excludes federal CO2 costs, as DENC's RGGI costs are sufficiently "known and verifiable" based on current law.

With respect to the fuel forecast DENC used in its modeling, the Commission agrees that DENC's method of using the ICF forecast to forecast energy prices in avoided cost proceedings, which the Commission has accepted since the 2012 Sub 136 Proceeding, continues to be appropriate. The Commission declines to accept SACE's recommendation regarding fuel forecasts for the reasons discussed in DENC's Reply Comments.

With regard to hedging, in the Sub 140 Phase One Order the Commission concluded it to be appropriate to recognize the hedging costs avoided due to energy purchases from QF renewable generation in calculating avoided energy costs. (Sub 140 Phase One Order at 42.) In the Sub 140 Phase Two Order, the Commission found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. (Sub 140 Phase Two Order at 30-31.) Based on the record in this proceeding, the Commission concludes that DENC has calculated avoided hedging costs appropriately for purposes of this proceeding, and accepts as reasonable and appropriate for this proceeding DENC's proposed hedging value of $0.02/MWh, which it assumed constant for all years of the Schedule 19-FP contract.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

Summary of the Evidence

In its Initial Statement, DENC explains that in the Sub 158 Avoided Cost Case, it proposed to adjust avoided energy cost payments to intermittent non-dispatchable QFs to reflect the increase in system supply costs—specifically, re-dispatch costs—caused by these generators, and that the Commission approved the proposed RDC, modified pursuant to DENC's agreement with the Public Staff, to be $0.78/MWh. In the Sub 167 Avoided Cost Case, the Commission approved DENC's proposal to continue to apply the $0.78/MWh RDC that was approved in the Sub 158 Order for purposes of Schedule 19-FP. (DENC Initial Statement at 12.)

DENC proposes an update to the RDC to accurately reflect its costs of the integration of intermittent, non-dispatchable QFs on its system. DENC states that, as explained in the 2018 Avoided Cost Case, it defines re-dispatch generation costs as additional fuel and purchased energy costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. DENC explains that as more and more intermittent generation like solar PV or wind is added to the grid, the level of uncertainty about re-dispatch costs increases due to unpredictable cloud cover or changes in wind speed. In order to assess the resulting re-dispatch costs, DENC used the Aurora planning model with a simulation topology of the Eastern Interconnection to capture the DOM Zone hourly prices interactively as well as the potential system cost impacts from intermittent resources outside DENC's service territory. DENC presented this approach as an improvement over the re-dispatch analysis conducted in the 2018 Avoided Cost Case as it models solar generation across a broader geographical region, models the entire eastern interconnect, and performs a more robust simulation.

DENC explains further that in the 2021 IRP Update, it took a chronological approach to modeling the re-dispatch cost, by utilizing one build plan from the 2020 IRP (Alternative Plan D) and studying 16 years chosen based on when resources were introduced or retired in the 2020 IRP Alternative Plan D build plan. For each simulation year, DENC performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, it performed an additional 200 simulations but applied different hourly renewable profiles from NREL's historical weather patterns studies to reoptimize the system cost.

DENC states that the total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel, variable operation and maintenance costs, emissions, and purchase/sale of energy and power costs. The re-dispatch cost is the delta of the system cost divided by DENC's expected total renewable generation. Based on these results, DENC constructed a generation re-dispatch cost curve for the entire Study Period reflected in the 2021 IRP Update. DENC calculated the average RDC for the ten years 2022-2031 to be $1.87/MWh and proposes to use this value to adjust the avoided energy cost payments made to intermittent non-dispatchable QFs under Schedule 19-FP. (DENC Initial Statement at 14-15.)

Based on its review of the revised methodology, the Public Staff generally finds it to be an improvement over the methodology approved in the Sub 158 Avoided Cost Case and used in the Sub 167 Avoided Cost Case. The Public Staff explains that the prior methodology focused only on a single year, running multiple PROMOD runs with varying solar output profiles at specific generation sites, to calculate the RDC. The new model, in contrast, uses Alternative Plan D from DENC's 2020 IRP to calculate the RDC in each future year by calculating the cost difference between "day ahead" and "real time" model runs, creating a RDC cost curve using the Aurora model. (Public Staff Initial Statement at 49-50.)

SACE notes that DENC's RDC has increased from $0.78/MWh in the Sub 158 and Sub 167 Avoided Cost Cases to $1.87/MWh in the current proceeding. SACE asserts that the methodology DENC used to develop the RDC is flawed and does not reflect the actual solar integration costs and may be too high. Exhibit B to SACE's comments (Kirby Report) argues that the methodology that DENC used to determine the RDC does not time-synchronize solar generation with power system data. The Kirby Report claims that these two items must be synchronized in order to produce accurate results. The Kirby Report also states that the historic solar data used to derive the RDC comes from twenty-two locations, all but three of which are outside of North Carolina with many being "far to the north." (SACE Initial Comments at 38-41, Exhibit B.)

SACE also contends that the increase in DENC's RDC appears to be based at least in part on an error. SACE claims that as more intermittent generation like solar PV or wind is added to the grid, "geographic smoothing" should smooth out the overall variability among renewable generation as generation is added in geographically distinct locations. SACE argues that DENC should have captured this effect when it modeled potential system cost impacts from intermittent resources outside DENC's service territory, but instead "if [DENC] interpreted the effect of geographic diversity to be to cause increased costs then modeling the broader region could have exacerbated the error." (Id. at 39.) CCEBA and NCSEA support SACE's positions regarding DENC's RDC. (Joint Intervenors Comments at 19.)

In its reply comments, DENC explains that it considers the RDC methodology to be a reasonable approximation of the re-dispatch costs that result from increased intermittent renewables on its system. DENC points out that SACE's critiques of the methodology overstate the relationship between solar generation output and system load, mischaracterize the impact of using a narrower geographic selection of locations, and appear to mistakenly assert that DENC applied assumptions about geographic diversity within the Aurora model when it did not. (DENC Reply Comments at 15.)

DENC first explains that while there is a relationship between cloud cover and load, cloud cover is not the primary driver of load forecast error. DENC states that during real world system operations, if both load and renewable generation are lower than expected in a given time period, then the resultant re-dispatch charges would be lower than a situation where only the renewable generation was lower than expected, all else equal. DENC notes that, however, load forecast error and solar generation forecast error are not perfectly correlated, and at times, they may have a negative relationship. DENC presents as an example that if during real world system operations load is higher than expected and renewable generation is lower than expected in a given time period, then the resultant re-dispatch charges would be greater than a situation where only the renewable generation was lower than expected, all else equal. DENC clarifies that this could happen in the winter when cloud cover increases heating and lighting demand while also reducing solar generation output. (Id. at 15-16.)

DENC also explains that it modeled 22 locations across a broad geographic region to represent the entire PJM RTO Balancing Authority and that including three locations in North Carolina is appropriate as the DENC service area is geographically compact. DENC also indicates that the addition of more locations within North Carolina would not have significant impacts on the model results. (Id. at 16.)

Finally, DENC explains that its statements regarding the increase in the level of uncertainty about re-dispatch increasing as more intermittent generation like solar PV or wind is added to the grid due to unpredictable cloud cover or changes in wind speed was not in reference to geographic smoothing. DENC does not expect geographic diversity to increase re-dispatch costs. DENC clarifies that it did not interpret the effect of geographic diversity to be to cause increased costs or configure the model to increase costs due to geographic diversity, but rather modeled the units and load on its system without applying any inputs regarding diversity at all, and any benefits due to diversity would have showed up as an output of the model. (Id. at 16.)

No party filed reply comments on DENC's proposed RDC.

Discussion and Conclusions

PURPA prohibits avoided cost rates to exceed the incremental cost to the electric utility of alternative energy. 16 U.S.C. § 824a-3(b). "Incremental cost of alternative energy" means the cost to the electric utility of the electric energy, which, but for the purchase from the QF, such utility would generate or purchase from another source. 16 U.S.C. § 824a-3(d). FERC's regulations implementing PURPA state clearly that they do not "require[] any electric utility to pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a)(2). N.C.G.S. § 62-156(b)(2) provides that avoided cost rates "shall not exceed . . . the incremental cost to the electric public utility which, but for the purchase from a small power producer, the utility would generate or purchase from another source."

Based upon the foregoing and the entire record, the Commission finds that DENC's updated methodology for calculating the RDC is an improvement from the methodology used in the Sub 158 and Sub 167 Avoided Cost Cases and is reasonable for use in this proceeding. The Commission agrees with DENC and the Public Staff that the new methodology performs a more robust simulation by modeling solar generation across a broader geographical region for sixteen years rather than the prior methodology's more limited geographic scope for one year. The Commission also agrees with DENC that it was appropriate to calculate the RDC with 3 of the 22 locations modeled being in North Carolina as that is representative of DENC's compact North Carolina service territory.

Consistent with the Sub 148 Order, which concluded that "it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplies by the QF and not the technology that the QF uses to generate electricity," the Commission finds that DENC's RDC appropriately accounts for the characteristics of the power supplies by QFs. For the reasons presented in DENC's Reply Comments, the Commission is not persuaded by the comments offered by SACE that DENC inappropriately considered the characteristics of QF power supplies, or that DENC inappropriately applied a presumption against geographic smoothing in its modeling. DENC has explained in detail the derivation of the updated RDC, and the improvements to the calculation methodology, and the Commission finds that the updated RDC is reasonable and should be approved as it will more accurately reflect DENC's actual avoided costs, as required by PURPA and Section 62-156.

The Commission therefore concludes that it is appropriate for DENC to apply a RDC of $1.87/MWh for purposes of Schedule 19-FP in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Summary of the Evidence

In its Initial Statement, DENC recalls that in the Sub 158 Order the Commission directed DENC to file a proposed protocol for avoidance of the RDC and that DENC filed such a proposed protocol in the Sub 167 Avoided Cost Case. In the Sub 167 Avoided Cost Case, DENC proposed that the RDC can be reduced to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD). DENC defined an ESD as a component of a QF facility that uses energy storage technology, including but not limited to battery storage. DENC proposed to calculate the reduction in variability as the percent reduction in variability from a case without storage to a case with storage. The output for the case without storage will be the actual metered output of the facility excluding the impact of storage, and the output for the case with storage will be the actual metered output for the facility including the impact of storage. DENC noted that determining the impact of storage will require that the storage device is separately metered. DENC explained that for a QF to be eligible for the RDC cost reduction, it must provide DENC with an hourly generation output forecast for every hour of the year. For the first year of the contract, the QF must provide the forecast on or before 90 days prior to the facility's commercial operations date (COD) and then for subsequent contract years, the QF may update the forecast on or before 90 days before the start of every calendar year of the contract. If no updated forecast is provided, DENC would use the previously provided forecast to calculate the RDC reduction credit. Every April, DENC would calculate the re-dispatch cost reduction using the prior calendar year forecast and metered data. DENC would provide the RDC reduction as a line item credit with the first payment following the April calculation. (DENC Initial Statement at 15-16.)

In the Sub 167 Order, the Commission concluded that DENC's proposed RDC avoidance protocol was appropriate and DENC complied with the Sub 158 Order directive to file a protocol for the avoidance of the RDC. The Commission found it reasonable to reduce the RDC to the extent a QF reduces the variability of its output through the use of an ESD and that the protocol is a reasonable proxy for estimating that reduction in costs. The Commission also concluded that, if any CSGs seek to avail themselves of the RDC avoidance protocol, it may be helpful for purposes of evaluating the results of the protocol in the future for DENC to monitor and provide the information regarding the types of forecasts, dispatch behavior, and solar volatility of CSGs that avail themselves of the RDC avoidance protocol, as requested by the Public Staff. The Commission encouraged DENC and the Public Staff to continue to discuss this information and directed DENC should address its proposed monitoring and reporting of this information in its initial filing in this proceeding. (Id. at 17.)

DENC explains in its Initial Statement that it plans to maintain the RDC avoidance protocol as approved in the Sub 167 Order for the purposes of this proceeding. DENC notes that with regard to the information that it agreed to monitor on an annual basis per the Public Staff's recommendation, no QFs (CSGs) have sought to avail themselves of the protocol, but if any CSGs do avail themselves of the protocol, DENC will continue to monitor the information requested by the Public Staff and will report on that information as needed in a future biennial avoided cost proceeding. (Id. at 17-18.)

The Public Staff does not object to the RDC avoidance protocol, and again recommends that the Commission direct DENC to file a report on the "types of forecasts and the ESD dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs in DENC's service territory in its future avoided cost filings." The Public Staff also repeats its recommendation that DENC "specifically address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC." (Public Staff Initial Comments at 50-51.)

While it did not address the RDC avoidance protocol in the Sub 167 Avoided Cost Case, in this proceeding SACE objects to the protocol's annual output forecast requirement. SACE claims that no other type of resource is required or capable of such a forecast. SACE also argues that the annual forecast will become outdated, and that the consistency of a solar QF's actual generation over the course of a year with such a projection is not directly relevant to variability or volatility of solar output or any resulting re-dispatch the solar generator may cause. SACE recommends that the Commission "require Dominion to adopt an RDC avoidance protocol that accurately reflects the solar QF's avoidance of the system costs, if any, imposed by solar generation," and requests that the Commission consider requiring review of DENC's compliance with SACE's RDC and RDC avoidance protocol recommendations by an independent technical review committee. (SACE Initial Comments at 39-40.)

In its reply comments, DENC explains that the purpose of the RDC is to account for the increased cost to dispatch DENC's system due to the addition of intermittent distributed solar generation QFs and, as a result, the purpose of the protocol is to permit solar generation QFs that want to avoid the RDC through an ESD to do so. As a result, solar generation QFs are the only facilities that must provide this forecast because they are the only facilities that impose the re-dispatch costs on the system. (DENC Reply Comments at 20.)

DENC notes that no QF is required to guarantee its hourly output over a year or more in advance or provide a perfect forecast. Instead, the RDC avoidance protocol is made available to intermittent QFs that choose to use an ESD to manage the output of the facility, and is designed to allow for a proportional reduction of the RDC. (Id.)

DENC further explains that a year-ahead forecast allows a QF to account for the movement of the sun, the design of the QF facility, and some level of expected seasonable cloud cover, which DENC expects to be a smooth profile. DENC considered the deviation from this profile to be more reasonable than deviation from an observed mean, such as average hourly generation across a year, average hourly generation by month, average hourly generation by hour of day, or average hourly generation by hour of day by month. DENC believes the variability relative to the QF-provided profile (in the form of a year-ahead forecast) to be the most reasonable low-burden method to use to calculate a proxy for variability reduction achieved with an ESD. (Id. at 21.)

DENC acknowledges that a day ahead forecast could conceivably be used, but would be significantly more burdensome than a single annual profile to both DENC and the QF as the QF would need to provide, and DENC would need to verify receipt of, an hourly forecast every day at least 24 hours in advance of the beginning of the day. Failure to provide a forecast would by necessity nullify the protocol for the year in order to protect customer interests and prevent gaming. DENC explains that an hour-ahead forecast would be even more excessively burdensome and would not be appropriate for implementing the RDC, which is based on re-dispatch between the day ahead market and real time operations. DENC notes that no evidence has been presented to indicate that providing an annual hourly generation profile would be burdensome for a QF and expects that the information necessary to construct such a profile is typically available as part of the development of a solar facility. With regard to the "age" of the forecast, DENC considers the QF-provided forecast to be a proxy for a smooth profile, as the QF is in the best position to provide that profile. Considered as a smooth profile, DENC states that the age of the forecast is not relevant unless new information about the movement of the sun, the design of the facility, or seasonal cloud cover becomes available. (Id. at 21-22.)

DENC opposes SACE's recommendation that DENC be required to adopt a modified RDC avoidance protocol consistent with SACE's recommendations and for an independent technical review committee with stakeholder input to verify that the modified protocol meets SACE's demands. DENC demonstrates that these recommendations are unnecessary due to the appropriateness of the RDC avoidance protocol as presented in DENC's Initial Statement and defended in its Reply Comments. (Id. at 22.)

Discussion and Conclusions

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

The Commission continues to find DENC's protocol reasonable for the reasons articulated in the Sub 167 Order. In addition, we agree with DENC that it is not unreasonable to require QFs seeking to avail themselves of the RDC avoidance protocol to submit year-ahead forecast information, because it would be the QFs seeking the benefit of the resulting RDC reduction. The Commission also agrees with DENC that a year-ahead forecast is the most efficient and least burdensome requirement for both DENC and QFs seeking to avail themselves of the RDC avoidance protocol and therefore is appropriate for use in this proceeding. The Commission anticipates that most QFs will have this information, or similar information, available from the development of the solar project and that providing such information should not be overly burdensome. As the Public Staff did not raise any new issues with the RDC avoidance protocol and DENC has not made any changes from the protocol as approved in the Sub 167 Order, the Commission finds that DENC's RDC avoidance protocol continues to be reasonable for use in this proceeding.

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

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

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

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

Summary of the Evidence

In its Initial Statement, DENC states that since the 2012 biennial avoided cost proceeding (Docket No. E-100, Sub 136, the 2012 Avoided Cost Case), it has used the peaker methodology to calculate the avoided capacity cost rates for the Schedule 19-FP rate schedule.

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

DENC explains that in the 2018 and 2020 Avoided Cost Cases, it utilized the 2018 PJM Cost of New Entry study prepared by The Brattle Group and Sargent & Lundy (Brattle Report) with the CT equipment cost based on the actual procurement cost for the Greensville combined cycle power plant. For this proceeding, based on the agreement with Duke Energy, DENC utilized the 2021 EIA Annual Energy outlook costs for an F-class turbine and did not make any adjustments to the CT equipment costs. DENC did make adjustments to reflect economies of scale and the cost benefits associated with building four CTs at a single site. (Id. at 20-21.)

In its Initial Comments the Public Staff supports the use of the peaker methodology, but observes that there may come a time when the peaker methodology is not appropriate for use in North Carolina. Specifically, as utilities seek decarbonization, generation will increasingly come from renewable resources that have high capital costs and low variable costs which, all else being equal, will tend to depress avoided energy rates. The Public Staff notes that the Utilities continue to use the cost of a CT to determine the avoided cost of capacity, but in a low-carbon future, peaking capacity may come from renewable resources and energy storage. The Public Staff also notes that DENC's 2021 IRP Update Alternative Plans B and C has no CTs built during the planning horizon. The Public Staff agrees with the Utilities' approach in this proceeding on evaluating, calculating, and applying an adjustment to the EIA published data. (Public Staff Initial Comments at 29-30.)

SACE and the Joint Intervenors suggest in their respective Initial Comments that the Commission should begin to reconsider the appropriateness of the peaker methodology for avoided cost determinations. (SACE Initial Comments at 3; Joint Intervenor Initial Comments at 17-18.) SACE also contends that the Utilities' choice of an F-class turbine to establish avoided capacity is outdated and a more appropriate peaking resource would have been an aeroderivative gas turbine in the very near term, and batteries or a 100% green hydrogen-powered turbine shortly thereafter. (SACE Initial Comments at 8-13, 37.) The Joint Intervenors do not comment on DENC's proposed installed CT cost calculation.

In its Reply Comments, DENC acknowledges that additional factors or methods for determining avoided costs may need to be considered in the future and agrees that, as the energy landscape continues to develop, there may be additional considerations to analyze in terms of the appropriate methodology to calculate avoided cost rates in North Carolina avoided cost proceedings. DENC agrees with the Public Staff, however, that for this proceeding the peaker methodology remains appropriate and reasonable. (DENC Reply Comments at 3.) In its joint reply comments, Duke Energy requests that the Commission approve the peaker methodology's continued use in this proceeding given that it remains a reasonable and well-accepted methodology by which to calculate avoided energy and capacity costs and no party directly challenged its use in this proceeding. (Duke Energy Reply Comments at 36.)

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

DENC explains further that a primary driver in considering whether to implement aeroderivative CTs in particular is the need to effectively integrate intermittent resources, like solar, that cause a greater need for quick-start flexible units. DENC notes that the growing use of aeroderivatives with some Southeastern utilities with increasing solar penetration is evidence of the need for utilities to invest in higher cost resources to manage the growing intermittency on their systems. While more Southeastern utilities are using aeroderivative CTs to help with solar integration, DENC disagrees that that means aeroderivative CTs should be used to calculate avoided capacity costs in North Carolina. DENC recognizes that SACE cites to Dominion Energy South Carolina's (DESC) recent use of aeroderivatives in its avoided capacity cost calculations, but DESC operates a system very different from DENC: DENC has approximately three times the MW capacity as DESC; the total MW of generating capacity contained within PJM is much greater; and DESC has a significantly higher degree of solar penetration (3.48% of available summer generating capacity in DENC compared to 12.7% in DESC). DENC also enjoys more supply diversity than DESC by being a member of PJM and therefore has not included the need for aeroderivatives in its recent IRPs like DESC has done. (Id. at 8-9.)

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

Duke Energy points out that although an aeroderivative turbine may provide greater flexibility attributes than an F-class CT, an F-class CT provides fast start and ramping capabilities at an installed cost approximately 60% below the cost of an aeroderivative CT. Duke Energy also explains that, consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost. Even if a utility's next planned unit is not a simple cycle peaker, the peaker methodology still accurately represents a valid estimate of the utility's avoided costs. Similar to DENC, Duke

Energy also points out that the cost causer for the more expensive aeroderivative CT unit would be the solar providers themselves and, thus, the incremental cost of constructing such a CT versus F-class CTs should not also be paid for by customers to the solar providers as avoided costs. (Duke Energy Reply Comments at 8-11.)

In their Joint Reply Comments, NCSEA and CCEBA agree with SACE that an aeroderivative gas turbine is the appropriate avoided capacity resource in the near term. (NCSEA and CCEBA Reply Comments at 4.)

Discussion and Conclusions

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

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

(Sub 140 Phase One Order at 48.)

Based upon the foregoing evidence and the entire record in this proceeding, the Commission concludes that DENC appropriately relied on publicly available industry sources for determining the installed per-kW cost of a CT and that its source information was tailored in a manner consistent with the guidance previously provided by the Commission in the Sub 158 Order with respect to cost increments and decrements. The Commission finds that the Utilities’ approach to simplify and increase the transparency of the calculation of CT cost estimates is reasonable and will allow for more efficient updates in subsequent proceedings and is appropriate for use in this proceeding. Specifically, the Commission finds that the Utilities’ consensus to use the 2021 EIA annual energy outlook costs for an F-class turbine, without making any adjustments to the equipment costs, to be reasonable. The adjustments made to reflect economies of scale and the cost benefits associated with building four CTs at a single site are also reasonable given the Utilities’ usual practice of building multiple CTs at one site.

The Commission disagrees with SACE that an aeroderivative CT should be used instead of an F-class CT in this proceeding for the reasons stated in DENC’s and Duke Energy’s Reply Comments. Specifically, SACE’s examples of other Southeastern utilities that have used aeroderivative CTs to calculate avoided capacity rates are materially different from DENC with respect to solar penetration, RTO access, and other factors, and therefore do not support requiring DENC to utilize an aeroderivative CT to calculate capacity costs in North Carolina.

Moreover, the Commission finds persuasive DENC's explanation that because the peaker methodology provides a hypothetical exercise to value capacity, the F-class CT is the appropriate basis for this calculation due to the higher proportion of its value deriving from the capacity it provides with less value derived from its other attributes. Finally, the Commission agrees with DENC and Duke Energy that it would be contrary to the purpose of avoided cost to pay intermittent resources higher capacity rates to account for those resources' creation of the need to add more expensive, quick-start units to make up for the solar resources' intermittency and lack of dispatchability. The Commission finds that use of the F-frame CT as the basis for the Utilities' CT capital costs is appropriate under the peaker methodology, most reflective of current system conditions, and supported by the Public Staff, and therefore continues to be appropriate.

The Commission also finds reasonable the Utilities' continued use of the peaker methodology in this proceeding. As the energy landscape in North Carolina continues to develop, there may be additional considerations to analyze in terms of the appropriate methodology to calculate avoided cost rates in North Carolina avoided cost proceedings, and new factors or methodologies to consider. For purposes of this proceeding, however, the Commission agrees with the Utilities and the Public Staff that the peaker methodology remains appropriate and reasonable The methodology remains a reasonable and accepted approach to calculating avoided costs and specific evidence to support a shift away from the peaker methodology has not been presented in this docket. Any proposals to adjust or replace the peaker methodology can be addressed in future biennial avoided cost proceedings.

The Commission therefore concludes that the CT cost information and adjustments made by the Utilities are consistent with the Sub 158 Order's directives and that DENC's cost of the hypothetical CT of $616/kW is reasonable for use in this proceeding to calculate avoided capacity costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

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

Summary of the Evidence

In its Initial Statement, DENC recounts that in the Sub 148 Order, the Commission approved DENC's proposal to eliminate the 3% adder that had historically been included in its avoided energy rates. DENC also recalls that in the Sub 158 Order, the Commission found that power backflow on substations in DENC's North Carolina service territory from solar generation on the distribution grid continued to increase such that avoided line loss benefits associated with distributed generation have been reduced or negated, and that it was appropriate that DENC continue not to include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network. DENC notes that prior to joining with Duke Energy in the joint request that was addressed in the Continuance Order, DENC updated its evaluation of the amount of backflow on the North Carolina portion of its service area in the Sub 167 Avoided Cost Case (2020 Backflow Study). DENC reports that the 2020 Backflow Study, while not included in the Sub 167 Initial Statement, showed that the number of transformers experiencing backflow had continued to increase since the Sub 158 Avoided Cost Case: of 41 transformers with connected distributed solar, the study showed 24 realizing consistent backflow (58.5%), an increase from the 16 out of 38 transformers (42%) consistently experiencing backflow in the 2018 study conducted for the Sub 158 Avoided Cost Case. (DENC Initial Statement at 10-11.)

Exhibit DENC-12 to DENC's Initial Statement presents DENC's updated line loss analysis, and shows that compared to the 2018 study and the 2020 Backflow Study, the number of transformers experiencing backflow has continued to increase as more Solar DG has become operational. Of the 42 transformers with Solar DG connected, 34 transformers realize consistent backflow. Only 3 transformers are shown to have consistent positive flow as compared to 4 transformers in the 2018 and 2020 studies, which indicates that only 3 of the 42 transformers still have capacity for additional load reduction capability. (Id. at 11-12, Exhibit DENC-12.)

In its Initial Statement the Public Staff supports DENC continuing to exclude a line loss adder from the standard offer avoided cost rate given the high backflow at DENC's substations. (Public Staff Initial Comments at 16.) No other parties commented on DENC's removal of the line loss adder.

Discussion and Conclusions

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

Based on the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to continue to not include a 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer for the purposes of this streamlined proceeding. DENC's updated line loss study demonstrates a continued increase in the number of transformers on the North Carolina portion of DENC's system experiencing consistent backflow and decrease in the number of transformers with capacity for additional load reduction capability, and shows a pattern of this development increasing over time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

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

Summary of the Evidence

In its Initial Statement, DENC recalls that in the Sub 158 Order, the Commission ruled that "with input from the Public Staff, [the Utilities] shall evaluate appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing." (Sub 158 Order at Ordering Paragraph 13.) DENC explains that for the purposes of the streamlined 2020 Avoided Cost Case, it continued to apply the PAF that was approved in the Sub 158 Order and the Commission approved this proposal in the Sub 167 Order. DENC notes that the Sub 158 Order directive regarding PAF became one of the Sub 158 Additional Issues that DENC discussed with Public Staff on multiple occasions. For purposes of this proceeding, DENC reached consensus with the Public Staff that DENC will use the Weighted Equivalent Unforced Outage Factor (WEUOF), which accounts for unit unavailability caused by maintenance and forced outages, to determine the PAF. DENC agreed with the Public Staff to use a 5-year average, instead of the previously used 3-year average, to calculate the WEUOF. DENC and the Public Staff also agreed that DENC will have the flexibility to determine the months to be used in the overall PAF calculation, and would provide support for use of those months in DENC's Initial Statement. As a result, for this proceeding DENC calculated a PAF of 1.07 using 5 years of history for the months January, February, June, July, and August and it utilized these months for consistency with PJM's "Peak Period Months" in the PJM Manual 10. (DENC Initial Statement at 23-24.)

In its Initial Statement, the Public Staff agrees with DENC's proposed PAF adjustment and supports the use of the WEUOF metric for the Utilities, which should create a uniform calculation methodology that can be used in the future. The Public Staff recommends that the Commission direct Duke Energy and DENC to address the inclusion of solar and wind generator outage data in the calculation of the PAF in their next avoided cost filings, including the current status of outage reporting requirements set by the North American Electric Reliability Council (NERC). The Public Staff states that WEUOF is calculated using data from the Generator Availability Data System (GADS), which is maintained by NERC. GADS does not currently require solar generation reporting and DENC does not report outages from its solar generation facilities into GADS. Solar facilities are therefore excluded from the calculation of WEUOF. The Public Staff notes that solar outage data is unlikely to impact WEUOF and PAF, but as carbon legislation requires increased solar development, suggests that this outage data will become increasingly important in future PAF calculations. (Public Staff Initial Statement at 15-16.)

In its reply comments, DENC does not oppose the Public Staff's recommendation, and states that if the Commission agrees with the Public Staff, DENC will address the appropriateness of including solar and wind generator outage data in the calculation of the PAF in its initial filing for the next biennial avoided cost proceeding. DENC also states that it does not oppose providing the status of NERC outage report requirements in the next biennial proceeding, should the Commission find that to be appropriate. DENC clarifies that when the NERC reporting requirements, outage coding protocols, and any updated WEOUF calculation definitions are known, it will be best able to address the appropriateness of including solar outage data in the calculation of its PAF, including whether incorporation of such data could be accomplished in a manner consistent with the peaker methodology. (DENC Reply Comments at 4-5.) In its Reply Comments, Duke Energy notes that NERC's solar generating reporting instructions are currently under review and not yet finalized. (Duke Energy Reply Comments at 13.)

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

Discussion and Conclusions

In the Sub 158 Order, the Commission found that the PAFs proposed in the Utilities' respective initial statements were appropriate based on the Sub 148 proceeding standard of using a metric or metrics that assess generating unit "availability" and a methodology used to calculate this availability based upon an informed discussion of utility system planning and load forecasting. The Commission also directed the Utilities, with Public Staff input, to evaluate the appropriateness of using other reliability indices, specifically the EUOR metric, to support development of the PAF prior to the next biennial avoided cost filing. The Commission also adopted the Public Staff's recommendation to require the Utilities to continue to use three (as used by DENC) to five (as used by Duke Energy) years of historic outage rate data to support the PAF. (Sub 158 Order at 40-42.) In the Sub 167 Order, the Commission permitted the Utilities to address this issue in their next biennial full avoided cost proceeding. (Sub 167 Order at 21, 52.)

The Commission finds that DENC's proposal to use the WEUOF method to calculate its PAF, as agreed to with the Public Staff, is reasonable for purposes of this proceeding. Usage of the WEUOF methodology meets the Commission's directive in the Sub 158 and 167 Orders to consider the appropriateness of using other reliability indices such as the EUOR metric to support development of the PAF. The Commission also finds DENC's and the Public Staff's agreement to use a 5-year average, with DENC determining the months used, in the PAF calculation to be reasonable as the months selected by DENC align with PJM's "Peak Period Months" in the PJM Manual 10.

Based upon the foregoing and the entire record herein, the Commission concludes that it is appropriate for DENC to use a PAF of 1.07 in its avoided cost calculations for all QFs and to use the WEUOF method to determine the PAF. The Commission also finds the Public Staff's recommendation that the Utilities address the inclusion of solar and wind generator outage data in their next biennial avoided cost filings to be reasonable, with the understanding that when the NERC reporting requirements, outage coding protocols, and any updated WEOUF calculation definitions are known, the Utilities will be best able to address the appropriateness of including solar outage data in the calculation of its PAF, including whether incorporation of such data could be accomplished in a manner consistent with the peaker methodology.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

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

Summary of the Evidence

In its Initial Statement, DENC states that on September 8, 2021, it filed an addendum to its 2021 IRP Update as filed on September 1, 2021, in Docket No. E-100, Sub 165 identifying DENC's next undesignated capacity need as arising in 2024. The calculation of seasonal levelized rates shown in its Initial Statement included no avoided capacity costs through 2023 since DENC's 2021 IRP Update showed the first avoidable capacity in 2024. (DENC Initial Statement at 22-23.) On January 7, 2022, DENC filed corrected standard avoided capacity rates, explaining that it recalculated its proposed capacity rates to reflect DENC's accurate capacity position as its previous calculations inadvertently excluded approximately 500 MW of solar capacity. As a result, DENC's updated first year of undesignated capacity need is 2026.

In the Public Staff's Initial Statement, the Public Staff explains that the calculation of avoided capacity rates for each utility reflects the present value of avoided capacity costs beginning in its first year of need for all resources except certain QFs fueled by swine waste, poultry waste, and certain existing hydro power QFs less than 5 MW. The Public Staff states that DENC's 2026 first year of capacity need is reasonable and based upon DENC's most recently filed IRP. (Public Staff Initial Statement at 28-29.)

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

Discussion and Conclusions

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

Based on the foregoing, the Commission concludes that DENC's corrected addendum to its 2021 IRP Update submitted on January 7, 2022, in Docket No. E-100, Sub 165 serves this purpose, that DENC's next year of undesignated capacity need is 2026, and that DENC appropriately relied on that identified first avoidable capacity need in determining the first year of avoidable capacity need for purposes of this proceeding.

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

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

Summary of the Evidence

In its Initial Statement, DENC refers to the Commission's *Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations* issued on August 17, 2021, in Docket No. E-100, Sub 158 (Retrofit Storage Order), in which the Commission made several rulings on the Retrofit Storage Stakeholder Group report DENC filed jointly with Duke Energy in that docket in September 2020. As relevant to DENC, in the Retrofit Storage Order the Commission concluded that: (1) a new CPCN is not required for the addition of storage to an existing generating facility, but the facility must file with the Commission written notice of the amendment to either the applicable CPCN or the report of proposed construction consistent with Commission Rules R8-64 and R8-65; (2) the addition of energy storage to an existing generating facility requires an amendment to the existing PPA and does not require execution of a new PPA; and (3) the term for retrofit energy storage shall be the same as the term that remains on the PPA for the facility. (DENC Initial Statement at 25.)

DENC notes that in the Retrofit Storage Order, the Commission approved the parties' agreement that DC-coupled energy storage systems should be allowed once revenue grade meters are available, and directed the Utilities to provide an update on the status of the availability of DC meters in initial filings in the 2021 avoided cost proceeding. Relevant to this directive, DENC explains that ANSI C12.32 – "American National Standard for Electricity Meters for the Measurement of DC Energy" – was published on March 4, 2021, and outlines the acceptable performance criteria for commercial, revenue-grade, DC meters. DENC states that with this standard published, the next step is for meter manufacturers to have their meters tested to the new standard's requirements. At the time of DENC's Initial Statement, based on DENC's communications with several meter manufacturers, none of those manufacturers have a meter certified under the new standard. DENC states that once an ANSI DC meter is available, it will need to determine an appropriate method to test its accuracy, both in a lab and in the field. (Id. at 25-26.)

Also, in the Retrofit Storage Order the Commission noted that the parties did not address the procedure for how and the point in time at which a facility secures eligibility for a specific avoided cost rate or methodology when adding energy storage, and directed the parties to address this issue for resolution by the Commission. DENC posits that a QF that desires to incorporate energy storage to an existing facility, the output of which the QF has committed to sell to DENC, would submit to DENC a new LEO Form reflecting the retrofitted facility, and the avoided cost rate and methodology that are current at the time the QF submits the LEO Form would apply to the retrofit storage component. DENC proposes new LEO Forms specific to retrofit storage additions to be available to QFs seeking to establish LEOs for such projects. DENC proposes that, consistent with the Commission's conclusion in the Retrofit Storage Order that the addition of energy storage to an existing generating facility requires an amendment to the existing PPA and does not require execution of a new PPA, DENC and the QF would execute an amendment to the existing PPA to account for the retrofit storage. DENC clarifies that, consistent with the Commission's ruling that the term for retrofit energy storage shall be the same as the term remaining on the PPA for the facility, the QF would receive the annual levelized rate as approved in this proceeding for each of the remaining years of the original PPA, even if more than 10 years remains in the term. (Id. at 26-28.)

DENC indicates that with regard to the interconnection of retrofit storage additions, the existing NCIP provides a sufficient framework and process for DENC to study requests to add battery storage at existing distribution voltage sites in DENC's service area. DENC explains that to pursue an energy storage retrofit to a solar farm in operation in a serial study process, the Interconnection Customer will submit an Interconnection Request with study deposit to study and identify any grid or protection modifications needed to accommodate the proposed energy storage interconnection. To pursue an energy storage retrofit for an Interconnection Request that is active in study or in construction, the Interconnection Customer would submit a Modification Inquiry so that DENC can determine if the energy storage addition is a Material Modification. If a Material

Modification, DENC would require the Interconnection Customer would submit a new Interconnection Request and study deposit to pursue the energy storage retrofit under a new queue number. If not a Material Modification, the study and any construction parameters would be incorporated under the existing queue number with the Interconnection Customer submitting an Interconnection Request documenting the additional information needed to study the energy storage. (Id. at 28.)

Finally, DENC explains that in the Retrofit Storage Order the Commission encouraged the parties to continue to investigate issues related to retrofit storage additions, "including term and rate design, to incent the addition of storage to uncontrolled generating facilities in the interest of providing value to the utilities' systems." DENC states that the rate design approved by the Commission in the 2018 and 2020 Avoided Cost Cases provides a high degree of granularity and incentives for QFs to determine whether to add storage capability to their facilities, and that there is no need to revise that rate design at this time. DENC notes that if a QF desires even greater granularity and price signals than what is offered by the current Schedule 19-FP rate design, DENC's Schedule 19-LMP offers the most precise price signals possible and continues to be available to QFs to select. (Id. at 28-29.)

No parties raised any concerns with DENC's proposed Retrofit Storage LEO Forms or process for addressing QFs seeking to add retrofit storage to their facilities. In its Reply Comments, DENC noted the Public Staff's confirmation that it does not object to DENC's Retrofit Storage LEO Forms. (DENC Reply Comments at 23, n. 49.)

Discussion and Conclusions

In the Retrofit Storage Order, the Commission made several rulings regarding the addition of storage to an existing generating facility, as described in DENC's Initial Statement, and directed the Utilities to provide an update on the status of the availability of DC meters in its initial filings in the 2021 avoided cost proceeding as well as to address the procedure for how and the point in time in which a facility secures eligibility for a specific avoided cost rate or methodology when adding storage. (Retrofit Storage Order at 7-8, 10-11.)

The Commission finds that DENC's proposed procedure to be applied if an Interconnection Customer adds storage to its existing facility is reasonable and should be approved. Specifically, the Commission finds that DENC's proposals to execute an amendment to the existing PPA, provide avoided cost rates as approved in this proceeding for the duration of the existing PPA term, and follow the already-provided framework under the NCIP and the "material modification" process therein are reasonable as they are consistent with the Commission's findings in the Retrofit Storage Order, not contested by any party, and appropriate given DENC's specific circumstances as discussed in its Initial Statement.

With respect to the Commission's directive in the Retrofit Storage Order to continue to investigate issues related to rate design, the Commission also agrees with DENC that the rate design approved by the Commission in the 2018 and 2020 Avoided Cost Cases provides a high degree of granularity and incentives for QFs to determine whether to add storage capability to their facilities, and that there is no need to revise that rate design at this time. As DENC rightly points out, any QF that desires even greater granularity and price signals can utilize Schedule 19-LMP.

The Commission acknowledges that as of the filing of DENC's Initial Statement, no manufacturers with which DENC has communicated have DC meters certified under the new ANSI C12.32 standard, and based on DENC's statements in this docket finds that DENC met the directive to provide an update on this issue in this case.

Finally, the Commission finds that DENC's proposed Retrofit Storage LEO Forms, as modified by the letter and exhibits filed by DENC on June 29, 2022, are reasonable and appropriate. as no party objected to the proposed forms with respect to new retrofit storage provisions and they will provide DENC with information specific to the retrofitted facility that will be useful in managing such arrangements, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

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

Summary of the Evidence

In its Initial Statement, DENC discusses FERC Order No. 872, issued on July 16, 2020, which updated FERC's regulations implementing PURPA. DENC notes that in the order establishing the 2020 Avoided Cost Case, the Commission acknowledged that Order No. 872 may "driv[e] additional changes to PURPA implementation" in North Carolina, and in the Sub 167 Order recognized that it would consider proposals stemming from Order No. 872 and its potential effect on PURPA implementation in North Carolina in this proceeding. Specifically, DENC explains that Order No. 872 imposes new rules with respect to the (1) one-mile rule given the development of large numbers of affiliated projects and (2) viability of a project as FERC required that QFs now must "demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO." (Order No. 872 at P 684.)

DENC proposed to revise its LEO Forms to include confirmation that the QF is not less than one mile, or between 1 and 10 miles, of an affiliated facility using the same energy resource. DENC explained that if the QF is located between 1 and 10 miles of an affiliated facility using the same energy resource, the revised LEO Forms allow the QF to provide more detailed confirmations to rebut the presumption that it is located at the same site as the affiliated project. (DENC Initial Statement at 29-31.)

DENC also proposes to modify its LEO Forms to include a statement by the QF to demonstrate commercial viability and financial commitment, stating that the QF has taken meaningful steps to obtain site control adequate to commence construction of the project at the proposed location and submitted all required applications including filing fees to obtain all necessary local permitting and zoning approvals. DENC believes that these modifications, in combination with the existing requirement that the QF must have submitted an Interconnection Request and reached certain milestones in the interconnection process, will ensure that the QF will have sufficiently demonstrated its commercial viability and financial commitment to justify obtaining a LEO consistent with Order No. 872. (Id. at 31-32.)

In its Initial Statement, the Public Staff generally supports DENC's revisions to its LEO Forms. The Public Staff finds that those modifications are consistent with Order No. 872 and recommends that the Commission approve the revised LEO Forms. (Public Staff Initial Comments at 55-57.)

In its Reply Comments, SACE objects to DENC's originally proposed revisions to its LEO Form, which required a QF that is located between 1 and 10 miles from an affiliated facility to provide additional information to rebut the presumption that it is located at the same site as the affiliated project. SACE states that the presumption under the one-mile rule is that facilities located between 1 and 10 miles from one another are at separate sites and there is no need to provide DENC with additional information concerning their separateness. SACE also expressed concern that requiring the additional information could result in confusion between the LEO Form and the QF's FERC Form 556. (SACE Reply Comments at 7-8.)

On June 29, 2022, DENC filed a letter in this docket addressing SACE's comments and proposing to revise the changes to DENC's LEO Forms to require only factual statements regarding a QF's geographic location with respect to any affiliates using the same energy resource, but no additional information. DENC represented that it had discussed its revised changes with SACE and that SACE agreed that the changes address its main concern with DENC's updated LEO Forms.

Discussion and Conclusions

Order No. 872 requires that QFs "demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO." (Order No. 872 at P 684.) FERC found that a showing of commercial viability and financial commitment would ensure that QF projects that are not sufficiently advanced in their development would be included in the utility's resource planning. (Id. at P 684.) Order No. 872 also explained that any factors that a state requires a QF to demonstrate in order to receive a LEO "must be within the control of the QF." (Id. at P 685.) According to FERC, examples of such a showing are "(1) taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location; and (2) filing an interconnection application with the appropriate entity." (Id.)

Order No. 872 also adopted a new rule governing when affiliated QFs are considered to be located at the same site, and therefore considered a single facility for purposes of the 80 MW small power producer limitation. The rule states that (1) there is an irrebuttable presumption that affiliated small power producer (SPP) QFs that use the same energy resource and are located one mile or less from each other are located at the same site, (2) there is also an irrebuttable presumption that affiliated SPP QFs that use the same energy resource and are located 10 miles or more apart are located at separate sites, and (3) there is a rebuttable presumption that affiliated SPP QFs that use the same energy resource are located more than 1 mile and less than 10 miles from each other are located at separate sites. (Id. at P 466.)

Based on the evidence presented herein, the Commission finds and concludes that DENC's revisions to its LEO Forms to include an affirmative statement of commercial viability and financial commitment are reasonable and consistent with Order No. 872 and should be approved. The Commission also finds that the revisions to DENC's LEO Forms to incorporate FERC's updates to the one-mile rule, as modified by DENC's June 29, 2022 letter and exhibits, are reasonable and consistent with Order No. 872 and should be approved.

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

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

Summary of the Evidence

In its Initial Statement, DENC noted in discussing the RDC that behind the meter resources do not have the capability to effectively follow direct signals from PJM or relayed instructions by DENC. As a result, such resources are not eligible to participate in ancillary service markets for the benefit of system customers. (DENC Initial Statement at 13, n. 19.)

In its Initial Statement, the Public Staff explains that it, Duke Energy, and certain other intervenors discussed how some QFs may be capable of providing ancillary services to the grid at potentially a lower cost than Duke Energy's own resources, and highlights challenges associated with implementing QF compensation for these services. The Public Staff notes that PURPA's mandatory purchase obligation does not extend to ancillary services, nor does it preclude procurement of ancillary services from QFs. Ultimately, the Public Staff concludes that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke Energy's SISC by smoothing their volatility. The Public Staff solicits feedback from Duke Energy, DENC, and other intervenors on the potential benefits of initiating a proceeding to investigate this matter and potentially establish a pilot program to procure a small amount of ancillary services from inverter-based resources, either through the establishment of a limited competitive solicitation from QFs, or a pilot program at one of Duke Energy's or DENC's utility-owned solar sites. (Public Staff Initial Statement at 18-19.)

In their Initial Comments, the Joint Intervenors recommend that the Commission order further evaluation of solar and solar + storage facilities' ability to provide ancillary services and the related contractual, commercial, and technical issues, and support an ancillary services pilot. (Joint Intervenors Initial Comments at 16-17.) SACE recommends the Commission require Duke Energy to commission an independent study of this issue or establish a pilot program. (SACE Initial Comments at 31.)

In its Reply Comments, DENC agrees with the Public Staff that PURPA does not require utilities to purchase ancillary services from QFs, and further clarifies that PURPA does not require utilities to provide QFs with access to ancillary services markets. DENC states that with respect to PJM, access to spinning reserves, frequency control, and voltage support (reactive power) ancillary compensation is available to QFs through direct market participation, but DENC is not required to achieve market participation on behalf of or for a QF. DENC notes that among many other challenges, cost allocation issues make the inclusion of ancillary services in avoided cost rates truly infeasible. DENC states that ancillary services should not be part of its avoided cost rates because DENC's customers already pay for these ancillary services obtained by PJM, and the PJM market structure does not allow for DENC's customers to avoid any ancillary costs due to a QF providing an ancillary service, even assuming that the QF had the technical ability to provide the service. DENC explains that requiring payment for any ancillary services that a QF was able to provide would therefore contradict the fundamental principle of PURPA that the utility cannot be required to pay more than its avoided cost for QF output. (DENC Reply Comments at 24-25.)

With regard to spinning reserves specifically, DENC explains that PJM is obligated to maintain a certain quantity of total ten (10) minute reserves on the system, including a subset of reserves that are synchronized to the system (Synchronized Reserves). DENC notes that to participate in the reserve market, a unit must be a PJM market participant, located in front of the PJM meter, that provides offers in Day Ahead and Real Time and any resources that do not participate in the PJM market cannot contribute to PJM's reserve requirement and do not reduce the amount of reserves that PJM must procure, and therefore do not reduce the cost of reserves to customers. DENC concludes that it would therefore be inappropriate for customers to compensate QFs for reserves in an avoided cost rate when the QF does not avoid any reserve cost for the customers. (Id. at 25.)

DENC explains that there would also be no benefit to customers for it to host a pilot for ancillary reserves when QFs cannot participate in the PJM reserve market and cannot provide an avoided reserve cost benefit to customers. Similarly, DENC states that it would not be appropriate for it to pay QFs for frequency control, which is managed by PJM and limited to facilities that are "in front of the meters" from PJM's perspective, which QFs are not. DENC points out that it has no mechanism to administer a frequency control market and compensate behind-the-meter facilities for this service, assuming a QF could provide it. If a QF were able to provide any level of frequency control, the physical benefit would be socialized across PJM, but the PJM market structure would provide no compensation to the Company and its customers in exchange for the benefit. (Id. at 25-26.)

With regard to reactive power versus real power, DENC explains that PJM provides two channels of cost compensation. The first is that in PJM, on an energy basis, if a unit must lower its real power output to produce reactive power, it is compensated at a "lost opportunity" level, which is essentially the same LMP that the generator is paid for its real power. In that way, the generator does not lose any revenue while producing reactive power in lieu of real power. PJM therefore does not pay a premium above the energy price for units that provide reactive power. Likewise, DENC states, it would not be appropriate, and would violate the avoided cost principle, for it to pay a premium over the energy cost for any reactive support provided by a QF, even assuming the QF had the technical ability to provide such support. (Id. at 26-27.)

The second channel for reactive cost compensation is a cost of service filing with FERC for the recovery of generator plant costs associated with providing reactive capability. DENC notes that a stand-alone facility that is not part of the DENC fleet and is a member of PJM may pursue an independent reactive cost recovery filing at FERC and the cost would be allocated across all customers in DOM Zone. Conversely, requiring DENC to pay a QF for reactive capability under PURPA, again assuming the QF had the technical ability to provide the service, would cause DENC's customers to bear the full cost of that payment while other PJM members in DOM Zone would benefit but not be allocated any portion of the cost. DENC explains that there is currently considerable resistance among PJM load serving entity to providing this reactive capability compensation to distribution-connected resources as the real impact is minimal. DENC also points out that the reactive power cost recovery structure may be changing in the near term as there are initiatives at both FERC and PJM to review the structure. DENC additionally notes that there is concern that generators may be compensated twice for the same plant capability if they receive payment for capacity in the PJM capacity market as well as reactive services. (Id. at 27-28.)

In its reply comments, the Public Staff offers that the issue of procurement of ancillary services from third parties has expanded beyond an avoided cost issue, and recommends that the Commission open a separate docket to solicit comments specifically related to a potential pilot program with Duke Energy or more generally to the utilization of inverter based resources to provide ancillary services. The Public Staff notes that fewer third-party projects are selling their power through standard offer and negotiated contracts under PURPA, and that large-scale competitive procurements for renewable energy, such as Duke Energy's CPRE program and Carbon Plan through the ongoing Duke Energy 2022 Solar Procurement, are increasingly responsible for much of the solar interconnected to Duke Energy's grid. The Public Staff suggests that in the interest of minimizing the amount of regulatory attention diverted by the establishment of a pilot program for ancillary services, it may be beneficial for Duke Energy and stakeholders to focus on potential revisions to future competitive procurements triggered by need identified with the Carbon Plan, which might include dispatchable contracts and other mechanisms by which inverter based resources owned by third parties and Duke Energy can be utilized to provide ancillary services. (Public Staff Reply Comments at 4-7.)

SACE's and Joint Intervenors' reply comments support the Public Staff's suggestion for a pilot program to study the technical ability of QFs to provide ancillary services and the associated costs. (SACE Reply Comments at 4-5; Joint Intervenors Reply Comments at 7.) Joint Intervenors also suggest that the Commission establish a stakeholder process to evaluate the technical, contractual, and legal questions surrounding QF provision of ancillary services. (Joint Intervenors Reply Comments at 7.)

Discussion & Conclusions

In the Sub 158 Order, the Commission directed the Utilities to address the potential for QFs to provide positive ancillary services and, if warranted, the proper compensation for doing so. Specifically, the Commission stated that the Utilities should evaluate whether a "QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide." (Sub 158 Order at Ordering Paragraph 24.) In the Continuance Order, the Commission directed this issue be included in the issues to be addressed in this proceeding.

The Commission agrees with DENC and the Public Staff that PURPA does not require purchase of or compensation for ancillary services. The Commission further agrees with DENC that PURPA also does not require it to facilitate access to markets for QFs. Based on the evidence presented, the Commission also concludes that, due to DENC's membership in PJM and the market rules and processes already established in RTO for the provision of and compensation for ancillary services, it would not be appropriate or reasonable to include DENC in any further evaluation of the potential for QFs to provide and receive compensation for ancillary services.

The Commission agrees with DENC that ancillary services should not be part of DENC's avoided cost rates because its customers already pay for ancillary services obtained by PJM, and the PJM market structure does not allow for DENC's customers to avoid any ancillary costs due to a QF providing an ancillary service, even assuming that the QF had the technical ability to provide the service. Due to its participation in PJM, DENC's North Carolina customers would not realize any benefit of any ancillary services that a QF was able to provide, if it could provide them, but instead its North Carolina ratepayers would bear the full cost of such services. The Commission finds that requiring payment for any ancillary services that a QF was able to provide would therefore contradict the fundamental principle of PURPA that the utility cannot be required to pay more than its avoided cost for QF output. Any additional proceedings or pilots addressing this issue should therefore not apply to DENC, and no further action or analysis by or relating to DENC is needed at this time with regard to the potential for QFs to provide and receive compensation for ancillary services.

Taken together with the Commission's findings and conclusions discussed earlier in this order, the Commission further finds and concludes that DENC has sufficiently addressed through its Initial Statement and Exhibits and Reply Comments the Sub 158 Additional Issues that are relevant to DENC as directed by the Continuance Order, and no further action is required of DENC with regard to these issues at this time.

IT IS, THEREFORE, ORDERED as follows:

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

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

3. That DEP, DEC, and DENC shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's

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

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

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

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

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

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

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

10. That DENC shall use a re-dispatch charge of $1.87/MWh in calculating DENC's rates in this proceeding;

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

12. That DENC's proposed revisions to its LEO Forms, as modified, and proposed Retrofit Storage LEO Forms, as modified, are approved;

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

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _______________, 2022.

NORTH CAROLINA UTILITIES COMMISSION

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing *Proposed Order*, filed in Docket No. E-100, Sub 175, were served electronically or via U.S. mail, first-class postage prepaid, upon all parties of record.

This the 1st day of July, 2022.

/s/Andrea R. Kells

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