STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALIEGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	
	)	**JOINT PROPOSED**
Biennial Determination of Avoided	)	**PARTIAL ORDER OF THE**
Cost Rates for Electric Utility	)	**CAROLINAS CLEAN**
Purchases from Qualifying Facilities –	)	**ENERGY BUSINESS**
2021	)	**ASSOCIATION AND THE**
	)	**NORTH CAROLINA**
	)	**SUSTAINABLE ENERGY**
	)	**ASSOCIATION**

BY THE COMMISSION: This is the 2021 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. 824a-3, and the Federal Energy Regulatory Commission (FERC) implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings are also held pursuant to N.C.G.S. § 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in N.C.G.S. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC establish the responsibilities of FERC and state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production.

[1] Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30, 128 (1980); see also 45 Fed. Reg. 12,214 (1980).

Section 210 of PURPA requires FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring the purchase and sale of electric power by electric utilities to cogeneration and small power production facilities. In adopting such rules, FERC stated:

> Under Section 201 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.[2]

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

With respect to electric utilities subject to state regulation, FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any

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

other means reasonably designed to give effect to FERC's rules. The Commission implements Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and made determinations regarding other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

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

On August 13, 2021, the Commission issued its Order Establishing Biennial Proceedings, Requiring Data, and Scheduling Hearing. Pursuant to that Order, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (together, Duke or Duke Energy), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion or DENC), Western Carolina University (WCU), and Appalachian

State University, d/b/a New River Power and Light (New River) were made parties to these proceedings.

The following parties filed Petitions to Intervene that were granted by the Commission: North Carolina Sustainable Energy Association (NCSEA), Carolinas Clean Energy Business Association (CCEBA), Southern Alliance for Clean Energy (SACE), Carolina Industrial Group for Fair Utility Rates I (CIGFUR I), Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), and Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) (collectively, CIGFUR), and Appalachian Voices. Participation of the Public Staff was recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On November 1, 2021, DENC filed its Initial Statement and Exhibits and confidential avoided cost information. Also on November 1, 2021, Duke Energy filed its Joint Initial Statement and Exhibits and confidential avoided cost information. On November 22, 2021, Duke Energy filed a correction to Exhibit 12 of its initial filing.

On December 16, 2021, WCU and New River filed a Notice of Appearance and Motion for Extension of Time.

On December 20, 2021, the Commission granted the Motion for Extension of Time to WCU and New River, extending the date for parties to file the required statements and exhibits to December 22, 2021.

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

On January 7, 2022, DENC filed corrected versions of its November 1, 2021 filings.

On January 24, 2022, New River filed an Affidavit of Publication of Public Notice to serve as proof of publication and in compliance with the Commission's August 13, 2021 Order.

On January 31, 2022, WCU filed an Affidavit of Publication of Public Notice to serve as proof of publication and in compliance with the Commission's August 13, 2021 Order.

On February 2, 2022, NCSEA, CCEBA, and SACE filed a Joint Motion for Extension of Time to file initial and reply comments.

On February 7, 2022, the Commission granted the Joint Motion for Extension of Time, extending the date for the parties to file initial comments to through and including February 24, 2022 and extended the date for parties to file reply comments to through and including March 28, 2022.

On February 14, 2022, DENC filed an Affidavit of Publication to serve as proof of publication of the Public Notice as required in the Commission’s August 13, 2021 Order.

On February 21, 2022, Duke Energy filed an Affidavit of Publication to serve as proof of publication of the Public Notice as required by the Commission’s August 13, 2021 Order.

On February 22, the public hearing was held, as scheduled. Duke Energy, DENC, and the Public Staff appeared at the public hearing.

On February 24, 2022, the Public Staff filed confidential and redacted versions of its Initial Comments; CCEBA and NCSEA filed confidential and redacted versions of their Joint Initial Comments; SACE filed confidential and redacted versions of its Initial

Comments; and Appalachian Voices filed its Initial Comments with Exhibit A. Appalachian Voices filed Exhibit B to its Initial Comments on February 25, 2022.

On March 1, 2022, New River filed its Amended Proposed Rates and Contracts in reference to its December 21, 2021 filing.

On March 9, 2022, DENC filed for reference public and confidential versions of all public contracts between VEPCO/DENC and qualifying facilities.

On March 11, 2022, Appalachian Voices filed a Response to New River's Amended Proposed Rates and Contracts filed on March 1, 2022.

On March 24, 2022, Duke Energy filed a Joint Motion for Extension of Time.

On March 25, 2022, the Commission granted the Joint Motion for Extension of Time, extending the date for the parties to file reply comments through April 1, 2022.

On March 31, 2022, SACE filed Reply Comments to the Initial Statement of the Public Staff and to the Joint Initial Comments of CCEBA and NCSEA.

On April 1, 2022, New River filed Reply Comments; DENC filed Reply Comments; CCEBA and NCSEA filed Joint Reply Comments; the Public Staff filed Reply Comments; Duke Energy filed Reply Comments; and NCSEA filed Reply Comments on the Net Excess Energy Credit (NEEC) Rate Revision Proposal.

On May 16, 2022, the Commission issued its Order Requiring the Filing of Proposed Orders and Briefs.

On June 17, 2022, various parties filed their Proposed Orders and Briefs.

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

FINDINGS OF FACT

1. The Commission approves the proposed revised contractual documents submitted by Duke Energy, including the Large QF Notice of Commitment (NOC) Form submitted as Reply Comments Exhibit 1, superseding and replacing the form of that document originally submitted as DEC/DEP Exhibit 7.
2. The Commission finds that Duke's natural gas pricing methodology, using eight years of forward market pricing, should be revised in due to several factors, including the use of five years of forward market pricing in Duke's Carbon Plan filing. The Commission adopts the recommendation of CCEBA, NCSEA, and SACE that Duke's natural gas pricing methodology utilize eighteen months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period.
3. In the 2023 avoided cost proceeding it will be appropriate for the Commission to determine how the approved Carbon Plan should be incorporated into the calculation of avoided cost rates.
4. In its Joint Initial Statement in the 2023 avoided cost proceeding, Duke shall include a proposal for the incorporation of the approved Carbon Plan into avoided cost rates.
5. It is premature at this time for the Commission to determine whether existing QFs may be eligible to receive compensation under their power purchase agreements or other agreements for ancillary services they can provide Duke.
6. It is appropriate for the Commission to open a new docket following approval of the Carbon Plan in which to further investigate the ability of both existing and

new solar and solar paired with storage facilities to provide and be compensated for ancillary services they can provide Duke.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1 (DUKE ENERGY FORM CHANGES)

The evidence supporting these Findings of Fact is found in the initial comments and reply comments of the parties and the entire record in the proceeding.

SUMMARY OF THE EVIDENCE

In its August 13, 2021 Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing (the "Procedural Order"), the Commission required Duke Energy and the other utilities in this docket to include in their initial filings "Proposed standard forms(s) of contract between qualifying facilities and the utility, describing any differences between said proposed standard form(s) of contract and the currently approved standard contract, including the reasons for such differences."

Duke Energy provided with its initial filing clean and redlined copies for both DEC and DEP of its proposed Terms and Conditions for the Purpose of Electric Power ("Terms and Conditions") (DEC Ex. 4 and DEP Ex. 4), its proposed Notice of Commitment Form for QFs for Schedule PP (DEC/DEP Ex. 6), and its Notice of Commitment Form for QFs larger than 1 MW in size. (DEC/DEP Ex. 7). Duke Energy's proposed changes would have required a QF to show that:

> (i) it has obtained a CPCN; (ii) for new QFs requesting to interconnect to the utility's system, the QF has met all requirements to enter the Definitive Interconnection System Impact Study (DISIS) Process under NCIP Section 4.4.1 and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5; (iii) has site control for the entire proposed term of delivery under a future [power

> purchase agreement (PPA)]; and (iv) has provided reasonable evidence and documentation of the QF's commitment to develop the project by including a status update on permitting, procurement of any long lead-time materials, execution of third-party engineering, procurement and construction contracts to construct the facility, and execution of any third-party transmission agreements, if applicable.[3]

No party objected to the proposed changes to Duke Energy's Terms and Conditions, though there was some discussion among the parties concerning the changes to the Notice of Commitment (NOC) forms that Duke Energy proposed.

In its initial comments, the Public Staff stated that it "generally supports" the revisions to Duke's NOC forms, and agreed with Duke "that the revisions incorporate the new commercial viability and financial commitment requirements established in [FERC] Order No. 872, align the legally enforceable obligation (LEO) process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from the NOC to a PPA."[4]

NCSEA and CCEBA also stated that they were "generally comfortable" with the proposed changes. However, they noted that in Section 4 of the proposed form, Duke required a QF to represent that it will, subject to a limited exception, begin delivering the output of its facility to Duke no later than 365 days after the NOC form Submittal Date. NCSEA and CCEBA noted that Duke's expected time to complete interconnection studies and construct interconnection facilities was approximately four years, leaving a QF unable to form a legally enforceable obligation, execute a PPA and secure pricing until approximately three years into the interconnection study and construction process.

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[3] Duke Joint Initial Statement at 51-52.
[4] Public Staff Initial Comments at 56.

This situation, they noted, would require a QF to incur substantial study costs and to pay for interconnection facilities before having any PPA or price certainty, a situation they describe as untenable for any proposed QF.

NCSEA and CCEBA also noted that the exception proposed by Duke did not solve the above problem, because it only gave a day-for-day extension to the 365-day deadline for any days by which Duke's completion of the interconnection facilities and network upgrades exceeds the QF's requested interconnection date. NCSEA and CCEBA pointed out that if a QF submitted an interconnection request on March 1, 2022 and requested an in-service date of March 1, 2026 due to Duke's expected schedule, it would remain exposed and unable to form an LEO until March 1, 2025, through no fault of its own.

NCSEA and CCEBA requested amendments to the proposed NOC form which would require the QF to represent that it will begin delivering the output of its facility to Duke within 90 days of Duke's completion of all required interconnection facilities and network upgrades. They described this proposal as "generally consistent with the deadline for achieving commercial operation included in Duke PPAs approved by this Commission for use in connection with the CPRE and Green Source Advantage programs and by the South Carolina [Public Service Commission (PSCSC)] in connection with PURPA implementation."[5]

In its Reply comments, Duke Energy stated that its intent in revising the Large QF NOC form was to provide for a different delivery term requirement for existing QFs

[5] NCSEA / CCEBA Joint Initial Comments at 24.

(with existing interconnection agreements) that have been operational as compared to new interconnection requests for QFs that have not yet achieved commercial operation. However, in light of CCEBA and NCSEA's comments, Duke Energy amended Section 4 to further clarify this position. Duke Energy also agreed that further extensions of the in-service-date may be appropriate where the Seller is making a good faith effort to advance the project but is delayed due to circumstances beyond its control and which do not result from its fault or negligence. Based on that, Duke Energy added an additional proviso to Section 4 of its proposed NOC form providing for such an extension if the QF Seller was making good faith efforts to advance its project.

Duke Energy filed an updated Large QF NOC Form as Reply Comments Exhibit 1, which it stated was intended to supersede and replace DEC/DEP Exhibit 7 as initially filed for approval.

DISCUSSION AND CONCLUSIONS

The Commission commends the parties for resolving their differences on the issue of changes to the Duke Energy NOC/LEO forms. Given that there were no other objections to the proposed contractual changes submitted by Duke Energy, the Commission finds those changes to be reasonable and compliant with the Commission's orders. Specifically, the Commission approves Duke Energy's Large QF NOC Form, filed as Reply Comments Exhibit 1, which contains the compromise language to address the concerns of NCSEA and CCEBA.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2
(GAS PRICING METHODOLOGY)

The evidence supporting these Findings of Fact is found in the initial comments and reply comments of the parties and the entire record in the proceeding.

SUMMARY OF THE EVIDENCE

In 2017, the Commission determined that even though intervenors had presented "substantial, competent, and material evidence and well-articulated arguments" in support their positions objecting to Duke's use of eight-year forward market pricing for natural gas costs, the Commission was "not persuaded that a change in the fuel forecasting methodology approved in the 2016 Sub 148 Order is appropriate, *at this time*." Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 148, 77-78 (October 11, 2017) ("Sub 148 Order") (emphasis added).

In the streamlined 2020 biennial avoided cost proceeding, Duke applied the established eight-year-market-ahead methodology but contended that it should be allowed to use ten years of forward natural gas market price data before transitioning to commodity price estimates derived from fundamental forecasts. Comments filed by CCEBA, NCSEA, and SACE pointed out that even eight years of forward market prices presented serious concerns regarding the liquidity of price data, and advocated for a transition period between forward-only forecast and the fundamental forecast to smooth the transition between forecast methodologies. Duke disagreed, but stated that it "may support a different position on natural gas commodity price forecasting methodologies in future proceedings." Because the streamlined nature of the 2020 proceeding did not allow for thorough consideration of the issue, the Commission authorized Duke to continue using the eight-year-forward-contract methodology.

Meanwhile, in the 2020 Duke integrated resource planning (IRP) proceeding, CCEBA and NCSEA presented the expert report of Kevin Lucas critiquing Duke's natural gas forecast methodology.[6] Mr. Lucas concluded that Duke's use of forward market forecasts, compared to a pricing forecast based more on fundamentals, provides less realistic and less reliable natural gas price projections for the mid-2020s through the mid-2030s. Mr. Lucas highlighted the volatility inherent in relying on forward market prices which, when used to establish IRP modeling – or in the present proceeding, avoided cost rates – can result in substantially different results within relatively short periods of time and recommended that Duke utilize eighteen months of forward market prices before transitioning to a blended fundamentals forecast, using at least two reputable sources, for the remainder of the planning period.[7]

The PSCSC adopted Mr. Lucas's approach in considering the 2020 Duke IRPs. The PSCSC specifically found that Duke's natural gas forecast methodology was "flawed and results in generation mixes which do not represent the most reasonable and prudent means of meeting Duke's energy and capacity needs."[8] The PSCSC also concluded that "Duke's Natural Gas pricing forecasts rely too heavily on forward contract prices determined at a market low point and maintained for over 10 years in the forecast period,

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[6] Initial Comments of the North Carolina Sustainable Energy Association and the Carolinas Clean Energy Business Association on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Integrated Resource Plans, pp. 19-20, Docket No. E-100, Sub 165 (March 1, 2021). Id. at Exhibit 3, pp. 37-64 ("Lucas Report").
[7] Lucas Report at 55.
[8] South Carolina Public Service Commission Order 2021-447, p. 17, Docket Nos. 2019-224-E & 2019-225-E (June 28, 2021) ("SCPSC IRP Order").

and commits Duke to large-scale buildouts of natural gas generation assets, at the expense of renewables and storage, endangering Duke's internal commitment to net-zero generation by 2035."[9] The PSCSC ordered Duke to modify the 2020 IRP and in all future IRPs to "remodel its portfolios using natural gas pricing forecasts that rely on market prices for eighteen months before transitioning over eighteen months to the average of at least two fundamentals-based forecasts, as recommended by CCEBA Witness Lucas."[10]

The Public Staff has advocated for Duke to use no more than five years of forward market data before transitioning to Duke's fundamental forecast.[11] Public Staff has identified no utilities other than DEC and DEP that rely wholly on forward prices for terms greater than six years and has observed that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana each rely on market prices for the first five years, blend market and fundamental prices for the next five years, and switch to the fundamental forecast for the remainder of the planning period.[12] NCSEA has previously recommended that Duke use forward market prices for two years, with a transition in the next three years to the average of a set of recent fundamentals forecasts.[13] Alternatively, NCSEA stated that it would not object to the use of forecast methodology used by Dominion – 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months.[14]

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[9] *Id.*
[10] *Id.* at 88.
[11] Initial Statement of the Public Staff, pp. 21-28, Docket No. E-100, Sub 158 (February 13, 2019).
[12] *Id.*
[13] Proposed Order of the North Carolina Clean Energy Business Alliance, the North Carolina Sustainable Energy Association, and the Southern Alliance for Clean Energy, pp. 67-68, Docket No. E-100, Sub 158 (September 4, 2019).
[14] *Id*.

CCEBA, NCSEA, and SACE contend the Commission should change the approved eight-year market forward approach based on two developments. First, Duke has proposed in its Carbon Plan to replace the ten-year-forward-contract methodology used in prior IRPs with five years of market gas and a 3-year blend to fundamentals – consistent with the Public Staff's longstanding position and the PSCSC's 2020 Order.[15]

Second, events over the past year have shown the limitations of forward market prices, which performed worse than fundamental forecasts such as the Energy Information Administration's (EIA) Annual Energy Outlook in anticipating increases in natural gas prices. The volatility of forward market pricing is particularly problematic in times of high volatility, which the market is now experiencing due to global factors such as the war in Ukraine and Covid-related economic disruptions.

The Public Staff acknowledges that Duke intends in its Carbon Plan to use five years of forward market prices, followed by a three year period blending the forward market prices with a fundamental price forecast derived from the average of several fundamental price forecasts, and supports that approach as consistent with past Commission avoided cost orders and providing for a reasonable blending period that eliminates the current abrupt price change when the forecast switches from forward markets to fundamentals. Yet while the Public Staff recommends that this method be used in in future avoided cost filings, it does not recommend Duke recalculate its avoided energy rates in this proceeding on grounds that the current methodology "technically

[15] Duke Energy Verified Petition for Approval of Carbon Plan, Chapter 2, p. 17, Docket No. E-100, Sub 179 (May 16, 2022).

complies" with past Commission orders and is in alignment with the natural gas forecasting methodology in the 2020 IRP Supplemental Portfolio B.

Duke states in its Joint Initial Statement that it continued to use the eight-year-forward-contract methodology that the Commission adopted in the 2016 proceeding to reduce the number of potential contested issues for the Commission's determination. However, Duke does not contest that in the stakeholder engagement process underway to develop the Carbon Plan, Duke has committed to: (1) use 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, EVA, IHS, and Wood Mackenzie to calculate market fundamental pricing.

NCSEA and CCEBA recommend the Commission require Duke to utilize 18 months of forward market prices before transitioning to a blended fundamentals forecast, and SACE similarly recommends that the Commission require Duke to use 18 months of forward market prices, 18 months of blended prices, followed by fundamental forecasts. In addition, NCSEA and CCEBA take issue with Duke's use of IHS pricing data to set the fundamentals forecast, arguing that it is a private forecast which does not allow for transparency. Duke relied on IHS pricing for their fundamental forecasts in both DEC's and DEP's respective 2020 IRPs, and to prepare Duke's Schedule PP in the 2020 E-100, Sub 167 avoided cost proceeding, and the Commission approved Duke's filings in both cases. Nevertheless, NCSEA, CCEBA, and SACE recommend that the Commission require Duke to use at least two reputable sources to determine the fundamentals forecast prices, with SACE recommending that Duke average the IHS data with EIA's prices.

<u>DISCUSSION AND CONCLUSIONS</u>

The evidence shows that Duke's use of eight years of forward market data is anomalous in the industry, inconsistent with the practice of Duke's regulated affiliates in other states, and introduces volatility and imprecision into the natural gas forecasting used in calculation of avoided cost rates. The accuracy of the eight-year forward approach is questionable given the illiquidity of markets that far in the future and is particularly problematic at a time of high volatility compared to the stability of fundamental forecasts. The Commission therefore finds that Duke should no longer use eight years of forward market data in the gas price projections, and that no procedural barrier or concern warrants avoiding that determination in the current proceeding given the Commission's duty to determine accurate avoided cost rates based on the evidence before it.

That leaves the question of what methodology should be used instead. The Public Staff has advocated for use of only five years of forward market prices, and Duke intends to use a consistent approach in its Carbon Plan development, and indeed, as noted above, has used that approach in the proposed Carbon Plan it recently filed with the Commission.[16] However, the Commission agrees with NCSEA and CCEBA that an 18-month-ahead futures market, followed by a period of blended rates, followed by a fundamentals forecast, is more defensible given the testimony of Mr. Lucas and the PSCSC's thorough evaluation and adoption of his recommendations.

In addition, the Commission agrees with the NCSEA and CCEBA critique of Duke's use of IHS pricing data to set the fundamentals forecast. The IHS forecast is a

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[16] *Id.*

private forecast that does not allow for transparency. Duke should use at least two reputable sources to determine the fundamentals forecast prices.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4 (CARBON COSTS)

The evidence supporting these Findings of Fact is found in the initial comments and reply comments of the parties and the entire record in the proceeding.

SUMMARY OF THE EVIDENCE

In its Initial Comments the Public Staff discusses the inclusion of carbon costs in avoided energy rates. Specifically, the Public Staff notes that under North Carolina SL 2021-165 (H.B. 951) the Commission is required to approve a Carbon Plan by December 31, 2022, and that the Carbon Plan will incorporate the carbon dioxide (CO2) emissions reduction required by H.B. 951. The Public Staff explains that although H.B. 951 does not impose a direct price on CO2 emissions, the statute imposes a limit on total CO2 emissions – a “mass cap” – which is directly related to a carbon price because “[i]n capacity expansion models, setting a mass cap will yield a model result with an implied price on carbon, which is indicative of the cost per ton of carbon abatement. Decreasing the amount of allowed emissions will increase the implied carbon price.” As a result, “[t]he increase in total system costs associated with carbon regulation, whether implemented via a mass cap or carbon price, is the total cost of carbon abatement.”

The Public Staff states however that “[n]ot all of the total cost of carbon abatement is avoidable in the context of calculating avoided costs” and that the Public Staff will “review the Carbon Plan and seek to make a determination in that docket of the appropriate avoidable cost of carbon, if any, that should be included in the calculation of avoided energy rates." The Public Staff proposes that "once a Carbon Plan is approved and the avoidable cost of carbon, if any, is determined within those proceedings" Duke should be required to "use the approved Carbon Plan as the expansion portfolio and include the Commission-approved avoidable cost of carbon in its calculation of avoided energy and capacity rates, if appropriate."

In its Initial Comments SACE similarly discusses the application of a carbon price in the calculation of avoided cost rates based on the carbon-reduction mandate of H.B. 951. SACE states that these carbon reduction requirements "must guide Duke's procurement beginning immediately" and that H.B. 951 "makes it possible to calculate a cost of carbon." SACE proposes that rather than waiting until a final Carbon Plan has been approved, Duke should apply the carbon price used in its IRP to represent a reasonable proxy – $5/ton in 2025 and escalated at a rate of $5/ton per year thereafter, or in the alternative the Regional Greenhouse Gas Initiative (RGGI) allowance price. SACE states that it is inappropriate for Duke to wait until subsequent proceedings to incorporate the carbon reduction mandates of H.B. 951 into the calculation of avoided cost rates and that Duke should include these costs immediately in the calculation of avoided cost rates.

In their Joint Initial Comments, NCSEA and CCEBA state that under the new resource planning regime required by HB 951, the Commission is required to approve a resource plan for Duke that can be expected to include a mix of new resources, including significant volumes of solar and wind along with some natural gas and potentially other new technologies as they become available. NCSEA and CCEBA state that they support the concept of incorporating the requirements of H.B. 951 and the Carbon Plan into avoided cost rates, especially considering Governor Cooper's Executive Order 246 encouraging the Commission to include the social costs of carbon in the development of the Carbon Plan.

In its Reply Comments Duke states that because H.B. 951 does not legislate a direct price or tax on carbon emissions that can be avoided by purchase from QFs, the cost of implementing the carbon reductions mandated by H.B. 951 are not yet known and verifiable. Duke argues that excluding any cost of carbon in this proceeding is consistent with the Commission's findings in the *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* Docket No. E-100, Sub 167, August 13, 2021 (*2020 Sub 167 Order*) and earlier *Order Setting Avoided Cost Input Parameters*, Docket No. E-100, Sub 140, December 31, 2014 (*Phase I Sub 140 Order*) that avoided costs should be calculated using only "known and verifiable" costs, and that "speculative costs" that are not "sufficiently certain" to be avoided by customers should not be included in avoided costs. Duke argues that, in this proceeding, there is no certainty regarding the resources to be developed or any future implied cost of carbon to be included in the approved Carbon Plan and, therefore, no real or known and verifiable costs associated with future carbon emission reductions under the Carbon Plan that should be avoidable at this time. Accordingly, any implied cost of carbon cannot be accurately determined until the Commission approves a Carbon Plan.

Duke disagrees with SACE's recommendation that the assumptions used in Duke's 2020 IRP Portfolio B should be used as a benchmark for potential future carbon reduction because Duke asserts those costs are not known and verifiable costs that are avoidable by customers today. Duke argues instead that HB 951 sets out a clear process that is already well under way to expeditiously develop and approve a Carbon Plan that will set Duke on a path to achieve the State's carbon emission reduction goals.

Duke agrees with the Public Staff's recommendation that, once a Carbon Plan is approved and the avoidable cost of carbon, if any, is determined within those proceedings, the Commission could direct Duke to use the approved Carbon Plan as the expansion portfolio in its next avoided cost filing. That expansion portfolio would implicitly include the Commission-approved avoidable cost of carbon in its calculation of avoided energy and capacity rates, if appropriate. Duke states that it is amenable to the Public Staff's proposal and agrees that the future base portfolio selected from the Carbon Plan should be used to calculate avoided cost rates in the next biennial avoided cost proceeding. Because the Commission will formally approve the Carbon Plan, the modeled cost of the resources identified to meet HB 951's carbon reduction goals will then be known and verifiable. Duke also raises the question of whether renewable energy credits and environmental attributes should be credited to customers if customers are paying QFs for avoided carbon benefits of generation.

In their Reply Comments NCSEA and CCEBA agree with the Public Staff and SACE that the carbon reduction mandates of H.B. 951 should be incorporated into the calculation of avoided cost rates. NCSEA and CCEBA agree with the Public Staff that it would be appropriate for Duke to include the approved Carbon Plan in the production cost modeling used to determine avoided energy rates under the peaker method, although NCSEA and CCEBA acknowledge that the appropriate application of this modeling will require further analysis and discussion at that time. NCSEA and CCEBA also agree with SACE that it would not be appropriate for Duke to delay the modeling of Carbon Plan compliance until 2030 when the 70% reduction mandate is required. Given that Duke will be required to take action to achieve the 70% reduction long before 2030, NCSEA and CCEBA state that Duke's modeling should incorporate the incremental implied carbon price as such changes are made between 2022 and 2030.

NCSEA and CCEBA state that they do not object in concept to Public Staff's proposal to further evaluate the appropriate application of the Carbon Plan in the calculation of avoided cost rates after the Carbon Plan has been approved.

DISCUSSION AND CONCLUSIONS

The development and approval of the Carbon Plan will establish a least-cost path to the decarbonization requirements of H.B. 951. The Commission agrees that it is appropriate for Duke to incorporate the approved Carbon Plan into the calculation of avoided cost rates in the 2023 avoided cost proceeding but notes that the specific application of the approved Carbon Plan to avoided cost rates requires further consideration and fact-finding during the 2023 avoided cost proceeding once the Carbon Plan has been approved.

Based upon the foregoing evidence and the entire record in this proceeding, the Commission therefore finds that in Duke's initial statement in the 2023 avoided cost proceeding, Duke will include a proposal for the incorporation of the approved Carbon Plan in the calculation of avoided cost rates, including whether and to what extent it is appropriate to include an implied cost of carbon, as proposed by the Public Staff, or different measure of carbon cost in those calculations. The Commission also determines it will be appropriate in the 2023 avoided cost proceeding for parties to evaluate whether the approved Carbon Plan should be incorporated into the existing peaker methodology or whether a revised avoided cost methodology is more appropriate in light of the approved Carbon Plan.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6 (ANCILLARY SERVICES)

The evidence supporting these Findings of Fact is found in the initial comments and reply comments of the parties and the entire record in the proceeding.

SUMMARY OF THE EVIDENCE

In its Procedural Order the Commission instructed Duke to address "the potential for qualifying facilities to provide ancillary services and appropriate compensation." In its Joint Initial Statement Duke concluded that after "investigating this complex issue" that "a QF selling 'must take' energy under PURPA cannot provide incremental positive ancillary services value under current system operations" and that "QFs are already fully compensated for their capacity and energy output under the peaker method such that no additional compensation is appropriate under PURPA." Duke listed a number of reasons why it believes this to be the case, including (1) that Duke does not have sufficient operational control over QFs; (2) the "must take" structure of existing QF PPAs is not compatible with QFs offering ancillary services; and (3) the peaker method already includes consideration of ancillary services.

In its Initial Comments the Public Staff stated that since the E-100 Sub 158 proceeding the "Public Staff has had numerous discussions with intervenors and Duke to discuss what, if any, ancillary services might be provided by QFs, and whether it is reasonable and cost effective for Duke to procure these services from QFs within the context of PURPA." The Public Staff notes that while PURPA's mandatory purchase obligation does not extend to ancillary services, it also does not prohibit the procurement of ancillary services from QFs. The Public Staff believes that as Duke procures additional renewable generation to comply with its Carbon Plan, some ancillary services may be provided at the least cost from inverter-based resources such as solar, both with and without energy storage. The Public Staff points out that a challenge of the provision of ancillary services from QFs is that ancillary services often require generators to produce less energy and capacity because some output is withheld to maintain the ability to ramp up, or is decreased following a ramp down signal. The Public Staff states that "without knowing Duke's ancillary service costs, it is difficult to determine the degree to which procuring ancillary services from QFs could provide savings to ratepayers." The Public Staff took the position that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility, and that the parties would benefit from a more detailed understanding of the technical ability to procure ancillary services from inverter-based resources and the associated costs.

In their Joint Initial Comments, NCSEA and CCEBA dispute Duke's assertion that QFs are not capable of providing ancillary services. First, NCSEA and CCEBA state that Duke's characterization of operational control of QFs is incomplete and that the changes required to facilitate the provision of ancillary services from QFs are easily attainable. Specifically, NCSEA and CCEBA state that Duke significantly overstates the technical barriers to the provision of ancillary services by existing QFs because QFs may already be equipped with automatic generation control (AGC) capability that would allow them to currently, or with limited modification, provide ancillary services, and QFs without advanced control capabilities could be evaluated to determine the feasibility of performing necessary upgrades, and NCSEA and CCEBA anticipate that such upgrades could be made without substantial cost.

NCSEA and CCEBA also state that QFs already provide certain ancillary services to Duke without compensation, which is unjust and unreasonable. Specifically, existing QFs are capable of providing voltage support/reactive power and are required to do so within a specific range under their interconnection agreements (IAs). The IAs also require Duke to pay QFs for reactive power provided outside that range and if Duke pays its own generators for reactive power within the specified range. NCSEA and CCEBA also note that Duke appears to provide reactive power from its own renewable energy facilities in other jurisdictions, as described in a recent Duke filing at FERC.

NCSEA and CCEBA further comment that QF operations and PPAs could be modified to incentivize valuable ancillary services. Although NCSEA and CCEBA acknowledge that most existing QF PPAs are "must take" agreements, a QF could agree to modify its PPA if there was sufficient opportunity to provide ancillary services, and NCSEA and CCEBA provide examples of such contractual structures. NCSEA and CCEBA also state that the Commission could permit a QF to receive payment for ancillary services under its IA, as an alternative to a modified PPA.

NCSEA and CCEBA argue that contrary to Duke's assertion, the peaker method does not incorporate the provision of and compensation for ancillary services. NCSEA and CCEBA state that while it might be possible to include the value of ancillary services provided by a QF in an avoided cost calculation, Duke's current avoided cost rates do not include such values. Avoided capacity costs under the peaker method are based on the projected cost to construct a simple-cycle combustion turbine (CT), including the fixed capital, financing and fixed operating costs associated with the construction and operation of the CT facility. Avoided energy costs under the peaker method represent an estimate of the variable operating costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. However, neither avoided energy nor avoided capacity costs under North Carolina's peaker method expressly include ancillary services.

Finally, NCSEA and CCEBA assert that the Commission and stakeholders should evaluate how new solar and solar + storage facilities can provide and receive compensation for providing ancillary services. NCSEA and CCEBA note that Duke's discussion of ancillary services in their Joint Initial Statement is limited to existing QF, and that new solar and solar + storage facilities may be more readily capable of providing ancillary services. NCSEA and CCEBA point to examples of solar generators providing ancillary services in other jurisdictions under various contractual structures.

To address these issues, NCSEA and CCEBA request that the Commission order further evaluation of solar and solar + storage facilities' ability to provide ancillary services and the related contractual, commercial, and technical issues. NCSEA and CCEBA request the initiation of a stakeholder process to address these issues.

In its Initial Comments, SACE states that QFs already provide positive ancillary services and could provide additional ancillary services with relatively low-cost modifications. SACE asserts that ancillary services provided by QFs should be included in Duke's avoided cost rates and refutes Duke's claim that QFs are already fully compensated for ancillary services under existing avoided cost rates. SACE also states that Duke's assertion that it is already providing necessary ancillary services itself is counter to the basic principle of PURPA, that QFs should be compensated for costs they allow the utility to avoid. It is therefore inconsequential whether Duke already provides avoidable ancillary services from its own generators. SACE states that Duke's alleged lack of operational control over QFs could be easily resolved with limited investments and contract revisions, and that agreed-upon contract revisions could address the existing must-purchase structure as a limitation to the provision of ancillary services.

In its Reply Comments, Duke states that no action in this proceeding is needed or appropriate to compensate QFs for ancillary services. Duke reiterates its arguments that its existing avoided cost rates already appropriately compensate QFs for any ancillary services delivered to Duke and states that this Commission has "extremely limited" jurisdiction over ancillary services. Duke states that the avoided capacity cost of a CT unit under the peaker method fully represents the capacity and energy value that can be avoided by purchasing power from a QF and that avoided costs may not exceed the actual costs avoided by the utility. Duke also reiterates its argument that a QF providing ancillary services would be required to sell less than its full output, contrary to its rights under PURPA.

Duke also states that the parties have not identified any other jurisdictions outside of regional transmission organizations (RTOs) in which QFs are compensated for ancillary services, which Duke suggests is based on limited state jurisdiction over ancillary services. Duke further asserts that it does not compensate its own generators for reactive power service and it is therefore not required to compensate QFs for such service. Finally, Duke disagrees with SACE, NCSEA and CCEBA, and the Public Staff that a stakeholder process or establishment of a pilot program to assess solar facilities' ability to provide ancillary services is not necessary or appropriate, and that any process to transition Duke's modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would create rather than avoid costs and would require a fundamental change in how the grid is operated. Duke does not support a new proceeding to evaluate these issues and believes that no further Commission action on this issue is needed at this time.

In its Reply Comments, the Public Staff states that it has become clear that the issue of ancillary services has expanded beyond an avoided cost issue, particularly as procurement of inverter-based resources is increasingly occurring outside of PURPA contracts. The Public Staff recommends that the Commission open a separate docket to solicit comments specifically related to the utilization of inverter-based resources to provide ancillary services, including the development of a pilot program for such purpose.

The Public Staff observes that the energy landscape in North Carolina is shifting, with large-scale competitive procurements for renewable energy increasingly responsible for much of the solar interconnected to Duke's grid. The Public Staff asserts that in the interest of minimizing the amount of regulatory attention diverted by the establishment of a pilot program for ancillary services, it may be beneficial for Duke and stakeholders to focus on potential revisions to future competitive procurements triggered by need identified within the Carbon Plan, and that these revisions might include dispatchable contracts and other mechanisms by which inverter-based resources owned by third parties and Duke can be utilized to provide ancillary services to the grid. The Public Staff addresses the potential for a dispatchable PPA structure to allow renewable generators to provide ancillary services to the grid, and the Public Staff urges Duke to work collaboratively with stakeholders to propose an alternative PPA, potentially based upon fixed capacity payments that would allow for full dispatchability and the provision of ancillary services from inverter-based resources in future RFPs for Carbon Plan resources. The Public Staff proposes that this dispatchable PPA structure could be based upon the dispatchable PPA proposed by First Solar in the CPRE dockets.

DISCUSSION AND CONCLUSIONS

In its Sub 158 Order the Commission instructed Duke to evaluate:

> [W]hether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide[.][17]

In response, Duke made the arguments it has repeated in its comments in this docket regarding the nature of PURPA "must take" contracts and operational control.

The Commission agrees with the comments of the Public Staff, NCSEA and CCEBA, and SACE in response to Duke's statements regarding ancillary services. The Commission agrees with NCSEA, CCEBA, and SACE that contractual, operational, and technical changes could be made to facilitate the provision of ancillary services by QFs. The Commission also agrees with NCSEA, CCEBA, and SACE that PURPA neither

[17] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 158, April 15, 2020, p. 136.

requires nor prohibits the inclusion of ancillary services in avoided cost rates and that the existing avoided cost rates under the peaker method do not include compensation for any positive ancillary services a QF may be able to provide, other than the decrement under Duke's integration charge. The Commission also notes that it may also be appropriate for the provision of and compensation for ancillary services to take place outside of PPAs, such as through IAs or other contractual mechanisms.

The Commission also agrees with the Public Staff, NCSEA, CCEBA, and SACE that the potential provision of ancillary services by inverter-based resources – including both solar and solar paired with storage – is an important issue in the context of both current and future renewable energy and storage resources in North Carolina. The Commission acknowledges that certain contractual and technical challenges inherent in allowing existing QFs to provide ancillary services may be alleviated or eliminated in new resources that come online under the Carbon Plan's resource mix, and that it would be valuable for the Commission and relevant stakeholders to further evaluate this issue outside of the avoided cost proceeding.

The Commission therefore concludes that following the approval of the Carbon Plan it is appropriate to open a new docket for the purposes of further investigating the ability of solar and solar paired with storage resources to provide ancillary services to Duke, the appropriate compensation structure for such services, and the related legal, contractual, and technical issues associated with this topic. Following the opening of the docket the Commission will allow initial comment by Duke, the Public Staff, and stakeholders regarding the appropriate scope of the proceeding, and the Commission encourages the parties to work collaboratively in this process. To the extent the

Commission determines following that proceeding that it is appropriate for existing QFs to have the opportunity to provide ancillary services to Duke for compensation, those findings will be incorporated into the subsequent avoided cost proceeding.

IT IS THEREFORE ORDERED AS FOLLOWS:

1. That the proposed revised contractual documents submitted by Duke Energy, including the Large QF NOC Form submitted as Reply Comments Exhibit 1, superseding and replacing the form of that document originally submitted as DEC/DEP Exhibit 7, are approved.
2. That in its calculation of avoided energy rates Duke shall utilize eighteen months of forward natural gas market prices before transitioning to a blended fundamentals forecast that employs at least two reputable sources for the remainder of the planning period.
3. That in determining natural gas pricing, Duke shall not use eight years of forward market pricing, which is inconsistent with the five years of market forward pricing used in Duke's proposed Carbon Plan. The Commission finds that using five years of market forwards is more defensible than use of eight years of market forwards.
4. That in the 2023 avoided cost proceeding the Commission will determine how the approved Carbon Plan should be incorporated into the calculation of avoided cost rates.
5. That in its Joint Initial Statement in the 2023 avoided cost proceeding, Duke shall include a proposal for the incorporation of the approved Carbon Plan into avoided cost rates.

6. That it is premature at this time for the Commission to determine whether existing QFs may be eligible to receive compensation under their power purchase agreements or other agreements for ancillary services they can provide Duke.
7. That, upon approval of the Carbon Plan, the Commission will open a new docket in which to further investigate the ability of both existing and new solar and solar paired with storage facilities to provide and be compensated for ancillary services they can provide Duke.

ISSUED BY ORDER OF THE COMMISSION.

This the _______ day of ________, 2022.