NC Electric Membership Corporation
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June 22, 2017

VIA HAND DELIVERY

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Clerk's Office
N.C. Utilities Commission

Martha Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

Re: Docket No. E-100, Sub 148

Dear Ms. Jarvis:

Accompanying this letter are the original and twenty-five (25) copies of North Carolina Electric Membership Corporation's ("NCEMC") ***Public*** and ***Confidential*** Post Hearing Filing to be filed in the above-referenced docket. Upon filing, please return date stamped copies in the enclosed envelope.

NCEMC will share the filing with parties pursuant to execution of an Non-Disclosure Agreement ("NDA") or confirmation by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") that the requesting party has an NDA with DEC and DEP which permits disclosure.

Also, an electronic version of the ***Confidentia***l filing will be provided to briefs@ncuc.net.

Should you have any questions, please do not hesitate to contact me at 919.875.3060.

Sincerely,

Michael D. Youth
Associate General Counsel

MDY/bl
cc: Parties of Record
Attachments

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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JUN 22 2017
Clerk's Office
N.C. Utilities Commission

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	**NCEMC'S**
Biennial Determination of Avoided Cost	)	**<u>PUBLIC</u>**
Rates for Electric Utility Purchases from	)	**POST-HEARING**
Qualifying Facilities – 2016	)	**FILING**

INTRODUCTION

The instructors at NARUC's rate school have been known to distill the complexity of a general rate case to two simple questions: "How much?" and "Who pays?" North Carolina Electric Membership Corporation's ("NCEMC") position in this complex proceeding can likewise be distilled to a simple statement: Ratepayers should pay no more than PURPA requires. This is not an outlandish position – it reflects a foundational principle in these proceedings, the concept of "ratepayer indifference." To this end, NCEMC generally supports Duke Energy Carolinas, LLC's ("DEC"), Duke Energy Progress, LLC's ("DEP"), and Dominion North Carolina Power's ("DNCP")[1] (collectively "the electric utilities") proposed revisions to (i) their avoided cost rates and (ii) implementation of the Public Utility Regulatory Policies Act ("PURPA").

The North Carolina Utilities Commission ("Commission") has a unique opportunity in this proceeding to maintain ratepayer indifference to the electric utilities' avoided cost rates. If the Commission, acting in its quasi-legislative capacity, fails to take

[1] Since initiation of this proceeding, DNCP has changed its name to Dominion Energy North Carolina.

proactive steps to ensure continued ratepayer indifference, ratepayers will bear (and be adversely impacted by) electric utility payments to qualifying facilities ("QFs") that are significantly more than PURPA requires.

Since the enactment of PURPA, QFs have been increasingly encouraged in North Carolina, culminating today in the fact that "North Carolina is now first in the nation for per capita solar energy, and second in the nation for total installed solar generation[.]"[2] While ratepayers have been indifferent to much of the encouragement and development thus far, the State has reached a tipping point. The QF solar capacity on the grid has begun to create costs – integration costs – at the same time that it is avoiding costs. These costs are not netting out; instead, the integration costs are growing while avoided costs are diminishing. Under the current implementation framework, ratepayers – not QFs – bear the burden of these growing integration costs.

As a native load wholesale ratepayer, NCEMC is concerned about the undeniable ratepayer cost increases associated with perpetuation of the existing PURPA implementation framework. During the evidentiary hearing, NCEMC's concerns were captured by the following exchange between North Carolina Sustainable Energy Association's ("NCSEA") counsel and DEC/DEP witness Bowman:

> Q (Ledford): What are the undeniable cost increases with which the EMCs are concerned?
>
> A (Bowman): I believe it relates to the overpayments ... the billion dollars. You know, the co-ops buy system average energy from – from DEC and DEP, and they pay for a portion of those costs. So they're it's my opinion that they're concerned

[2] Pre-filed Direct Testimony of DEP Witness David Fountain, p. 11, Commission Docket No. E-2, Sub 1142 (June 1, 2017).

> about increasing costs when they're buying bulk power from us.

Transcript of Hearing Volume 3 ("Tr. Vol. __"), pp. 14-15, Commission Docket No. E-100, Sub 148 (April 18-21, 2017).[3]

Integration costs are rising because QFs have begun affecting (and, going forward, will increasingly affect) the operation of the electric utilities' grids. DEC/DEP witness Holeman recounted a 2014 meeting with grid operators

> from California and Texas who were ahead of the curve in terms of solar integration, they came and explained their lessons learned. ... And they talked about back then challenges with operationally excess energy, challenges with operationally deficient energy, the ramping increases. That was the first time I heard the concept that these morning down-ramps and these afternoon up-ramps are approaching vertical, which means instantaneous change, and *their guidance to us was to get ahead of it.*

Tr. Vol. 2 at pp. 149-150 (emphasis added); see Tr. Vol. 2 at p. 163. During the 2014 biennial proceeding, few would have predicted that North Carolina would begin experiencing California-like operational challenges as early as 2016. Yet here we are. Today, as a result of solar, California contends with duck curves,[4] extreme ramp-rates (both downward toward the duck belly and upward out of the duck belly),[5] negative pricing, congestion, operationally excess energy,[6] energy "dumping,"[7] an energy imbalance

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[3] NCEMC's cost concerns are compounded by the fact that NCEMC's members also face rate increases attributable to the cost of safely disposing of/storing coal combustion residuals.

[4] See Tr. Vol. 2 at pp. 73-74 (Holeman testimony).

[5] See id. at p. 74.

[6] See id.

[7] See Tr. Vol. 5 at p. 87 (DEC/DEP witness Freeman testimony).

market,[8] forced curtailment, and early retirement of assets. See Ethan Howland, *Negative prices jump to Cal-ISO day-ahead*, Megawatt Daily (newsletter of S&P Global/Platts) 6 (May 3, 2017); Jonathan Nelson and Ethan Howland, *Calif. Commission, others eye plant retirements*, Megawatt Daily (newsletter of S&P Global/Platts) 2 (April 25, 2017); Ethan Howland, *California oversupply volumes grow*, Megawatt Daily (newsletter of S&P Global/Platts) 3 (April 21, 2017); Jeffrey Ryser, Eric Wieser and Jonathan Nelson, *Calif. solar growth leading to more curtailment*, Megawatt Daily (newsletter of S&P Global/Platts) 5 (March 28, 2017);

While North Carolina is not yet in the same position as California, it has already begun experiencing some of the same challenges, such as an increasing number of reliability exceedance alerts, and will no doubt experience more of the same challenges within this biennium. "[O]ur challenge is going to be to stay ahead of the growth of solar resources in DEP and I think we can learn from California, and we should." Tr. Vol. 2 at p. 180 (Holeman testimony).

As DEC/DEP witness Holeman testified, the electric utilities cannot adopt a wait-and-see attitude with regard to solar's current and looming operational impacts;

> hope and luck is not operational planning. We have to plan and then execute prudent operational discipline 24 x 7 x 365. ... The adverse impacts to reliable system operations that I have described are challenging the system's capability to respond to abnormal system conditions, future load demand changes, and are causing risks to reliability and security conditions on the BA. ... [T]he current and growing system operational challenges facing DEP and DEC are not merely "growing pains" to be accepted by the Companies as a temporary condition that will somehow resolve itself on their own. Instead, as set forth in the testimony of the Companies' other witnesses, it is appropriate to evolve the way in which solar QFs are added to and controlled on the Companies' energy grids to enable DEC and DEP to reliably serve our customers' energy needs.

[8] See Tr. Vol. 2 at p. 74 (Holeman testimony)

Tr. Vol. 2 at pp. 115-116. Unsaid in witness Holeman's testimony, but nevertheless implied, is the following warning that carries dire implications for North Carolina's ratepayers: If the PURPA implementation framework in North Carolina is not modified to more accurately calculate avoided costs and enable smarter integration of QF solar, then electric utilities will have no option but to ensure reliability is maintained by, among other things, investing in infrastructure and incurring integration costs. This proceeding represents the Commission's last chance "to get ahead of it" and – via a modified implementation framework that minimizes integration costs or, where such costs have become unavoidable, places the burden of these costs on the QFs causing them – ensure ratepayers' position will more truly approximate indifference.

For these reasons, NCEMC generally supports the electric utilities' proposals, as amended during the proceeding. However, while NCEMC generally supports the electric utilities' proposals, NCEMC nonetheless believes it important to highlight – via the attached proposed partial order – two specific actions the Commission can take to better mitigate the risk of overpayment by retail and native load wholesale ratepayers and thus to better ensure a just and reasonable outcome for ratepayers:

1. The Commission should change the standard offer eligibility threshold from 5 MW to 1 MW;[9] and
2. the Commission should direct the electric utilities to (a) take reasonable steps to fully quantify solar-related integration costs and (b) as soon as is practicable,

[9] House Bill 589, Ed. 3, 2017-2018 Session ("H589") is currently pending before the General Assembly. If enacted, H589 will require the Commission to change the standard offer eligibility threshold from 5 MW to 1 MW.

account for these costs in their non-standard power purchase agreement ("PPA") rates.

NCEMC's proposed findings of fact, discussion, and conclusions of law are set out in the proposed partial order attached hereto as **Attachment A**.

Respectfully submitted, this the 22nd day of June, 2017.

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

By: ______________________________

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CERTIFICATE OF SERVICE

It is hereby certified that the foregoing document, together with all attachments thereto, has been served upon all parties of record by electronic mail, or depositing the same in the United States mail, postage prepaid.

This the 22nd day of June, 2017.

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ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	**NCEMC'S**
Biennial Determination of Avoided Cost	)	**PUBLIC**
Rates for Electric Utility Purchases from	)	**PARTIAL PROPOSED**
Qualifying Facilities – 2016	)	**ORDER**

PROPOSED FINDING, DISCUSSION, AND CONCLUSION NO. 1

FINDING OF FACT

In this proceeding, in which the Commission is called upon to make rates and rules, the Commission exercises its delegated legislative authority.

DISCUSSION

G.S. 62-156 requires the Commission, on a biennial basis, to "determine the rates to be paid by electric utilities for power purchased from small power producers" and to make rules regarding, for example, the terms of standard offer power purchase contracts, and the methodology for calculating the avoided cost of energy to the utilities.[10]

"The rate making activities of the Commission are a legislative function. … Rule making is likewise an exercise of the delegated legislative authority of the Commission, under G.S.

[10] While G.S. 62-156 applies only to qualifying facilities ("QFs") which depend upon hydroelectric power as their primary source of energy, see G.S. 62-3(27a), the rates and rules determined in this biennial proceeding serve to implement PURPA and thus apply to all qualifying facilities. See Order Setting Avoided Cost Input Parameters, p. 3, Commission Docket No. E-100, Sub 140 (December 31, 2014).

62-30 and G.S. 62-31, to supervise and control the public utilities of this State and to make reasonable rules and regulations to accomplish that end. Actions of an administrative agency which involve the exercise of a legislative rather than a judicial function are not res judicata." State ex rel. Utilities Com. v. Edmisten, 294 N.C. 598, 603, 242 S.E.2d 862, 866 (1978).

The Commission has already clarified in this proceeding that its "ratemaking decisions are made pursuant to its delegated legislative authority, and do not constitute res judicata or even stare decisis. ... Moreover, the nature of these recurring biennial proceedings has always required consideration of current economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation. ... Although the filings and final orders in [earlier] biennial avoided cost proceeding[s] may prove to be helpful background to this proceeding, those final orders have no binding adjudicative effect on parties to, or issues in, this proceeding." Order Denying Motion, pp. 7-8, Commission Docket No. E-100, Sub 148 (January 18, 2017).

CONCLUSION OF LAW

While filings and final orders in earlier biennial avoided cost proceedings, including the 2014 biennial avoided cost proceeding, prove to be helpful background to this proceeding, the filings and final orders in earlier proceedings have no binding adjudicative effect on the issues in this proceeding. The nature of these recurring biennial proceedings has always required consideration of current operational and economic conditions facing public utilities and QFs and whether changed operational and economic conditions justify changes in avoided cost rates and/or PURPA implementation.

PROPOSED FINDING AND DISCUSSION NO. 2

FINDING OF FACT

Since the 2014 biennial avoided cost proceeding, the operational and economic conditions faced by North Carolina's electric utilities have changed significantly.

DISCUSSION

DEC/DEP witness Bowman testified that "[i]n only five years, installed utility-scale solar capacity has increased dramatically in DEC and DEP from approximately 125 MWs in 2012 to 1,600 MWs (approximately 1,100 MWs installed in DEP and 500 MWs installed in DEC, respectively)" at the end of 2016. Tr. Vol. 2 at p. 321. At the time of the evidentiary hearing in April 2017, DEC's and DEP's total installed solar capacity had increased to approximately 2,000 MW. DNCP has experienced similar unprecedented growth in installed solar capacity during the last three years. See, e.g., Tr. Vol. 5 at p. 137 (DNCP witness Gaskill testimony indicating a total of 350 MW of installed solar in the DNCP BA as of February 1, 2017).

Public Staff witness Metz provided a summary of the operational challenges now facing North Carolina's electric utilities because of the dramatic growth in QF solar capacity:

> DEC and particularly DEP face unique challenges in the continued operation of their electrical grids as increasing amounts of PURPA-mandated "must take" generation and non-dispatchable generation are being added. The impacts to date have been, but are not limited to: power

> flowing from distribution circuits back onto the transmission system (reverse, or "negative," power flows); excess energy generated at times when there is insufficient system load (overgeneration events); difficulty planning for day-ahead operations due to the growth of variable generation; difficulty of real time operation of their electrical systems due to high levels of intermittent generation relative to load; more frequent operation of ancillary resources to meet the increasing ramp-up and ramp-down needs of their systems; and the need to sell or "dump" excess generation at a loss. These impacts are already occurring with existing levels of interconnected solar generation. Continued growth in unconstrained and non-dispatchable generation will only serve to exacerbate the current system challenges.

Tr. Vol. 8 at p. 119.

The changed operational conditions faced by North Carolina's electric utilities have in turn changed, or present significant risks of changing, the economic conditions facing the electric utilities and their retail and wholesale ratepayers.

DEC/DEP witness Holeman testified that DEP "must select a Security Constrained Unit Commitment that is necessary to reliably provide firm native load service in the DEP BA and meet NERC Reliability Standards. ... [T]he Security Constrained Unit Commitment's Lowest Reliability Operating Level ("LROL"), *below which the BA cannot reduce operational output*, must be retained through the mid-day valley of the demand curve each day to provide for: (i) frequency regulation; (ii) resource availability to meet the evening peak demand; as well as (iii) resource availability to meet the next morning's peak demand, which is generally higher than the previous evening's peak demand for winter load patterns." Tr. Vol. 2 at pp. 98-99. Witness Holeman further explained that "the DEP BA is continuing to experience rapid growth of unplanned solar QFs. These facilities maximize their output and continue to inject energy into the BA during the mid-day load valley when system demand is at its lowest. The BA cannot reduce its LROL level, causing system generation required for reliability to exceed the net system demand (actual load minus unscheduled/unconstrained solar QF energy), resulting in operationally excessive energy on the BA - *caused by operationally excessive solar QF installed capacity.* ... The levels of unconstrained solar energy already being experienced during mid-day hours on certain non-summer days are forcing DEP to either: (i) increasingly ramp and cycle its intermediate and non-nuclear base load generators; and/or (ii) to sell the operationally excess solar QF energy into a neighboring BA using non-firm transmission, if available and if such transmission is not curtailed. Both of these options create potential real-time operating and reliability complexities and challenges. Looking ahead to 2017 and 2018, these challenges and risk will be amplified, particularly on the DEP BA as the quantity of solar QF installed capacity increases." Tr. Vol. 2 at p. 70.

DEC/DEP witness Holeman further testified that "[d]uring calendar year 2016, there were 33 days and 105 hours when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections. [By February 21, 2017], there were [already] 19 days and 71 hours [in 2017] when the DEP BA had operationally excess energy due to unscheduled and unconstrained solar QF injections." Tr. Vol. 2 at p. 80. "The operationally excess energy that DEP is projected to experience will approach *370 gigawatt hours per year*, concentrated between the hours of 10 a.m. and 3 p.m. Similarly, the DEC BA will also increasingly begin to experience operationally excess energy[.]" Id. at p. 82.

Overgeneration results in several adverse impacts to ratepayers. First and foremost, retail and wholesale ratepayers essentially pay full avoided cost for operationally excess energy produced by solar QFs, but the same ratepayers do not consume the energy they purchased; instead, subject to transmission availability, the energy purchased at full avoided cost is exported or "dumped" at below-cost prices to another BA, where it is being consumed by that BA's customers. The below-cost export or "dumping" of energy is inimical to the economic interests of ratepayers of the exporting utility. Furthermore, the harm presented by this cross-BA subsidy will be magnified if energy prices go negative and ratepayers begin having to not only pay for the energy at full avoided cost but also to have the importing BA to accept the energy.

NCSEA witness Johnson acknowledged that the dumping of energy is concerning: "I'm not denying that during some hours of some days there was already a concern about extra energy, energy that is not as valuable as we would like it to be[.]" Tr. Vol. 7 at p. 354.

During an exchange with Commissioner Bailey, Public Staff witness Metz opined that the creation and dumping of operationally excess solar QF energy is economically unfair for the North Carolina ratepayers who pay for its production via avoided cost payments:

Q (Bailey): … if a Company has to dump power to another BA, is that in its own ratepayers' advantage or disadvantage?

A (Metz): So without going through the numbers that were in the confidential exhibit, I would say they speak for themselves on what's taking place on what one BA is paying for energy as approved by the avoided cost rates as a backwards looking function, then being potentially fair to the other utilities taking it is at their - what is it - on the margin -- on the margin price, economic term, I apologize.

Q: … [D]o you agree that it's not likely to be in the North Carolina ratepayers' advantage if they have to start dumping excess power to other BAs?

A: For the -- I would define it as a disparity. The one who's having to get rid of it is at a disservice to the individual who's getting - in my words and my opinion - a good deal for the other balancing area. *It doesn't seem quite fair to me.*

Tr. Vol. 8 at pp. 254-255 (emphasis added).

Barring significant modernization expenditures by the electric utilities – which would increase the integration costs presently borne by ratepayers – operationally excessive installed solar QF capacity also threatens increased congestion-related transmission costs for the State's ratepayers.

On cross-examination, DEC/DEP witness Bowman engaged in the following exchange:

Q (Ledford): … the EMCs report that they depend on DEC and DEP's bulk power services, especially their transmission services, to serve the EMC customers in North Carolina? … Would you agree … that DEP has not experienced any transmission constraints due to overgeneration?

A (Bowman): Yes. It says *not at this time*, no transmission congestion.

Tr. Vol. 3 at pp. 15-16 (emphasis added). At no point did witness Bowman state that transmission congestion is not a concern on DEP's system. DNCP witness Gaskill testified that "[t]he fact that the LMPs are lower in North Carolina than the DOM Zone as a whole is a reflection of the fact that congestion and losses exist between the North Carolina nodes and the DOM Zone as a whole." Tr. Vol. 5 at p. 196. He explained that "[a]s more generation is added in a location where it is not needed, the cost of congestion and marginal losses increases, reflecting the re-dispatch cost to enable this generation to flow to locations on the transmission grid where it is needed to serve load." Tr. Vol. 6 at p. 90. During an exchange with Commissioner Bailey, witness Gaskill clarified the connection between operationally excessive installed solar capacity, overgeneration, and the heightened risk of congestion-related transmission cost increases:

Q (Bailey): So more specific, in the future you don't really see a situation where you're going to have so much excess power generation that you're going to have to sell it or give it away to some other balancing authority?

A (Gaskill): Well, where -- if that occurred, how that would manifest itself in PJM is you would see actually negative LMPs.

Q: Okay.

A: That has occurred not a lot yet. There are a few hours where you see negative LMP. That's an indication of extreme congestion on the system where you have an overgeneration event and no lines to take it out. You see that happening a lot, say, like in the Midwest, you might say, where you have a lot of wind --

Q: Right. A lot of wind.

A: -- you have negative LMPs. We haven't really seen that.

Q: That's a good point. You don't really see that taking place in Dominion, PJM area of the state?

A: *Not in the immediate future. Again, it depends on how -- I mean, you have a lot of -- if you get enough solar or wind, it could very well happen.*

Tr. Vol. 6 at pp. 100-101 (emphasis added). Similarly, DEC/DEP witness Holeman responded to a question from Commissioner Bailey about congestion in the DEP BA by stating, "[c]ongestion on the transmission system happens all the time. It is a giant machine connected throughout the whole eastern interconnection, and congestion and outage and things like that happen all the time. ... So, if you're asking me can congestion occur, it makes the problems worse, it certainly can." Tr. Vol. 2 at pp. 175-176.

Where overgeneration and congestion are present, the specter of unreliability – and associated costs – becomes more material. Witness Holeman testified that "DEC and DEP must comply with all applicable NERC reliability standards and associated requirements, including the BAL standards. Together, the BAL-001, BAL-002, and BAL-003 standards are designed to enhance the reliability of each Interconnection by maintaining frequency within predefined limits every 30 minutes under all conditions, and effectively mandate every BA to balance generation resources to load demand within the BA during each 30-minute reporting period." Tr. Vol. 2 at pp. 85-86. Importantly, violation of a BAL can result in NERC-imposed penalties, see Tr. Vol. 2 at p. 104, the cost of which will ultimately be borne by an electric utility's retail and wholesale ratepayers.

When asked, "if you were to go below the LROL, you may not be able to ramp up quick enough to meet the next peak demand and, therefore, you could violate a [BAL]," witness Holeman responded, "Yes ... it could translate into violations." Tr. Vol. 2 at p. 184. "[M]y direct and rebuttal testimony spoke to two balancing authority ACE limit exceedance alarms that occurred on March 15th. We're seeing that type of challenge now. The operators in DEP did a fantastic job of responding to that and not allowing an exceedance alarm to turn into a violation of BAL-001, but those are indication to an operator that is, if solar continues to grow or really any intermittent resource grows to the scale that we're talking about, we have got to be operationally prepared for that." Id. at pp. 167-68.

"[W]e've stayed reliable and we've not had any violations. But the concerning thing is we're seeing more of these exceedance alarms." Id. at p. 171. To date, DEP has "used th[e JDA-enabled] economic exchange of energy on non-firm hourly transmission to accommodate [overgeneration and to react to exceedance alarms.] But as solar continues to grow that hourly non-firm transmission is just not as sustainable or a dependable way to do that." Id. at p. 167; see id. at p. 152. The Commission finds particularly instructive the response of witness Holeman to one of Commissioner Brown-Bland's questions: "[I]f solar were to continue to become, to continue to grow and become a greater source there, operators would be able to handle it?" Tr. Vol. 2 at p. 166. Witness Holeman responded, "I think operators *under the existing tool set, I'm not sure they could.*" Id. (emphasis added).

Based on this evidence, the Commission concludes that perpetuation of the status quo rate- and policy-framework will adversely impact ratepayers in the absence of significant modernization expenditures by the electric utilities.

Equally instructive is the fact that "throwing money at the problem" – in the form of significant grid modernization expenditures – might mitigate the solar-driven reliability concerns but would adversely impact ratepayers as illustrated by the following record evidence.

DEC/DEP witness Holeman explained that "the concern with the LROL violating, compromising the Lowest Reliability Operating Limit is, if you shut down resources to meet that valley that drops below LROL, you may not have them back based on the operating characteristics of those resources for that afternoon peak, which puts us in a deficit energy situation, which is equally as dangerous and presents an equally reliability risk as operationally excess energy." Tr. Vol. 2 at p. 133. The electric utilities could, at ratepayer expense, address the symptom rather than deal with the underlying cause; in other words, the electric utilities could seek to modernize their grids by, among other things, installing additional gas-fired combustion turbines to handle QF solar-induced deficit energy situations. For example, DNCP witness Petrie testified that "[d]ue to the intermittency of the distributed solar generation coming online, [DNCP] is considering adding aeroderivative CTs to its system, which have a higher installed cost than the large frame turbines that the Company has built since the year 2000, but also have faster start-up and ramping capability." Tr. Vol. 5 at pp. 223; see id. at pp. 227-228. Witness Petrie explained "[t]he catch is it's more expensive. ... it's 67 percent more expensive than a conventional large frame combustion turbine. ... it's actually adding to capacity costs because we're – we have to spend more money because of these quick start, fast ramping aeroderivative machines." Tr. Vol. 6 at p. 95. DEC and DEP appear to be considering similar modernization efforts: "[I]ncreasing levels of variable unscheduled and unconstrained solar QFs may create an incremental need for faster response load following generation to meet system loads when solar generation either increases or decreases rapidly. ... As more non-dispatchable solar is added, additional flexible resources of all types may be required to reliably manage system operations." Tr. Vol. 2 at p. 212

(DEC/DEP witness Snider testimony).[11] The electric utilities' retail and wholesale ratepayers ultimately bear the cost of such modernization efforts.

In sum, the electric utilities have clearly and credibly asserted that, absent changes to their avoided cost rates and the manner in which the Commission implements PURPA, they face a "Sophie's choice" between (a) not modernizing their grids to make them capable of integrating GWs of QF solar (yet passing along to their retail and wholesale ratepayers the costs of reacting to the intermittent QF solar capacity on their grids together with any costs of reduced reliability, including but not limited to the costs of penalties associated with NERC BAL violations) and (b) modernizing their grids at considerable expense to make them capable of integrating GWs of QF solar (and passing these integration costs through to their retail and wholesale ratepayers – and not the QFs causing these costs – because, as discussed below, the electric utilities' standard offer avoided cost rates have not been reduced to account for integration costs and the interconnection process is not designed to

[11] On June 12, 2017, DEC filed an application for a Certificate of Public Convenience and Necessity ("CPCN") for a 402 MW (winter rating) simple-cycle advanced combustion turbine ("CT") natural gas-fueled electric generating unit located in Lincoln County, near Stanley, North Carolina. DEC asserts the need for this CT arises in part because "[a]s of December 31, 2016, approximately 500 MW (nameplate) of compliance and non-compliance intermittent renewable generation was interconnected to the Duke Energy Carolinas system. The Duke Energy Carolinas 2016 IRP projects that a total of approximately 1,800 MW (nameplate) of rated compliance and non-compliance renewable energy resources will be interconnected to the Company's system by 2025, with that figure growing to approximately 2,200 MW (nameplate) by 2031. The load following capability of the Lincoln County CT Addition provides additional system flexibility to help accommodate the impacts resulting from the increasing amounts of intermittent resources being added to the Duke Energy Carolinas system." Application for CPCN, p. 7-8, Commission Docket No. E-7, Sub 1134 (June 12, 2017).

capture all integration costs from the QFs).[12] It would not, however, be fair to the electric utilities' retail and wholesale ratepayers were the Commission to put the electric utilities to this choice, particularly as a more just and equitable alternative exists – namely, modifying avoided cost rates and PURPA implementation.

In past orders, this Commission has noted that "[e]ach electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. *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." See, e.g., Order Setting Avoided Cost Input Parameters, p. 3, Commission Docket No. E-100, Sub 140 (December 31, 2014) (emphasis added).

In the 2014 biennial avoided cost proceeding, "the Commission determine[d] that there ha[d] been widespread QF development under the [then-]existing framework without adverse impacts to utility ratepayers." Id. at p. 56. However, as discussed above, the operational and economic conditions facing electric utilities and their ratepayers have changed significantly and, in order to ensure a framework exists that is just and reasonable

[12] Recovery of "direct" interconnection costs via the interconnection process can be challenging, see, e.g., Order Approving REPS and REPS EMF Rider and REPS Compliance Report, Commission Docket No. E-2, Sub 1109 (January 17, 2017), let alone recovery of the less direct types of costs discussed here.

to ratepayers, the Commission concludes that the electric utilities' rates and this Commission's implementation of PURPA must change.

CONCLUSION OF LAW

The Commission concludes that the electric utilities' rates and this Commission's implementation of PURPA must change to maintain just and reasonable treatment of the electric utilities' retail and wholesale ratepayers.

PROPOSED FINDING, DISCUSSION, AND CONCLUSION NO. 3

FINDING OF FACT

Integration of QFs, particularly solar QFs, into the electric utilities' systems gives rise to significant costs that are not currently being accounted for in the electric utilities' avoided cost rates and, as a result, are being borne by the electric utilities' retail and wholesale ratepayers.

DISCUSSION

In the 2014 biennial avoided cost proceeding, NCSEA witness Beach testified that "it is important to acknowledge that solar generation may cause utilities to incur additional costs for regulation and operating reserves to integrate the resource. These costs are not captured by the peaker method, but should be taken into consideration." Transcript of Testimony Heard 7-9-14, Raleigh Vol. 5 pp 1-196, p. 155, Commission Docket No. E-100, Sub 140 (July 30, 2014). At the time witness Beach made this concession, he argued that no integration cost adjustment needed to be made in the 2014 proceeding because, at that time, only "approximately 350 MWs of solar are interconnected to the Duke utilities' distribution systems" in both North and South Carolina and, at this relatively low level of penetration, "the incremental avoided line losses will offset the increased integration costs." Id. at p. 162. Even if the current Commission assumes, arguendo, that the integration costs associated with 350 MWs of solar on DEC's and DEP's grids were offset by avoided line losses in 2014, the Commission faces two drastically changed conditions: First, there is approximately six times more solar on the grid today than there was at the time of the 2014 proceeding and, second, the energy being produced by this solar is not avoiding line losses in the same way that 350 MWs of solar may have been at the time of the 2014 proceeding.

DEC/DEP witness Yates testified that "[a]s of December 31, 2016, … more than 1,600 MW of third-party developed solar [was] connected to DEC's and DEP's grid in North Carolina, with another 4,900 MW [in the] the interconnection queue." Tr. Vol. 2 at p. 25. As of December 31, 2016, approximately 1,100 MWs of the connected solar was located in DEP territory. See Tr. Vol. 2 at pp. 321, 336 (DEC/DEP witness Bowman's testimonial Figures 1 and 6). By April 10, 2017, the connected QF solar capacity in DEP territory had grown to 1,552 MW. Tr. Vol. 2 at pp. 100, 105, 123, 136, 165 (DEC/DEP witness Holeman's testimonial Figure 2 and testimony). Consequently, at the time of the evidentiary hearing, approximately 2,000 MW of solar was connected to DEC's and DEP's grids. See Tr. Vol. 3 at pp. 13-14 (DEC/DEP witness Snider confirms "the total number of megawatts developed … [is] just a hair over 2,000 megawatts").

Integration of this QF solar has required, and going forward will increasingly require, the electric utilities (and their ratepayers) to incur integration costs. Integration costs are varied and sundry, as the studies cited in the following paragraphs indicate. Some integration costs arise because of how the electric utility operates its system when significant intermittent capacity is interconnected to the system. Other integration costs reflect investment in equipment including but not limited to (i) early retirement/replacement costs incurred because of the wear-and-tear on equipment like capacitors created by intermittent QF solar;[13] and (ii) new equipment and related costs incurred to accommodate the growing operational challenges presented by QF solar (e.g., new aeroderivative CTs to accommodate ramping).

In the 2014 biennial avoided cost proceeding, DEC/DEP introduced into evidence a Pacific Northwest National Laboratory 2014 study report, entitled *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* ("2014 PNNL Report").[14] The 2014 PNNL Report was revisited in this proceeding. See, e.g., Tr. Vol. 3 at pp. 73-74 (DEC/DEP witness Snider testimony). The 2014 PNNL Report calculated integration costs of \$1.43/MWh for a "compliance" level of solar penetration (i.e., 673 MW) in 2014,

[13] In addition to the studies cited below, DEP witness Simpson pre-filed the following in DEP's currently pending general rate case: "The dynamic demands on DE Progress' system such as the penetration of renewables is already exposing the limits of the legacy grid." Pre-filed Direct Testimony of DEP Witness Robert Simpson, p. 24, Commission Docket No. E-2, Sub 1142 (June 1, 2017). This statement illustrates how the wear-and-tear of intermittent QF solar is creating or at least contributing to early retirement/replacement costs.

[14] Accessible at http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf (last accessed on May 26, 2017).

~$3.70/MWh for a "smooth high" level of solar penetration (i.e., 1,700 MW) in 2016, and ~$3.50/MWh for a "mid" level of solar penetration (i.e., 2,260 MW) in 2018. <u>See</u> 2014 PNNL Report, Table ES.1 and Figure ES.4.

In this proceeding, the parties stipulated an additional, more recent PNNL study report into the record. <u>See</u> Tr. Vol. 3 at p. 126. PNNL's 2016 study report is entitled *Duke Energy Photovoltaic Integration Study: Regulated 2020 Case for Carolina Service Areas* ("2016 PNNL Report"). **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] [END CONFIDENTIAL]

Even if, arguendo, avoided line losses completely offset solar integration costs of $1.43/MWh or less in 2014 (as argued by NCSEA witness Beach), the two PNNL study reports indicate that integration costs are rising as solar penetration rises. At the same time, the record in this proceeding indicates that the increased penetration of solar in the State has resulted in diminished avoidance of line loss. For example, DNCP witness Gaskill testified that "line losses are not in fact avoided for most new QFs." Tr. Vol. 5 at p. 143. Public Staff witness Metz testified that "as more DG is interconnected to the DNCP grid, ...[avoided line] loss reductions will continue ... [and so i]t is no longer appropriate to include a line loss adder in the avoided cost rate schedules when line losses will continue to diminish as more DG is interconnected." Tr. Vol. 8 at pp. 130-131. Public Staff witness Metz also testified that "it may be appropriate for DEP to consider such an adjustment [i.e., elimination of its line loss adder] in future proceedings given the similar flow conditions [on the DEP system] as observed by DNCP on its grid." Id. at pp. 131-132.

Despite the foregoing evidence – the best evidence available – of rising integration costs, neither DEC/DEP nor DNCP reduced their proposed avoided cost rates to reflect the created (as opposed to avoided) costs associated with integrating large quantities of solar into their systems. See, e.g., Tr. Vol. 2 at p. 208 (DEC/DEP witness Snider testimony); Tr. Vol. 5 at pp. 192-193 (DNCP witness Gaskill testimony); Tr. Vol. 5 at p. 222 (DNCP witness Petrie testimony).

Public Staff witness Hinton testified that "the uncertainty associated with additional integration costs that are not yet fully quantified" is contributing to the risk that QFs will be overpaid by ratepayers. Tr. Vol. 8 at pp. 23-24. Moreover, Public Staff witness Hinton confirmed that "right now there's costs being shed" by QFs to the electric utilities' retail and wholesale ratepayers. Id. at p. 238.

No intervenor presented evidence in this proceeding that PV integration costs do not exist or offered any study report to rebut the PNNL study reports.

For perspective, the Commission observes that DEC's and DEP's proposed avoided cost rates in this proceeding are between $35 and $55 per MWh, see Tr. Vol. 3 at pp. 50-53 (DEC/DEP witness Snider testimony) and that accounting for integration costs of between $3.50 and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh, per the PNNL study reports, would result in a further reduction of the proposed rates of between 6.4% and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The Commission considers such a potential overestimate of avoided cost rates for solar QFs significant.

The Commission also notes that DEC and DEP are accounting for solar integration costs in their 2016 integrated resource plans ("IRPs"). For example, in calculating the present value revenue requirements ("PVRR") of its IRP's modeled portfolios, DEP states that "PVRR includes the cost of integrating solar as represented in the Duke Energy

Photovoltaic Study published by Pacific Northwest National Lab in March 2014."[15] DEP's Revised 2016 IRP (Public), p. 73 nt. 9, Commission Docket No. E-100, Sub 147 (September 30, 2016); see DEC's Revised 2016 IRP (Public), p. 67 nt. 10, Commission Docket No. E-100, Sub 147 (September 30, 2016).

PURPA requires that the rates offered to the QF reflect the purchasing electric utility's avoided cost, which ensures that ratepayers remain "indifferent" between the costs of utility and non-utility electricity generation. 16 U.S.C.A. § 824a-3(b), (d). This "ratepayer indifference" principle is intended to ensure that retail and wholesale ratepayers remain financially indifferent as to whether the electric utility generates the electricity itself or purchases the electricity from a QF.

As the Commission has stated in earlier proceedings, "overestimating avoided costs creates costs ultimately borne by ratepayers[.]" See, e.g., Order Setting Avoided Cost Input Parameters, p. 21, Commission Docket No. E-100, Sub 140 (December 31, 2014). In other words, overestimating avoided costs violates PURPA's "ratepayer indifference" principle. The Commission is sympathetic to DEC's and DEP's assertion that they declined to propose lower rates to account for integration costs because their standard offers are

[15] The Commission has acknowledged "the important relationship that exists between the biennial avoided cost proceeding and the IRP, and ... maintain[ing] internal consistency between these proceedings." Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, p. 27, Commission Docket No. E-100, Sub 140 (December 17, 2015). This Commission has also "recognize[d] the least cost nature of the IRP planning process and agree[d] that it is important that the inputs and assumptions utilized in the IRP proceeding carry forward through the following biennial avoided cost proceeding." Id. at p. 16.

generic while the quantified integration costs are solar-specific, see Tr. Vol. 4 at p. 53 (DEC/DEP witness Snider testimony) and to the electric utilities' assertions that they continue to explore full quantification of solar integration costs; however, the Commission is also aware that the overwhelming majority of QFs electing the standard offer have been solar (and are likely to continue to be solar) and that integration costs that are unaccounted for in the electric utilities' avoided cost rates are currently being paid for (and will continue to be paid for) by the electric utilities' retail and wholesale ratepayers instead of by the solar QFs.[16] An inability to fully quantify PV integration costs may excuse the electric utilities' lack of accounting for them, but it does not justify ignoring the existence of known but only partially quantified costs – costs which are currently inflating avoided cost rates and being paid for by ratepayers – as this Commission balances the interests before it.

In the face of uncertainty, an appropriate reduction of the standard offer eligibility threshold can mitigate the risk of the ongoing overpayments articulated by Public Staff witness Hinton.

Beyond the standard offer approved in this proceeding, DEC/DEP witness Snider testified that "[d]epending on the future adoption rate of non-controllable QF solar and the Companies' further analysis of the costs and potential benefits of integrating these small

[16] Integration costs are not the only factor contributing to an overestimation of DEC's and DEP's avoided cost rates. DEC and DEP have asserted that their Option A and Option B hours and rate structure are "increasingly providing a subsidy [at ratepayer expense] to the small QFs eligible for the Schedule PP by overvaluing their capacity avoidance during the Companies' winter peak hours[.]" Tr. Vol. 2 at p. 219 (DEC/DEP witness Snider testimony).

solar generators onto their systems, it may be necessary to address the [integration] costs in future standard offer avoided costs filings. Furthermore, in the context of larger negotiated QFs, the Companies believe it is appropriate to address the costs of ancillary services and other potential integration costs that relate to the specific characteristics of these QF generators." Tr. Vol. 2 at p. 208.

CONCLUSION OF LAW

The electric utilities' current inability to fully quantify and account for PV integration costs in their proposed rates results in standard offer rates that more likely than not overestimate the electric utilities' avoided costs for solar QFs by an undetermined yet potentially significant amount, a risk factor which mitigates against maintaining the standard offer eligibility threshold at 5 MW and in favor of reducing the standard offer eligibility threshold to 1 MW.

Furthermore, given the record before it, the Commission directs the electric utilities to continue their efforts to fully quantify solar integration costs and report on their findings in the 2018 biennial proceeding. The Commission also directs the electric utilities to input appropriate quantifications of integration costs into their negotiated avoided cost rates as soon as practicable, keeping in mind the Commission's admonition that "the use of up-to-date data in determining the inputs for negotiated avoided cost rates is not only permitted, but is expected." Order of Clarification, p. 3, Commission Docket No. E-100, Sub 140 (March 5, 2015).[17]

PROPOSED FINDING, DISCUSSION, AND CONCLUSION NO. 4

FINDING OF FACT

There is growing acknowledgment among the parties that it may be appropriate to lower the current 5 MW standard offer eligibility threshold.

DISCUSSION

With regard to eligibility for the standard offer, DEC and DEP have proposed "lowering the capacity threshold from 5 MW to 1 MW[.]" See, e.g., Tr. Vol. 2 at p. 338 (DEC/DEP witness Bowman testimony). Similarly, DNCP has proposed to "[r]educe the threshold at which a QF qualifies for the standard rates and contract terms from 5 MW to 1 MW." See, e.g., Tr. Vol. 5 at p. 143 (DNCP witness Gaskill testimony).

SACE witness Vitolo "recommend[ed] that the Commission maintain current policy by requiring DEC, DEP, and DNCP to allow renewable QFs up to 5 MW eligibility for

[17] This directive takes on increased importance in light of the General Assembly's consideration of House Bill 589, Ed. 3, 2017-2018 Session ("H589"). If enacted, H589 would amend G.S. 62-156(c) to include the following language relevant to negotiated avoided cost rates: "In establishing rates for purchases from [non-standard] small power producers, the utility shall design rates consistent with the Commission-approved avoided cost methodology for a fixed five-year term." To the extent there is any question, this Commission directive should be construed as approving an avoided cost methodology that includes an adjustment to account for quantified integration costs. A QF may pursue arbitration if it disputes the appropriateness of an electric supplier's integration cost adjustment.

Schedule PP, Schedule PP-1, and Schedule 19-FP, respectively." Tr. Vol. 7 at p. 30. Similarly, NCSEA witness Harkrader testified that "NCSEA … recommends maintaining the Standard Offer threshold at 5 MW[,]" id. at p. 392; however, NCSEA witness Johnson acknowledged that a revision could be appropriate, testifying that "on balance, it would be unwise to change the threshold *so drastically*. If the Commission is inclined to modify the threshold, I would recommend making a much smaller step in that direction – perhaps to 3.75 or 4 MW. … [T]aking a much smaller step toward lowering the threshold would be prudent, rather than drastically changing it from 5 MW to 1 MW." Id. at p. 329 (emphasis added). The Commission notes that, in adopting these positions, SACE and NCSEA focus on what is in the best interest of QF developers (as is appropriate for advocates with their interests); however, the Commission must balance the interests of the electric utilities and their ratepayers, as well as QF developers, in order to advance the public interest.

The Public Staff supported maintenance of the 5 MW threshold in the 2014 biennial avoided cost proceeding. Importantly, in this proceeding, the Public Staff supports a reduction of the current threshold. Public Staff witness Hinton testified that "th[e] significant growth of facilities from which the utilities are obligated to purchase the energy and capacity has increased the risk of potential overpayments by ratepayers. In addition, the higher penetration of resources poses operational and technical challenges to the utilities in their obligation to provide safe, reliable, and economic service to ratepayers. As such, the Public Staff believes it is appropriate for the Commission to consider modifications to the standard offer threshold." Tr. Vol. 8 at p. 57. "The Public Staff recommends that the Commission reduce the standard offer threshold from its current 5-

MW level to a level that more currently reflects current conditions in the QF marketplace and better protects ratepayers from the risk of overpayment." Id. at p. 58. Ultimately, witness Hinton concluded that "[w]hile the Public Staff finds support for lowering the threshold to either one MW or two MW, it appears that the 1-MW limit may have more practical significance. As indicated by witness Bowman and DNCP witness Gaskill, the reduced threshold will allow the avoided cost rates offered to more QFs to be based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce the exposure of ratepayers to potential overpayment due to changing market conditions." Id. at p. 60.

CONCLUSION OF LAW

Given the changed operational and economic conditions facing the electric utilities and the heightened risk under these changed conditions, maintenance of a 5 MW standard offer threshold will lock in overpayments by the electric utilities' retail and wholesale ratepayers for a biennium, the Commission concludes the electric utilities' proposed revised standard offer threshold of 1 MW strikes an appropriate balance and is approved.