Kendrick C. Fentress
Associate General Counsel

Mailing Address:
NCRH 20/P. O. Box 1551
Raleigh, North Carolina 27602

o: 919.546.6733
f: 919.546.2694

Kendrick.Fentress@duke-energy.com

November 2, 2020

VIA ELECTRONIC FILING

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

Re: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits
Docket No. E-100, Sub 167

Dear Ms. Campbell:

Attached please find for filing in the above-captioned docket, the Joint Initial Statement for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). Consistent with the Commission's August 13, 2020 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Scheduling Order") and the October 30, 2020 *Order Granting Continuance and Establishing Reporting Requirements (*"Order Granting Continuance"*)*, both issued in the above-captioned docket, the Joint Initial Statement presents for Commission approval the Companies' standard avoided cost rates and contract terms and conditions for qualifying facilities ("QFs") one (1) megawatt and less. As the Commission approved in the Order Granting Continuance, this filing updates the inputs to the Companies' avoided cost energy rates and avoided capacity rates based on the methodological guidelines and requirements approved in the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 158.

The Companies have designated portions of their respective Exhibits 2 and Exhibits 8 to this Joint Initial Statement as confidential and trade secret information. Pursuant to N.C. Gen. Stat. § 132-1.2, the Companies respectfully request that the Commission protect this data from public disclosure. Exhibit 2 discloses estimated costs to procure additional energy, as well as the projected cost of new utility-owned generation. Public disclosure could hinder the Companies from obtaining the most cost-effective energy and capacity necessary to meet the needs of its customers. Exhibit 8 includes confidential and trade secret information, as well. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs, in Docket No. E-100, Sub 167 has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, property addressed to parties of record.

This the 2nd day of November. 2020.

Kendrick C. Fentress

Kendrick C. Fentress
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
Tel. 919.546.6733
Kendrick.Fentress@duke-energy.com

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 167

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020	)))))	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") ("the Companies"), pursuant to the Commission's August 13, 2020 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("2020 Scheduling Order"), and submit the Companies' 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") eligible for the Companies' respective Schedule PPs and establish a legally enforceable obligation ("LEO") for QFs 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. The Companies' Submissions also comply with the requirements of the Commission's prior avoided cost orders, except where the Commission has granted the Companies and Dominion Energy North Carolina ("Dominion" and collectively, the

"Utilities") request for a continuance of certain study and stakeholder coordination requirements set forth in the *2020 Scheduling Order* and the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms For Qualifying Facilities,* issued in Docket No. E-100, Sub 158 ("*2018 Sub 158 Order*").[1]

In summary, based on a generic solar profiling, the avoided cost rates for the Companies have decreased by approximately two percent for both DEC and DEP when compared to the avoided cost rates approved in the *2018 Sub 158 Order*. A primary driver for the approximately two percent decrease in these proposed avoided cost rates is a slight decline in natural gas prices since the 2018 Sub 158 avoided cost proceeding.

The Companies' Joint Initial Statement detailing the calculation of these 2020 avoided cost rates follows.

JOINT INITIAL STATEMENT OF DEC AND DEP

I. Introduction and Background

Section 210 of PURPA requires the Companies to purchase the output from QFs and to pay them nondiscriminatory rates that are just and reasonable to the Companies' ratepayers and that do not exceed the Companies' incremental cost of alternative energy or "avoided costs."[2] Through PURPA, Congress delegated to this Commission the responsibility of implementing PURPA's "must purchase" requirements, consistently with FERC's PURPA regulations.[3] FERC's PURPA regulations specifically require state

[1] *See Order Granting Continuance and Establishing Reporting Requirements*, Docket No. E-100, Sub 167 (Oct. 30, 2020) ("Order Granting Continuance").

[2] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, at 3, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69"). *See generally*, 16 U.S.C. § 824a(3)(a); 18 C.F.R .292.304(a).

[3] *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, the

regulatory authorities such as the Commission to establish standard rates for purchase from smaller QFs with a design capacity of 100 kilowatts ("Kw") or less and provide States flexibility to establish standard rates for QFs with a design capacity greater than 100 kW.[4]

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 agreements to be used by the State's electric public utilities in purchasing energy and capacity from small power producers.[5] Pursuant to recent modifications of the State's PURPA implementation framework enacted by Session Law 2017-192 ("HB 589"), the Companies' standard offer avoided cost rates and contracts are currently available to QFs up to 1,000 kW. HB 589 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 PPAs with an aggregate new capacity of 100 MW subsequent to November 15, 2016.[6]

HB 589 also prescribed new limits on the maximum length of fixed-term standard offer rates and contracts to 10 years and refined the calculation of avoided capacity cost rates.[7] Section (b)(3) of N.C. Gen. Stat. § 62-156 now directs that a future capacity need

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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 become effective December 31, 2020. The Companies intend to address the revised regulations in a subsequent standard offer avoided cost filing to be made on or before November 1, 2021, or as otherwise directed by the Commission.

[4] *See* 18 C.F.R. 292.304(c).

[5] N.C. Gen. Stat. § 62-156(b).

[6] N.C. Gen. Stat. § 62-156(b)(1). As of the date of this filing, 11 QFs totaling 5.56 MW have executed standard offer PPAs committing to sell their output to DEC and 4 QFs totaling .40 MW have executed standard offer PPAs committing to sell their output to DEP under either the standard offer rates and terms approved in the 2016 Avoided Cost Proceeding in Docket No. E-100, Sub 148 or Sub 158 standard offer rates and terms in effect since November 15, 2016.

[7] *Id.*

shall only be avoided in a year where the Commission's most recently approved biennial integrated resource plan ("IRP") for the Companies 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.[8] 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 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.[9]

The General Assembly's enactment of HB 589 in 2017 also evolved the State's solar procurement framework for larger QFs and other renewable generators by reducing the maximum term of fixed price mandatory purchase contracts under PURPA to five years, while also creating new alternative competitive and customer driven programs, such as the Competitive Procurement of Renewable Energy Program ("CPRE"), the large customer directed procurement of renewable energy ("Green Source Advantage Program" or "GSA") program, Solar Rebate Program and the Community Solar Program, to add more cost-effective solar to the Companies' systems.[10]

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[8] N.C. Gen. Stat. § 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.a.1 of the Companies' Joint Initial Statement.

[9] N.C. Gen. Stat. §62-156(b)(2).

[10] *See* N.C. Gen. Stat. § 62-110.8 (establishing Competitive Procurement of Renewable Energy Program); N.C. Gen. Stat. §62-159.2 (establishing large-customer directed renewable energy procurement program);

The Commission has implemented the State's revised PURPA implementation framework under HB 589 in the past two avoided cost proceedings in 2016-2017 ("2016 Sub 148 proceeding") and 2018-2019 ("2018 Sub 158 proceeding"), respectively. The *2016 Sub 148 Order* recognized that these changes to the State's PURPA implementation framework were needed to better manage the recent unparalleled and uncontrolled growth of solar QFs in the State, as the Commission highlighted that solar QF generating facilities installed on the Companies' electric systems had increased dramatically from 125 MW in 2012 to over 1,600 MW in 2016.[11] The *2016 Sub 148 Order* also emphasized that the State's pre-existing PURPA policies had created a "distorted marketplace" for uncontrolled solar QF development and that the pace and level of QF development continuing unabated would pose serious risks of overpayment by utility ratepayers and increased operational and reliability risks for the Utilities.[12]

While HB 589 has significantly revised the State's PURPA implementation framework, robust solar and other QF development has continued in North Carolina, primarily through CPRE and the other alternative customer-directed programs enacted in HB 589. As shown in Figure 1, approximately 4,492 MW of solar and 389 megawatts of non-solar capacity are either installed or under contract, which reflects an increase of 34 percent since 2018. Significant additional solar capacity exceeding 4,947 MW also continues to be developed in the State.[13]

N.C. Gen. Stat. § 62-155(f) (establishing solar rebate program); and N.C. Gen. Stat. §62-126.8 (establishing community solar energy facilities program).

[11] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 16, Docket No. E-100, Sub 148 (Nov. 11, 2017) ("2016 Sub 148 Order").

[12] *Id.*, at 16-17, 81-83.

[13] Reflects all pending utility-scale solar Interconnections Requests in the North Carolina and FERC-jurisdictional interconnection queues.

Figure 1

DE Carolinas:		
On-Line and Under Contract	MW	SubTotal
Biogas	63	
Hydroelectric	32	
Solar	700	
Wind	-	
Other	-	
	794	794
Under Contract, but not On-line	MW	SubTotal
Solar	646	
	646	1,440
Pending, Not Under Contract, Not On-Line	MW	SubTotal
Solar	1,495	
Battery		
DEC Total	1,495	2,935

DE Progress:		
On-Line and Under Contract	MW	SubTotal
Biogas	278	
Hydroelectric	16	
Solar	2,386	
Wind	-	
Other	15	
	2,695	2,695
Under Contract, but not On-line	MW	SubTotal
Solar	760	
	760	3,455
Pending, Not Under Contract, Not On-Line	MW	SubTotal
Solar	3,452	
Battery	117	
DEP Total	3,569	7,024

This robust development of new solar QF and other renewable energy capacity has continued during a now-extending period of historically low avoided cost rates over the past decade due to declining commodity prices and other factors. As noted, when applied to a generic solar profile, the Companies' new ten-year standard offer avoided cost rates being filed in this proceeding reflect a modest decrease of two percent for DEC and DEP for solar QFs compared to the avoided cost rates approved in the *2018 Sub 158 Order*. When applied to baseload QFs capable of delivering energy around the clock, the new ten-year standard offer avoided cost rates increased for DEC by four percent and decreased for DEP by three percent from the rates approved in the 2018 Sub 158 proceeding.

In the recent 2018 Sub 158 proceeding, the Commission continued its implementation of the revised PURPA standard offer framework enacted by HB 589. The

2018 Sub 158 Order directed the Utilities, and primarily the Companies, to develop additional refinements to their standard offer avoided capacity and energy rates and terms and conditions for purchasing QF power for consideration in this proceeding, as further detailed in the *2020 Scheduling Order*. As addressed in the Utilities' Joint Motion Seeking Continuance[14] recently granted by the Commission, the Companies are updating their avoided cost rates to meet the requirements of N.C. Gen. Stat. § 62-156(b) in this proceeding and are concurrently continuing to develop their responses to these additional refinements, in some cases, with stakeholders. The Companies will also update the Commission by December 7, 2020 on their plans to address the Sub 158 additional issues in updated avoided cost filings to be made in November 2021, as directed by the *Order Granting Continuance*.

II. Overview of Exhibits Supporting Initial Statement Filing

As required by Ordering Paragraph three (3) of the Commission's *2020 Scheduling Order*, DEC and DEP each submit for approval proposed standard avoided cost rates for qualifying cogeneration and small power production facilities, as further discussed and supported herein.

- DEC Exhibit 1 presents proposed clean and redlined copies of DEC's Purchased Power Schedule PP.
- Confidential DEC Exhibit 2 presents the supporting calculations for the energy and capacity credits, inflation rates, and discount rates used to derive DEC's proposed avoided capacity and energy cost rates for hydroelectric ("hydro")

[14] See DEC, DEP & Dominion's Notification of Intended Compliance, Request for Continuance of Compliance with Certain Requirements & Request to Modify Timing of Biennial Proceedings, Docket No. E-100, Sub 167 (filed Oct. 20, 2020) ("Utilities' Joint Motion Seeking Continuance").

QFs and other QFs respectively. Information included in Exhibit 2 is designated Confidential and is being filed under seal.

- DEC Exhibit 3 presents clean and redlined copies of DEC's proposed Standard PPA available to QFs eligible for Schedule PP.
- DEC Exhibit 4 presents clean and redlined copies of DEC's proposed Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions").
- DEC Exhibit 5 presents DEC's annualized rates.
- DEC Exhibit 6 presents clean and redlined copies of DEC's updated Notice of Commitment Form for QFs eligible for Schedule PP.

DEP Exhibits 1-6 present the same information for DEP as described above for DEC. The Companies further address the updates presented in these Exhibits to this Joint Initial Statement in Parts III through VII that follow.

The Companies are also filing certain studies to be included in the record in this proceeding, as required by Ordering Paragraph four (4) of the Commission's *2020 Scheduling Order* and prior Orders issued in the 2018 Sub 158 proceeding:

- DEC/DEP Joint Exhibit 7 is the Companies' 2020 Duke Energy North Carolina Energy Efficiency ("EE") and Demand-Side Management ("DSM") Market Potential Studies, prepared by Nexant, as previously filed with the Commission on June 23, 2020 in Docket No. E-100, Sub 165.

- DEC Exhibit 8 is DEC's 2020 Resource Adequacy Study, previously filed as Attachment III to DEC's 2020 biennial integrated resource plan ("IRP") filed with the Commission on September 1, 2020 in Docket No. E-100, Sub 165.[15]
- DEP Exhibit 8 is DEP's 2020 Resource Adequacy Study, previously filed as Attachment III to DEP's 2020 biennial IRP filed with the Commission on September 1, 2020 in Docket No. E-100, Sub 165.[16]

The Companies are also making available additional detail and supporting technical data for DEC's and DEP's respective Resource Adequacy Studies as directed by the Commission,[17] to be provided electronically upon request, consistent with the information made electronically available to intervenors and the Commission in the 2020 IRP proceeding, Docket No. E-100, Sub 165.

III. The Peaker Methodology and Avoided Energy and Capacity Rate Calculations

Consistent with prior biennial avoided cost filings, the Companies have each developed their avoided capacity and energy costs using the component or "peaker" methodology.

The Commission approved the Companies' continued use of the peaker methodology, or "peaker method", as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs in the 2018 Sub 158 proceeding and a number of prior

[15] Duke Energy Carolinas, LLC Integrated Resource Plan 2020 Biennial Report, at Docket No. E-100, Sub 165 (filed Sept. 1, 2020) ("DEC 2020 Biennial IRP").

[16] Duke Energy Progress, LLC Integrated Resource Plan 2020 Biennial Report, at 112-114, Docket No. E-100, Sub 165 (filed Sept. 1, 2020) ("DEP 2020 Biennial IRP").

[17] *See Order Denying Motion for Reconsideration*, at 6, Docket No. E-100 Sub 158 (July 21, 2020).

biennial avoided cost proceedings.[18] As recognized in these prior avoided cost proceedings, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)."[19]

In applying the peaker method to calculate their avoided cost rates in this 2020 biennial avoided cost proceeding, the Companies have used modeling and assumptions consistent with those used in their most recent 2020 biennial IRPs[20] and/or utilized Commission-approved inputs and methodologies adopted in the 2018 Sub 158 proceeding, to streamline the issues before the Commission in fixing the Companies' standard avoided cost rates. This approach, which should not be viewed as precedential to how the Companies will address such issues in future proceedings, will allow the Commission to more expeditiously review and approve the Companies' standard offer avoided cost rates, while allowing the Companies to continue their ongoing efforts to address the additional study requirements prescribed in the *2018 Sub 158 Order* as well as to engage with the Public Staff and interested stakeholders regarding how the State's implementation of PURPA should evolve in response to FERC's revised regulations issued in Order No 872.

[18] *See 2018 Sub 158 Order,* at 134 (Ordering ¶ 10); *see Order Setting Avoided Cost Inputs,* at 8 (Finding of Fact 6), Docket No. E-100, Sub 140 (Dec. 31, 2014) ("*Phase I Sub 140 Order").*

[19] *See Phase I Sub 140 Order,* at 30 (Stating 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.

[20] Certain 2020 IRP inputs have been updated for minor corrections.

a. Avoided Capacity Cost Calculations

In the *2018 Sub 158 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."[21] The Commission also determined that the Companies appropriately calculated their avoided capacity rates consistent with N.C. Gen. Stat. § 62-156(b)(3), and directed the Companies to include a clear statement identifying the utility's first year of avoidable capacity need in their 2020 IRPs.[22] The Companies have followed this direction and adhered to the same methodology recently approved by the Commission for calculating their respective avoided capacity rates, as further described below.

1. First year of avoidable capacity need has been determined consistent with the *2018 Sub 158 Order* and the Companies' 2020 IRPs

DEC and DEP have developed their avoided capacity rates consistent with the methodology that they used in the 2018 Sub 158 proceeding and that the Commission approved in the *2018 Sub 158 Order* as appropriately implementing N.C. Gen. Stat. § 62-156(b)(3). As identified in the Companies' recently-filed 2020 IRPs, DEC's next avoidable undesignated capacity need occurs in 2026, while DEP's next avoidable undesignated capacity need occurs in 2024.[23] Compared to the standard offer avoided cost rates approved in the 2018 Sub 158 proceeding, DEC's first year of avoidable capacity need shifted forward from 2028 to 2026, while DEP's first year of avoidable capacity need

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[21] *2018 Sub 158 Order*, at 134 (Ordering ¶ 10).

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

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

shifted outward from 2020 to 2024.

Also consistent with the *2018 Sub 158 Order*, DEC and DEP have expressly included provisions in their Schedules that recognize that in certain circumstances, QFs fueled by swine waste, poultry waste, and hydro power, receive capacity payments calculated regardless of the Companies' demonstrated need for future capacity reflected in their respective IRPs. Specifically, the Commission directed the Utilities to amend their standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydro facility that has a PPA in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C. Gen. Stat. § 62-156(b)(3).[24] As recently amended by Session Law 2019-132, N.C. Gen. Stat. § 62-156(b)(3) now provides that a future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission has identified a projected capacity need to serve system load other than for (i) swine or poultry waste for which a need is established consistent with N.C. Gen. Stat. § 62-133.8(e) and (f) and (ii) *hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than five MW.* Because the Companies' standard offers are only available to QFs 1 MW and less, the Companies did not include avoided cost rates for hydro small power producers in excess of 1 MW in their standard offer; however, the Companies

[24] *2018 Sub 158 Order*, at 135 (Ordering ¶ 18).

commit to complying with N.C. Gen. Stat. § 62-156(b)(3) with respect to negotiated PPAs with eligible hydro QFs greater than 1 MW but equal to or less than 5 MW.

2. Avoided CT unit capital costs have been calculated consistent with the approach approved in the *2018 Sub 158 Order*

Consistent with the Commission's directives in prior avoided cost proceedings,[25] the *2018 Sub 158 Order* concluded that the Utilities should use the installed cost of a CT unit derived from publicly available industry sources, such as the United States Energy Information Administration ("U.S. EIA"), tailored to adapt such information to the Carolinas for purposes of calculating their avoided capacity costs.[26] The *2018 Sub 158 Order* additionally directed that in the 2020 biennial avoided cost proceeding the Utilities should evaluate and apply cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility.[27]

In this proceeding, DEC and DEP have each calculated their respective avoided capacity cost based upon the U.S. EIA's published overnight cost of a CT unit, tailored to the extent needed to adapt such information to North Carolina consistent with the Commission's previous avoided cost orders.[28] The CT overnight cost increased

[25] *Phase I Sub 140 Order*, at 40.

[26] *2018 Sub 158 Order*, at 32-33. Notably, this publicly available data does not reflect (and continues to be materially higher than) the Companies' proprietary estimates of the projected capacity costs of constructing new CT units in the Carolinas, as utilized in the Companies' 2020 IRPs.

[27] *2018 Sub 158 Order*, at 33.

[28] *See* U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, at Table 6-1 (p. 6-3) (Feb. 5, 2020), *available at* https://www.eia.gov/analysis/studies/powerplants/capitalcost/ (last visited Oct. 29, 2020).

approximately 14% compared to the Companies' 2018 Sub 158 avoided cost filing ($624/kW in 2018 filing versus $713/kW in the 2020 filing) primarily due to a smaller economies of scale adjustment and a lower unit capacity rating.

As explained above, for purposes of streamlining this proceeding, the Companies have not recommended any additional adjustments to their CT costs at this time. The Companies intend to use the additional time between now and in advance of their next avoided cost filing to discuss any potential adjustments to their CT costs with the Public Staff.

3. The Companies have applied the same equivalent availability methodology approved in the *2018 Sub 158 Order* to develop a Performance Adjustment Factor capacity multiplier

In the 2018 Sub 158 proceeding, the Commission approved DEC's and DEP's continued recognition of a performance adjustment factor ("PAF") in determining the appropriate calculation of avoided capacity to be paid to QFs.[29] The *2018 Sub 158 Order* reiterated the *2016 Sub 148 Order's* finding that inclusion of a PAF in avoided capacity rates is appropriate, and should be based upon a metric or metrics that assess generating unit "availability." The Commission therefore approved the Companies' proposed PAF of 1.05, based upon the equivalent availability ("EA") metric and the use of five years of historic outage rate data during Duke's critical peak season months.[30] In accepting the Companies' utilization of the EA metric for purposes of calculating the PAF, the

[29] *2018 Sub 158 Order*, at 40 (describing the history of the PAF as a capacity multiplier designed to address the fact that standard avoided capacity rates are paid on a per-kWh basis, such that setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours, without any reasonable opportunity to experience outages during each peak period, in order to receive the total available avoided capacity payment. The PAF recognizes that the Utilities' generating units experience outages and do not operate 100% of the time and allows QFs to also experience unplanned outages during peak periods and still receive the utility's full avoided capacity costs).

[30] *2018 Sub 158 Order*, at 41.

Commission additionally accepted the Public Staff's recommendation for the Utilities to consider other reliability metrics besides the EA. The Commission directed Duke and the Public Staff to address the appropriateness of using the Equivalent Unplanned Outage Rate ("EUOR") metric in the next avoided cost proceeding, finding that the use of the EUOR "may have merit given that EUOR [appropriately excludes planned outages from the calculation of the PAF, but] includes an additional type of outage classified as "maintenance" outages which can also occur during peak demand periods."[31]

At this time, the Companies have continued to use the EA metric and to apply the same methodology approved in the *2018 Sub 158 Order* to calculate the PAF capacity multiplier. As explained above, for purposes of this proceeding, and to avoid introducing issues that could result in more lengthy proceedings before the Commission, the Companies have not recommended any additional adjustments to the Commission-approved EA metric to compute the PAF, and have followed the same methodology of compiling five years of historic equivalent availability data for the entire fleet during the Companies' critical peak season months of January, February, July, and August. This critical peak season reflects the high load periods in which the Companies typically do not schedule planned maintenance outages for fleet generating facilities. Based upon these calculations, DEC's and DEP's respective equivalent availability during this timeframe averages to approximately 94%, which supports a slightly higher PAF of 1.06 as compared to the PAF of 1.05 approved in the *2018 Sub 158 Order*[32] and in the prior *2016 Sub 148*

[31] *2018 Sub 158 Order*, at 41; *see also 2020 Scheduling Order*, at 1.

[32] *Id.*, at 135 (Ordering ¶ 11).

Order.[33] The Companies plan to use the time between now and their next avoided cost filing to discuss the appropriateness of utilizing the EUOR metric with the Public Staff.

4. The Companies are proposing to treat run-of-river hydro QFs consistent with Commission precedent and the Hydro Stipulation

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.[34] In 2014, the Companies and the NC Hydro Group entered into a stipulation in Docket No. E-100, Sub 140[35] ("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 offers filed at the Commission prior to December 31, 2020, to calculate the avoided cost rates for small hydro QFs of 5 MW or less through December 31, 2020.[36] As the Commission recognized in the *2018 Sub 158 Order*[37] and in the prior *2016 Sub 148 Order*[38], the General Assembly has subsequently amended the State's implementation of PURPA through HB 589 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while at the same time establishing flexibility for the Companies to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in

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33 *2016 Sub 148 Order*, at 109 (Ordering ¶ 8).

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

35 *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014*, Stipulation of Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and North Carolina Hydro Group, Docket No. E-100, Sub 140 (filed June 24, 2014).

36 Hydro Stipulation, at ¶¶ 3(a) and 4.

37 *2018 Sub 158 Order*, at 42.

38 *Id.*, at 39.

calculating future avoided cost rates.[39] The *Sub 158 Order* therefore directed the Companies to address whether the special 2.0 PAF capacity multiplier should continue for the standard offer in this biennial proceeding.[40]

Consistent with the Hydro Stipulation, the Companies have included a 2.0 PAF in DEC's and DEP's standard offer capacity calculation for run-of-river hydro QFs without storage under 1 MW. The Companies negotiated the Hydro Stipulation in good faith, and its terms and conditions were based both upon North Carolina's policy of supporting small hydro QFs and the relatively small and finite amount of small hydro capacity in the state.[41]

Additionally, in the 2018 Sub 158 proceedings, the Companies filed a letter with the Commission that outlined their intentions for the continuing applicability of terms and conditions of the Hydro Stipulation for hydro QFs five MW and less.[42] In the letter, the Companies stated their intent to honor their commitment under the terms of the Hydro Stipulation to apply a 2.0 PAF capacity multiplier for purposes of calculating avoided cost rates for those hydro QFs without storage. DEC and DEP did not agree to extend the 2.0 PAF beyond the current Hydro Stipulation's expiration at the end of 2020 due to intervening changes to PURPA implementation in North Carolina enacted by HB 589. This commitment included hydro QFs that were no longer eligible for the Companies' standard offer due to their contract capacity in excess of one MW and that were now eligible to enter into negotiated PPAs with the Companies pursuant to N.C. Gen. Stat.§ 62-156(c). As noted in the letter, and for the avoidance of doubt, DEC and DEP will continue

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[39] *See* N.C. Gen. Stat. § 62-156(b)(3); (c).

[40] *2018 Sub 158 Order*, at 42.

[41] Hydro Stipulation, at ¶ 3.

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

to honor the 2.0 PAF for purposes of calculating avoided cost rates in those negotiated PPAs through December 31, 2020, and have included a 2.0 PAF multiplier in the calculation of avoided capacity rates for hydro QFs without storage eligible for the standard offer. The Companies' commitment was expressly subject to any future adverse regulatory decisions by the Commission. The Companies make the same commitment here, again subject to the any adverse regulatory decisions by the Commission that they should not offer a 2.0 PAF to hydro QFs 1 MW and less (standard offer) or to hydro QFs greater than 1 MW but equal to or less than 5 MW.

b. <u>Avoided Energy Cost Calculations</u>

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"), 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 unit, which is often referred to as the marginal unit. Consistent with the approach followed in the 2018 Sub 158 and prior proceedings, the Companies have relied upon the PROSYM generation production cost modeling platform to derive the Companies' system marginal energy costs, which represents the forecasted energy costs that a QF could avoid. The Companies have calculated their avoided energy costs consistent with the *2018 Sub 158 Order*, as further described below.

1. <u>The Companies have used the commodity price forecast methodology approved in the *2018 Sub 158 Order*</u>

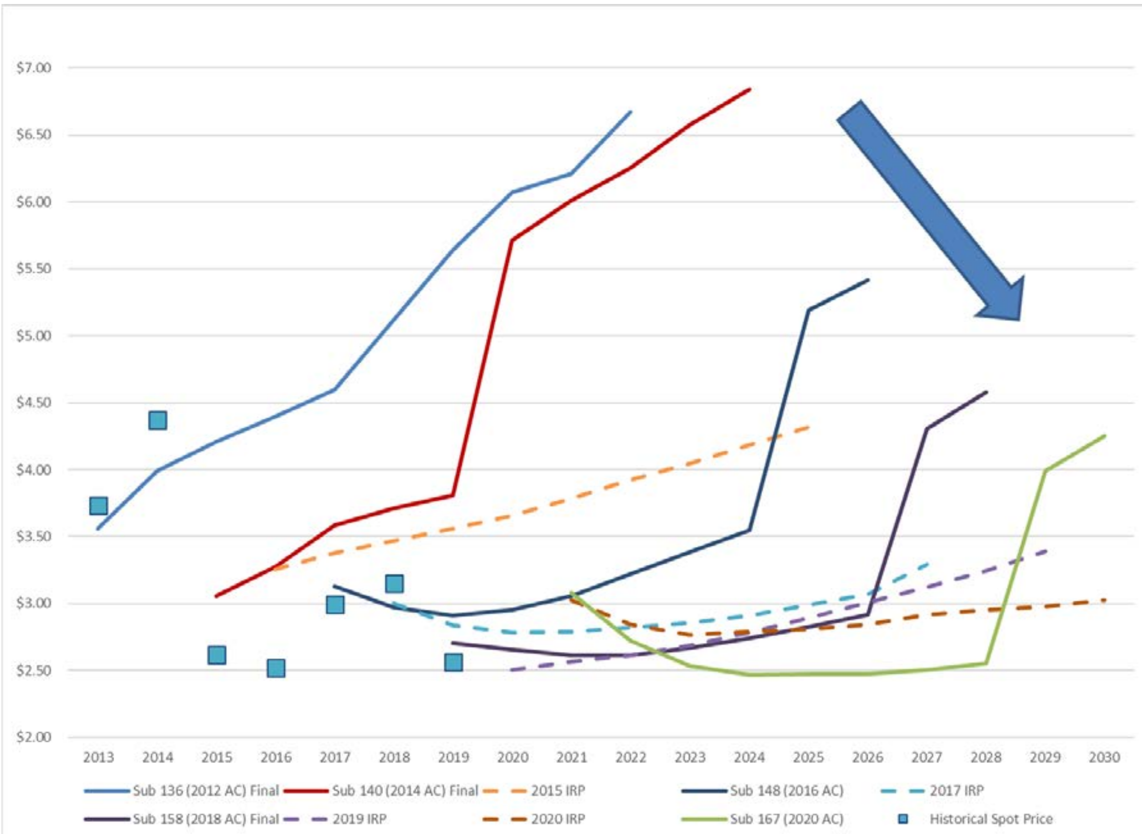
The appropriate methodology to accurately forecast commodity prices over the fixed future term of ten-year standard offer avoided cost contracts has been a contested issue in biennial avoided cost proceedings since 2014, when the Companies began relying upon ten years of forward contract natural gas market price data. Consistent with the Companies' IRPs and avoided cost filings since 2014, the Companies' recently filed 2020 biennial IRPs again rely upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived based upon fundamental forecasts over the remainder of the planning period. However, in the *2016 Sub 148 Order* and the *2018 Sub 158 Order*, the Commission determined that the Companies should be required to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period.[43] Therefore, for purposes of this more streamlined proceeding, the Companies have developed their respective avoided energy rates by relying upon the methodology directed to be used in the *2018 Sub 158 Order*, as opposed to the methodology consistent with the Companies' 2020 IRPs.

For the avoidance of doubt, the Companies continue to believe that the methodology that they have utilized since 2014 and included in their 2020 IRPs relying upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived from fundamental forecasts after year ten is accurate and appropriate for both integrated resource planning and calculating avoided costs. The Companies' recent historical experience demonstrates that utilization of ten years of forward natural as market price data has produced reasonably accurate forecasts over time.

[43] *2016 Sub 148 Order*, at 109 (Ordering ¶¶ 5-6); *2018 Sub 158 Order*, at 136 (Ordering ¶ 20).

Figure 2 below depicts historical spot prices and the ten-year forward natural gas prices from DEC's recent IRPs as well as the Companies' authorized avoided energy rates dating back to 2012.

Figure 2



The significant upward dislocation in the Sub 140, Sub 148, and Sub 158 avoided cost price forecasts in the latter years of the ten-year contract periods is due to the Commission's continued findings that fundamental forecast data should be utilized after year eight of the planning period for purpose of calculating avoided energy costs. As shown by the Companies' actual experience in subsequent IRPs, however, this continued reliance on lagging fundamental forecast pricing has consistently proven to be inaccurate over the past few years and has led to significant overpayment risk to QFs as the Companies' standard offer avoided energy rates have continued to exceed the natural gas commodity costs that the Companies are actually able to avoid.

Since the 2018 Sub 158 proceeding, natural gas commodity prices have remained low, with modest fluctuation since 2018, and the forward market continues to remain suppressed for the current ten-year term of avoided cost rates approved in this proceeding. However, in the interest of efficiency for this proceeding, the Companies have developed their respective avoided energy costs based upon a commodity price forecasting methodology that is consistent with the *2018 Sub 158 Order* (but, notably, inconsistent with the Companies' 2020 IRPs). Specifically, the Companies are relying upon forward market price data out eight years (2021-2028) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies' avoided energy cost rates before transitioning to fundamental forecast data starting in year nine. The Companies plan to continue to discuss this issue with the Public Staff in the future with the goal of maintaining consistency with the Companies' IRPs in future biennial avoided cost proceedings and providing the most accurate forecasts achievable.

2. <u>The Companies have included the avoided hedging adjustment that the Commission accepted in the 2018 Sub 158 proceeding</u>

In the 2018 Sub 158 proceeding, the Companies advocated that it was not appropriate to pay QFs an avoided fuel hedging value for their must-purchase power under PURPA, and did not include a hedge value in their proposed avoided energy cost calculations. The Commission's *2018 Sub 158 Order* determined that renewable generation is capable of providing fuel price hedging benefits, and, therefore, required DEC and DEP to recalculate their avoided energy rates to include a fuel hedging value utilizing the Black-Scholes Model to determine the hedging value of renewable generation.[44] After discussing this determination with the Public Staff, the Companies explained in their filing letter that they had updated their avoided energy cost rate calculations to include the same hedge value approved for Dominion Energy North Carolina in their Sub 158 avoided cost rates.[45] For purposes of this streamlined 2020 standard offer avoided cost rate proceeding, the Companies have developed their respective avoided energy rates to incorporate the same avoided fuel hedge value recently accepted in the 2018 Sub 158 proceeding.

3. <u>An avoided energy line loss adjustment continues to be appropriate for standard offer distribution-interconnected QFs</u>

The Companies' Schedule PP rates, as approved in the 2018 Sub 158 proceeding and prior proceedings, include avoided energy credits that vary depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. In the past, the Companies have consistently supported offering different avoided energy credits based on the point of interconnection to the Companies' systems, because that approach more accurately reflected differences in DEC's or DEP's actual avoided costs due to differences in avoided energy line losses for transmission level and distribution level QFs. In the 2016 Sub 148 proceeding, Dominion filed a study showing that surging distribution-interconnected QF solar development was causing power backflow on substations throughout Dominion's North Carolina service territory. Relying upon the Dominion study, the Commission determined that the previously-recognized "avoided line loss benefits associated with distributed generation have been reduced or negated" for

[44] *2018 Sub 158 Order*, at 62.

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

future QFs requesting to interconnect to the Dominion distribution system, and approved Dominion's request to eliminate the line loss adder from its standard offer avoided energy payments for QFs interconnecting on its distribution network.[46]

In the 2018 Sub 158 proceeding, the Companies undertook a similar line loss study. The Companies determined, however, that it was appropriate for DEC and DEP to continue offering a line loss adder, as their studies showed that the number of substations on their respective systems where backflow was reducing or negating the avoided line loss benefits of distribution-connected QFs was not substantial enough to eliminate the line loss adder for relatively small 1 MW or less standard offer QFs. The Commission approved the Companies' determination and further concluded that it was appropriate for the Utilities to continue to "study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the next biennial avoided cost proceeding."[47] Additionally, the Commission found that the Companies' proposal to assess the individual characteristics of QFs that are not eligible for Schedule PP standard offer rates and to address the line loss adder analysis as part of the PPA negotiation process was consistent with N.C. Gen. § 62-156(c) by taking into consideration the individual characteristics of the QF.[48]

Consistent with this Commission direction,[49] the Companies have analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of

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[46] *Id.* at 8 (Finding of Facts 17-18).

[47] *2018 Sub 158 Order*, at 36.

[48] *Id*.

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

substations that currently are or are expected to experience backfeed in the near future because of the recent growth in utility-scale QF growth. Currently, in DEP, 100 out of 408 substation banks, or 24.5%, are backfeeding into the transmission system due to distribution-connected generation. The Companies' analysis further indicates that despite the high number of queued projects requesting to interconnect to the DEP distribution system in the near future, only about 132 out of 408 substations, or 32% of DEP's substations, are estimated to experience backfeed before the projects being addressed by this avoided cost proceeding start connecting.[50] This relatively low percentage is in part due to the concentrated nature of QF solar development in more rural areas of the DEP eastern North Carolina service territory.

For DEC, the percentages of substation banks currently experiencing backfeed due to distribution-connected projects is significantly less – only 4.2%. Even accounting for the estimated impact of queued projects requesting to interconnect to the DEC distribution system, this number only grows to 7.7%. This is due to DEC having less than half the amount of connected, under construction, and queued distributed generation projects within its service territory than DEP and, additionally, DEC having a greater number of substations than DEP (1041 total substation banks analyzed).

Based upon this analysis, the Companies have determined that it is appropriate to retain a line loss adder for distribution-connected standard offer-eligible QFs contracting under Schedule PP at this time. For the 100 MW of aggregate standard offer QF generation seeking to interconnect to the Companies' distribution systems, the potential for avoided

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

line loss benefits from this Schedule PP-eligible QF generation remains on most substations within both the DEP and DEC service territories. However, for proposed distribution-connected QFs that are not eligible for Schedule PP, and in accordance with the *2018 Sub 158 Order*, the Companies plan to continue considering whether the QF's energy output would backfeed the substation and inject energy onto the transmission system. Consistent with HB 589, the Companies will assess the individual characteristics of the QF and address through negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate on a case-by-case basis.[51]

In addition to addressing the appropriateness of a line loss adjustment for standard offer distribution connected QFs, the Commission also directed the Utilities and the Public Staff to work together to more precisely define the issues around avoided transmission and distribution capacity benefits for the Commission's consideration in the next avoided cost proceeding.[52] The Companies plan to discuss this issue with the Public Staff and advise the Commission on the Companies' determinations in the next biennial avoided cost proceeding.

4. <u>The Companies have included the solar integration decrement to avoided energy rates approved in the *2018 Sub 158 Order*</u>

As North Carolina has experienced unparalleled growth in utility-scale QF solar interconnected with and injecting power into the Companies' systems, both the Companies and the Commission have increasingly scrutinized the avoided costs (and the potential for increased costs) associated with incremental solar generation. In the *2016 Sub 148 Order*,

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

[52] *2018 Sub 158 Order*, at 36.

the Commission emphasized that it would be “appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power, if the Utilities’ cost data ‘demonstrates marked differences’ in the value of the energy and capacity provided by these QFs.”[53] In the 2018 Sub 158 proceeding, the Commission specifically directed the Companies to consider factors relevant to the characteristics of QF-supplied power—specifically intermittent and non-dispatchable power—in designing rates to meet PURPA’s objectives of appropriately valuing the Companies’ incremental costs of alternative energy to be avoided from purchasing power from a QF.[54]

In the 2018 Sub 158 proceeding, the Companies proposed an integration services charge specific to integrating new intermittent solar energy generation into the Companies’ systems. The Companies designed the charge to recognize the impact on operating reserves, or increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity. The Companies’ ongoing evaluation of integration costs as well as the Astrapé Study filed in the 2018 Sub 158 proceeding[55] showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases.

The Astrapé Study determined both the average integration cost for a given block of solar capacity as well as the higher, incremental integration cost associated with additional increments of solar. Balancing the interests of customers and solar QFs, the

[53] *2016 Sub 148 Order*, at 98; *see also California Pub. Utilities Comm'n*, 133 FERC ¶ 61,059, at P 23 (Oct. 21, 2010) (recognizing that avoided cost rates may be designed to “differentiate among [QFs] using various technologies on the basis of the supply characteristics of the different technologies”).

[54] *2018 Scheduling Order,* at 1.

[55] The Astrapé Solar Integration Study supporting the integration services charges was presented to the Commission as DEC/DEP Exhibit 2 to the Companies’ Reply Comments filed March 27, 2019, in Docket No. E-100, Sub 158.

Companies requested approval of an integration services charge to be included in Schedule PP designed to reflect the average integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources. The charge would only apply to solar QF generators contracting to sell prospectively (whether new solar QFs or new PPAs with operating QFs after the term of the current agreement terminates), and the Companies would update this average charge every two years in future biennial avoided cost proceedings. The solar integration services charges presented in the 2018 Sub 158 proceeding were $1.10/MWh for DEC and $2.39/MWh for DEP and were based only on existing plus HB 589 transition solar capacity in DEP (2,950 MW) and DEC (840 MW).[56]

During the 2018 Sub 158 proceeding, the Companies and the Public Staff entered into a Stipulation resolving all issues related to the solar integration services charges,[57] which the Commission approved, in part, in its *2018 Sub 158 Order.*[58] Specifically, the *2018 Sub 158 Order* approved the integration charge amounts calculated in the Astrapé Study and approved the exemption for Controlled Solar Generators from being assigned the charge.[59] The Commission, however, determined that to remain consistent with FERC's regulations implementing PURPA, the charge should remain fixed during the term of a new QF's contract, as opposed to being subject to biennial adjustments throughout the

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

[57] *See* Stipulation of Partial Settlement Regarding Solar Integration Services Charge, Docket No. E-100 Sub 158 (filed May 21, 2019).

[58] *2018 Sub 158 Order*, at 90, 93.

[59] *Id.*

term of the contract. The Commission therefore approved a fixed solar integration charge to be included in the Companies' respective avoided energy rates in the amount of $1.10/MWh for DEC and $2.39/MWh for DEP for QFs establishing an LEO on or after November 1, 2018.[60] The Commission also directed the Companies to undertake an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings about the Companies' ancillary service costs associated with intermittent, non-dispatchable generation.[61]

In this proceeding, the Companies have incorporated the same integration services charges into their avoided energy rates in the same manner as approved in the *2018 Sub 158 Order*. Accordingly, the Companies do not propose any modifications to the integration charge amounts or to the rate design approved in the *2018 Sub 158 Order*, which currently assigns new solar generators the average versus incremental integration charge. The Companies plan to evaluate these methodological and rate design issues between now and the next biennial avoided cost proceeding and to engage with the Public Staff and other interested stakeholders. The Companies are also undertaking the formation of the independent technical review committee, as directed in the *2018 Sub 158 Order*, to review the Astrapé Study methodology and the model used for system simulations. The Companies will update the Commission on these efforts on December 7, 2020, and, ultimately, plan to include a report detailing the committee's feedback, in the Companies' initial filing in the next biennial avoided cost proceeding.

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[60] *Id*, at 93.

[61] *Id*.

5. Evaluating a real-time pricing rate option tariff to provide more granular rate structures and price signals

The *2018 Sub 158 Order* also directed the Companies to evaluate methods to better align the Utilities' avoided cost rates with actual real-time system conditions to enable QFs to maximize their facilities' value to ratepayers through real-time pricing or other tariffs that provide more granular rate structures and price signals, and if found to be appropriate, the Companies should establish and offer a real-time pricing-based avoided cost tariff as an optional alternative to their Schedule PPs.[62] The Companies continue to evaluate potential real-time pricing or other tariffs that could provide more granular rate structures and price signals to QFs for the benefit of customers and plan to further evaluate this issue under the recent revisions to FERC's implementing regulations established in FERC Order No. 872. The Companies will make any recommendations to the Commission on this issue in their next biennial avoided cost filing.

IV. 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 $/MWh basis versus a separate fixed payment for capacity).[63] 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

[62] *Id.* at 134 (Ordering ¶ 7).

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

Option A and Option B rate structures and proposed more granular rate designs to better recognize the value of QF energy and capacity. The Public Staff's initial comments on the Companies' Schedule PP rate design concluded that the Companies' proposed rate design "compl[ies] with the Commission's [Sub 148 Order] directive to propose more granular rates," but suggested that additional granularity, beyond the Companies' initial proposal was "appropriate and beneficial to North Carolina ratepayers."[64] The Public Staff therefore proposed the Companies implement a three-step methodology expanding the Companies' initial rate design and focusing on more granularly defined premium peak hours and additional shoulder month periods to further distinguish rates in more critical summer and winter seasons as compared to DEC and DEP's initially proposed rate design.

After engaging with the Public Staff on rate design issues, the Companies filed a Partial Settlement with the Public Staff 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").[65] Overall, the Sub 158 Rate Design Stipulation's avoided cost rate designs were generally consistent with the initial designs offered by both the Companies and the Public Staff, but 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 *2018 Sub 158 Order* approved the Sub 158 Rate Design Stipulation and found the rate designs included therein to be appropriate for use in calculating DEC and DEP's avoided energy and capacity

[64] Initial Comments of the Public Staff, at 48, 54, Docket No. E-100, Sub 158 (filed Feb. 12, 2019) ("Public Staff Initial Comments").

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

rates.[66]

In this proceeding, the Companies are continuing to utilize the Commission-approved avoided energy and capacity rate designs outlined in the Sub 158 Rate Design Stipulation. Figure 3 details the avoided energy rate design for DEC and DEP. As exemplified in Figure 3, Summer months are defined as calendar months June through September and Winter months are defined as calendar months December through February. All other months are defined as Shoulder months.[67]

Figure 3

ENERGY (1)																									
Independent Energy Price Blocks		1. Summer Premium Peak (PM)			2. Summer On-Peak (PM)			3. Summer Off-Peak		4. Winter Premium Peak (AM)			5.Winter On-Peak (AM)			6.Winter On-Peak (PM)			7.Winter Off-Peak		8. Shoulder On-Peak			9.Shoulder Off-Peak	
DEC Energy (2)	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 (PM)				Premium				On (PM)		Off	
Winter (Dec-Feb)		Off					On (AM)	Premium			On (AM)	Off							On (PM)					Off	
Shoulder (Remaining)		Off						On				Off						On							Off
DEP Energy (2)	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 (PM)			Premium				On (PM)	Off		
Winter (Dec-Feb)		Off				On (AM)		Premium			On (AM)		Off							On (PM)				Off	
Shoulder (Remaining)		Off					On					Off							On						Off

(1) Stipulated Rate Design E-100 Sub 158
(2) Note blocks reflect hour-ending.

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

[66] *2018 Sub 158 Order*, at Finding of Fact 4.

[67] 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.

the Astrapé Solar Capacity Value Study, and the Companies have continued to use the seasonal allocations approved in the *2018 Sub 158 Order*.

As approved in the *2018 Sub 158 Order*, the Schedule PP capacity rate design offers three distinct pricing periods to most accurately reflect the marginal capacity value to customers during each period, as exemplified below in Figure 6. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the winter months of December, January, February and March. No capacity payments apply during the remaining months. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The seasonal months and three capacity pricing periods are the same for DEC and DEP.

Figure 4 highlights the Summer and Winter on-peak hours for DEC and DEP.

<u>Figure 4</u>

CAPACITY (1)																									
Independent Price Blocks				1.Summer On								2.Winter On (AM)								3.Winter On (PM)					
DEC / DEP Capacity (2)	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 (Jul - Aug)																		On							
Winter (Dec - Mar)								On (AM)												On (PM)					

(1) Stipulated Rate Design E-100 Sub 158
(2) Note Blocks reflect hour-ending.

As noted above, the Companies have adopted the same seasonal allocation of capacity value approved in the *2018 Sub 158 Order*, which is heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As approved in the

2018 Sub 158 Order, 100% of DEP's loss of load risk is assigned to the winter while 90% of DEC's loss of load risk is assigned to the winter.[68]

In summary, the Companies have designed their avoided capacity and energy rates in accordance with the stipulated rate design approved in the *2018 Sub 158 Proceeding,* 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.

1. The Companies' recent DSM/EE proceedings and 2020 IRPs demonstrate the Companies' emphasis on winter DSM

The Commission's *2018 Sub 158 Order* directed the Companies to respond to the Commission's directive that they should place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands and should address this issue in the Company's Initial Statement in this proceeding.[69] To that end, DEC recently added a winter-focused smart thermostat-based load control option to its Residential Power Manager Load Control Service – Rider PM; DEP likewise added a similar modification to its Residential Service Load Control Rider. The Commission approved both modifications, directing the Companies to include additional information on winter-based DSM in their 2021 DSM/EE rider filings.[70]

Further, as highlighted in the 2020 IRPs, the Companies have recently undertaken a Winter Peak Shaving Study focused on emphasizing winter DSM through innovative rate

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[68] For purposes of this proceeding, the Companies have not updated their seasonal allocations based upon their recently filed 2020 Resource Adequacy Studies, which are being reviewed by the Commission and parties to the 2020 IRP proceeding, Docket No. E-100, Sub 165. The Companies' 2020 Resource Adequacy Studies continue to identify 100% of DEP's loss of load risk occurring in the winter while approximately 97% of DEC's loss of load risk is now projected to occur during the winter.

[69] 2018 Sub 158 Order, at 134 (Ordering ¶ 6).

[70] *Order Approving Program Modifications*, Docket No. E-7, Sub 1032, and *Order Approving Program Modification*, Docket No. E-2, Sub 927, both issued Oct. 13, 2020.

initiatives combined with advanced demand response and load shifting programs.[71] The Companies continue to study this issue and intend to comply with the Commission's directives to include information on this issue in their 2021 DSM/EE annual rider filings. Additionally, the Companies' DSM/EE Collaborative continues to discuss and consider winter-focused DSM/EE programs.

V. <u>Modifications to Schedule PPs and Terms and Conditions</u>

The Companies have amended their Schedule PP tariffs to reflect the updated avoided cost rates supported in Part III through IV above. The Companies have also made limited modifications to their Schedule PP PPAs and Terms and Conditions approved in the *Sub 158 Order*, including to reflect the Companies' plans to make an updated avoided cost/standard offer filing in November 2021. The Companies have also addressed the special avoided capacity rates available to certain legacy hydro QFs and swine/poultry waste-fueled QFs selling under REPS, as further discussed in Section III.a.1 above.

VI. <u>Modifications to Standard Offer PPA</u>

The Companies have made limited revisions to their standard offer PPA forms presented in DEC's and DEP's respective Exhibit 3. First, the Companies have deleted the limiting reference to hydro generating facilities in the recitals to reflect that HB 589 expanded the definition of small power producer in N.C. Gen. Stat. § 62-3(27a) to include all types of small power producer QF under PURPA. The Companies also amended Section 6 to provide that the Companies may require standard offer Sellers above 100 kW to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. The Companies do not have any present intent to require such

[71] *See* Dec 2020 IRP, Chapter 4, at 36; DEP 2020 IRP, Chapter 4, at 36.

information from small standard offer QFs. However, the Companies believe this change is appropriate at this time to better align this provision with revised standard offer eligibility under HB 589 and to recognize that it may become appropriate in the future to request operational data from smaller QFs during the terms of these PPAs as increasing penetrations of distributed energy resources are installed on the Companies' systems. Finally, the Companies have updated the Appendix A energy storage protocols applicable to standard offer solar QFs integrating battery storage to incorporate certain changes to the existing storage protocols consistent with the protocols most recently utilized in the CPRE Tranche 2 RFP.

VII. Standard Offer Notice of Commitment Form

The *2016 Sub 148 Order* directed the Companies to make certain modifications to the standardized Notice of Commitment forms first adopted by the Commission in the 2014 Sub 140 proceeding,[72] pursuant to which QFs in North Carolina establish LEOs memorializing their commitment to sell the output of their generating facilities to the Companies. The Commission specifically approved separate Notice of Commitment 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.[73]

On November 13, 2017, the Companies filed revised Notice of Commitment forms, which were approved for usage on December 17, 2017.

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[72] *Phase II Sub 140 Order*, at 9 (Finding of Fact 24).

[73] *2016 Sub 148 Order*, at 105-108.

Since November 1, 2018, when the Sub 158 standard offer rates became effective, the Companies have received 11 Notices of Commitment for approximately 5.56 MW under the Sub 158 Schedule PP standard offer, and have received 2 Notices of Commitment from larger QFs (not eligible for the Sub 158 Standard Offer) for approximately 8.4 MW requesting to negotiate a PURPA PPA. Notably, 9 of 13 of these new Notice of Commitment forms were for solar QFs, suggesting that more significant interest continues to exist in new small solar QF development under the standard offer than other technologies.

The Companies are not proposing substantive changes to the current LEO standards and standard offer Notice of Commitment form through this Joint Initial Statement. However, the Companies are proposing limited ministerial changes to the Schedule PP standard offer Notice of Commitment form to state that QFs submitting the Notice of Commitment form after the filing of these updated rate schedules shall be eligible for the new avoided cost rates filed in this docket, as well as to make clear that the "Effective Date" of the Notice of Commitment form and establishment of a LEO thereunder will be used for purposes of determining the priority of QFs for eligibility for Schedule PP under N.C. Gen. Stat. § 62-156(b) (limiting eligibility to an aggregate 100 MW).

Specific to the LEO standard and Notice of Commitment form for QFs above 1 MW seeking to enter into negotiated PPAs under PURPA, the Companies are also not proposing substantive changes at this time. However, the Companies plan to prospectively evaluate modifications to the process for larger QFs to establish a non-contractual LEO in response to FERC's recent adoption of 18 C.F.R. 292.304(d)(3), establishing that state regulatory authorities should prescribe reasonable and objective criteria pursuant to which

QFs must "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a [LEO]." The Companies continue to be concerned about the non-binding commitment that QFs delivering a Notice of Commitment form are making to the Companies, especially where significantly larger negotiated commitments of QF capacity and energy are concerned. The Companies plan to engage with the Public Staff, Dominion, and other interested parties to discuss the State's LEO standard and PPA negotiation process for non-standard larger QFs and will present updated proposals to implement 18 C.F.R. 292.304(d)(3), on or prior to November 2021.

Accordingly, in this proceeding, the Companies are proposing only ministerial changes to the current standard offer Notice of Commitment form approved in the Sub 158 Proceeding.

CONCLUSION

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

Respectfully submitted, this the 2nd day of November, 2020.

Kendrick C. Fentress

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

E. Brett Breitschwerdt
Kristin M. Athens
McGuireWoods LLP
501 Fayetteville Street, Suite 500
PO Box 27507 (27611)
Raleigh, North Carolina 27601
Telephone: (919) 755-6563
Telephone: (919) 546-6733
bbreitschwerdt@mcguirewoods.com
kathens@mcguirewoods.com

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 East Six Forks Road, Suite 260
Raleigh, North Carolina 27609
Telephone: 919.828.5250
bkaylor@rwkaylorlaw.com

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

VERIFICATION COMPLIES WITH VIDEO NOTARIZATION RULES

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-100, SUB 167
COUNTY OF MECKLENBURG)

The undersigned, Glen Allen Snider, being first duly sworn, deposes and says that he is Director – Integrated Resource Planning and Analytics – Carolinas; that he has read the foregoing 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 Allen Snider

Sworn to and subscribed before me
this 2 day of November, 2020

Peggy Holton
Notary Public Peggy Holton

My Commission Expires: 12/22/2021

PEGGY HOLTON
NOTARY
PUBLIC
WAKE COUNTY, NC

[SEAL]

I signed this notarial certificate on 11/2/2020 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Wake County

Stated physical location of principal during video notarization: Union County