**STATE OF NORTH CAROLINA**
**UTILITIES COMMISSION**
**RALEIGH**

DOCKET NO. E-100, SUB 194

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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| In the Matter of<br>Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2023 | )<br>)<br>)<br>)<br>)<br>) | **JOINT INITIAL STATEMENT AND PROPOSED STANDARD AVOIDED COST RATE TARIFFS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC** |

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "the Companies"), pursuant to the Commission's August 7, 2023 Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing ("2023 Scheduling Order"), and submit this Joint Initial Statement and Exhibits in support of DEC's and DEP's proposed avoided cost rates, updated Schedule PP tariffs, and standard contract terms and conditions ("Submissions"). The Companies' Submissions set forth their proposed standard offer avoided cost rates for qualifying cogenerators and small power production facilities ("QFs") that are eligible for the Companies' respective Schedule PPs and establish a legally enforceable obligation ("LEO") committing to sell their output to the Companies on or after the date of this filing.

The Companies' Submissions are designed to comply with Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Federal Energy Regulatory Commission's ("FERC") regulations requiring standard rates for purchases from small QFs under PURPA, as well as North Carolina's biennial standard offer PURPA implementation framework.[1] The Companies' Submissions continue to reflect the use of the peaker methodology and standardized approach to calculating the Companies' avoided costs approved by the Commission in Docket No. E-100, Sub 175 (the "2021 Sub 175 proceeding"), which were informed by extensive engagement with the Public Staff and other stakeholders.

As detailed in this Joint Initial Statement, the Companies' standard avoided costs set forth in Schedule PP have increased since 2021. When weighted based on a generic solar profile, DEC's avoided cost rates have increased by approximately 24% while DEP's avoided cost rates have increased by approximately 13% when compared to the avoided cost rates approved by the Commission in the 2021 Sub 175 proceeding.[2] Drivers for the increase in proposed avoided cost rates include higher energy rates due to increases in market fuel prices and higher capacity rates due to the first avoidable capacity need for DEC and DEP falling earlier within their respective 10-year rate period coupled with a higher CT overnight cost when compared to the 2021 Sub 175 proceeding.

In addition to presenting the Companies' updated standard offer avoided cost rates and Schedule PP Submissions, DEC and DEP are also presenting their updated Net Excess Energy Credits ("NEEC") as directed by the Commission's March 23, 2023 Order Approving Revised Net Metering Tariffs in Docket No. E-100, Sub 180 (the "Sub 180 NEM Order") and August 3, 2023 Order Establishing Net Excess Energy Credit for NEM Tariff in Docket No. E-100, Sub 175 (the "Sub 175 NEEC Order").

[1] As required by 18 C.F.R. § 292.302(b)(1)-(3), the Companies are also filing with the Commission their respective forecasted system cost data from which avoided costs may be derived. This information was most recently filed on November 2, 2020, in the 2020 biennial avoided cost proceeding (Docket No. E-100, Sub 167).

[2] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 175 (Nov. 22, 2022) ("Sub 175 Order").

In support of this Joint Initial Statement and the Companies' Submissions, as well as the updated NEEC calculations presented herein, DEC and DEP respectfully show the Commission as follows:

## I. INTRODUCTION AND BACKGROUND ON NORTH CAROLINA'S IMPLEMENTATION OF PURPA

### A. PURPA'S Mandatory Purchase Obligation and Standard Offer Requirements

Pursuant to Sections 201 and 210 of PURPA, electric utilities such as DEC and DEP are required to offer to purchase electric energy from qualifying cogeneration and small power production facilities or "QFs."[3] This is known as the "mandatory purchase obligation" under PURPA.

PURPA requires that the rates electric utilities pay to purchase QF energy shall not exceed the electric utilities' "avoided costs," which PURPA defines as the incremental cost to the electric utility of the electric energy, which, but for the purchase from such QFs, such utility would generate or purchase from another source.[4] PURPA also requires that the rates for purchases of QF power be set in a manner that is just and reasonable to the utility's customers, in the public interest, and nondiscriminatory towards QFs.[5] In enacting PURPA, Congress directed FERC to prescribe regulations to encourage the development

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[3] *See* 16 U.S.C. § 824a-3(a).

[4] Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69 at 7, FERC Stats. & Regs. ¶30,128, (1980) ("FERC Order No. 69" or "Order No. 69"); *see also* Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978, 23 FERC ¶ 61,304, 61,644 (1983). On July 16, 2020, FERC issued Order No. 872, which approved certain revisions to its regulations implementing Sections 201 and 210 of PURPA. These revised rules became effective December 31, 2020. *See* Qualifying Facility Rates and Requirements, Order No. 872, 85 Fed. Reg. 54,638 (Sept. 2, 2020), 172 FERC ¶ 61,041 ("FERC Order No. 872" or "Order No. 872"); Qualifying Facility Rates and Requirements, Order No. 872A, 173 FERC ¶ 61,158 (Nov. 19, 2020) ("FERC Order No. 872A").

[5] *See* 18 C.F.R. § 292.304(a).

of QFs under PURPA and delegated to state commissions the responsibility of implementing FERC's regulations, including PURPA's mandatory purchase obligation.[6] In 1980, FERC issued its initial rulemaking order, FERC Order No. 69, establishing regulations to implement PURPA. Among FERC's regulations to implement PURPA, FERC prescribed additional details regarding electric utilities' obligation to purchase energy and capacity made available by QFs, including expressly prescribing that electric utilities shall not be required to pay more than the avoided costs for purchases from QFs.[7]

FERC also recognized in Order No. 69 that smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates with electric utilities and required states implementing PURPA to make standard rates and terms available to QFs that are 100 kilowatts ("kW") and smaller.[8] FERC's regulations also provide that states "may" put into effect standard rates for purchases for QFs larger than 100 kW.[9]

In 2020, FERC issued Order No. 872 revising its regulations implementing PURPA's mandatory purchase obligation "based on demonstrated changes in circumstances since [its] PURPA Regulations were first adopted to ensure that the regulations continue to comply with PURPA's statutory requirements established by Congress."[10] Order No. 872's modifications to FERC's regulations implementing PURPA provide additional options to utilities and state regulatory authorities in implementing the mandatory purchase obligation requirements of PURPA that "are designed to benefit QFs,

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[6] *See* 16 U.S.C. § 824a-3(f); *see also FERC v. Mississippi*, 456 U.S. 742, 750-51, 102 S.Ct. 2126 (1982).

[7] *See* 18 C.F.R. § 292.303(a); 18 C.F.R. § 292.304(a)(2).

[8] *See* Order No. 69 at 12,223; 18 C.F.R. § 292.304(c).

[9] 18 C.F.R. § 292.304(C)(2).

[10] Order No. 872 at ¶ 20.

purchasing utilities, and electric consumers."[11] The Companies' most recently approved Notice of Commitment Form was revised to reflect, among other things, the new commercial viability and financial commitment requirements for establishing a legally enforceable obligation, as established in Order No. 872.[12] The Companies' as-available rate methodology approved in the 2021 Sub 175 proceeding for purchasing QF energy at rates based on the Companies' avoided cost for energy calculated at the time of delivery also aligns with the updated Order No. 872 framework for calculating avoided costs.[13] The Companies will continue to monitor market developments and assess whether to further incorporate additional aspects of the new avoided cost rate setting options established under Order No. 872 in future avoided cost proceedings.[14]

### B. Implementation of PURPA in North Carolina

Through PURPA, Congress delegated to this Commission the responsibility of implementing PURPA's mandatory purchase requirements, consistently with FERC's PURPA regulations.[15] North Carolina's PURPA implementation framework requires the Commission to implement PURPA through biennial avoided cost proceedings, and specifically, to approve standard contract avoided cost rates and power purchase

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[11] *Id.* at ¶ 28; *see also* 18 C.F.R. § 292.304.

[12] *See* 18 C.F.R. § 292.304(d)(3); Order No. 872 at ¶¶ 684-96.

[13] Sub 175 Order at 50-53.

[14] In addition to offering avoided cost rates set in this proceeding, the Companies also regularly issue competitive procurements of renewable energy that are open to solar QFs (and may be opened to other small power producer QFs in the future) that provide an alternative framework for QFs to sell controllable and renewable power to the Companies at the Companies' avoided cost of competitively procuring such resources. A "Competitive Solicitation Price" determined through a transparent and non-discriminatory competitive solicitation may be used to establish QF energy and/or capacity rates under PURPA. *See* 18 C.F.R. § 292.304(b)(8). Order No. 872 at ¶¶ 114-22.

[15] Order No. 69, at 7; *see also* Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978, 23 FERC ¶ 61,304, 61,644 (1983). On July 16, 2020, FERC issued Order No. 872, 172 FERC ¶ 61,041 (2020), which approved certain revisions to its regulations implementing Sections 201 and 210 of PURPA. These revised rules became effective December 31, 2020.

agreements to be used by the State's electric public utilities in purchasing energy and capacity from small power producers.[16] Pursuant to N.C.G.S. § 62-156, the Companies' standard offer avoided cost rates and contracts are currently available to QFs up to 1,000 kW.[17] The statute further provides that eligibility for the standard offer shall prospectively be reduced to a capacity eligibility limit of 100 kW after each electric public utility enters into power purchase agreements ("PPA") with an aggregate new capacity of 100 MW subsequent to November 15, 2016.[18]

North Carolina also limits the maximum length of fixed-term standard offer rates and contracts to 10 years and has refined the calculation of avoided capacity cost rates.[19] Section (b)(3) of N.C.G.S. § 62-156 further directs that a future capacity need shall only be avoided in a year where the Companies' most recently approved biennial integrated resource plan ("IRP") has identified a projected capacity need to serve system load and the identified need can be met by the type of QF resource based upon its availability and reliability of power.[20] Additionally, with respect to the calculation of avoided cost rates, Section (b)(2) provides that a determination of the utility's avoided energy costs shall include consideration of the following factors over the term of the PPA: (i) the expected costs of the additional or existing generating capacity that could be displaced; (ii) the

[16] N.C.G.S. § 62-156(b).

[17] N.C.G.S. § 62-156(b)(1).

[18] *Id.* As of the date of this filing, nine QFs totaling 5.81 MW have executed standard offer PPAs committing to sell their output to DEC and 10 QFs totaling 1.498 MW have executed standard offer PPAs committing to sell their output to DEP under either the standard offer rates and terms in effect since November 15, 2016.

[19] *Id.*

[20] N.C.G.S. § 62-156(b)(3). Exceptions to this IRP-designated first year of capacity need standard include certain hydroelectric QFs and swine and poultry QFs selling under the State's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"), as further discussed in Section III.C.1 of the Companies' Joint Initial Statement.

expected cost of fuel and other operating expenses of electric energy production that a utility would otherwise incur in generating or purchasing power from another source; and (iii) the expected security of the supply of fuel for the utility's alternative power sources.[21] Finally, N.C.G.S. § 62-156(c) limits the maximum term of fixed price mandatory purchase contracts under PURPA to five years.

### C. **<u>The Commission's Prior Orders[22] Approving the Companies' Standardized Avoided Cost Methodology, Rates, and Contracting Documents</u>**

The Commission has implemented the State's current PURPA implementation framework in the past four avoided cost proceedings in 2016-2017 ("2016 Sub 148 proceeding"), 2018-2019 ("2018 Sub 158 proceeding"), 2020-2021 ("2020 Sub 167 proceeding"), and most recently in the 2021 Sub 175 proceeding. As part of this implementation process, the Commission's April 15, 2020, Sub 158 Order directed the Utilities (and primarily DEC and DEP) to develop additional refinements to their standard offer avoided capacity and energy rates. These 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 metric, to support development of the performance adjustment factor ("PAF");
- The extent of backflow at substations;

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[21] N.C.G.S. § 62-156(b)(2).

[22] Order Establishing Standard Rates and Contract Terms of Qualifying Facilities, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("Sub 148 Order"); Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 158 (Apr. 15, 2020) ("Sub 158 Order"); Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 167 (Aug. 13, 2021) ("Sub 167 Order").

- The potential for QFs to provide ancillary services and appropriate compensation; and
- The results of an independent technical review of the Astrapé Study solar integration services charge ("SISC") methodology (together, the "Sub 158 Additional Issues").

Through Fall 2021, the Companies worked to address the Sub 158 Additional Issues, including through significant engagement with the Public Staff, Dominion Energy North Carolina ("DENC"), and stakeholders. The Companies reported their progress regarding the Sub 158 Additional Issues to the Commission in eight progress reports filed in the 2020 Sub 167 proceeding, and the Commission's Sub 167 Order[23] identified three additional issues for the Companies to address in their November 1, 2021 filings:

- Continuation of the PAF to be applied to avoided capacity rates for hydro QFs 1 MW or less;
- Avoided hedging costs; and
- The inclusion of start costs for production cost modeling used to determine avoided energy rates.

The Companies engaged in significant discussions with the Public Staff, DENC, and other stakeholders on these issues in an attempt to achieve consensus for a standardized approach to calculate their avoided costs and to minimize the number of contested issues in avoided cost proceedings. The Companies addressed each of these issues in the 2021 Sub 175 proceeding, highlighting the considerable alignment achieved, and the Commission approved the Companies' refinements to their standardized avoided costs calculation approach in its final order.[24]

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[23] Sub 167 Order at 58.

[24] Sub 175 Order at 14 ("The Commission has approved the use of the peaker method as reasonable and appropriate for deriving forecasted avoided capacity costs in . . . a number of prior biennial avoided cost proceedings. The Commission has also developed significant guidance through prior orders in past biennial

As part of preparing their 2023 Submissions and consistent with the Commission's Sub 175 Order, the Companies considered other potential methodologies for calculating long-term fixed avoided cost rates, including those identified by FERC in Order No. 872 and as codified in 18 C.F.R. § 292.304(b). As described in more detail below, the Companies determined that continued use of the peaker methodology and the standardized approach to calculating avoided costs used in the Companies' previous filings and approved most recently in the Sub 175 Order is the most appropriate means by which to calculate the Companies' avoided costs at this time. Accordingly, the Companies' 2023 Submissions and avoided cost rate calculations presented in this Joint Initial Statement continue to utilize the most recent Commission-approved, standardized approach to calculating their forecasted avoided costs of capacity and energy to be delivered over specified future terms.[25]

## II. OVERVIEW OF EXHIBITS FILED IN SUPPORT OF JOINT INITIAL STATEMENT

As required by Ordering Paragraph No. 3 of the 2023 Scheduling Order, DEC and DEP each submit for approval proposed standard avoided cost rates, tariffs, and contract documents, as further discussed and supported herein.

(1) DEC Exhibit 1 presents proposed clean and redlined copies of DEC's Purchased Power Schedule PP.

(2) DEC Exhibit 2 (Confidential) presents supporting calculations for the energy and capacity credits, inflation rates, and discount rates used to derive DEC's

avoided cost proceedings that inform how the peaker method is applied by utilities in North Carolina and the Commission finds value in retaining this framework for this proceeding."); *see generally* Sub 175 Order at 67-72 (approving the Companies' avoided cost methodology, calculations, and rates).

[25] *See* 18 C.F.R. § 292.304(d)(1)(ii).

proposed avoided capacity and energy cost rates. Information included in Exhibit 2 is designated Confidential and is being filed under seal.

(3) DEC Exhibit 3 presents clean and redlined copies of DEC's proposed Standard Offer Power Purchase Agreement available to QFs eligible for Schedule PP.

(4) DEC Exhibit 4 presents clean and redlined copies of DEC's proposed Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions").

(5) DEC Exhibit 5 presents DEC's annualized rates.

(6) DEC/DEP Exhibit 6 presents clean and redlined copies of the Companies' updated Notice of Commitment Form for QFs eligible for Schedule PP.

(7) DEC/DEP Exhibit 7 presents clean and redlined copies of the Companies' Notice of Commitment Form for QFs larger than 1 MW in size.

DEP Exhibits 1-5 present the same information for DEP as described above for DEC, while the Notice of Commitment Forms presented in Exhibit 6 and Exhibit 7 are applicable to both Companies. The Companies further address the updates presented in these Exhibits to this Joint Initial Statement in Parts III through VIII that follow.

The Companies are also filing certain studies and supporting documents to be included in the record in this proceeding as support for their proposed standard avoided cost rates and corresponding contracting documents:

(8) DEC/DEP Exhibit 8 (Confidential) provides additional technical support for certain inputs to DEC's and DEP's avoided energy and capacity cost calculations.

(9) DEC/DEP Exhibit 9 shows the geographical location of substations with

backflow in North Carolina and South Carolina as further addressed in Section III.b.3 of the Companies' Joint Initial Statement.

(10) DEC/DEP Exhibit 10 is the Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study, prepared by Astrapé Consulting (the "2023 SISC Study").

Finally, the Companies are presenting their NEEC methodology and updated calculations pursuant to the Commission's 2023 Sub 180 NEM Order.

(11) DEC Exhibit 11 presents DEC's updated NEEC rates, and DEP Exhibit 11 presents DEP's updated NEEC rates consistent with the Commission-approved methodology.

## III. LONG-TERM FIXED AVOIDED COST RATE METHODOLOGY AND CALCULATIONS

### A. Peaker Methodology

In both North Carolina and South Carolina, the Companies have historically applied the "peaker methodology" (the "peaker method") to quantify each utility's avoided costs, and the Companies believe this method continues to be reasonable and appropriate for calculating DEC's and DEP's forecasted avoided costs as presented in this proceeding. The Commission has consistently approved the Companies' continued use of the peaker method as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs, including most recently in the 2021 Sub 175 proceeding.[26] As recognized in these prior avoided cost proceedings, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a

[26] *See* Sub 175 Order at 5 (Finding of Fact No. 4); Sub 167 Order at 60 (Ordering Paragraph No. 8); Sub 158 Order at 134 (Ordering Paragraph No. 10); *see also* Order Setting Avoided Cost Inputs, Docket No. E-100, Sub 140 at 8 (Finding of Fact No. 6) (Dec. 31, 2014) ("Phase I Sub 140 Order").

combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)."[27] In particular, the peaker method is recognized as an acceptable method for determining avoided cost in the widely relied-upon PURPA Title II Compliance Manual published by the National Association of Regulatory Utility Commissioners, the Edison Electric Institute, and other industry organizations.[28] The Companies' use of the peaker method has also been approved by the Public Service Commission of South Carolina.[29]

In the Sub 175 Order, the Commission directed the Utilities "to evaluate before the next biennial proceeding whether to propose an alternative method to calculate avoided costs, including those FERC has recently determined to be reasonable and appropriate for calculating avoided costs in Order No. 872 and that are now included in 18 C.F.R. 292.304(b)."[30] FERC Order No. 872 identified three non-exclusive potential methodologies for calculating a utility's avoided costs:

- *Locational Marginal Price*. FERC Order No. 872 established a "rebuttable presumption that a state regulatory authority or nonregulated electric utility may use a Locational Marginal Price as a rate for as-available qualifying facility

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

[28] Robert Burns & Ken Rose, PURPA Title II Compliance Manual at 35 (Mar. 2014) ("PURPA Title II Compliance Manual"), *available at* https://www.naruc.org/our-programs/resources/; *see also* PURPA Title II Compliance Manual 2.0 at 72 (July 2021), *available at* https://pubs.naruc.org/pub/47AD30DC-1866-DAAC-99FB-975A60906D6B.

[29] Order Regarding Avoided Cost Methodologies, Standard Offers, Form Contracts, and Commitment to Sell Forms, Order No. 2022-330, Docket Nos. 2021-89-E & 2021-90-E (S.C.P.S.C. May 5, 2022).

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

energy sales to electric utilities located in a marked defined in § 292.309(e), (f), or (g).”[31]

- *Competitive Price.* “A state regulatory authority or nonregulated electric utility may use a Competitive Price as a rate for as-available qualifying facility energy sales to electric utilities located outside a market defined in § 292.309(e), (f), or (g). A Competitive Price may be either a Market Hub Price or a Combined Cycle price[.]”[32]

- *Competitive Solicitation Price.* “A state regulatory authority or nonregulated electric utility may use a price determined pursuant to a competitive solicitation process to establish qualifying facility energy and/or capacity rates for sales to electric utilities, provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner[.]” FERC’s regulations provide that a solicitation must be open and transparent, open to all sources, satisfy that electric utility’s capacity needs, taking into account the required operating characteristics of the needed capacity, conducted at regular intervals, subject to oversight by an independent administrator, and certified as fulfilling these criteria by state regulatory authority through a post-solicitation report.[33]

FERC also amended its regulations to clarify that rates for purchases of energy from a QF pursuant to a legally enforceable obligation may vary through the life of the obligation and be set at the electric utility’s avoided cost for energy calculated at the time of delivery.[34]

In the 2021 Sub 175 proceeding, the Companies proposed and the Commission approved an updated as-available energy or marginal cost rate[35] methodology that generally aligns with the Locational Marginal Price (“LMP”) concept as applicable to the Carolinas.[36] Based upon a review of the Companies’ current PURPA implementation

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[31] 18 C.F.R. § 292.304(b)(6).

[32] 18 C.F.R. § 292.304(b)(7).

[33] 18 C.F.R. 292.304(d)(2).

[34] *Id.*

[35] As described in Section IV of this Joint Initial Statement, the Companies are proposing to rename the Marginal Cost Rate in the current Schedule PP to the As-Available Rate in proposed Schedule PP.

[36] LMP is primarily applicable to utilities in regional transmission organizations. The Companies utilize a DEC/DEP system-wide proxy to calculate as-available rates.

framework as directed in the Sub 175 Order, the Companies have continued to utilize the current Commission-approved methodology for quantifying as-available energy delivered by a QF and have determined that it is not necessary to further update their PURPA implementation framework to adopt any of the methodologies identified in Order No. 872 for purposes of setting long-term fixed rates for avoided capacity and energy at this time.

Continued use of the Commission-approved peaker method to calculate the Companies' forecasted avoided costs of capacity and energy is consistent with the Companies' current, standardized approach to calculating avoided costs under N.C.G.S. § 62-156(b) and (c) remains non-discriminatory to QFs and just and reasonable to the electric consumer and in the public interest at this time.

### B. Incorporation of the Carbon Plan and Integrated Resource Plan ("CPIRP") into Avoided Cost Rates

In its Sub 175 Order, the Commission also directed the Companies to "explain in their next biennial avoided cost filings how the Carbon Plan has been incorporated into avoided cost rates and how any Commission-approved avoidable cost of carbon is factored into Duke's calculation of avoided cost rates."[37] The Commission also reiterated its expectation that inputs and assumptions used to develop avoided cost rates should be aligned with resource planning assumptions used in the Companies' most recent resource plan, which is the Companies' CPIRP as filed with the Commission on August 17, 2023, in Docket No. E-100 Sub 190.[38]

To appropriately incorporate the CPIRP into the Companies' avoided costs, the

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

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

Companies calculated their avoided energy and capacity costs using data from the 2023 CPRIP Core Portfolio P3 Base ("Portfolio P3"), which is the reference portfolio identified in the Companies' most recent biennial CPIRP filed with the Commission.[39] Using Portfolio P3 is consistent with past Commission guidance to align the avoided cost filing with the utility's most recent IRP—here, the CPIRP.[40]

### C. Avoided Capacity Cost Calculations

In the Sub 175 Order, the Commission directed the utilities to "continue to calculate avoided capacity costs using the peaker method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need."[41]

#### i. First Year of Avoidable Capacity Need

DEC and DEP have developed their avoided capacity rates consistent with the methodology that they used in the 2018 Sub 158, 2020 Sub 167, and 2021 Sub 175 proceedings and that the Commission most recently approved in the Sub 175 Order as appropriately implementing N.C.G.S. § 62-156(b)(3). As background, the Commission's Sub 158 Order directed the Companies to include in future IRPs a clear statement identifying each utility's first year of avoidable capacity need to be used in determining their respective avoided capacity costs.[42]

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[39] CPIRP Appendix C at 56.

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

[41] Sub 175 Order at 70 (Ordering Paragraph No. 5).

[42] *Id.* at 10 (Findings of Fact Nos. 19, 22).

Appendix C (Quantitative Analysis) to the 2023 CPIRP presents DEC's and DEP's quantification of their next avoidable capacity need.[43] DEP's next avoidable undesignated capacity need occurs in 2024, while DEC's next avoidable undesignated capacity need occurs in 2028. As compared to the 2021 Sub 175 proceeding, both DEC's and DEP's first years of avoidable capacity need are unchanged. However, due to the passage of time, this represents an earlier capacity need in the 10-year calculation span than used to calculate the prior 2021 Sub 175 avoided cost rates. The Companies' analysis to determine their respective first years of avoidable capacity need is further detailed in DEC/DEP Exhibit 8.

Also consistent with the Sub 175 Order and N.C.G.S. § 62-156(b)(3), DEC and DEP have included alternative avoided capacity rate calculations in their Schedule PP rates that recognize that certain QFs fueled by swine waste, poultry waste, and certain existing hydro power QFs less than 5 MWs, are assigned immediate capacity value.[44]

**ii. Avoided CT Unit Cost Assumptions**

Prior to making their initial filing in the 2021 Sub 175 proceeding, DEC and DEP worked with the Public Staff and DENC to develop the methodology for calculating CT cost estimates using publicly available sources, such as the United States Energy Information Administration ("EIA"), as directed by the Commission in its Sub 158 Order.[45] The parties arrived at a consensus standardized approach to streamline the determination of the avoided CT capacity cost in a manner that fairly values the avoided capacity cost for

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[43] CPIRP Appendix C at 112-13.

[44] Sub 167 Order at 6 (Finding of Fact Nos. 7, 17, 60) (Ordering Paragraph No. 8). In its Sub 158 Order, the Commission found that the clear intent of the General Assembly is to treat swine and poultry waste QF resources and 5 MW or less legacy hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period.

[45] *See* Sub 158 Order at 32-33, 134 (Ordering Paragraph No. 9).

QFs while ensuring customers do not overpay for capacity. The Commission found that approach to be "reasonable, consistent with prior Commission orders, and appropriate for the purposes of calculating avoided capacity costs[,]"[46] and the Companies have implemented the same standardized approach in this proceeding. DEC/DEP Exhibit 8 provides additional supporting information for the standardized CT cost calculation methodology, which is aligned with the methodology used by DENC.

For the fixed operations and maintenance ("FOM") cost component, the Companies used the publicly available FOM data from the same EIA data source and made adjustments using internal data to reflect the FOM economies of scale associated with a four-unit CT project. DEC/DEP Exhibit 8 also provides additional supporting information for the FOM cost component.

**iii. Performance Adjustment Factor Capacity Multiplier**

In past avoided cost proceedings, the Commission has recognized the PAF as a capacity multiplier designed to address standard avoided capacity rates being paid on a per-kWh basis, such that setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours.[47] The Commission determined that avoided capacity rates excluding a PAF left QFs without any reasonable opportunity to experience outages during each peak period and receive the total available avoided capacity payment.[48] Thus, the PAF recognizes that the Utilities' generating units experience unplanned outages and do not operate 100% of the

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[46] Sub 175 Order at 14.

[47] *See* Sub 158 Order at 40 (describing the history of the PAF).

[48] *Id.*

time during peak periods and allows QFs to also experience unplanned outages during peak periods and still receive the utility's full avoided capacity costs.[49]

Prior to making their initial filing in the 2021 Sub 175 proceeding, the Companies worked with DENC and the Public Staff to consider the use of appropriate reliability metrics for developing the PAF. These discussions resulted in a consensus to adopt the Weighted Equivalent Unplanned Outage Factor ("WEUOF") metric for each utility's respective generation fleet to calculate the PAF, and the Commission approved this consensus approach in its Sub 175 Order.[50] Accordingly, the Companies have continued to use the standardized WEUOF methodology to calculate their respective PAFs in the current proceeding. DEC's and DEP's respective system WEUOF averages to approximately 4.8% and 6.5%, respectively, which results in a PAF of 1.05 for DEC and 1.07 for DEP. DEC/DEP Exhibit 8 provides additional supporting information for the PAF calculation.

#### iv. Proposed Discontinuation of the Outdated 2.0 PAF for Run-of-River Hydro QFs

North Carolina's legacy implementation of PURPA afforded hydro QFs with unique legislative treatment that, for a number of years, resulted in the utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[51] The Commission approved a 2.0 PAF for run-of-river hydro QFs more than two decades ago in the 1996 avoided cost proceedings in Docket No. E-100, Sub 79.[52] Based in part on that

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[49] *Id.*

[50] Sub 175 Order at 20.

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

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

unique legislative treatment and the Commission's then-existing 2.0 PAF for run-of-river hydro QFs without storage, the Companies and the NC Hydro Group entered into a stipulation in 2014 in Docket No. E-100, Sub 140[53] ("Hydro Stipulation"), in which the parties agreed, among other things, that the Companies would continue to include the previously-approved 2.0 PAF in standard offer tariffs filed at the Commission prior to December 31, 2020 and to use a 2.0 PAF to calculate the avoided cost rates for small hydro QFs of 5 MWs or less through December 31, 2020.[54] As the Commission recognized in the Sub 158 Order[55] and in the prior Sub 148 Order,[56] the General Assembly has subsequently amended the State's implementation of PURPA through Session Law 2017-192 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while, at the same time, establishing flexibility for the Companies to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in calculating future avoided cost rates.[57] Because of these legislative changes pertaining to hydroelectric generating facilities, the Commission found it appropriate in the 2018 Sub 158 proceeding "to consider again the question of the appropriate PAF to apply in calculating capacity rates to run-of-the-river hydro QFs after the natural expiration of the Hydro Stipulation."[58]

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

[54] Hydro Stipulation at ¶¶ 3(a), 4.

[55] Sub 158 Order at 42.

[56] Sub 148 Order at 39.

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

[58] Sub 158 Order at 42.

In the 2020 Sub 167 proceeding, when the expiration of the Hydro Stipulation was imminent, the Companies explained that they would retain the 2.0 PAF for run-of-river hydro QFs 1 MW and less eligible for the standard offer (in effect from November 1, 2020, until October 31, 2021). The Companies noted, however, that the Hydro Stipulation expired on December 31, 2020. Accordingly, the Companies indicated that they would include the 2.0 PAF for negotiated PPAs with hydro QFs greater than 1 MW but less than 5 MWs until December 31, 2020.[59] In the Sub 167 Order, the Commission cited the expiration of the Hydro Stipulation and agreed with the Companies' conclusion that, after December 31, 2020, they "are no longer required to offer a 2.0 PAF to run-of-river hydro QFs greater than 1 MW but less than 5 MWs."[60] The Commission also directed the Companies to address the appropriate PAF for run-of-river standard offer hydro QFs in their Sub 175 initial statement.[61]

In the 2021 Sub 175 proceeding, the Companies proposed to discontinue the 2.0 PAF on the grounds that the Hydro Stipulation, by its plain terms, does not require the continuation beyond December 31, 2020, of an elevated PAF for any run-of-river hydro QFs under 5 MWs in capacity, regardless of whether the actual capacity is below, at, or above 1 MW.[62] The Companies also highlighted the State's reforms to PURPA implementation providing flexibility to enter into longer-term avoided cost rate contracts with certain QFs and to value legacy hydro QF capacity less than 5 MW in calculating new avoided cost rates for these facilities. Although the Commission acknowledged expiration

[59] Joint Initial Statement, Docket No. E-100 Sub 167 at 17-18 (Nov. 2, 2020).

[60] Sub 167 Order at 20.

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

[62] *See* Hydro Stipulation, at ¶¶ 2-4.

of the Hydro Stipulation and the fact that no party offered any justification for extending the 2.0 PAF, the Commission found that "the parties did not fully litigate this issue" and directed the Companies to continue the 2.0 PAF.[63] The Commission further noted that it "may consider whether to discontinue the 2.0 PAF based on evidence presented in the next avoided cost proceeding."[64]

Accordingly, DEC and DEP are proposing standard offer avoided cost rates for run-of-river hydro QFs that are equivalent to other QFs and reflect the same standard PAF of 1.05 for DEC and 1.07 for DEP, not the elevated and outdated PAF of 2.0. The Commission has already approved standardizing the PAF adder for run-of-river hydro QFs that are in excess of 1 MW and subject to bilaterally negotiated PPAs with the PAFs paid to the other renewable resource generators. In Docket No. E-7, Sub 1254, Northbrook Carolina Hydro, LLC ("Northbrook"), a 5 MW run-of-river hydro QF, filed a complaint and a request for the Commission to issue a declaratory ruling that its PPA, which included a 1.06—and not a 2.0 PAF—was inconsistent with N.C.G.S. § 62-156(c) and the avoided cost methodology established in the Sub 158 Order. In its April 18, 2022 Order Denying Motion to Dismiss and Denying Requested Relief ("Northbrook Order"), the Commission noted that the avoided cost methodology approved in the Sub 158 Order provided that requiring a 2.0 PAF to calculate the avoided cost rates of hydro QFs without storage was appropriate until expiration of the Hydro Stipulation (December 31, 2020). The Commission further found that it was appropriate under the Sub 158 Order, "to transition hydroelectric QFs currently selling the output of their facilities pursuant to the Hydro Stipulation *to an applicable sales*

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[63] Sub 175 Order at 20.

[64] *Id.*

*agreement that is generally available to QFs, either the utility's standard offer contract or a negotiated contract, beginning December 31, 2020*."[65] Northbrook began its negotiations for a new PPA with DEC in January 2021, after the December 31, 2020 expiration of the Hydro Stipulation. Accordingly, the Commission denied Northbrook's claim for a 2.0 PAF in its negotiated PPA, concluding that "[a]fter the expiration of the Hydro Stipulation, or after December 31, 2020, the Commission-approved avoided cost methodology for the PAF for Small Hydro QFs is the same for all other QFs."[66] Because Northbrook exceeded 1 MW, the Commission did not directly address the question of the appropriate PAF for hydro QFs 1 MW or less that remain eligible for the standard offer. However, the Commission noted in its discussion that "the method by which avoided costs are calculated should, to the extent possible, remain consistent in both standard and negotiated contacts."[67]

Continuing to apply the elevated 2.0 PAF does not reflect the Companies' forecast of avoided capacity costs or otherwise results in customer indifference and runs contrary to the basic principles of PURPA. For this reason, the Companies again propose to discontinue to 2.0 PAF.

**D. Avoided Energy Cost Calculations**

Avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt-hour ("$/MWh"),

[65] Order Denying Motion to Dismiss and Denying Requested Relief, Docket No. E-7, Sub 1254 at 5 (Apr. 18, 2022) (emphasis added) (internal quotations and citation omitted).

[66] Northbrook Order at 7.

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

include items such as avoided fuel and avoided variable operating and maintenance ("VOM") expenses. The peaker method credits the QF for avoiding energy, more specifically fuel and VOM costs, from the most expensive units projected to be operating on the system at a given point in time, which are often referred to as marginal units. Consistent with the standardized approach followed in the 2021 Sub 175 proceeding and prior proceedings, the Companies have relied upon the EnCompass production cost model to derive the Companies' system marginal energy costs, which represents the forecasted energy costs that a QF could avoid. The Companies have updated their avoided energy cost calculations consistent with the Sub 175 Order, as further described below.

**i. Natural Gas Commodity Price Forecast Methodology**

In the Sub 175 Order, the Commission approved calculation of the Companies' respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period.[68] However, the Companies acknowledged in both their 2021 Joint Initial Statement and Reply Comments that they had committed in the Carbon Plan stakeholder meetings to adjust their natural gas forecasting methodology to (1) reflect five years of forward market natural gas forecasts followed by three years of blending before transitioning to fundamental forecasts; and (2) utilize the average of fundamental forecasts developed by EIA, and IHS to calculate market fundamental pricing. The Commission's Sub 175 Order likewise acknowledged that "the natural gas forecasting method proposed by Duke in its Carbon Plan will be more appropriate for use in the [2023] avoided cost

[68] Sub 175 Order at 23.

biennial proceeding."[69] Consistent with the Companies' commitment to stakeholders, both the Companies' 2022 Carbon Plan and 2023 CPIRP reflect this updated natural gas forecasting approach,[70] and the Companies have accordingly developed their avoided energy costs relying upon five years of forward natural gas pricing followed by three years of blending before transitioning to fundamental forecasts.

**ii. Avoided Fuel Hedging Cost Adjustment**

In the Sub 175 Order, the Commission approved the Companies' fuel hedging adjustment, which utilizes the Black-Scholes Model to determine the hedging value of renewable generation. The Companies have applied the same standardized approach to calculate the avoided fuel hedging adjustment in this proceeding. The Companies' Black-Scholes calculation resulted in a fuel hedge value of $0.80/MWh and is incorporated in the Companies' avoided energy rates in this docket. DEC/DEP Exhibit 8 provides additional supporting information for the avoided fuel hedging adjustment.

**iii. Avoided Line Loss Adjustment for Standard Offer QFs under 1MW and Criteria for Distribution-Connected QFs Greater than 1 MW**

The Companies' Schedule PP, as approved in the 2021 Sub 175 proceeding and prior proceedings, includes avoided energy credits that vary depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. In the past, the Companies have consistently supported offering different avoided energy credits based on the point of interconnection to the Companies' systems, because this approach more accurately reflected differences in DEC's or DEP's actual avoided costs

[69] CPIRP Appendix C at 42-43.

due to differences in avoided energy line losses for transmission level and distribution level QFs. In the 2021 Sub 175 proceeding, the Companies evaluated the geographic concentration of backfeeding substations and found that both DEC and DEP are currently experiencing increasing levels of backflow into the transmission system due to increasing QF solar generation. The Companies' updated analysis showed in DEP that 106 out of 407 substation banks, or 26%, are backfeeding into the transmission system due to distribution-connected generation. For DEC, the percentages of substation banks experiencing backfeed due to distribution-connected projects continues to be significantly less—only 48 out of 1048 banks analyzed, or 4.6%, are backfeeding.

In the 2021 Sub 175 proceeding, the Companies also presented a map showing the geographic locations of substations with backflow in North Carolina and South Carolina. This exhibit showed the concentrated nature of QF solar development in more rural areas, especially in the DEP eastern North Carolina service territory. However, distribution-connected QFs were not as geographically concentrated in DEC or DEP territory as compared to DENC.[71] Based upon the Companies' analysis, both DEC and DEP proposed to maintain the line loss adder for standard offer-eligible QFs contracting under Schedule PP at this time. For QFs greater than 1MW that are not eligible for the standard offer, which could backflow a more significant amount of energy into the transmission system, the Companies proposed to assess the individual characteristics of the QF and address through negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate on a case-by-case basis. The Companies proposed to

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

assess the amount of potential backflow from distribution-connected QFs greater than 1 MW against the following criteria to determine if the line loss adder is appropriate: (i) the substation bank that serves the distribution point-of-interconnection has distributed energy resources ("DER") backflow of greater than or equal to 50%;[72] or (ii) the addition of the QF would cause the DER backflow to become greater than or equal to 50%. If these criteria are met, the QF will receive the transmission rates that exclude marginal loss factors for capacity and energy.

The Sub 175 Order approved the Companies' proposal to retain the line loss adders for standard offer-eligible QFs contracting under Schedule PP.[73] In addition, the Commission approved the proposed methodology for evaluating whether negotiated offer QFs are eligible for the line loss adder on a case-by-case basis.

For this proceeding, the Companies updated the backflow analysis and found that in DEP, 106 out of 415 substation banks, or 26%, are backfeeding into the transmission system due to distribution-connected generation. For DEC, 49 out of 1034 banks analyzed, or 4.7%, are backfeeding. The number of banks with backflow remains relatively unchanged since the 2021 analysis. DEC/DEP Exhibit 9 presents an updated map of the geographic locations of substations with backflow in North and South Carolina. These maps, like the backflow analysis, have changed little since the last analysis was completed in 2021. Based upon this updated analysis, the Companies propose to retain the line loss

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[72] The DER backflow percent is calculated by dividing the summation of backflow energy measured at the substation bank by the DER generation on that substation bank. Fifty percent (50%) backflow is the point in which the amount of DER generation being consumed locally equals the amount of DER generation backflowing into the transmission system.

[73] Sub 175 Order at 6 (Finding of Fact No. 17).

adder for standard offer-eligible QFs contracting under Schedule PP and continue to evaluate negotiated QFs on a case-by-case basis per the previously approved methodology.

#### iv. Updated Solar Integration Cost Decrement Supported by the 2023 SISC Study

The avoided costs (and the potential for increased ancillary service costs) associated with integrating incremental solar generation has been an issue of significant importance in recent avoided cost proceedings as North Carolina has experienced significant growth in utility-scale QF solar interconnected with and injecting power into the Companies' systems. In the last three avoided cost proceedings, the Commission has approved the Companies' proposed integration service charge specific to integrating new intermittent solar energy generation into the Companies' systems. These charges were calculated based upon solar integration cost studies conducted by Astrapé Consulting in 2018 ("2018 SISC Study")[74] and 2021 ("2021 SISC Study")[75] and were designed to quantify the impact on operating reserves, or increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity into the DEC and DEP systems. Both the 2018 SISC Study and 2021 SISC Study showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases.

The 2018 SISC Study quantified both the average integration cost for a given block of solar capacity as well as the higher, incremental integration cost associated with integrating additional increments of solar above the levels already interconnected to the DEC and DEP systems. Balancing the interests of customers and solar QFs, the Companies

[74] DEC's and DEP's Reply Comments, Exhibit 2, Docket No. E-100, Sub 158 (Mar. 27, 2019).

[75] 2021 Sub 175 Joint Initial Statement, Exhibit 11, Docket No. E-100, Sub 175 (Nov. 1, 2021).

requested approval of integration services charges that would apply only to new QFs requesting to sell power under Sub 158 avoided cost rates and that were designed to reflect the "average" (lower) integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources.

In response to a Commission directive in the Sub 158 Order, the Companies initiated an independent technical review of Astrapé's methodology and modeling used for system simulations to calculate the SISC. Brattle Consulting led the review as principal consultant with the involvement of technical experts from three national renewable energy laboratories as well as participation by the Public Staff and the South Carolina Office of Regulatory Staff as regulatory observers (the "Technical Review Committee" or "TRC").

Taking into account input from the TRC and at the Companies' direction, Astrapé Consulting developed the updated 2021 SISC Study that incorporated the TRC report's findings and updated its modeling and analysis of the integration costs associated with integrating incremental solar into the DEC and DEP systems. In its Sub 175 Order, the Commission found that the 2021 SISC Study "reasonably quantified solar integration costs for DEC and DEP" and "commend[ed] Duke and the TRC for the work undertaken to comply with [the Commission's] directive."[76] The Commission further directed that the Companies, in their next biennial avoided cost proceeding, should (1) address whether reserve levels used to calculate the SISC could be further refined depending on each day's volatility forecast; and (2) consider the effect of the SEEM, if any, on the calculation of the SISC.[77]

[76] Sub 175 Order at 38.

[77] *Id.*

To calculate the SISC for this 2023 avoided cost proceeding, the Companies again engaged Astrapé to conduct the 2023 SISC Study. Astrapé followed the same methodology to prepare revised SISC quantifications as supported by the TRC and approved by the Commission in its Sub 175 Order. Like the 2018 and 2021 SISC Studies, the 2023 SISC Study quantified both the average integration cost for a given block of solar capacity as well as the higher, incremental integration cost associated with integrating additional increments of solar above the levels already interconnected to the DEC and DEP systems. Balancing the interests of customers and solar QFs, the Companies are again requesting approval of integration services charges that would apply only to new QFs requesting to sell power under Sub 194 avoided cost rates and that were designed to reflect the "average" (lower) integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources.[78]

Consistent with the Commission's directive, the updated 2023 SISC Study addresses the appropriate operating reserve levels consistent with the weather-adjusted 8,760 hour forecast for the 2027 study year in question. For example, more flexible utility-scale storage resources are forecasted including battery capacity of 370 MW in DEC and 327 MW in DEP. Additionally, the 2023 SISC Study has factored in the effect of SEEM upon the final results, utilizing 25 MW blocks of min/max capacity ranging from $30-$60/MWh, totaling 200 MW in total for the Companies.

Based upon Astrapé's 2023 SISC Study, the Companies have incorporated solar

[78] Incremental integration costs identified in the 2018 Astrapé SISC Study for solar above the HB 589 mandated procurement requirements would have imposed significantly higher incremental integration cost but would not have needed to be updated as each vintage of solar QF would have been assigned their full incremental integration cost at the time of contracting. The Companies did not recommend this approach in the interest of balancing the impact on new QFs versus existing QFs.

integration cost decrements of $1.09 per MWh for DEC and $1.62 per MWh for DEP into the uncontrolled solar avoided energy rates. Consistent with the 2021 SISC study, these represent Tranche 2 Average SISC rates for DEC and DEP. DEC/DEP Exhibit 10 presents the 2023 SISC Study supporting the proposed SISC rates.

Finally, pursuant to the Commission's Sub 175 Order,[79] the Companies report that as of the date of this filing, there are no QFs that have contracted to sell QF power as a controlled solar generator to avoid the SISC.

## IV. "AS-AVAILABLE" RATES UNDER SCHEDULE PP

Under FERC's regulations implementing PURPA's mandatory purchase obligation, a QF may elect to sell energy either (1) as the QF determines energy to be available based on avoided cost rates "calculated at the time of delivery," or (2) pursuant to a legally enforceable obligation for delivery of energy or capacity over a specified term for rates calculated either at the time of delivery or at the time the obligation is incurred.[80] In Order No. 872, FERC amended its regulations to provide states greater flexibility to (i) utilize locational marginal prices (where available) or competitive prices to set rates for as-available QF energy sales[81] and (ii) mandate that variable avoided energy rates calculated at time of delivery could also be used to set the energy rates for QFs electing to sell energy pursuant to a LEO.[82] With respect to the latter, FERC provided state regulatory authorities

[79] Sub 175 Order at 38.

[80] 18 C.F.R. § 292.304(d)(1)-(2).

[81] 18 C.F.R. § 292.304(b)(6)-(7).

[82] 18 C.F.R. § 292.304(d)(1)(iii) ("The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery."); 18 C.F.R. § 292.304(d)(2) ("[A] state regulatory authority . . . may require that rates for purchases of energy from a qualifying facility pursuant to a [LEO] vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.").

"flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered."[83] Explaining this new rule, FERC recognized that allowing states to implement variable energy rates in QF contracts based on the time of delivery "ensures that QF rates do not exceed the avoided cost rate cap imposed by PURPA[,]" thus balancing the risk allocation between QFs and utility customers.[84]

Likewise, FERC underscored that the use of transparent market prices to establish as-available rates "allows those rates to automatically adjust—up and down—as avoided costs change."[85] Accordingly, FERC revised its regulations to permit state regulatory authorities to set "as-available" rates using either pricing established through a liquid market hub or "Combined Cycle Prices" established by a state-approved formula incorporating "published natural gas price indices, a proxy heat rate, and variable operations and management costs[.]"[86] FERC also identified that its regulations and intent in allowing these competitive pricing mechanisms is to allow States greater flexibility to accurately measure a purchasing electric utility's avoided cost for as-available energy at the time of delivery.[87]

Consistent with FERC's policy goals and analysis in Order No. 872, the Companies updated their respective Schedule PP tariffs in the 2021 Sub 175 proceeding to use the

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[83] 18 C.F.R. § 292.304(d)(2).

[84] FERC Order No. 872 at ¶ 723.

[85] *Id.* at ¶ 31.

[86] 18 C.F.R. § 292.304(b)(7)(i)-(ii).

[87] FERC Order No. 872 at ¶ 214.

hourly marginal cost of producing energy to calculate avoided costs for QFs that elect to sell energy to the Companies on an "as-available" basis. In their 2021 Schedule PP tariffs, the Companies described this "as-available" rate option as the "Marginal Cost Rate." For this 2023 proceeding, the Companies are offering "as-available" rates calculated using the same methodology that the Commission approved in its Sub 175 Order. However, the Companies' 2023 Schedule PP tariffs discontinues use of the "Marginal Cost Rate" term and instead refers simply to the "As-Available Rate." This shift in nomenclature is consistent with both the terminology used in FERC's regulations and with the Companies' Schedule PP tariffs filed with the South Carolina Public Service Commission.

Consistent with the methodology approved by the Commission in the 2021 Sub 175 proceeding, the Companies' As-Available Rates will be calculated ex-post at the end of the month for each hour in a given month based on the joint dispatch outcomes for DEC and DEP[88] during that month using the incremental cost of production of the next megawatt hour. Because the As-Available Rates are calculated at the end of each calendar month, QF compensation will be based on actual marginal costs rather than market forecasts. In this way, As-Available Rates will accurately compensate QFs for the energy they provide based upon the utility's avoided costs calculated "at the time of delivery" in accordance with PURPA, while protecting the Companies' customers from potential overpayment. The Companies are also retaining the Two-year Fixed Rate[89] contract option that exists under the Schedule PP approved in the Sub 175 Order.

[88] The Companies will determine joint dispatch of DEC and DEP system resources based upon, among other things: (1) the incremental variable production cost, including fuel, variable operating and maintenance expenses, emission allowances, and reagents; (2) the replacement cost of supply resources, including power plants; and (3) start-up costs for peaking units.

[89] Previously referred to as the "2-Year Variable Rate."

At this time, the Companies are not proposing to offer a long-term fixed capacity rate and variable energy rate option based upon the Companies' avoided energy cost calculated at the time of delivery, as now allowed under 18 C.F.R. 292.304(d)(2). In future biennial proceedings, the Companies will continue to evaluate this concept along with the other new options for establishing avoided cost rates under FERC's implementing regulations, as updated in Order No. 872.

## V. SCHEDULE PP RATE DESIGN

The Companies' Schedule PP pays QFs on a volumetric rate basis (i.e., both avoided energy and capacity is paid on a ¢/kWh basis versus a separate fixed payment for capacity).[90] The rates are designed to credit QFs for avoided energy supplied during pre-designated on-peak and off-peak hours. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak, premium-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours.

In the 2018 Sub 158 proceeding, DEC and DEP initially proposed an updated Schedule PP rate design that eliminated the pre-existing Option A and Option B rate structures and proposed more granular rate designs to better recognize the value of QF energy and capacity. After engaging with the Public Staff on rate design issues, the Companies filed a Partial Settlement on April 18, 2019, addressing the Companies' and the Public Staff's agreement on appropriate avoided energy and avoided capacity rate design methodologies ("Sub 158 Rate Design Stipulation").[91] Overall, the Sub 158 Rate

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

[91] Agreement and Stipulation of Partial Settlement, Docket No. E-100, Sub 158 (Apr. 18, 2019).

Design Stipulation's avoided cost rate designs sought to better balance the need for a granular rate design with providing Schedule PP customers clear and consistent price signals through the term of customers' contracts. The Sub 158 Order approved the Sub 158 Rate Design Stipulation and found the rate designs included therein to be appropriate for use in calculating DEC's and DEP's avoided energy and capacity rates.[92] The Companies utilized the same rate design in both the 2020 Sub 167 and 2021 Sub 175 proceedings, and the Commission approved the same.[93]

In this proceeding, the Companies are continuing to utilize the standardized Commission-approved avoided energy rate design methodology outlined in the Sub 158 Rate Design Stipulation. Based on the Rate Design Stipulation's review process for the continued appropriateness of the rate design, the Companies are also proposing some adjustments to the hourly definitions within the existing nine (9) energy price blocks for both DEC and DEP to better align with forecasted energy values. Figure 1 details the updated avoided energy rate design for DEC and DEP. As exemplified in Figure 1, although certain start and end hours have changed, Summer months continue to be defined as calendar months June through September and Winter months continue to be defined as calendar months December through February. All other months continue to be defined as Shoulder months.[94] DEC/DEP Exhibit 8 provides additional supporting information for the hourly changes.

[92] Sub 158 Order at 8 (Finding of Fact No. 4).

[93] Sub 167 Order at 40; Sub 175 Order at 56.

[94] The specific on-peak, off-peak and premium peak hours are detailed in the Monthly Rate section of DEC's and DEP's respective Schedule PPs.

## Figure 1: Updated Avoided Energy Rate Design for DEC and DEP

| DEC Energy Independent Price Blocks | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Premium Peak | | | Summer On-Peak | | | Summer Off-Peak | | Winter Premium Peak | | | Winter On-Peak (AM) | | | Winter On-Peak (PM) | | | Winter Off-Peak | | Shoulder On-Peak | | | Shoulder Off-Peak | |
| Hour Ending | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| Summer (Jun - Sep) | Off | | | | | | | | | | | | On | | | | | Premium | | | | On | | Off |
| Winter (Dec - Feb) | Off | | | | | On | Premium | | | On | Off | | | | | | | On (PM) | | | | | | Off |
| Shoulder (Remaining) | Off | | | | | | On | | | | Off | | | | | | On | | | | | | | Off |

| DEP Energy Independent Price Blocks | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Summer Premium Peak | | | Summer On-Peak | | | Summer Off-Peak | | Winter Premium Peak | | | Winter On-Peak (AM) | | | Winter On-Peak (PM) | | | Winter Off-Peak | | Shoulder On-Peak | | | Shoulder Off-Peak | |
| Hour Ending | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
| Summer (Jun - Sep) | Off | | | | | | | | | | | | | | On | | | | Premium | | | | On | |
| Winter (Dec - Feb) | Off | | | | On | | Premium | | | Off | | | | | | | | On (PM) | | | | | | Off |
| Shoulder (Remaining) | Off | | | | | On | | | | Off | | | | | | | | On | | | | | | Off |

This methodology and review are consistent with the modeling approach utilized in the approved 2018 Sub 158, 2020 Sub 167, and 2021 Sub 175 avoided energy rates.

Under the Sub 158 Rate Design Stipulation, QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent with the approach the Companies have historically utilized with respect to QF rate design under prior vintages of Schedule PP. The Public Staff and the Companies agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé 2018 Solar Capacity Value Study. Astrapé completed a new resource adequacy study in 2023 ("2023 Resource Adequacy Study")[95] and the Companies have used the loss of load risk identified in this more recent study for updating the avoided capacity rate design in this proceeding.

The Sub 194 Schedule PP capacity rate design reflects updated pricing periods to most accurately reflect the marginal capacity value to customers during each period, as

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

exemplified below in Figure 2. Based on results from the 2023 Resource Adequacy Study, the loss of load risk for both DEC and DEP is now exclusively in the winter periods and thus the prior summer PM capacity payment period for DEC has been discontinued. As detailed in DEC/DEP Exhibit 8, the loss of load risk is concentrated in the winter months of December through February and the prior capacity payment month of March has been discontinued for both DEC and DEP. The capacity payment period for both Companies is depicted in Figure 2 below and consists of defined AM hours for each Company during the winter months of December through February. Figure 2 highlights the Winter on-peak hours for DEC and DEP.

**Figure 2: DEC and DEP Capacity Independent Price Blocks**

<table>
<tr><th colspan="25">DEC Capacity Independent Price Blocks</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Winter (Dec - Feb)</td><td></td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<table>
<tr><th colspan="25">DEP Capacity Independent Price Blocks</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Winter (Dec - Feb)</td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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The seasonal allocation of capacity value remains heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. DEP's loss of load risk is 100% Winter, which is unchanged from that approved in the Sub 175 Order. DEC's loss of load risk is also now 100% winter based on the new 2023 Resource Adequacy Study and increased from 96% winter in the 2021 Sub 175 proceeding based on the 2020 Resource Adequacy Study. DEC/DEP Exhibit 8 provides additional technical detail regarding the new capacity payment periods and seasonal allocation.

In summary, the Companies have designed their avoided capacity and energy rates in accordance with the stipulated rate design approved in the Sub 158 Order and incorporated updated loss of load risk data from the 2023 Resource Adequacy Study to inform the avoided capacity rate design.[96] The Companies have engaged with the Public Staff prior to this filing and plan to continue to discuss the accuracy and appropriateness of the rate design with the Public Staff between now and the next biennial avoided cost proceeding.

## VI. MODIFICATIONS TO SCHEDULE PPs AND TERMS AND CONDITIONS

The Companies have amended their Schedule PP tariffs to reflect the updated avoided cost rates supported in Sections III above and the revised as-available rate structure discussed in Section IV. The Companies have also made limited modifications to their Schedule PP and Terms and Conditions approved in the Sub 175 Order. For Schedule PP, these changes include:

- Administrative revisions for clarity and consistency, such as adjusting the relevant docket number to reflect the E-100, Sub 194 Proceeding and applicable effective date;
- Adjusting the naming conventions for the term "Marginal Cost Rates" by replacing it with the term "As-Available Rates" while maintaining the same definition as the original term;
- Adjusting the naming convention for the term "Variable Rate" by replacing it with the term "Two-Year Fixed Rate" while maintaining the same definition as the original term;

[96] The Companies have provided further detail regarding their avoided energy and avoided capacity rate design in DEC/DEP Exhibit 8.

- Ensuring that references to rates accurately and clearly distinguish between Long-Term Rates, Two-Year Fixed Rates, and the Companies' As-Available Rates;
- Clarifying that QFs that elected to receive the Variable Rate pursuant to prior approved versions of the Schedule PP will now be subject to the As-Available Rate; and
- Clarifying that a QF electing As-Available Rates may be required to provide a scheduling notification to DEC or DEP for as-available energy delivered.

For the Terms and Conditions for the Purchase of Electric Power, the Companies propose the following changes:

- Revisions of Section 1 and Section 3 to further define the notification and administrative requirements for a change of control and the Companies' right to terminate or suspend the agreement;
- Revision of Section 6 to adjust the calculation methodology in the event of early contract termination;
- Revision of Section 9 to limit the period for billing adjustments due to error to three (3) years; and
- Revision of Section 13 to clarify the triggering date of the Seller's obligation to pay the Interconnection facilities charges.

The Companies are providing clean and redline versions of DEC's and DEP's Standard Offer Terms and Conditions in DEC Exhibit 4 and DEP Exhibit 4.

## VII. MODIFICATIONS TO STANDARD OFFER PPA

The Companies have made limited revisions to their standard offer PPA forms presented in DEC's and DEP's respective Exhibit 3. The standard PPA forms now refer to the renamed As-Available Rates and Two-Year Fixed Rates and contain updated contact information for the Companies. The Companies have not made any revisions to Exhibit A Energy Storage Protocol.

## VIII. NOTICE OF COMMITMENT FORMS FOR STANDARD OFFER AND LARGE QFs

FERC's regulations implementing PURPA provide QFs the option to "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term[.]"[97] Both FERC and the Commission have held that a QF may form a "LEO" by committing itself to sell to an electric utility, resulting in either a contract or in a non-contractual, but binding, legally enforceable obligation.[98]

Desiring an administratively-efficient process for QFs to establish non-contractual LEOs in North Carolina, the Commission first adopted a standardized Notice of Commitment form in the 2014 Sub 140 proceeding.[99] Since that time, QFs in North Carolina have been required to submit a Notice of Commitment Form in order to establish a LEO and to memorialize their commitment to sell the output of their generating facilities

[97] 18 C.F.R. § 292.304(d)(ii).

[98] Sub 148 Order at 105 (*citing JD Wind 1, LLC*, 129 FERC ¶ 61,148 at ¶ 25, *reh'g denied*, 130 FERC ¶ 61,127 (2010) ("[A] QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.").

[99] Sub 148 Order at 9 (Ordering Paragraph No. 24).

to the Companies.[100] In the Sub 148 Order, the Commission directed the Companies to make certain modifications to the Notice of Commitment forms and approved separate forms and requirements, depending on whether the QF is eligible for the Companies' Schedule PP standard offer tariffs (1 $MW_{AC}$ or less), or where the QF is greater than 1 $MW_{AC}$ and requesting to negotiate a PURPA PPA with the Companies.[101]

In the 2021 Sub 175 proceeding, the Companies proposed to update the Notice of Commitment forms to accomplish three primary objectives: (1) incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872;[102] (2) align the Notice of Commitment Form with the now-approved queue reform process under the North Carolina Interconnection Procedures; and (3) update the non-standard offer Notice of Commitment Form to establish a more standardized and efficient process for QFs to proceed from Notice of Commitment Form to PPA. During the comment phase of the 2021 Sub 175 proceeding, the Companies worked with intervenors to address concerns raised in their initial comments and subsequently filed a revised Notice of Commitment for Commission approval that reflected consensus among the Companies', intervenors, and the Public Staff.

The Sub 175 Order approved the Companies' revised Notice of Commitment Form, acknowledging the alignment reached by the parties. The Commission noted that the "proposed revisions appropriately incorporate the new commercial viability and financial

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[100] *Id.*; *see also* In the Matter of Cube Yadkin Generation, LLC, Complainant, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Order Granting Moton to Dismiss, Docket Nos. E-2, Sub 1177 & E-7, Sub 1172, at 6. (July 16, 2018) (concluding that a QF's commitment to sell its output to a facility under PURPA through the use of the approved Notice of Commitment form (referred to as a LEO form) is a necessary prong in establishing a LEO).

[101] Sub 148 Order at 105-08.

[102] 18 C.F.R. § 292.304(d)(3); FERC Order No. 872 at ¶¶ 684-96.

commitment requirements established in FERC Order No. 872."[103] The Commission also concluded that the revised Notice of Commitment Forms "balance[d] Duke's need for assurance that projects entering the DISIS study process are commercially viable and progressing toward construction and sale of the project's output with QFs' need for reasonable opportunities to obtain financing."[104] In light of the previous consensus reached and the Commission's approval, the Companies are proposing only minor revisions to the Notice of Commitment Form in this proceeding, including to more clearly define the "Submittal Date" and, for the Small QF Notice of Commitment Form, only, more clearly state the Interconnection requirements.

The Companies' Notice of Commitment Form for QFs up to 1 MW eligible for Schedule PP and larger QFs not eligible for the standard offer are set forth in <u>DEC/DEP Exhibit 6</u> and <u>DEC/DEP Exhibit 7</u>, respectively.

## IX. <u>NET EXCESS ENERGY CREDIT</u>

As part of the Companies' revised Net Energy Metering ("NEM") Tariffs approved by the Commission in its Sub 180 NEM Order, NEM customers who export power are compensated at a NEEC. In the 2021 Sub 175 proceeding, the Public Staff proposed that calculation of the NEEC should be determined in the Companies' biennial avoided cost proceedings. The Companies did not object to this proposal, and the Commission subsequently directed the Companies to file for Commission approval their respective NEECs and calculation methodology in future biennial avoided cost proceedings.[105]

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[103] Sub 175 Order at 60-61.

[104] *Id*. at 61.

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

The Commission first approved the Companies' proposed NEECs in its August 3, 2023 Order Establishing Net Excess Energy Credit for NEM Tariff in Docket No. E-100, Sub 175 (the "2023 NEEC Order"). Those rates became effective October 1, 2023.

The NEECs as shown on DEC Exhibit 11 and DEP Exhibit 11 are calculated based on a five-year term in a consistent manner with the two- and 10-year fixed term rates shown on Schedule PPs. The five-year rates are then weighted based on a typical rooftop solar production profile to determine an annual value. The annual value includes an energy component, and a capacity component when applicable. For this docket, both DEC and DEP have a need for capacity starting within the first five years making the inclusion of a capacity component appropriate for each Company's NEEC at this time. The current NEECs will remain in effect until the Commission approves new NEECs to be included in DEC's and DEP's respective NEM tariffs.

## X. ENERGY STORAGE RETROFIT RATES

On September 29, 2021 in Docket Nos. E-100, Sub 101 and E-100, Sub 158, the Companies filed their Energy Storage System Retrofit ("ESS Retrofit") Compliance Filing (the "Compliance Filing"), proposing a framework for operating QFs selling power to DEC and DEP that elect to materially alter (e.g., retrofit) their facility to incorporate a co-located battery energy storage system to amend their current PPA to incorporate new ESS Retrofit rates for the remainder of the QF's existing term of contract.[106] The Compliance Filing

[106] ESS Retrofit Compliance Filing, Attachment C, Docket Nos. E-100, Sub 101 and E-100, Sub 158 (filed Sept. 29. 2021) (Attachment C to the ESS Filing provided that "to establish eligibility for New ESS retrofit avoided cost rates, a QF proposing to materially alter its generating facility to integrate an ESS must submit a Notice of Commitment form to establish a legally enforceable obligation. Interconnection Customers submitting a Notice of Commitment Form prior to November 1, 2023, will be eligible to receive a published avoided cost rate for the term that remains on the QF Interconnection Customer's original PPA as of January 1, 2023. These published rates will remain available until the earlier of November 1, 2023, or when 100 MW of incremental ESS retrofit additions have submitted Notice of Commitment Forms under the new rates.

provided that to establish eligibility for published ESS Retrofit avoided cost rates, an ESS Retrofit project must submit a Notice of Commitment Form prior to November 1, 2023 and that published ESS Retrofit Rates would remain available until "the earlier of November 1, 2023, or when 100 MW of incremental ESS retrofit additions have submitted Notice of Commitment forms under the new rates."[107] Finally, the Compliance Filing provided that any ESS Retrofit project that submits a Notice of Commitment Form after November 1, 2023 would be eligible for a negotiated rate based on the most recent Commission-approved avoided cost methodology for the ESS Retrofit project.

In its May 12, 2022 Order Granting Waivers to Implement Energy Storage System Expedited Study Processes and Approving Process to Establish Eligibility of avoided Cost Rates for Retrofit Energy Storage Systems (the "ESS Retrofit Order"), the Commission approved the Companies' proposal for eligibility for avoided cost rates for ESS Retrofit projects as reasonable.[108] The Commission further directed the Companies to "submit a report on the status of ESS Retrofit projects with sufficient information for the Commission to determine if the eligibility for avoided cost rates should be expanded to include QFs with LEOs established after November 1, 2016."[109] The Commission further clarified that it "will revisit the eligibility for QFs with a LEO established after November 15, 2016, and the availability of standard rates for ESS Retrofits that submit a NOC after November 1,

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Interconnection Customers submitting a Notice of Commitment form after November 1, 2023, will be eligible to receive a negotiated New ESS retrofit avoided cost rate consistent with the Commission-approved methodology at the time the QF commits to the ESS retrofit and obligates itself to sell the ESS' output to Duke Energy.").

[107] *Id*. at 5.

[108] Order Granting Waivers to Implement Energy Storage System Expedited Study Processes and Approving Process to Establish Eligibility of Avoided Cost Rates for Retrofit Energy Storage Systems, Docket No. E-100, Sub 101 & E-100, Sub 158 (May 12, 2022).

[109] *Id.* at 5.

2023, once Duke provides information regarding the implementation of the ESS Retrofit process through the reports required in this order."[110]

Pursuant to the ESS Retrofit Order, on January 23, 2023, the Companies filed their Update Regarding Expedited Study Processes Available to ESS Retrofit, notifying the Commission that there was no relevant data to report given the absence of any ESS Retrofit projects participating in the 2022 DISIS Phase 1 study.[111] On July 31, 2023, the Companies filed a second update informing the Commission that the Companies still had not received any ESS Retrofit project applications or Notice of Commitment Forms.[112]

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

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[110] *Id.* at 4-5.

[111]DEC's and DEP's Update Regarding Expedited Study Processes Available to ESS Retrofit Projects, Docket No. E-100 Sub, 101 and E-100 Sub 158 (Jan. 23, 2023).

[112] DEC's and DEP's Second Update on Interconnection Customer Participating in Energy Storage System Retrofit Process, Docket No. E-100, Sub 101 & E-100 Sub 158 (July 31, 2023).

## XI. CONCLUSION

WHEREFORE, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission approve their respective updated Schedule PP avoided cost rates and terms and conditions, as presented in this Joint Initial Statement and provide any further relief the Commission deems to be just, reasonable, and in the public interest.

Respectfully submitted, this the 1st day of November, 2023.

*E. Brett Breitschwerdt*

Ladawn Toon
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551 / NCRH 20
Raleigh, North Carolina 27602
Telephone: (919) 546-6733
Ladawn.Toon@duke-energy.com

E. Brett Breitschwerdt
Tracy S. DeMarco
Ami P. Patel
McGuireWoods LLP
501 Fayetteville Street, Suite 500
PO Box 27507 (27611)
Raleigh, North Carolina 27601
EBB Telephone: (919) 755-6563
TSD Telephone: (919) 755-6682
APP Telephone: (919) 546-6733
bbreitschwerdt@mcguirewoods.com
tdemarco@mcguirewoods.com
apatel@mcguirewoods.com

*Counsel for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*

**VERIFICATION**

STATE OF NORTH CAROLINA )
)
) DOCKET NO. E-100, SUB 194
COUNTY OF WAKE )

The undersigned, Glen Allen Snider, being first duly sworn, deposes and says that he is Managing Director of Carolinas Integrated Resource Planning and Analytics; that he has read the foregoing Joint Initial Statement and Proposed Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC and knows the contents thereof; that the same are true of his own knowledge, except as to those matters stated on information and belief, and as to those matters, he believes them to be true.

Glen A. Snider

Signed and sworn to before me this day by Glen A. Snider
*Name of principal*

Date: 11/1/2023

STATE OF NORTH CAROLINA )
)
COUNTY OF Mecklenburg )

Subscribed and sworn to before me this 1 day of November, 2023.

*Official Signature of Notary*

Preeti S. Patel, Notary Public
*Notary's printed or typed name*

My commission expires: Oct 8 2025

[OFFICIAL SEAL]

PREETI S PATEL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
OCTOBER 08, 2025
MECKLENBURG COUNTY, NC