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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	ORDER ESTABLISHING STANDARD
Rates for Electric Utility Purchases from	)	RATES AND CONTRACT TERMS FOR
Qualifying Facilities – 2016	)	QUALIFYING FACILITIES

HEARD: Tuesday, February 21, 2017, at 9:00 a.m.; Tuesday, April 18, 2017, at 9:30 a.m.; Wednesday, April 19, 2017, at 9:30 a.m.; Thursday, April 20, 2017, and 9:30 a.m.; Friday, April 21, 2017, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, James G. Patterson, and Lyons Gray

APPEARANCES:

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BY THE COMMISSION: This is the 2016 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) regulations implementing those provisions, 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 also are held pursuant to 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 G.S. 62-3(27a).

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

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status. For such purchases, electric utilities are required to pay rates 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 jurisdiction, 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 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

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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.

HOUSE BILL 589

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute, as it was effective when the Commission established this proceeding, provided 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 therein. The definition of the term "small power producer," for purposes of G.S. 62-156, as in effect when the Commission established this proceeding, was more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) included only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding power producers using other types of renewable resources. While this matter was pending before the Commission, the General Assembly enacted House Bill 589, amending G.S. 62-3(27a) and G.S. 62-156, and enacting G.S. 62-110.8, which establishes a program for the competitive procurement of energy and capacity from renewable energy facilities.

PROCEDURAL BACKGROUND

On June 22, 2016, the Commission issued an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Hearing. Pursuant to that Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion); Western Carolina University (WCU); and New River Power and Light Company (New River) were made parties to these proceedings.

The following parties timely filed petitions to intervene that were granted: North Carolina Sustainable Energy Association (NCSEA); Public Works Commission of the City of Fayetteville; Carolina Utility Customers Association, Inc.; Carolina Industrial Groups for Fair Utility Rates I, II, and III; Southern Alliance for Clean Energy (SACE); Strata Solar, LLC; North Carolina Pork Council; NTE Carolinas Solar, LLC; Cypress Creek Renewables, LLC (Cypress Creek); O_2 EMC, LLC; and North Carolina Electric Membership Corporation (NCEMC). Participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On April 11, 2017, the North Carolina Attorney General's Office gave notice of intervention pursuant to G.S. 62-20.

On November 15, 2016, DEC and DEP (Duke) and Dominion (collectively, the Utilities) each filed their initial comments, statements, and exhibits. On November 28, 2016, WCU and New River filed proposed avoided cost rates.

On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant certain materials in the Utilities' initial comments, which was denied by Commission order issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule. Similar to Duke's request included in its initial comments, the Public Staff requested an evidentiary hearing in this proceeding, and requested modifications to the procedural schedule. On December 30, 2016, the Commission issued an Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, granting Duke and the Public Staff's requested evidentiary hearing and modifying the procedural schedule in this proceeding.

On January 17, 2017, DEC and DEP filed confidential avoided cost information.

On or after February 13, 2017, 900+ consumer statements of position were filed in this docket.

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of Notice of Public Hearing as required by the Commission's June 22, 2016 Order. The public hearing was held on February 21, 2017, as scheduled. Twelve witnesses testified at the public hearing.

On February 21, 2017, Dominion filed the direct testimony of J. Scott Gaskill and Bruce Petrie, and Duke filed the testimony and/or exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, III, and Gary Freeman.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson, and Kurt Strunk; Cypress Creek filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D.; and the Public Staff filed the testimony and exhibits of John Hinton, Jay Lucas, and Dustin Metz. Also on March 28, 2017, NCEMC filed initial comments.

On April 10, 2017, Dominion filed the rebuttal testimony of witnesses Gaskill and Petrie, and Duke filed the rebuttal testimony of witnesses Bowman, Snider, Holeman, and Freeman.

On August 8, 2017, Duke and Dominion jointly filed a motion, requesting that the Commission take into consideration Session Law 2017-192 (S.L. 2017-192 or HB 589) as additional authority in deciding the legal and policy issues in this proceeding. The Commission concludes that this motion should be granted. As reflected in the discussion and conclusions in this order, the Commission considered the authority enacted by S.L. 2017-192 in determining the issues in this proceeding.

In addition to the foregoing, there were other motions, orders, and filings not specifically mentioned which are matters of record.

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

FINDINGS OF FACT

1. The economic and regulatory circumstances facing QFs and electric public utilities in North Carolina have changed since the Commission's last biennial review of standard avoided costs rates.

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

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

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

5. For nonrenewable QFs, when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's integrated resource planning (IRP) forecast period when a capacity need is demonstrated

during that period; however, providing a levelized capacity payment over the term of the contract is a reasonable means of implementing this capacity payment.

6. It is appropriate for the utilities to continue to evaluate the capacity benefits of QF generation and to make other changes as needed to accurately reflect the avoided capacity benefits provided by QF generation of all resource types over the short and long run.

7. The availability of a combustion turbine (CT) is not determinative for purposes of calculating a Performance Adjustment Factor (PAF), because the fixed costs of a peaking unit under the peaker methodology employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

8. It is appropriate to require DEC, DEP, and Dominion to utilize a PAF of 1.05 in their respective avoided cost calculations for all QFs, other than hydroelectric QFs without storage capability, and to utilize a PAF of 2.0 in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued by further order of the Commission or in accordance with the stipulation filed by DEC, DEP, and the NC Hydro Group and the Commission's December 31, 2014, Order in Docket No. E-100, Sub 140 (Sub 140).

9. DEC and DEP's proposed seasonal allocation weightings of 80% for winter and 20% for summer are appropriate for use in weighting capacity value between winter and summer, and should be used in calculating DEC and DEP's avoided capacity rates in this proceeding.

10. It is not appropriate for DEC and DEP to reset energy prices under the standard offer contract every two years at this time.

11. It is appropriate to require DEC and DEP to recalculate their avoided energy rates using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period.

12. The input assumptions used by Dominion for the purpose of determining its proposed avoided energy rates, including the avoided costs related to fuel hedging activities, are appropriate for use in this proceeding.

13. An imminent violation of a North American Electric Reliability Corporation (NERC) BAL Standard is a system emergency, as defined in 18 CFR 292.101(b)(4); therefore, it is appropriate for DEC, DEP, and Dominion to curtail PURPA QFs when a NERC BAL Standard violation is imminent.

14. It is appropriate for DEC and DEP to amend their standard offer contract to incorporate the imminent violation of a NERC BAL Standard into the system emergency provision.

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15. It is appropriate for DEC, DEP, and Dominion to file procedures with the Commission stating how they would curtail QFs on a nondiscriminatory basis when there is a system emergency.

16. It is appropriate for Dominion to make locational energy pricing adjustments to its avoided energy rates accounting for the locational value of distributed generation located in its North Carolina service area.

17. There is power backflow on substations in Dominion's North Carolina service territory from solar generation on the distribution grid such that avoided line loss benefits associated with distributed generation have been reduced or negated.

18. It is appropriate for Dominion to eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network.

19. It is appropriate for Duke to continue to include the line loss adjustments in its avoided energy calculations and to study the effects of distributed generation on power flows on its electric systems to determine if there is sufficient power backflow at its substations to justify eliminating the line loss adjustment from their standard offer avoided cost calculations filed in the next avoided cost proceeding.

20. It is appropriate to require DEC, DEP, and Dominion to propose avoided cost rates in the next biennial avoided cost proceeding that reflect consideration of factors such as the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity, without regard to the technology the QF uses to generate electricity.

21. It is appropriate to require WCU and New River to offer to all QFs contracting to sell one MW or less variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year term standard offer. The changes the Commission approves herein to DEC's proposed ten-year avoided capacity rates should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

22. It is appropriate to add a fourth requirement to the current Commission standard for the establishment of a legally enforceable obligation (LEO) for QFs. Therefore, a QF may establish a LEO when it has (1) self-certified with FERC as a QF, (2) made a commitment to sell its output to a utility under PURPA using the approved Notice of Commitment Form (NoC), (3) filed a report of proposed construction (RPC) or received a Certificate of Public Convenience and Necessity (CPCN) for the construction of the facility, and (4) submitted a completed interconnection request pursuant to the North Carolina Interconnection Procedures (NCIP). For a QF larger than one MW that has been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date on which the commitment to sell is established shall be the earlier of (i) 105 days after the submission of the interconnection request, or (ii) upon the receipt of the system impact study from the public utility. For a QF larger than one MW

that has not been designated as an A or B project in the interconnection queue at the time of its interconnection request, the date of the commitment to sell shall be the earlier of (i) 105 days after the project is first designated as an A or B project, or (ii) upon the receipt of the system impact study from the public utility. In either case, where the QF has or has not been designated an A or B project, the 105-day period as part of establishing a LEO will remain in effect until the Commission issues a final order in Docket No. E-100, Sub 101. If, by final order issued in that docket, the Commission alters the NCIP's 105 day-deadline for providing a QF with the results of the utility's system impact study, that altered deadline shall be substituted for the 105-day standard approved in this order. If, prior to the expiration of the 105 days or the substituted date from Docket No. E-100 Sub 101, the utility anticipates being unable to deliver the results of the system impact study to the QF, the utility may petition the Commission for an extension of that deadline and a delay in the establishment of the QF's LEO. In the proceeding on such a petition, the utility shall bear the burden of proof to justify any requested extension and delay, and the length thereof. The Commission shall address such petitions on an expedited basis and determine the appropriate deadline extension and LEO date on a case-by-case basis.

23. For any QF that withdraws its commitment to sell, it is appropriate to limit such a QF to "as available" rates for the two years following the withdrawal of the commitment.

24. It is appropriate to require DEC, DEP, and Dominion to modify the NoC to reflect the additional requirement for QFs larger than one MW, and to explain the consequences of withdrawal of a NoC.

25. It is appropriate for the Public Staff to convene a working group that includes DEC, DEP, Dominion, and other interested parties, with the goal of developing consensus around proposed revisions to the notice of commitment form, making further refinements to the LEO standard, and other procedures for streamlining the negotiated PPA process.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 1

The evidence for this finding of fact is found in the testimony of Duke witnesses Yates, Bowman, Snider, and Holeman; Dominion witness Gaskill; the Public Staff witnesses Hinton and Metz; and NCSEA witnesses Johnson and Harkrader.

Summary of the Evidence

The parties provided extensive testimony and exhibits regarding the economic and regulatory conditions facing QFs and utilities in North Carolina. Duke witness Yates testified that North Carolina is now at a critical crossroads regarding the integration, development, and customer costs of renewable generation, specifically QF solar generation, under PURPA. He testified that, as of 2016, 60% of all installed PURPA solar projects in the United States are located in North Carolina, attributing this to North Carolina having "significantly encouraged" solar development under PURPA compared

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to other states. Witness Yates further testified that the existing policies that led to this growth in PURPA solar have also created a distorted solar marketplace resulting in artificially high costs being passed on to North Carolina residents, businesses, and industries, while potentially degrading operation of Duke's electric systems. He supported these arguments with data and by making reference to the testimony of other Duke witnesses. He concluded his testimony by stating that Duke believes that its proposed changes are reasonable and necessary to ensure that its customers and the State's energy systems prosper as Duke continues to add renewable generation resources, and that Duke looks forward to continued collaboration with interested parties to consider improvements that are critical to North Carolina's sustainable energy future.

Duke witness Bowman testified regarding the PURPA regulatory scheme. She emphasized that Congress assigned implementation of PURPA to state commissions that are best suited to consider and balance PURPA's goals with the economic and regulatory circumstances that vary from state-to-state and utility-to-utility. She further testified that North Carolina has evolved its implementation of PURPA over time as economic and regulatory circumstances have changed, including adjusting the standard offer eligibility threshold, as well as the technologies eligible for 10- and 15-year standard offer contracts. Witness Bowman testified that the Commission has balanced the interests of QFs, the utilities, and customers through the State's PURPA standard offer implementation, recognizing that the overpayment risk to customers historically has been relatively small as QFs entitled to long-term rates were of limited number and size. However, she further testified that, since 2005, the State's implementation of PURPA has remained relatively unchanged. Therefore, witness Bowman argued that changing economic and regulatory circumstances – specifically the "surging" growth of utility-scale QF solar in North Carolina – is now driving the need for comprehensive review of the Commission's PURPA policies.

In support of her argument, witness Bowman highlighted the growth in utility-scale solar over the past few years, with approximately 1,100 MW of third-party QF solar now installed on DEP's system and 500 MW installed on DEC's system. She also noted that an estimated 4,900 MW of additional third-party QF solar capacity (approximately 3,800 MW in DEP and 1,100 MW in DEC) are already in development and are requesting to interconnect and sell power to DEC or DEP. Witness Bowman also testified that PURPA is now the predominant driver of the continued development of solar QF projects in North Carolina, as the State's Renewable Energy Tax Credit has expired and as DEP and DEC have achieved long-term compliance with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) requirements. She also noted that the additional solar renewable energy certificates (RECs) made available from solar-powered QFs are being used to meet the future requirements of the general REPS requirements rather than the solar set-aside requirements.

Witness Bowman continued her testimony by addressing why North Carolina is experiencing greater PURPA growth than other states. She testified that the Commission's historic PURPA polices, including the threshold to establish a LEO and the long terms for standard contracts offered to QFs under 5-MW in generation capacity are more favorable than other jurisdictions, and have made North Carolina the fastest growing

solar development marketplace in the Southeast and a leader in distributed utility-scale solar deployment nationally. She observed that Section 210(m) of PURPA, as enacted by the EPAct, provides for termination of the PURPA "must-purchase" obligation for utilities in organized markets and regional transmission organizations where QFs have non-discriminatory access to competitive wholesale energy and capacity markets. Witness Bowman also stated that other states in the Southeast have not adopted PURPA implementation policies as favorable to QFs as North Carolina's policies. Additionally, she testified that other jurisdictions around the country with significant PURPA development have recently taken steps to adjust their PURPA standard offer implementation, largely in response to significant growth of intermittent wind and solar QF generation that was increasingly causing over-supply and growing operational challenges. She argued that continuing the State's current PURPA policies may cause even greater interest in selling QF solar power under the current PURPA regime and significantly increase the overpayment risk for customers as QFs are no longer of limited size and number. Finally, Witness Bowman testified that in assessing the public interest under PURPA, the Commission should consider two broader purposes of the State's energy policies under the Public Utilities Act: 1) to assure the delivery of reliable and least cost electricity to citizens and businesses of the State, and 2) to integrate a diverse and cost-effective mix of renewables and demand side resources to reliably serve customers.

Duke witness Snider testified that Duke's estimated long-term fixed purchase power obligation for the 1,600 MW of installed solar QFs as of year-end 2016 is approximately $2.9 billion dollars over the remaining 12-14 year terms of these agreements. He also testified that if these contracts were valued at the avoided cost rates Duke proposed in this proceeding, they would have a value of only $1.9 billion, resulting in what he views as a potential long-term "overpayment" of approximately $l.0 billion. Witness Snider also testified that it is critical for the Commission to appreciate that customers' current financial obligation and exposure to "overpayment" risk could increase significantly in the future, as approximately an additional 1,100 MW of solar QFs under 5 MW have established LEOs under the Commission's current policy.

Duke Witness Holeman testified to his recent experience as system operator and the growing operational concerns, reliability risks, and North American Electric Reliability Corporation (NERC) compliance challenges of integrating significant additional QF solar into the DEP and DEC Balancing Authority Areas (BAAs). He testified that DEP and DEC are independent Balancing Authorities (BAs) and must independently balance generation resources, unscheduled QF energy injections, and load demand in real-time, which is essential to providing reliable firm native load service, maintaining compliance with mandatory reliability standards, and achieving reliable bulk electric system operations across the Eastern Interconnection. Witness Holeman described Duke's growing operational experience over the past 18 months with growing levels of installed PURPA solar, and highlighted the potential for future challenges to reliable system operations, based on significant additional PURPA solar proposed to be installed over the next few years.

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Witness Holeman further testified that solar QFs are making “unscheduled” and “unconstrained” energy injections into Duke’s electric systems, outside of the Security Constrained Unit Commitment process, such that balancing the system is becoming increasingly volatile due to large and uncertain swings in the unscheduled and unconstrained solar QF energy injections. He testified that growing injections of unscheduled QF solar is requiring DEP to increasingly manage the Security Constrained Unit Commitment of its network generating resources at their lowest reliable operating limit (LROL), which Duke defines as the minimum operating level necessary to reliably provide frequency regulation and load-following resource availability to meet the evening peak as well as the next morning’s peak demands. Witness Holeman presented figures and testimony analyzing how solar QFs’ non-summer energy production between 10 a.m. and 3 p.m. is not coincident with DEP’s and DEC’s load shape and is increasingly requiring steep down-ramping of network resources, as well as causing operationally excess energy to meet the LROL, during the late morning. After solar production peaks during the mid-day and then declines in the afternoon, DEP is increasingly experiencing deficit energy situations requiring steep ramping up of network resources to meet evening peak loads. Witness Holeman also testified that the variability, volatility, and intermittency of QF solar energy production is causing DEP system operators to have limited operational situational awareness over the performance of these generators intra-day (caused by intermittency of solar production) and day-ahead (caused by variability of solar production) and is also requiring increasingly steep ramping of the BA’s load-following network resources.

Witness Holeman also testified that DEP is now experiencing “operationally excess energy” with some regularity during an increasing number of days and hours throughout the year, including 105 hours in 2016 and 71 hours on 19 days during the first month and a half of 2017. Witness Holeman also forecasted that continued growth in installed QF solar capacity will significantly increase operationally excess energy in the DEP BA to 370 gigawatt hours per year by 2022. Witness Holeman also testified how the growing levels of operationally excess energy caused by the increasing levels of solar QFs will continue to put the DEP BA at risk of violating the mandatory NERC BAL reliability standards.

Dominion witness Gaskill testified to the significant influx of solar QF development that has occurred in Dominion’s North Carolina service area since the Commission’s most recent biennial avoided cost proceeding. Witness Gaskill testified that when the previous avoided cost case commenced in February 2014, Dominion had only seven PPAs executed in its North Carolina service area for approximately 58 MW of solar QF capacity, and only one of those PPAs concerned a project that was operational. In contrast, he testified that, as of February 1, 2017, Dominion had 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina, of which, approximately 350 MW is operating and 150 MW is in development. Witness Gaskill presented data showing that, from an interconnection perspective, there was approximately 1,000 MW of capacity in Dominion’s North Carolina distribution queue, and another 1,800 MW in the PJM queue for transmission level interconnections. He also emphasized that the vast majority of QFs

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established LEOs qualifying for the standard contract or negotiated avoided cost rates under the 2014 biennial proceeding.

Witness Gaskill also testified that, because the average on-peak load of its North Carolina service area during 2015 was approximately 518 MW, the amount of North Carolina distributed solar generation that is operational, under construction, or under contract equals or exceeds Dominion's average on-peak load requirements. He noted that the total distributed solar capacity planned for Dominion's North Carolina system rises to approximately 680 MW when QFs that have established LEOs, but not executed PPAs, are included, which exceeds the average on-peak load requirements by approximately 160 MW. He noted further that when the capacity of projects with CPCNs, but no LEOs, is accounted for, the total planned capacity increases dramatically to over 1,500 MW, almost three times Dominion's on-peak load requirements. Witness Gaskill also noted that Dominion's service area anticipates little load growth.

Witness Gaskill testified that three areas of avoided costs are impacted when distributed solar generation exceeds load: distribution line losses are not avoided; locational marginal prices (LMPs) are lower; and incremental QF generation cannot defer or avoid future capacity needs because there is no further load to offset. He testified that the modifications to the standard offer rates and terms Dominion has proposed are intended to address these impacts of the influx of distributed solar development, while remaining consistent with the requirements of PURPA and FERC's rules. He stated that while the Commission addressed similar proposals to some of these modifications in previous avoided cost proceedings, in light of the significant growth in solar QF development that has occurred since the 2014 biennial proceeding, it is imperative that the Commission reconsider these issues on a prospective basis for new solar QFs, or Dominion and its customers will be forced to overpay for new QF output in contravention of PURPA's intent. He noted the Commission's January 18, 2017 order in this docket, stating that the Commission has always established avoided cost rates and implemented PURPA in light of the then prevailing economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation.

Public Staff witness Hinton testified to the level of solar QF development over the past five years in North Carolina, totaling approximately 2,000 MW installed and approximately 7,000 MW of additional solar QFs proposing to interconnect and sell power to the Utilities. He also testified that this significant growth of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. He suggested that the sheer volume of QF projects currently being developed in North Carolina calls into question FERC's premise in Order No. 69[1] that future over-estimations and under-estimations of fixed long-term avoided costs would "balance out" over time. He also testified how this higher penetration of solar QF resources is posing operational and technical challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service to ratepayers. Witness

[1] See Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12, 214 at 12, 224 (Feb. 1980) (Order No. 69).

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Hinton further testified that the pace of QF solar development is now exceeding load growth experienced by the utilities.

NCSEA witness Johnson agreed that North Carolina has been experiencing significant growth in solar production and testified that this growth is both "substantial and more rapid than the relatively leisurely pace at which solar activity is occurring in nearby" southeastern states. In addition, NCSEA witness Harkrader agreed with the Utilities, that "over the past few years North Carolina has been an undisputed leader in terms of installed solar generating capacity." Witness Johnson further testified that the Commission should not adopt less favorable PURPA terms in order to slow the growth of solar. In support of this recommendation, he testified that growth in solar production has long been the goal of public policy makers in North Carolina and elsewhere. Further, witness Johnson testified that policies such as renewable portfolio standards, and tax incentives were adopted to break the "vicious cycle" of the comparatively high life cycle costs of solar electric generation versus traditional energy sources such as oil and coal. He then testified that, in North Carolina, the solar industry is starting to break this vicious cycle and that it "would be a mistake to slam on the breaks just as commercial mass scale is beginning to be achieved." Witness Johnson acknowledged that the challenges faced by the Utilities are real and testified that careful investigation should be conducted and an appropriate policy response should be developed to ensure that these challenges do not become more serious. However, he further testified, that these challenges should not be reason to slow the growth of solar. In his view, the Utilities have not recognized the benefits to society from the rapid growth in solar energy production and instead have focused their testimony in this proceeding "almost entirely" on the technical difficulties and operational challenges they are facing as a result of the growth in solar energy production. Witness Johnson concluded this portion of his testimony by stating that if the Commission adopts the Utilities' proposals, solar expansion will occur at a more leisurely pace, like what is occurring in Louisiana or Mississippi, and it will decrease the opportunity for solar energy production to break the vicious cycle of high costs and little experience.

In his post-hearing brief, the Attorney General addressed many of the Utilities' specific proposals to change the Commission's PURPA implementation. The Attorney General argues that the Utilities essentially admitted that their goal in proposing changes to PURPA implementation is to rein in what they view as "'unconstrained growth in solar generation.'" The Attorney General emphasizes the federal and state law requirement to encourage small power producers to support the goals of promoting energy conservation, more efficient use of energy resources, and energy independence of the United States. The Attorney General further argues that the many of the benefits to consumers from the increase in alternative energy available in North Carolina due to PURPA and other policies are not and cannot be captured in avoided cost calculations, for example, national security, environmental benefits, health benefits, competition and lower prices, and economic benefits. In support of his argument, the Attorney General notes that the testimony of the public witnesses at the February 21 public hearing and the 900+ consumer statements filed in this docket have been "robust and uniformly in support of renewable energy." As reflected in the other sections of this order, the Attorney General then argues that the Commission should maintain the status quo on its PURPA

implementation because the Utilities' proposals are either unsupported by the facts or contrary to the law.

Discussion and Conclusions

The Commission takes notice that subsequent to the close of proceedings in this docket, the North Carolina General Assembly enacted and the Governor signed House Bill 589. H.B. 589, N.C. Gen. Assem., 2017 Reg. Sess., S.L. 2017-192 (N.C. 2017). With respect to renewable QFs, this legislation resolved a number of the significant issues in this docket, and the Commission therefore need not address them. However, the legislation fails to address nonrenewable QFs such as combined heat and power QFs. Therefore, the Commission must address such issues for the nonrenewable QFs. As to these nonrenewable QFs, however, the Commission resolves the issues not addressed by HB 589 consistent with that legislation.

There is substantial evidence in this proceeding as to the amount and pace of the development of QFs, and in particular solar-powered QFs selling energy and capacity to the Utilities under the standard offer contract. The Utilities' witnesses' testimony on this issue is largely undisputed, and is supported by the independent and consistent testimony of the Public Staff's witnesses. Further, NCSEA's witnesses agree with the Utilities' fundamental argument that the development of QFs that has occurred in North Carolina is significant. The Commission finds highly persuasive the Duke witnesses' testimony that 60% of all installed PURPA solar projects in the United States are located in North Carolina, many of these QFs being sized at or just below the Commission-established 5-MW threshold for eligibility for the standard offer contract. The Commission also agrees with Duke witness Yates: North Carolina is at a critical crossroads regarding the integration, development, and customer costs of renewable generation, and specifically with regard to QFs powered by solar energy. Further, the Commission agrees with the Utilities' witnesses and Public Staff witness Hinton that the implications of the pace and level of QF development continuing unabated poses serious risk of overpayment by utility ratepayers and operational soundness of utility electric systems, and, ultimately, calls into question the State's continued compliance with PURPA's requirements. Therefore, based upon the foregoing and the entire record in this proceeding, the Commission finds that economic and regulatory circumstances facing QFs and utilities in North Carolina have changed since the Commission's last biennial review of standard avoided costs rates.

Having found that the record evidence demonstrates that the circumstances facing QFs and utilities in North Carolina have changed since the Commission's last biennial proceeding, the contested issues are whether this evidence justifies the Commission establishing new avoided cost rates and/or altering the Commission's implementation of PURPA. In the other sections of this order, the Commission will consider these contested issues in light of the evidence on the inputs included in the avoided cost rate methodology and the discrete aspects of the Commission's PURPA implementation. In the remainder of this section, the Commission addresses the broader question of PURPA's requirements and whether the evidence in this proceeding justifies establishing new avoided cost rates and changing the Commission's PURPA implementation. The Commission also agrees with witness Johnson, that in implementing PURPA, the

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Commission should not “slam on the brakes” in establishing rules for the development of QF resources. Rather, as the Commission’s policies have resulted in North Carolina cresting the hill, it now is appropriate to moderately ease off on the regulatory accelerator and depend in part on momentum created so as to moderate the financial impact on electric rate payers. Therefore, the Commission agrees with some recommended changes but not with others.

The Commission finds persuasive the testimony of Duke witnesses Yates and Bowman and Dominion witness Gaskill regarding the causal link between the amount of solar-powered QF development activity, on the one hand, and the Commission’s PURPA implementation and Commission-established avoided cost rates, on the other. The Commission agrees with witness Yates that existing regulatory and legislative policies have created a “distorted marketplace” for solar projects and that this results in artificially high costs being passed on to North Carolina ratepayers. The Commission further agrees with witness Yates that the increasing amount of solar-powered QFs interconnected to Duke’s electric systems is inhibiting the Companies’ ability to fulfil its public service mission and statutory obligation to provide safe and reliable energy to its customers at reasonable rates.

The Commission also finds persuasive the testimony of witness Bowman that the generating capacity of solar-powered generating facilities installed on Duke’s electric systems has increased from 125 MWs in 2012 to 1,600 MWs in 2016. The Commission is mindful of the policy declarations in G.S. 62-2(a), in particular, the policy to promote adequate, reliable, and economical utility service to all the citizens and residents of the State, which witness Bowman testified should be considered in assessing the public interest under PURPA. The Commission agrees with witness Bowman that there is a causal link between avoided cost rates and PURPA implementation, on the one hand, and the level of solar-powered QF development in the state, on the other. For example, she testified that, despite the expiration of the North Carolina renewable energy tax credit and the fact that the Duke utilities have enough solar RECs to meet the solar set-aside requirements beyond 2030, the development of solar-powered QFs with a generating capacity between four and five MW continues. Further, as cited by witness Bowman, two policy developments differentiate North Carolina from other states: the modifications to PURPA enacted by the EPAct, which relieved a number of utilities across the country from PURPA’s “must purchase” obligation, and that other states’ PURPA policies are not as favorable to QFs as North Carolina’s policies. Her testimony is made more compelling in light of the independent, but consistent, testimony of the Dominion witnesses and the Public Staff witnesses. Although NCSEA witness Johnson draws different conclusions from this evidence, he agrees with the basic premise that North Carolina’s PURPA policies have contributed to QF development at a more rapid pace than in other states.

Finally, in this section the Commission addresses what changes to the Commission-established avoided cost rates and PURPA implementation are appropriate in light of the foregoing evidence and the legal framework for avoided cost set out in PURPA, North Carolina law, and Commission precedent. First, as testified to by Duke witness Bowman, under the cooperative federalism program established in Section 210

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of PURPA, this Commission is tasked with balancing PURPA's goals with the economic and regulatory circumstances facing QFs and utilities in North Carolina. This Commission is guided by FERC's regulations promulgated under PURPA, but afforded "great latitude" in determining North Carolina's PURPA policies and establishing avoided cost rates. See Order No. 69 at 12,230-12,231. Second, as testified to by Public Staff witness Hinton, PURPA and the FERC rules implementing PURPA require each electric utility to purchase electricity produced by QFs at the utility's "incremental cost of alternative energy," commonly called "avoided costs." These rates must be just and reasonable to the electric consumers, in the public interest, and non-discriminatory to the QFs. Properly established, the avoided cost rates make the purchasing utility indifferent to purchasing electric output from a QF or from another source, including the utility building and owning its own generation facility. Third, as the witnesses in this proceeding have testified, PURPA requires the encouragement of QF development. Finally, this Commission is constrained to implement PURPA and establish avoided cost rates consistent with state law, including the policy declarations in G.S. 62-2(a) and the more specific directives in G.S. 62-156. Thus, the Commission's task in this proceeding is to resolve the tension existing within this legal framework by establishing just and reasonable avoided cost rates and making adjustments to the Commission's PURPA implementation where, in the Commission's discretion, such adjustments are justified by the evidence.

Since the first biennial avoided cost proceeding in 1981 (Docket No. E-100, Sub 36) the Commission has used its discretion to implement PURPA and establish avoided cost rates based upon the economic and regulatory circumstances existing at the time. The Commission has, for example, varied the length of standard offer contract that utilities are required to offer, the eligibility threshold for the standard offer contract based on QF generating capacity, and the availability of the standard offer contract based upon QF fuel sources. However, since the Commission conducted the 2004 biennial proceeding (Docket No. E-100, Sub 100) the Commission's implementation of PURPA and the methodology for establishing avoided cost rates have remained relatively unchanged.

Most recently, in the 2014 biennial proceeding, the Commission considered again the economic and regulatory circumstances facing QFs and utilities in North Carolina. In that two-phase proceeding, the Commission first considered changes to the method used to calculate avoided cost payments and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided cost. See Order Setting Avoided Cost Input Parameters, E-100, Sub 140, issued December 14, 2014 (Order on Inputs). In phase one, the Commission recognized that implementing PURPA and establishing avoided cost rates requires balancing the costs, benefits, and risks to all parties and utility customers, and that "regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy." Id. at 21-22. The Commission concluded that there was insufficient evidence that the current framework fails to comply with the requirements of PURPA or otherwise disadvantages QFs, and that, absent such evidence that would justify altering the Commission's earlier decisions, it was inadvisable to introduce regulatory uncertainty by changing that framework. Id. In the second phase of that proceeding, the Commission considered and established

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avoided cost rates consistent with the inputs developed in phase one. See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 140, December 17, 2015 (Phase II Order).

Unlike the 2014 biennial proceeding, in this proceeding the Commission has found substantial evidence that the economic and regulatory circumstances facing QFs and utilities in North Carolina have changed. For the foregoing reasons, and as detailed in the other sections of this order, the Commission concludes that this evidence demonstrates that it is now appropriate to make refinements to the Commission's implementation of PURPA and adjustments in the Commission-approved avoided cost rates. Consistent with the Commission's approach in past avoided cost proceedings, where the evidence fails to justify changing the avoided cost inputs or the Commission's PURPA implementation, the Commission will avoid introducing regulatory uncertainty; however, where the evidence supports changes, the Commission will use its discretion to require appropriate changes.

Finally, as an agency created by statute, the Commission is mindful that it exercises legislative functions and authority delegated to it by statute. See State ex. rel. Util. Com. v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). On July 27, 2017, the Governor signed House Bill 589 (S.L. 2017-192 or HB 589) into law. Session Law 2017-192 addresses contested issues in this proceeding in three ways: 1) by amending G.S. 62-156(b) to provide direction to the Commission on implementation of the PURPA standard contract offering; 2) by enacting G.S. 62-156(c) by providing direction to the Commission on implementation of PURPA negotiated contracts; and 3) by enacting G.S. 62-110.8 which establishes a requirement that DEC and DEP file with the Commission a program for the competitive procurement of energy and capacity from renewable energy facilities. More specifically, the amendments enacted in HB 589 broadened the definition of "small power producer" to include QFs that use renewable resources as a fuel source but not cogeneration facilities. See G.S. 62-3(27a); 16 U.S.C. 796; and 18 C.F.R. 292.101(b)(1). The amendments to G.S. 62-3(27a) and 62-156 became effective on July 27, 2017, when HB 589 became law and apply to standard contract rates and terms approved by the Commission or nonstandard negotiated agreements entered into on or after that date.

On August 8, 2017, Duke and Dominion filed a joint motion, requesting that the Commission take into consideration Session Law 2017-192 as additional authority in deciding the legal and policy issues in this proceeding. The Commission notes that it may take judicial notice of State statutes, G.S. 62-65(b), that a trial court is expected to take judicial notice of public statutes, and that such statutes need not be pleaded. Miller v. Roberts, 212 N.C. 126, 129, 193 S.E. 286, 288 (1937). Based upon the foregoing, including the effective date of the amendments to G.S. 62-3(27a) and G.S. 62-156, the Commission concludes that the Utilities' August 8, 2017 joint motion should be granted. The Commission further concludes that the enactment of G.S. 62-110.8, and the Commission's initiation of rulemaking to implement that section, renders moot the parties' requests to establish a separate proceeding related to the Utilities' use of a competitive procurement process for energy and capacity supplied by QFs. See Springer Eubank Co.

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v. Four County Elec. Membership Corp., 142 N.C. App. 496, 543 S.E.2d 197 (2001); see also Order Initiating Rulemaking Proceeding, Docket No. E-100, Sub 150, July 28, 2017. As reflected in the other sections of this order, the Commission considered the authority enacted by S. L. 2017-192 in determining the contested issues in this proceeding, where applicable.

Therefore, based upon the foregoing and the entire record in this proceeding, the Commission finds that the economic and regulatory circumstances facing QFs and electric public utilities in North Carolina has changed since the Commission's last biennial avoided cost proceeding. The Commission concludes that this change makes it appropriate for the Commission to establish avoided cost rates and to alter the contract terms for QFs in light of these changed circumstances. Significantly, actions by the North Carolina General Assembly have resolved legislatively major issues that otherwise the Commission would have been required to resolve. Therefore, the Commission will require the Utilities to file revised rate schedules, power purchase agreements, terms and conditions, and notice of commitment forms that are consistent with the Commission's conclusions reached in this order.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 2-4

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman, Freeman, and Snider; the testimony of Dominion witnesses Gaskill and Petrie; the testimony of NCSEA witnesses Harkrader, Johnson, and Strunk; and the testimonies of Cypress Creek witness McConnell, SACE witness Vitolo, and Public Staff witness Hinton.

Summary of the Testimony

The parties dispute whether the economic and regulatory conditions currently facing QFs and utilities in North Carolina make it appropriate for the Commission to 1) change the length of the long-term levelized rate options that the Utilities are required to offer under the standard option and/or 2) change the eligibility threshold for the standard option, based on the electric generating capacity of a QF.

Length of Term for the Standard Offer

Witness Bowman testified in support of Duke's proposal to eliminate the 5-year and 15-year standard contract term options, and instead, offer a single 10-year contract with fixed avoided capacity rates and avoided energy rates that update every two years as part of the Commission's biennial review of the Utilities' avoided costs.[2]

Witness Bowman acknowledged that the Commission has previously declined to eliminate the 15-year long-term fixed contracts; however, she argued that, at this time,

[2] Because the Commission finds in this order that Duke's proposal to reset avoided energy rates every two years is inappropriate, at this time, this section addresses only the levelized rates which the Commission concludes are required to comply with PURPA's requirements.

economic and regulatory circumstances compel the Commission to restrike the balance between encouraging QF development, on the one hand, and protecting customers from the risk of overpayment, on the other. In support of her argument, witness Bowman testified that the long-term avoided cost rates, long-term fixed rate contracts, as well as the low threshold to establish a LEO, have resulted in large numbers of solar QFs locking in avoided costs rates that are well in excess of the Duke's actual avoided costs in North Carolina for the next 15 years. Further, she testified, that as the number of solar QFs requesting to sell power under the standard avoided cost rates increases, the financial burden and risk of overpayments from these long-term fixed contracts likewise increase for DEC's and DEP's customers.

Duke witness Snider testified in support of Duke's proposed 10-year maximum term standard contract with capacity rates fixed over the term and energy rates readjusted as part of the Commission's biennial avoided cost proceedings. He first testified that the large number of solar-powered QFs, either in development or under construction, have taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved. Witness Snider further testified that the growing risks associated with the long-term financial obligations under existing PURPA standard offer contracts prompted Duke's proposed modifications. Development of these additional solar QFs inevitably means that Duke's financial obligation under PURPA and customers' exposure to overpayments could increase significantly in the future.

Dominion Witness Gaskill testified in support of Dominion's proposal to reduce the maximum term of a standard avoided cost contract from 15 years to 10 years. He testified that the goal of this proposal is to mitigate customers' exposure to the significant above-market payments for QF output that are resulting under current 15-year contract obligations. He testified that since the fixed long-term prices contained in PURPA contracts are based on projections of future costs for electricity, factors such as technology advances, declining equipment costs, and new fuel supply sources unavoidably prevent the rates paid under these contracts from exactly matching the utility's actual avoided cost in any given year of the PPA. Due to the decline in fuel and power prices in the last few years in particular, he testified that Dominion is significantly overpaying QFs with PPAs or LEOs obtained under the 2012 and 2014 standard offers. He also testified that longer term contracts increase the over/under payment created by the levelized rates available under the 2014 standard offer, as the QF receives rates that exceed Dominion's actual avoided cost in the contract's early years, and rates that are less than the actual avoided cost in the late years. Witness Gaskill argued that reducing the maximum standard offer contract term to 10 years will help address the more severe mismatch between locked-in contract prices and actual avoided costs that results from longer contract terms. He further testified that this proposal is consistent with PURPA and FERC's implementing rules and precedent. First, he stated that a 10-year term provides a basis for long-term project financing, as evidenced by the 5 of 12 non-standard contracts Dominion has entered into with solar QFs that contain 10-year terms, and that have shown the ability to achieve financing by either commencing operations or reaching late-stage development. Additionally, he noted that even with a reduced maximum term, Dominion still retains the obligation under PURPA to purchase QF output at the end of

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the contract period; the shorter contract term simply allows the prices Dominion must pay to align more closely with its actual avoided costs. Witness Gaskill also responded to SACE witness Vitolo's testimony that Dominion does not have 10-year PPAs with QFs sized under 5 MW simply because QFs that size have been eligible for the standard offer 15-year term. Witness Gaskill also stated that the developers of QFs sized at or under 5 MW and those sized greater than 5 MW are not distinguishable, since such developers, as admitted by their witnesses, simply break up their project portfolios into smaller increments to qualify for standard offer rates. He testified that, if developers can obtain financing for large projects with a 10-year term, they should be able to do so for small projects as well, due to the practice of financing pools of small projects together as a group.

Witness Gaskill also testified that assertions regarding QF versus utility-sponsored projects ignore fundamental differences between rate regulated utilities and QFs in terms of organization, regulation, financing, cost recovery, and the obligation to serve customers. Witness Gaskill also noted that Dominion faces a much higher burden than QF developers when seeking to obtain a CPCN and cost recovery for a new project. He testified that the utility must demonstrate that the investment can be used to meet customer needs at the least possible cost, and cited the three Virginia solar facilities referenced by witness Vitolo as cases where Dominion, in seeking CPCNs for those facilities, provided the Virginia State Corporation Commission (VSCC) evidence that customers would save an estimated $32 million net present value below projected market rates. He noted that the VSCC typically only approves a project if it is shown to be favorable for customers relative to other options. Finally, witness Gaskill agreed that longer depreciation lives for utility rate-based assets lower the near-term rate impact for utility projects. He testified, however, that this is appropriate because the lower annual depreciation costs are passed directly to customers via a lower revenue requirement. He noted in contrast that no near-term rate reduction accompanies longer QF contract terms; instead, any savings from the longer depreciation and lower financing costs are kept entirely by the QF, therefore increasing customer risk of overpayment with no offsetting cost benefit.

Witness Gaskill also testified that, while he has no reason to question developers' claims that a shorter term will, all else being equal, change financing requirements, that potential result is not a compelling reason to expose customers to the risk that accompanies 15-year fixed price contracts at avoided cost. He testified that, while PURPA's goal is to encourage QF development, he was not aware of any PURPA provision or rule that entitles developers to rates that ensure a particular rate of return or that guarantees any particular project (or class of projects) the ability to obtain financing. He stated that, instead, FERC promulgated the requirement cited by witness Hinton, that utilities must provide data from which avoided costs may be derived, based on its belief that in order to evaluate the financial feasibility of a QF project, an investor must be able to estimate the expected return on investment with reasonable certainty. He noted that the maximum financial feasibility period that FERC incorporated in that rule was 10 years.

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Witness Gaskill concluded that Dominion's experience is that a 10-year term is of sufficient length to allow QFs to obtain financing and complete projects, as evidenced by the five non-standard contracts with 10-year terms that Dominion has entered into with solar QFs, including all but one of such contracts signed within the past two years. He argued that a 10-year term is reasonable for the standard offer contract at this time, because it strikes an appropriate balance between encouraging QF development and protecting customers by reducing the risk of overpayments due to changes in market conditions over time that result in contract rates misaligning with actual avoided costs. He testified that, while PURPA's intent is to encourage QFs, PURPA's express requirements that rates paid to QFs be just and reasonable to utility customers and not exceed the utility's avoided costs, as well as the lack of any particular stated minimum term or guarantee of QF financing, show that the purpose is not intended to place customers at a disadvantage or to force them to pay more than their actual avoided costs. He stated that reducing the maximum contract term to 10 years will help ensure that rates paid to QFs better align with actual avoided costs through the life of the contract while continuing to encourage QF development in North Carolina.

Dominion Witness Petrie testified that the depreciation length of the three solar facilities that Dominion has in rate base is 35 years. Witness Gaskill further clarified the distinction between the avoided cost context and the utility self-build context, particularly with respect to changing cost forecasts. He testified that when Dominion needs additional generation to meet energy and capacity requirements, it determines the least cost option for obtaining that generation, taking into account fuel diversity and other factors, and must obtain Commission approval through a CPCN proceeding for investment in build options. He acknowledged that fuel forecasts can change from the time the decision to build or buy was made, but noted that when Dominion decides to build, the price is below the projected market price, or it would not make that decision. On redirect, witness Gaskill agreed that when Dominion decides to build generation, it must show that it is the least cost option, that there is a need for the generation, and that it could not purchase the generation from another source for less cost. He also agreed that Dominion customers still benefit from a utility-built generator even if the initial cost forecast changes, because the utility will only run the unit when it makes economic sense to do so. He contrasted that option with the take-or-pay context of a QF facility where Dominion has no choice whether to take the power. Finally, he agreed that while Dominion annually adjusts the fuel portion of its rates to reflect increases and decreases in the market through Commission proceedings, such is not the case with avoided cost contracts, which lock in prices for the duration of the contract.

Public Staff witness Hinton testified that the Commission has previously concluded that the long-term contract options serve important statewide policy interests while limiting the utilities' exposure to overpayments. Further, he testified that the Commission has cited G.S. 62-156(b)(1) and 62-133.8(d) for support of its decisions to require long-term contracts under the standard offer, generally, and, has cited G.S. 130A-309.01 to 130A-309.29, with respect to facilities fueled by trash or methane from landfills and environmental policy for support of requiring long-term contracts with facilities fueled by poultry or swine waste. Witness Hinton also noted that the Commission has recognized

that FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or LEOs with rates determined at the time the obligation is incurred. He acknowledged that FERC has never specified a minimum or maximum term to be offered by utilities to QFs, but noted the decision in Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61, 134 (Nov. 22, 2016) (Windham), that QFs are entitled to contracts long enough to allow QFs reasonable opportunities to attract capital from potential investors.

Witness Hinton then addressed the Utilities' arguments that long-term contracts increase the risk of overpayment of avoided costs, which will be passed on to ratepayers through higher rates. He testified that in past biennial avoided cost proceedings the Public Staff has maintained that long-term rates of at least 15 years should be available in order to ensure QFs could secure financing and that the use of a 15-year term is consistent with the long-range planning requirements of G.S. 62-110.1(c) and Commission Rule R8-60, which establishes a 15-year planning horizon. He further testified that, based upon the number of currently operating facilities and facilities in development, the 15-year fixed term contract has been accepted by the financing community and has been beneficial to QFs in North Carolina. Witness Hinton also testified that the Public Staff reviewed policies in other states and finds that some states require shorter term offers and others require longer terms, but there is no clear standard length of term. He continued by observing that avoided cost rates can change considerably over time and that there is always a risk of over- or under-payment, and made an analogy to a utility's commitment to build a generation plant, based upon forecasts of future prices.

On this background, witness Hinton testified that due to the rapid pace of QF development in North Carolina, the Public Staff believes it is appropriate for the Commission to consider a shorter-term structure for avoided cost rates. He argued that this would serve to reduce the risk borne by ratepayers for overpayments over a longer term. Therefore, he concluded that the Public Staff believes that the Utilities' proposal to limit the standard offer term to a 10-year fixed PPA is reasonable. He noted that DEC and DEP have signed 22 PPAs with QFs at 10-year terms, and that 6 of Dominion's 12 non-standard PPAs have 10-year terms, indicating that securing financing terms shorter than 15 years was possible. Witness Hinton further recommended that the Commission continue to monitor the amount of actual QF development and the stability of the avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to seek financing on reasonable terms.

NCSEA witness Johnson testified to how the Commission has implemented PURPA in contrast to other states, including addressing how the length of contract term impacts the ability to finance a QF project. NCSEA witness Harkrader testified that "QFs with a shorter contract term than 15 years would have a much smaller pool of potential debt and equity investors." She testified that, the 15-year contract term has allowed small QFs to access affordable debt and equity capital and enabled a capital structure that is affordable to the QF developer and, therefore, has encouraged QF development. She further testified that the standard offer, particularly the 15 year PPA term and fixed rate, has provided the certainty that has been necessary to encourage QF development in

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recent years, and this certainty has also played a critical role in driving down the cost of developing solar facilities and contributed to establishing a robust solar market. For example, she testified that when her company first started developing solar QFs in North Carolina, the market was relatively unsophisticated with respect to the development process, as well as the financing process, and the gains that have been made by industry in recent years have helped drive down the cost of solar development in North Carolina. These include: understanding and taking advantage of economies of scale with equipment suppliers; the creation and development of local supply chains and associated service providers related to solar racking, fencing, and landscaping; and the creation of a large, skilled local labor pool trained in installation and construction of solar-powered electric generating facilities. Additionally, the development of the industry has attracted suppliers, such as Schletter Inc. – a manufacturer of solar mounting systems – to relocate in North Carolina, further driving down costs. She concluded that the Utilities' proposed modifications to the implementation of PURPA would disrupt this success and would dramatically alter the landscape of companies that participate in QF development in North Carolina and beyond. NCSEA witness Strunk testified that the utilities' proposed changes to reduce the standard PPA term to ten years and to require the adjustment of avoided energy rates every two years would not provide QFs with a reasonable opportunity to attract capital from investors. He testified that these changes compress the recovery of capital investment in long-lived generation assets into a period too short to allow QFs to attract capital on reasonable terms.

SACE witness Vitolo testified that project financing could be jeopardized by reducing the standard offer term from fifteen years to ten, and that this proposal, in combination with the Utilities' other proposals, may therefore violate PURPA. In addition, he testified that reducing the standard offer contract duration results in differential treatment between QF solar projects and utility solar projects. He stated that the QF industry in North Carolina has demonstrated a clear ability to finance five-MW solar QFs with 15-year contracts, and that the utilities have shown that some larger facilities have been built with ten-year contracts. Witness Vitolo cautioned, however, that this does not necessarily indicate that smaller projects would also be able to obtain financing relying on a ten-year PPA. In addition, he testified that the proposed reductions in avoided energy and capacity rates to the rates approved in the 2014 proceeding may make it difficult for any facilities, large or small, to be financed for ten-year durations.

Witness Vitolo also testified that each of the Utilities have solar photovoltaic (PV) electric generating facilities in rate base, with recovery periods extending from 20 to 35 years. He noted that similar to a longer loan reducing monthly payments, a longer depreciation schedule allows for a reduced near-term rate impact, therefore making the investment more attractive. He argues that this differential treatment between the cost recovery provided for utility solar projects and QF generation is also problematic. Witness Vitolo recommended that, at a minimum, the Commission should maintain current policy by requiring the Utilities to allow renewable QFs to continue to make standard offer terms available for at least 15 years, and the Commission should consider requiring the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own PV assets.

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Cypress Creek witness McConnell testified that along with the pricing contained in a PPA, credit quality and tenor are the most critical components for a renewable energy project developer to be able to obtain financing. He testified that for the majority of projects, lenders are generally unwilling to lend against uncontracted cash flows, and that absent some sort of third-party credit enhancement (like a government guaranty), he has not seen a loan maturity or amortization for a project under 75 MW extend beyond the term of a fixed-price PPA. He further testified that the Utilities' proposal to limit the length of standard-offer contracts to ten-year terms would lead to ten-year amortization periods, which will mean less debt and greater sponsor equity requirements at lower returns and greater risk, and in turn will result in fewer projects getting financed and constructed.

By his post hearing brief, the Attorney General, representing the using and consuming public, argues that there is no evidence that QFs can survive the "simultaneous impact of lower avoided cost rates and the wholesale slashing of contract duration." Citing the testimony of witnesses Harkrader, McConnell, and Strunk, the Attorney General concludes that the reduction in the standard offer term proposed by the Utilities would not offer reasonable opportunities to finance QF projects. He further argues that the reduction in the term (and the eligibility threshold, addressed below), cannot be considered in isolation, rather, several factors will impact the value of the standard offer, for example, the decrease in avoided energy rates based on a decrease in forecasted natural gas and coal prices over the next 10 years. On this point, the Attorney General argues that none of the witnesses who testified that financing would be available for 10-year contracts took these other factors into account. Finally, the Attorney General argues that the evidence that supported the reduction in the length of the standard offer term was not specific to small QFs, citing testimony from witnesses that only addressed 10-year term contracts that were negotiated with QFs with generating capacity of 5 MW or larger.

Eligibility Threshold for the Standard Offer

Witness Bowman argued that it was appropriate and justified at this time to lower the capacity eligibility limit for standard avoided cost rates from 5 MW to 1 MW for QFs, other than QFs small hydro. Witness Bowman testified that in Order No. 69, the FERC recognized that although standard "one-size-fits all" avoided cost rates cannot account for the differences between QFs of various sizes and types, smaller QFs could be challenged by the transactional costs of negotiating individualized rates with utilities. She testified that FERC balanced those concerns by requiring states implementing PURPA to make standard rates and terms available to QFs with a design capacity of 100 kW and smaller. Witness Bowman noted that the FERC also allowed states to put into effect standard rates for purchases from QFs with a design capacity above 100 kW. She testified that at least 20 states currently have standard rates that are limited to QFs less than 100 kW, while utilities in at least 33 states have eligibility caps at or under 5 MW. Witness Bowman also emphasized that Duke is not recommending that the Commission adopt the FERC minimum of 100 kW as an eligibility threshold in this proceeding.

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Witness Bowman then recounted the Commission's implementation of the PURPA standard tariff eligibility, beginning with the establishment of the 5 MW eligibility threshold in 1985 when the small power production industry was nascent. She testified that the 5 MW standard offer eligibility criteria was intended to encourage the development of QFs that, at that time, may not have had the resources, experience, or expertise to negotiate with a utility. She next described a "surge" of solar QF development in North Carolina and how the 5 MW eligibility threshold had impacted the North Carolina solar market and Duke's customers. With respect to development of the North Carolina QF solar market, witness Bowman testified that in the last five years, distribution-level, utility-scale solar generation development around the 5 MW standard offer had "exploded" in North Carolina, particularly when compared with the rest of the United States. She testified that solar developers "disaggregate" potentially larger and more cost-effective solar projects to meet the 5 MW standard contract threshold, resulting in ongoing challenges in managing the interconnection of these generators to rural distribution circuits. Witness Bowman also testified that the 5-MW threshold had become a highly attractive development business model for sophisticated and well-capitalized entities from around the country to take advantage of the guaranteed, long-term, fixed rates of the standard contract by obtaining LEOs on behalf of multiple solar facilities with generation capacity of 5 MW or less. She concluded that the 5-MW threshold had served its purpose of encouraging the development of QFs, particularly solar QFs, in North Carolina and should now be evolved.

With respect to the 5 MW eligibility threshold impact on Duke's customers, witness Bowman testified that hundreds of standard contract solar projects between 1 MW and 5 MW had obtained LEOs in North Carolina, resulting in significant long-term financial commitments on behalf of DEC's and DEP's customers. She argued that these long-term contractual purchase obligations are also at rates well in excess of Duke's current system incremental or "avoided" costs. Witness Bowman testified that, since March 2015, when the Companies filed their previous avoided cost rates, approximately 300 projects between 4 MW and 5 MW had obtained CPCNs, thereby potentially establishing LEOs under rates based on inputs to avoided cost calculations made two years ago. She emphasized that these QFs have been able to "lock in" standard, long-term fixed rates, likely for the next 15 years. She further argued that during these lengthy intervals, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically, affecting the utility's actual avoided costs.

Witness Bowman next testified that a 1 MW eligibility threshold was appropriate and justified at this time, based on the current economic and regulatory circumstances. First, she argued that a 1 MW threshold is a reasonable proxy to differentiate between small QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial purposes by residential and commercial customers, on the one hand, and larger sophisticated commercial enterprises and power generation developers in the business of owning or operating power generation facilities, on the other. Second, she testified that the Companies' net metering tariffs are similarly available to customer-generation with a capacity of up to 1 MW in size. Third, she further

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testified that the FERC did not require QFs below 1 MW to self-certify as QFs. Finally, she testified that Duke's recent experience was that 1 MW solar projects are more likely to pass the Section 3 Fast Track interconnection study process, allowing both the standardized PPA and Interconnection Agreement to be obtained in a more streamlined fashion.

Witness Bowman also argued that a 1 MW eligibility threshold would result in integrating solar in a more well-planned and coordinated manner, while better protecting customers from paying rates above avoided costs. In support, she cited the Commission's Order on Clarification, issued March 6, 2015, in Docket No. E-100, Sub 140, where the Commission required the utilities to use the most up-to-date data for determining inputs to avoided cost rates for QFs that were eligible for negotiated, as opposed to standard, avoided cost rates. Witness Bowman also recalled that the Commission had previously issued orders in avoided cost proceedings on what factors should be considered in bilateral negotiations between the utilities and QFs. This aligning the avoided cost rates paid to QFs more closely with the utility's avoided costs at the time of the purchase, she argued, meets PURPA's objective of ensuring customers remain indifferent between purchasing utility generation and purchases from QFs at the utility's avoided costs. Moreover, witness Bowman testified, it protects both customers and QFs in periods of rising and declining energy costs.

Witness Bowman also testified that QFs with a nameplate capacity in excess of 1 MW were still entitled to sell power to the utilities at avoided cost rates. These larger QFs would receive avoided cost rates though bilateral negotiations with the purchasing utility and not through the standard offer. She acknowledged that in the most recent avoided cost case, the Commission had declined to approve the Utilities' request to reduce the eligibility threshold to 100 kW, in part based on allegations by QF developers that the Companies' PPA negotiation process was protracted and difficult. Witness Bowman reported, however, that since that decision in 2014, the Companies had gained greater experience in negotiating PPAs with QFs with generating capacity larger than 5 MW. Witness Bowman testified that Duke had negotiated more than 22 "PURPA-only PPAs" with large QFs since 2014, with 10 of these PPAs being negotiated since January 1, 2016. Further, she noted that, of these 10, three were with the same developer, and many are with developers that are owner/developers of other projects that are 5 MW or less and thus eligible for the standard offer. She testified that producing monthly avoided cost calculations for negotiated PPAs has become routine, and the negotiation process has become more standardized. Based on this experience, witness Bowman concluded that the Companies were sufficiently prepared to efficiently negotiate PPAs in good faith with QFs larger than 1 MW.

Witness Bowman also responded to the testimony opposing the reduction in the eligibility threshold from 5 MW to 1 MW. She noted that SACE witness Vitolo's testimony did not reference at all the "tremendous surge" of solar QFs at around the 5 MW level in North Carolina, which was one of the primary drivers of the Companies' proposal. She also disagreed with witness Vitolo's assertion that adjusting the threshold will lead to solar QFs foregoing economies of scale to build smaller projects eligible for the 1 MW standard

offer. Witness Bowman testified that the "disaggregation" of larger, more cost-effective, projects to smaller 5 MW ones has created ongoing challenges for DEC and DEP to manage the interconnection of these generators to rural circuits, especially on DEP's increasingly saturated distribution system. In contrast, she argued that the 1 MW threshold would better differentiate between the relatively small projects and the utility-scale solar projects. In response to witness Vitolo's argument that maintaining the 5 MW threshold would result in lower costs overall because it would allow QF developers to retain economies of scale associated with developing a 5 MW project, witness Bowman argued that the "lower costs" referred to would benefit solar QF developers and not the Utilities' customers.

Witness Bowman also responded to witness Vitolo's contention that a significant power imbalance exists between QFs and Utilities in their PPA negotiations. She reaffirmed her direct testimony that utility-scale QFs are no longer being developed by small, fledging developers, highlighting that six large power generation developers, including Cypress Creek Renewables, Strata Solar, and ESA Renewables, accounted for more than 65% of the Companies' combined interconnection queues between 1 MW and 5 MW. She also responded to witness Vitolo's assertion that QFs' negotiations with Duke for a PPA can take months. She noted that, under the current NoC Form approved by the Commission in its Phase II Order, QFs larger than 5 MW have up to six months to execute a PPA after DEC or DEP submits it for signature. Witness Bowman testified that large QFs sometimes wait until that six month period is expiring to execute a PPA, adding to the apparent length of time between the LEO date and execution date of PPAs.

Witness Bowman also elaborated on the Companies' intention to further streamline and standardize the PPA negotiation process as discussed by Public Staff witness Hinton in his direct testimony. She referenced Duke witness Freeman's testimony proposing contracting procedures to foster transparency and efficiency in the PPA negotiation process with QFs, and posited that these procedures could be implemented quickly after input from the Public Staff and other interested parties after the Commission issues a final order in this proceeding. Witness Bowman reaffirmed the Companies' intent to continue to negotiate in good faith and follow FERC and Commission guidance in negotiating PPAs with QFs larger than 1 MW. She again cited the Order on Clarification as directing DEC and DEP to use the most up-to-date data to determine inputs for negotiated rates. She noted that the Order on Clarification also instructed that any party was free to identify specific characteristics of a particular QF that merit consideration in the calculation of negotiated avoided cost rates. Witness Bowman specifically testified that Duke believed that inclusion of ancillary generation costs or other solar integration costs in the calculations of avoided cost rates for QFs ineligible for the standard offer was appropriate under FERC and this Commission's guidance for calculating avoided costs rates. She also testified that QFs may always request to review the inputs of DEC's and DEP's calculations of avoided costs, and that a QF may file a complaint with or engage in arbitration before the Commission if the QF disagrees with these inputs or otherwise believe the Companies are not negotiating in good faith.

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On cross-examination by NCSEA, witnesses Bowman and Freeman provided further details on how Duke intends to negotiate with QFs larger than 1 MW. Witness Freeman indicated that the Companies have developed more standardized terms and conditions for large QFs, which would ease the process of negotiations. Witness Freeman declined, however, to support requiring Commission approval of changes to the standardized large QF PPA. He argued that doing so could overburden the negotiation process by requiring approval every time the Companies determine that a change to the standard terms and conditions for large QFs is needed. Witness Freeman added that the Companies had successfully negotiated over 20 such negotiated contracts with large QF developers.

In response to questions from the Commission, witnesses Bowman and Freeman testified about the negotiations between the Duke and QFs over 1 MW. Witnesses Bowman and Freeman agreed that a complaint or arbitration proceeding before the Commission between DEC or DEP and a QF negotiating a PPA could involve many disparate issues, including the minimum length of a PPA and each individual QF's ability to obtain financing. Witness Bowman further responded that Duke does not intend for complaints or arbitrations before the Commission to increase as a result of changing the current standard offer eligibility. Witnesses Bowman and Freeman each testified that the number of QFs seeking PPAs could decrease as developers develop fewer, larger, facilities instead of more, smaller, ones to take advantage of economies of scale. Witness Bowman also testified that Duke does not object to the Commission establishing a formal or informal proceeding to resolve concerns and set expectations on how the Companies would negotiate avoided cost rates for QFs going forward.

Dominion witness Gaskill testified in support of Dominion's proposal limiting eligibility for standard avoided cost rates and contracts to QFs with 1 MW in capacity. He testified that reducing the threshold to 1 MW at this time would allow more QFs to enter into negotiated contracts rather than standard contracts, with several resulting benefits. First, witness Gaskill testified that this would better align avoided costs with each QF's LEO, because standard avoided cost rates, which are updated biennially and are available to any eligible QF that establishes a LEO within the two-year period, can result in QFs receiving rates based on avoided cost calculations that are several years old by the time the projects commence commercial operations. He further testified that this would better align with current market conditions, including changes in gas and power market prices. In addition, he testified that the timely updates possible with negotiated rates help mitigate the compounding impact of long contract terms on the disparity between the standard rates and actual avoided costs.

Second, witness Gaskill testified that allowing more negotiated rates would permit rates and terms to be customized to each specific project and location. He testified that one of the key limitations with the current PURPA implementation approach is the inability to incentivize QFs to locate in one location over another. Because all QFs under 5 MW, regardless of location, are eligible for the same standard offer, developers' main incentive is to locate projects where they can develop them at the least expense—not where the project would provide the most value to customers. The result, he testified, is a heavy

concentration of distributed solar on a few substations, stating that approximately 80% of the interconnected distributed solar on Dominion's North Carolina system is located on only 15 substations out of 42. He further testified that, while geographically dispersed distributed solar generation reduces the effect of intermittent cloud cover over any single location, therefore improving reliability and minimizing integration costs (such as increased operating reserves and load imbalance charges), the distributed solar generation in Dominion's North Carolina system does not offer these benefits because it is located on a narrowly distributed geographic and electrically-connected location with little load growth. With more negotiated contracts, he argued, Dominion would have greater opportunity to incentivize projects to locate in areas or on circuits that have a need for new generation. For example, witness Gaskill testified, this could be accomplished by paying for avoided line losses and capacity costs where a QF locates on a distribution circuit with excess load to offset, benefiting both Dominion and the QFs by allowing for increased avoided cost payments for more projects located in more valuable locations.

Third, witness Gaskill testified that, unlike standard offer contracts, negotiated contracts can include provisions that protect customers. For example, he noted that non-levelized rates ensure that the PPA rates better match Dominion's actual avoided costs throughout the life of the contract and protect against overpayment if the QF fails to perform later in its project life. Finally, witness Gaskill noted that 83% (60 out of 72) of the QF PPAs Dominion had signed at the time his testimony was filed were for projects sized 5 MW or below, and that 55 of those 60 standard contracts were developed by only seven different developers. He takes this as an indication that developers develop multiple 5-MW projects in order to take advantage of the two-year-old standard avoided cost rates. He concluded that reducing the standard offer threshold to 1 MW would preserve the standard offer for truly small QFs that need it and would allow rates paid to larger QFs to more closely align with the utility's actual avoided costs and protect utility customers from excessive overpayments.

Witness Gaskill responded to the other parties' testimony, stating that, while Dominion cannot know every potential QF's financing ability, QF developers in North Carolina tend to have large portfolios of generation projects around the country, and to be well-capitalized companies with access to financing resources that afford them the ability to negotiate a PPA. He also observed that these developers break up large portfolios of projects into multiple 5-MW projects in order to qualify for the standard offer, including standard avoided cost rates that can be two years old by the time a QF establishes an LEO. He noted especially the testimony of witness Strunk and witness McConnell that they group together multiple small projects in order to improve the financing terms of a larger portfolio. Witness Gaskill also testified that, in his opinion, large solar developers do not require the standard offer in order to develop QF projects. He testified that, based on his experience, larger developers have resources and sophistication to negotiate contracts, and the market would be better served by removing the incentive to break up the projects into small increments. He noted that witness McConnell's company, Cypress Creek, claimed on its web site that it had raised and invested over $1.5 billion and deployed or developed over 4 GW of local solar facilities, and that it is the largest and fastest-growing dedicated provider of local solar facilities. He

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opined that it would be illogical for large, sophisticated developers like Cypress Creek to require a standard offer in order to successfully finance and complete solar projects in North Carolina. Finally, witness Gaskill testified that the intent of the standard offer contract is to provide simplified and standard market access for truly small developers, not to permit large developers to break up large solar deployments into small individual projects in order to obtain higher pricing and better financing terms.

Witness Gaskill also testified that the standard offer threshold reduction will ultimately realize a positive benefit to developers, utilities, and customers in all of the areas identified by witness Vitolo. Noting that in some cases a negotiated PPA may take additional time up front, he nonetheless testified that over the life of the contract significantly less resources are required to administer a single 20-MW contract than multiple small project contracts. He testified that, regardless of whether an executed contract is standard or negotiated, it requires approximately the same number of hours to administer, including labor-intensive tasks such as performing monthly meter readings, settlement, invoice and billing, and payments. He stated that with its proposal to reduce the threshold to 1 MW, Dominion intends to encourage developers to build fewer, but larger projects, and thus greatly reduce the number of resources required to originate and administer the volume of QF contracts under consideration.

With regard to the balance of power in contract negotiations, witness Gaskill emphasized that the utility retains the obligation under PURPA to purchase QF output and cannot walk away from a negotiation. He further noted that the procedures for establishing avoided cost rates and the vast majority of terms and conditions of negotiated contracts are fairly well established such that they support efficient and successful negotiations, and that rarely do large contract negotiations include much negotiation or dispute regarding the contract rates themselves, since the rates are calculated based on avoided costs as of the LEO date for each project. He noted that Dominion has successfully negotiated contracts with 12 QFs totaling 214 MW. Finally, with respect to economies of scale and the interconnection queue, witness Gaskill testified that by removing the incentive to divide a portfolio of projects into 5-MW increments, reducing the standard offer threshold to 1 MW will encourage developers to seek larger projects. The change will therefore actually increase economies of scale and reduce the number of projects in the interconnection queue over time, while preserving the benefit of the standard offer contract for the truly small projects.

Concerning the Commission's previous decisions on this issue, witness Gaskill reiterated that the landscape of QF development in this State has changed significantly since the 2014 biennial proceeding. He noted that the Commission in this case must determine what the appropriate standard offer will look like for QFs developed going forward from this case, and that what may have been appropriate two years ago must be adapted to the circumstances Dominion faces today and anticipates it will face in the next two years. Witness Gaskill concluded that more negotiated contracts will provide important protection for customers by reducing the risk of overpayments to a large portfolio of QF projects. Witness Gaskill testified regarding Dominion's first quarter 2017 interconnection queue report filed in Docket No. E-100, Sub 101A. He testified that seven

active projects listed on the report have capacities greater than 5 MW and that the capacity of the remaining projects is approximately 5 MW. He also testified that, through repeated negotiations over time, Dominion arrives at essentially a standard contract with each developer.

Public Staff witness Hinton testified that the Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by FERC regulations, and while it has previously rejected efforts by the Utilities to lower the threshold for renewable QFs, it has also rejected efforts to increase the maximum cap for eligibility for the standard contract. He noted that in the Order on Inputs, the Commission stated that it "must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers," and found that increasing the maximum cap for eligibility for the standard contract may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers.

Witness Hinton further testified that in the Sub 140 proceeding, the Public Staff noted that "setting the standard above the minimum threshold required under PURPA allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale, while providing ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options available." However, the Public Staff also recognized the significant level of QF development in North Carolina since enactment of the REPS and the number of proposed QFs at or near the 5-MW standard threshold. The Public Staff expressed concerns about the challenges faced by QFs not eligible for the standard offer rates seeking to negotiate with the Utilities, and instead recommended that the Commission maintain the 5-MW standard threshold, finding that it represented an appropriate balancing point.

Witness Hinton then testified that since the Sub 140 proceeding, the significant growth in the number of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers, and that the higher penetration of resources was posing operational and technical challenges to the utilities. As such, he testified that it is appropriate for the Commission to consider modifications to the standard offer threshold, and recommended 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. Witness Hinton testified as to his evaluation of the following regulatory thresholds: 1) G.S. 62-110.1(g), which exempts nonutility-owned generating facilities fueled by renewable energy resources less than 2-MW in capacity from having to obtain a CPCN from the Commission; 2) Section 3 of the NCIP allows facilities up to 2-MW to be eligible for the Fast Track Process, regardless of location; 3) the Commission's March 30, 2009, Order Amending Net Metering Policy, issued in Docket No. E-100, Sub 83, established 1-MW as the maximum size of a facility in North Carolina eligible to net-meter, which was guided in part by G.S. 62-133.8(i)(6), directing the Commission to consider in its adoption of rules "whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a

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generation capacity of one megawatt or less;" and, 4) as pointed out by Duke witness Bowman, FERC has not required QFs below one MW to self-certify as a QF since 2010. In addition, witness Hinton testified that he agreed with Duke witness Bowman that there are also some practical reasons for supporting a reduction in size to 1-MW, including, in particular, the reduced likelihood of a facility between 1- and 2-MW passing the Fast Track Process. He agreed with witness Bowman and Dominion witness Gaskill that the reduced threshold would result in more QFs relying on negotiated PPAs, with a potential benefit that these QFs would be offered avoided cost rates 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.

NCSEA argues that until such time as there is a Commission-approved competitive procurement process under way for the electric utility, the threshold at which a QF qualifies for the Standard Offer should remain at 5 MW. NCSEA witness Johnson testified that the Utilities' proposed changes, including the proposed reduction in the eligibility threshold for the standard offer, have the effect of increasing the risks faced by QFs and make it more difficult to finance QF projects. NCSEA witness Harkrader testified to the difficulties associated with negotiating a PPA with the electric utilities, including that the Utilities accept few, if any, revisions to the PPA. In addition, Harkrader testified that in negotiating a PPA, the utility retains the right to change key terms and conditions. She testified that the length of the PPA term is an example of such a key term. Thus, she testified that NCSEA's position is that, given that an electric utility retains discretion when negotiating PPAs to set key terms that bear directly on whether a QF has a reasonable opportunity to attract capital from potential investors, maintaining the eligibility threshold for the standard offer at 5 MW results in fewer QFs having to negotiate PPAs.

Cypress Creek witness McConnell testified that scale is critical in project development, and that reducing the standard offer contract threshold to 1 MW would make financing projects in North Carolina much more challenging. He testified that much of the financing for 5-MW facilities was obtained through grouping a number of projects together into portfolios to create critical mass for debt and tax equity investors. If the standard offer threshold were lowered to 1 MW, an even larger number of projects would need to be grouped together into a portfolio, and the portfolio size would quickly become unmanageable due to the amount of due diligence required for that number of projects, which would largely shut out the institutional market from financing standard offer contracts.

SACE witness Vitolo testified that the Utilities' proposal to reduce the eligibility threshold for the standard offer will have several negative repercussions. First, he noted that the bilateral negotiation process for those facilities that do not qualify for the standard offer contracts are lengthy and resource-intensive and also take place with a significant power imbalance since the incumbent utility is generally the QF's only potential customer for its power. Second, he testified to the effect that the reduction in the standard offer contract threshold would have on economies of scale, stating that while variable costs such as the cost of panels, inverters, and land grow predictably with the size of the project, fixed costs such as legal, administrative, and some engineering costs do not. As such, a

larger project has a lower total cost per kilowatt than a smaller project. Reducing the capacity limit for standard avoided cost rates, he testified, may require the developer either to forego economies of scale that were otherwise available at the previous 5-MW threshold and instead build a smaller project to avoid the costs and risks of negotiation, or to retain the economies of scale of the larger project but also bear the cost and risk of a bilateral negotiation. Witness Vitolo also testified that reducing the eligibility for a standard offer contract could increase the number of projects under development, thereby adding additional stress on utility interconnection queues and the resources that the utilities have available to conduct bilateral negotiations.

Discussion and Conclusions

In light of the change in the economic and regulatory circumstances currently facing QFs and utilities in North Carolina, the Commission now addresses whether the evidence of these changed circumstances demonstrates that it is appropriate to approve the Utilities' proposals to require that the standard PURPA contract be limited to one 10-year term option available to QFs with a generating capacity up to 1 MW.

The Commission begins by recognizing that a QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's J.D. Wind Orders. Order No. 69 establishes the appropriateness of a fixed QF contract price for energy and capacity at the outset of the QF's obligation because fixed prices are necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore, its financial feasibility before beginning the construction of a facility. While the Commission is mindful that for a QF that chooses to provide energy or capacity pursuant to a LEO over a "specified term," that term must be long enough to allow the QF reasonable opportunities to attract capital from potential investors, Windham, at 134, FERC has also noted that its regulations do not specify a particular number of years for such LEOs. Id. at fn. 13. In addition, PURPA requires the Commission to put into effect (with respect to each electric utility) standard rates for purchases from QFs with a design capacity of 100 kW or less, and permits the Commission to put into effect standard rates for purchases from QFs with a design capacity of more than 100 kW. 18 C.F.R. 292.304(c).

As testified to by the witnesses in this proceeding and recognized by the Commission in its Order on Inputs, establishing the length of the standard offer term and the eligibility threshold for the standard offer, requires a balancing of costs, benefits, and risks to all parties. The Commission finds persuasive the testimony of Duke, Dominion, and the Public Staff's witnesses that demonstrates a causal link between the 15-year standard offer term and the 5-MW eligibility threshold and the distortions in the marketplace for QF-supplied power. The Commission agrees with Duke witness Bowman that the Commission's past decisions requiring the offering of a 15-year fixed rate to QFs up to 5 MW in generating capacity has achieved PURPA's goal of encouraging QF development, particularly solar-powered QFs. Accordingly, the Commission finds it appropriate to eliminate the requirement that the Utilities offer long-term capacity payments and energy payments for a 15-year term and that the standard offer be

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available to QFs with a generating capacity up to 5 MW. In determining the appropriate length of the standard offer term and eligibility threshold for the standard offer, the Commission will continue its approach of balancing the federal and North Carolina public policy requirements to encourage QF development against the risks and burdens (such as overpayment, default, and stranded costs) that long-term contracts place on the Utilities' customers. Unlike in the past, when the facilities entitled to long-term rates were "generally of limited number and size," see Phase II Order at 11, the evidence in this proceeding demonstrates, as witness Hinton testified, "the sheer volume of QF projects currently being developed in North Carolina is unparalleled."

The Commission is not persuaded by SACE witness Vitolo's argument that a 10-year maximum PPA is discriminatory in violation of PURPA because it results in QF solar projects being treated differently than utility projects with respect to recovery of costs. Instead, the Commission agrees with Dominion witness Gaskill and Duke witnesses Snider and Bowman that a utility must operate under cost-of-service rate recovery, which differs from how QFs recover their costs. For example, when a utility builds a plant and places it in rate base, it does not receive forecasted avoided cost for energy and capacity like the QFs, but instead earns a return on capital invested to meet its obligation to serve. Further, the addition of new utility-owned generation is driven by integrated resource planning that is scrutinized by the Public Staff and other interested parties before the Commission, and a specific plant addition is subject to review in CPCN proceedings, where the utility must usually demonstrate that the investment can be used to cost-effectively service customer energy and capacity needs. In contrast, a QF has no limit on, and the Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return. Significantly, as witness Gaskill testified, the longer depreciation lives for utility-owned assets are intended to lower the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to the customers through a lower revenue requirement. In contrast, any such savings from longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. The Commission concludes that matching these recovery periods would shift the balance too far towards encouraging QFs and exposing the Utilities' customers to more overpayment risk.

The Commission is also not persuaded that reducing the standard offer term from the 15 years to 10 years will violate PURPA's requirement that the LEO be long enough to allow the QF reasonable opportunities to attract capital from potential investors. The Utilities' witnesses testified that Duke and Dominion have offered, negotiated, and executed PPAs with terms of 10 years with larger QFs. Witness Bowman testified that no Southeastern state requires a standard offer term of longer than 10 years, and witness Hinton testified that based on the Public Staff's investigation, a 10-year term is reasonable to allow QFs to attract financing in light of current conditions. Further, although testifying in opposition to the Utilities' proposal, NCSEA witness Harkrader testified that a 10-year standard offer term will significantly reduce the pool of debt and equity investors willing to invest in a QF, but notably, she did not testify that a 10-year term would eliminate opportunities to attract investment. Likewise, witness McConnell testified that for small QFs, the reduction to a 10-year term would cause difficulty in obtaining sufficient debt and

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equity to finance construction and operation. Witness McConnell also did not testify that a 10-year term would eliminate a reasonable opportunity to attract investment, although he speculated that the difficulty could become an impossibility. NCSEA witness Strunk testified that the proposed reduction in the term of the standard contract and the other changes that the Utilities have proposed would not provide QFs with a reasonable opportunity to attract capital from potential investors. The Commission first notes that the proposed two-year reset in avoided energy rates is not approved in this order. This mitigates the impact that witness Strunk addressed in his testimony. Further, the Commission finds that the Utilities' evidence of the number of ten-year negotiated contracts with QFs that are currently operating sufficiently rebuts witness Strunk's arguments. For similar reasons, the Commission is not persuaded by the Attorney General's arguments based on this testimony. Therefore, the Commission concludes that the difficulties QFs might experience in attracting investment under a 10-year standard offer do not demonstrate that a 10-year term violates PURPA by eliminating the QF's reasonable opportunity to attract investment; rather, a reduced pool of investors and more difficulty in attracting investment are natural consequences of the rebalancing of the requirements to encourage QF development against the risks and burdens to the Utilities' customers.

Turning to the eligibility threshold for the standard offer, the Commission finds persuasive the evidence of the large number of QF projects currently operating or under development with a generation capacity at, or just below, 5 MW. This demonstrates a clear causal link between the Commission-established standard offer eligibility threshold and the growth and development activity of QFs in North Carolina. The Utilities' primary justification for reducing the standard offer eligibility threshold from 5-MW to 1-MW is that avoided costs rely on forecasts that carry a risk of inaccuracy. The Utilities' witnesses testified that reducing the eligibility threshold will improve the accuracy of calculation of avoided cost rates by increasing the use of negotiated contracts with QFs with rates based upon more timely and accurate calculations of the Utilities' avoided costs, and witness Hinton largely agreed with this concept. Mindful of FERC's direction to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF, the Commission finds merit in this argument and concludes that this evidence supports reducing the standard offer eligibility threshold.

In opposition to the proposed reduction in the eligibility threshold, the intervenor parties' arguments focus on virtues of the current 5-MW threshold: it allows QF developers to capitalize on economies of scale and it facilitates reduced transaction costs for QFs. The Commission agrees with these parties' witnesses that these virtues have been important in encouraging QF development in North Carolina. However, unlike in the Sub 140 proceeding, where the Commission found that very few negotiated contracts with QFs larger than 5-MW have been executed, see Order on Inputs at 20, in this proceeding there is substantial evidence that the Utilities and QFs larger than 5-MW have successfully negotiated contracts. Further, Duke witnesses Bowman and Freeman testified that Duke has gained experience negotiating contracts with larger QFs and is committed to streamlining that process in the future. Witness Bowman also testified that Duke does not intend to increase the number of complaint or arbitration proceedings

brought to the Commission when these negotiations fail. This evidence tends to mitigate the impact of a reduced eligibility threshold.

The Commission recognizes and takes seriously the intervenor parties' concerns that the Utilities will use "take it, or leave it" negotiation tactics. The Commission concludes that both parties to a negotiated PPA are under an obligation to act in good faith in the negotiation, execution, and performance of their contract obligations. This obligation to act in good faith, and the Commission's ability to enforce it against either party through complaint and arbitration proceedings, also mitigates the effect of the reduced eligibility threshold. Finally, with regard to economies of scale, the Commission finds persuasive the testimony of Dominion witness Petrie that standard and negotiated contracts require approximately the same number of hours to administer (including labor-intensive tasks such as performing monthly meter readings, settlement, invoice and billing, and payments) and that Dominion intends to encourage developers to build fewer but, larger projects, and thus greatly reduce the number of resources required to originate and administer the volume of QF contracts under consideration. This evidence also mitigates the impact on QFs' ability to take advantage of economies of scale.

On balance, in light of the change in the marketplace for QF-supplied power, the Commission finds that a reduction in the eligibility threshold is appropriate, and for reasons discussed above, a reduction will not violate PURPA's requirement to encourage QF development. The witnesses that proposed reductions in the standard offer eligibility threshold have suggested three alternatives: 1 MW, 2 MW, or something else, perhaps 3.75 or 4 MW. The Utilities' witnesses cited other regulatory contexts and practical reasons in support of their proposed 1-MW threshold, and Public Staff witness Hinton recognized the merits in this reasoning. Witness Hinton also suggested these considerations could also support a 2-MW threshold, but concluded that the 1-MW threshold "may have more practical significance," including allowing more QF contracts to be based on more timely information that "may reduce the exposure of ratepayers to potential overpayment due to changing market conditions." NCSEA witness Johnson suggested that the proposed 1-MW threshold might be "too extreme." Instead he suggested a 3.75 or 4-MW threshold would allow the Commission to evaluate the impact on the QF marketplace and, in any event, acknowledged that this issue could be revisited in a future biennial avoided cost proceeding. Finally, the Commission takes notice of amended G.S. 62-156(b), providing that, in implementing the standard purchase agreement long-term contracts up to ten years for the purchase of electricity from small power producers with a design capacity up to and including 1,000 kW (or 1 MW) shall be encouraged to enhance the economic feasibility of these facilities.

Based upon the foregoing and the entire record in this proceeding, the Commission finds that it is appropriate to require the Utilities to make the standard offer contract available to QFs with a generation capacity of up to 1 MW. As to those QFs that are "small power producers," as defined in G.S. 62-2(27a), the Commission concludes that G.S. 62-156 resolves this issue. As to those QFs that are cogeneration facilities, the Commission concludes that the evidence demonstrates that this reduction will promote PURPA's goal of making the Utilities indifferent to whether the energy or capacity

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purchased is supplied by a QF, through self-build, or otherwise, by increasing the number of QF projects that will negotiate contracts. The Commission further concludes that this reduction will not violate PURPA's requirement to encourage QF development, in light of the extensive record of the amount of QF-supplied power and number of QF projects operating and in development in North Carolina, including a growing number that have successfully negotiated and executed contracts with the Utilities.

The changes in the standard offer term and eligibility threshold, viewed jointly with the other changes being adopted by the Commission, reflect a comprehensive effort to modify the State's avoided cost policies towards a model that is more efficient and sustainable over the long term, while at the same time providing protection to ratepayers from overpayment risk and certainty to QFs. One part of this effort is the Commission's implementation of the General Assembly's directives enacted in HB 589. The Commission will continue to monitor the amount of actual QF development and the stability of avoided cost rates to ensure that ratepayers are not exposed to undue risk of overpayments, while at the same time providing QFs with an opportunity to obtain financing on reasonable terms.

In past biennial avoided cost proceedings, the Commission ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved. Therefore, the Utilities shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding. The Commission recognizes that the importance of a Commission-recognized active solicitation may be greater in the near future than it has been in the past as the Commission works to implement the requirements of newly enacted G.S. 62-110.8, and the Commission intends to develop

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its rules for the competitive procurement of renewable energy and implement that program in a manner that provides the certainty that Utilities and QFs need.

The Commission further concludes, based upon the foregoing and the entire record herein, that it is appropriate for Dominion to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, including the payment of capacity credits based on the PJM Reliability Pricing Model (RPM), subject to the same conditions as approved in the Sub 106 Order and most recently restated in the Order on Inputs, except as modified by this order.

Finally, the Commission finds good cause to make clear that the conclusions reached in this section apply equally to hydroelectric QFs without storage capacity (commonly called run-of-the-river hydro facilities). DEC and DEP filed Schedules PP-H and PPH-1, respectively, in which they proposed standard offer fixed rates available to run-of-the-river hydro QFs that are 5 MW and less for 5-, 10-, and 15-year terms, reflecting the terms and conditions of the Hydro Stipulation, which was filed and approved in Docket No. E-100, Sub 140. In doing so, Duke relied on the State policy set forth in G.S. 62-156 and the Commission's approval of the Hydro Stipulation. The Commission has historically relied on this State policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, as justification for treating these QFs differently than other QFs. However, these provisions were repealed or substantially amended by the enactment of S.L. 2017-192, undermining the policy rationale that prompted the Commission to approve the Hydro Stipulation in the Order on Inputs. Therefore, the Commission concludes that G.S. 62-156 requires that run-of-the-river hydro QFs be treated similarly to other QFs with regard to the Commission's implementation of the standard offer contract.

Based on foregoing and the entire record in this proceeding, the Commission finds that it is appropriate to require the Utilities to offer as a standard option long-term levelized capacity payments and energy payments for ten-year periods to all QFs contracting to sell one MW or less capacity.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witnesses Gaskill and Petrie; Public Staff witness Hinton; NCSEA witness Johnson; Cypress Creek witness McConnell; and SACE witness Vitolo.

Duke witnesses Bowman and Snider testified in support of Duke's proposal to calculate capacity costs taking into account each utility's relative need for additional generating capacity as determined by their respective IRPs. Witnesses Bowman and Snider both testified that PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to generate or purchase elsewhere to serve its

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customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. In support of her testimony, witness Bowman cited FERC's decision in Ketchikan, holding that while a utility is legally obligated to purchase energy or capacity provided by a QF, the purchase rate should include only payments for energy or capacity that the utility can use to meet its total system load.[3] She also cited N.C. Gen. Stat. § 62-156(b)(2), providing that "a determination of the avoided energy costs to the utility shall include . . . the expected costs of the additional or existing generating capacity which could be displaced." Witness Bowman acknowledged that the Commission has cited FERC's Hydrodynamics decision,[4] as supporting its determination that the Utilities should not include zeros in the early years when calculating avoided capacity rates. She distinguished Hydrodynamics from the circumstances of this proceeding, noting that Hydrodynamics pertained to a limit on installed capacity purchases by a utility and not to a utility proposal to recognize a capacity value only in years where the utility's IRP showed a need for such capacity.

Witness Snider also recommended that the Companies' relative need for incremental generating capacity should be accounted for in calculating its avoided capacity rates, arguing that prior to the year in which the next generation unit is needed to serve system load, the utility does not have a capacity need to avoid. Thus, witness Snider testified, the calculation of the capacity portion of the avoided cost rate should not ascribe value for years prior to the first avoidable capacity need. Witness Snider further testified that the first capacity need for both Duke utilities occurs in the 2022-2023 timeframe, as shown in their 2016 IRPs. He also testified that QFs under the standard offer tariff will receive capacity payments in years prior to the Companies' first capacity need because the QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs. Witness Snider concluded that this proposal is fair to Duke's customers because with this adjustment, the Duke utilities' customers would only be paying QF capacity payments equal to the economic value of an associated avoided capacity cost.

Dominion witnesses Gaskill and Petrie testified in support of Dominion's proposal to include no payment for capacity with its standard offer avoided cost rates. Witness Gaskill testified that, even if Dominion did have a near-term need for additional generation capacity in North Carolina, which it does not, additional distributed solar generation beyond what is already under contract would not allow Dominion to avoid future capacity expansions. In support of his argument, he testified that FERC has clearly stated that while utilities may be obligated under PURPA to purchase from QFs, an avoided cost rate need not include payment for capacity where a QF does not allow the purchasing utility to avoid building or buying future capacity—that, when a utility's demand for capacity is zero, the cost for capacity may also be zero. Further, he testified that FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility

[3] See City of Ketchikan, Alaska, 94 FERC ¶ 61,293 (2001) (Ketchikan).

[4] Hydrodynamics, 146 FERC ¶ 61,193 (2014) (Hydrodynamics).

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would generate itself or purchase from another source. He stressed the importance of the "but for" language in that definition in the context of capacity payments, noting that it is not the case that, "but for" the distributed solar QFs on its North Carolina system, Dominion would purchase or self-supply capacity. He concluded that, because it will not avoid capacity need due to incremental distributed solar generation in North Carolina, a capacity rate of zero accurately reflects Dominion's actual avoided costs for QF contracts signed today. He testified that unlike previous QFs interconnecting at distribution level that acted as load reducers and, by reducing Dominion's load obligation, deferred the need to buy or construct new capacity, because distributed solar generation now exceeds load in this area, there is no need for additional distributed solar in Dominion's North Carolina service area, and that because incremental distributed solar QF generation in North Carolina will not allow it to avoid capacity need, a zero capacity payment accurately reflects Dominion's actual avoided costs for QF contracts signed today.

Witness Petrie testified that several factors support this proposal. First, he testified that Dominion's 2016 IRP showed no capacity need until 2022 at the earliest, and that its preliminary updated load forecast as of December 2016 pushes that need for incremental capacity out to 2024. He further testified that the most recent PJM load forecast from January 2017 shows no need for capacity for Dominion until after the 2026 timeframe. Additionally, witness Petrie testified that, even if a need for new capacity did exist within Dominion's current long-term planning horizon, because its North Carolina service area is saturated with distributed solar QF projects, any new distributed solar generation added going forward will have little to no peak load reducing effect on the system. He testified that new solar QFs are not effective substitutes for new dispatchable generation, such as a CT, unless they are located near areas with increasing load growth and where additional generation is needed to reduce congestion and improve reliability. However, he testified that this is not the case for solar QFs in Dominion's North Carolina territory because while previous QFs interconnecting at the distribution level acted as load reducers, deferring the need for new capacity, distributed solar generation now exceeds load in the North Carolina service area, such that there is no more load to offset. For similar reasons, he noted, additional distributed solar in this area will not improve overall system reliability, especially with regard to meeting wintertime peak demands. Considering all of these factors, witness Petrie concluded that Dominion cannot avoid building or buying capacity by purchasing from new distributed solar generation in its North Carolina service area. Witness Petrie also testified that Dominion is considering the addition of aeroderivative CTs as quick-start, flexible units that can balance the system as more intermittent, non-dispatchable solar generation resources are added. However, because these aeroderivative CTs have a higher installed cost than the large frame turbines that Dominion has built since the year 2000 (an estimated 67% more than other CTs), their addition will result in increased long-term capacity costs for customers.

Witness Petrie further testified that pricing for solar generation should reflect its lack of dispatchability and limited usefulness during system emergencies. He testified that FERC's rules list several factors that should be considered when determining avoided cost rates for QFs including, among other factors, the availability of a QF's energy or capacity, the utility's ability to dispatch the QF, the QF's expected or demonstrated

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reliability, and the usefulness of the QF's energy and capacity during system emergencies. Witness Petrie also noted his understanding of FERC's recent explanation that its rules permit state regulatory authorities to consider factors such as capacity availability, dispatchability, reliability, and the value of energy and capacity when determining avoided cost rates, and, based on these factors, to set lower rates for purchases from intermittent QFs than for purchases from firm QFs. Witness Petrie also cited recent changes to PJM's capacity market rules as further evidence that additional distributed solar generation in Dominion's North Carolina service area is not the type of reliable capacity that would allow it to avoid capacity needs. He testified that these rule changes were intended to better reflect the changing resource mix in PJM, including the growing volume of intermittent generation, and to better align resource payments to performance. He noted that intermittent resources are particularly challenged under the new rules, as they can be subject to severe penalties for non-performance during summer and winter peak hours. He also pointed out that PJM training materials issued after FERC approved the new rules suggest that an acceptable offer for a 100-MW nameplate solar facility would be from 0 to 20 MW of firm capacity. He concluded that these changes demonstrate that solar capacity, as compared to the firm capacity of a dispatchable and reliable CT, is not capable of sustained, predictable operation during emergency conditions, and has limited value in the new PJM capacity market, from which Dominion's actual avoided costs are derived.

Witness Petrie also testified that Dominion, which has experienced winter peaks in two of the last three years, as well as PJM, have increased their focus on planning for winter reliability, the costs for which include procuring fuel supply backup, additional gas pipeline capacity, and improved winter testing and operations. He noted that the spikes in demand during periods of extreme cold over the last several years show the volatility of winter peak loads and the need for dispatchable generation on the system. He noted also that because solar generation output is near zero at 7 a.m. on cold winter mornings when these system peaks occur, a CT is still required in the winter.

Finally, witness Petrie testified that the addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day, while not impacting the timing of the winter peak load due to their minimal output at that time. He noted that, when Dominion reaches the threshold of aggregate solar additions of about 1,000 MW across its North Carolina service area, the summer peak hour is expected to shift from 5 pm to 6 pm or later. Witness Petrie testified that, as the summer peak hour shifts later in the day, any additional solar generation produces less summer peak load reducing effect, and is thus less effective in deferring or avoiding the next required capacity resource because solar output decreases in the later hours of the evening and, therefore, has lower capacity value. The marginal value of solar capacity, therefore, decreases as more solar generation is added to the system. Witness Petrie concluded that Dominion's proposal to make no capacity payments to QFs receiving the standard offer accounts for the fact that, due to all of these factors, additional North Carolina QF solar resources will not allow it to defer or avoid capacity needs. This proposed modification would also, he stated, avoid burdening customers with avoided cost payments that exceed Dominion's actual avoided costs. Witness Petrie concluded

that given these considerations and the factors described in his direct testimony, the appropriate capacity rate for new QFs located in this area is zero cents per kWh for the duration of the standard offer contract.

Witness Petrie testified that SACE witness Vitolo's assertion that as a PJM member, Dominion only has summer capacity needs, is incorrect and oversimplified. He testified that the PJM capacity market reflects the need for capacity planning to meet both summer and winter peaks, since under its new capacity market rules, PJM generators must provide reliable capacity during all months of the year. He disagreed that PJM has a surplus of winter capacity, citing the shortage of available generation during the winter of 2014 that demonstrated the need for the new rules. He also testified that since solar resources have little or no capacity to generate at the winter morning peak, they are subject to significant capacity performance penalties if they bid into this market, since under the new rules they are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days. Witness Petrie also testified that the 38% capacity value cited by witness Vitolo denotes capacity injection rights, not the market capacity value, of solar resources. He emphasized that, on a risk adjusted basis, the capacity credit of a solar resource offered into PJM's capacity market is in the nameplate capacity range of 0 to 20% (based on PJM's assumption that a typical solar facility may provide 38% in the summer, but only 2% in the winter). Whether a solar generator bids into the PJM market at 0 or 20% depends on how much penalty risk the generator is willing to accept. He testified that this reduced capacity credit percentage, combined with the potential penalties, demonstrates that, from a reliability perspective, solar resources can only be counted on for a small portion, if any, of their nameplate capacity, and that continuing to pay new solar QFs rates for avoided capacity, when they do not defer or avoid any capacity need, results in an overpayment beyond Dominion's actual avoided costs.

Witness Petrie also addressed Duke's proposal to include zeros in the calculation of the capacity rates for the years where the utility does not have a capacity need. He stated that, in the event that the Commission declines to accept Dominion's proposal to set capacity rates to zero for the duration of the standard offer contract, Dominion would agree with Public Staff witness Hinton's conclusion that Duke's proposal is reasonable and appropriate. He testified that while Duke's proposal would still result in Dominion overpaying QFs, it would come closer to valuing the capacity appropriately over the course of a long-term PPA than would paying a QF for capacity over the entire term, including for years in which there is no demonstrated need.

Witness Petrie agreed with witness Hinton that in the current circumstances it is appropriate for the Commission to reconsider this issue, since the traditional application of the peaker method is resulting in overpayment in excess of actual avoided costs and is not sending proper price signals to the market. He noted that there is historical precedent for the Commission allowing the utility to pay zero for capacity during the front years of a QF contract, citing orders issued in the 1994, 1996, and 1998 avoided cost proceedings in which the Commission recognized that, where no capacity costs are

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avoided, no capacity credit should be reflected in the capacity rate calculation. He stated that the evidence in this case is analogous to those proceedings.

Witness Petrie disagreed with NCSEA witness Johnson's argument that paying QFs for capacity only when the utility actually shows a capacity need discriminates against QFs. Witness Petrie testified that, as a regulated utility, Dominion has an obligation under the law to serve its customers reliably and at least cost. He testified further that North Carolina QFs cannot defer or avoid the need for new capacity because they do not reduce load on Dominion's system. He testified that paying for capacity when it is not needed or avoided contradicts the PURPA requirement that the rates a utility pays for QF output should not exceed the utility's avoided costs. He also testified that, contrary to witness Johnson's assertion, the principle of ratepayer indifference is also violated if customers pay the QF for capacity that is not actually avoided, because those customers are paying for something they do not receive. He noted that the determination of avoided costs and rates to be made in this proceeding is not a theoretical exercise, but instead represents real customer costs.

Finally, witness Petrie testified that, contrary to witness Vitolo's testimony, the circumstances of the Ketchikan case, in which he understood FERC to have found that if the utility does not have a demonstrated capacity need it should not be required to pay for incremental QF capacity, are similar to the current situation in North Carolina. He noted that as shown in Ketchikan, Dominion also currently has no near-term incremental capacity needs. He acknowledged that in the 2014 biennial proceeding, the Commission cited FERC's later Hydrodynamics decision in support of its determination in that docket that the Utilities should not include zeros for capacity in the early years when calculating avoided capacity rates. He testified that the situation in Hydrodynamics differed from the circumstances at issue in Ketchikan and those at issue in this proceeding, because it addressed a utility proposal to limit installed capacity purchases with no connection between that limit and the utility's own actual need. He noted that, in Hydrodynamics, FERC reiterated its earlier conclusion that when a utility's demand or need for capacity is zero, avoided cost rates need not include capacity cost. He stated that such is the case here, and therefore that the Ketchikan rationale does apply to this case and to Dominion's proposal.

Dominion witness Petrie clarified that it was not relevant that Dominion used the differential revenue requirement (DRR) method of determining avoided costs during the 1990s cases in which the Commission recognized that no capacity credit should be included where no capacity costs are avoided. He testified that, regardless of avoided cost methodology, if there is no demonstrated capacity need, the utility should not be required to pay for capacity. He agreed that all three traditional avoided cost methodologies have the same purpose: reasonably estimating the utility's future avoided cost.

Dominion witness Gaskill testified that the number of QF PPAs and related capacity that Dominion has entered into increased from 72 PPAs and 500 MW of capacity as of the date of his direct testimony to 76 PPAs and 521 MW of capacity as of the hearing

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date. Witness Gaskill also answered questions from NCSEA counsel comparing the amount of distributed solar generation on Dominion's North Carolina system as described in his testimony to the amount of solar generation either connected to its system or having an executed Interconnection Agreement that was identified in its February 1, 2017 interconnection queue report filed in Docket No. E-100, Sub 101A (and entered as NCSEA-Dominion Cross Exhibit 1). He clarified that the queue report is prepared by Dominion's interconnection team from which he operates separately. He testified, however, that the 435 MW of operational solar capacity noted in his testimony is consistent with the 345 MW of operational interconnected solar capacity reflected in the queue report, because the 435 MW total includes 90 MW of solar that is in the PJM wholesale interconnection queue, but is interconnecting to Dominion's distribution system. Similarly, he testified that the difference between his estimate of 363 MW in study phase as shown in Figure 2 to his direct testimony, and the 282 MW designated as Project A, Project B, or "Subordinate" in the queue report, is also likely due to his Figure 2 including PJM queue projects. He also noted that the total MW reflected by the queue report as "connected" and "IA executed" projects—519 MW—is comparable with his updated testimony that Dominion has entered into PPAs for 521 MW of solar capacity.

Witness Petrie testified that Dominion occasionally enters into contracts for capacity outside of QF agreements, and recently acquired replacement capacity related to the March 2017 deactivation of the Roanoke Valley Power facility (ROVA), some of which it filled through short-term capacity purchases in the PJM market. Witness Gaskill testified that the term of the contract for Dominion's purchases from this facility extended through mid-2019, but because the facility deactivated, Dominion was obligated to locate capacity to replace what that facility had committed through PJM's wholesale capacity market. He testified that Dominion is self-supplying the remainder of the capacity previously supplied by this facility. Witness Petrie agreed in response to questions by counsel for SACE and the Public Staff that Dominion engages in generation and transmission planning on a system wide basis, including North Carolina and Virginia.

Witness Gaskill further testified that, generally speaking, non-wholesale contracts, such as a contract for a QF selling under PURPA, would not be eligible to replace a capacity commitment by being bid directly into the PJM wholesale capacity market, because they are not participants in that market. Specifically as to the ROVA facility, he testified that because that facility had been committed into the PJM capacity market as a capacity performance resource, eligible replacement capacity had to be located in that market, and behind the meter QF solar generation would not have qualified as eligible replacement capacity for a capacity performance resource. He noted that the potential capacity value that can be derived from solar QFs is not from their generation of power but from their load reducing effect, because as they reduce the peak load over time, they reduce the amount of capacity Dominion must procure through PJM. But, as shown in this case where this generation exceeds the load requirements, there is no load reducing effect and no impact on PJM capacity market procurement. Witness Gaskill also clarified that as an alternative to putting power to Dominion as a QF, a developer could become a PJM market participant and sell its output into PJM. Witness Gaskill confirmed that in response to a Public Staff discovery request he reconstructed Figure 1 from Dominion's

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Initial Filing, which had shown the tremendous recent growth in QF solar development in its North Carolina service area since 2013, to show the current level of QF solar development on the North Carolina portion of Dominion's system compared to its system average on-peak load.

Public Staff witness Hinton testified regarding the traditional application of the peaker method and its valuing of capacity over the entire planning period. He stated that according to the theory of the peaker method, the utility's generating system is operating at the optimal point, the capital cost of a peaker (based on a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. He noted that in reality, however, no utility system operates at the most optimal point and utility planners have to deal with unexpected changes in load, fuel costs, and other factors that challenge optimality. He expressed concerns that the rapid and substantial increase in QF development raises doubts as to whether the traditional application of the peaker method would continue to be appropriate and provide the market with a correct price for capacity. He further noted that an end result of the traditional long-run application of the peaker method is that every kilowatt-hour (kWh) generated during on-peak hours provides capacity value and this value is quantified from the first day of QF operation, regardless of the utilities' short-run needs for additional capacity.

Witness Hinton further testified that contrary to the position taken by the Public Staff in prior proceedings regarding the use of zero capacity value in certain years, he believed that in light of current circumstances related to the amount of solar generation online and pending in the interconnection queue, it is appropriate for the utilities to adjust their avoided cost rates to provide a capacity payment to new QFs only when additional capacity is needed on the system. He further stated that by restricting the inclusion of a capacity credit until the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market.

Witness Hinton indicated that the Public Staff supports Duke's proposal to limit capacity payments until the IRP dictates a capacity need in this proceeding, but that conditions in future proceedings may lend to reconsideration of this issue, as well as the continued applicability of the peaker method. Witness Hinton noted that DEC indicates a resource need of approximately 3,903 MWs over the planning period (2017-2031), with the first resource need in the 2022/2023 timeframe, and DEP indicates a resource need of approximately 4,071 MWs over the same planning period, with the first resource need in 2021/2022.

With regard to Dominion's position that the existing and projected level of solar generation exceeds the load in its North Carolina service territory such that there are no more capacity costs to be avoided with additional QF generation, witness Hinton testified that Dominion's proposal seems to run counter to general principles of utility system planning. Witness Hinton testified that utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide

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basis. This system perspective is applied in various regulatory proceedings, including IRP proceedings, where witness Hinton noted that Dominion's 2016 IRP indicates a capacity need of approximately 4,457 MW, with the first resource need in 2022. In addition, witness Hinton testified that one of the central arguments in Dominion's application to join PJM was that Dominion's membership would make the utility part of a vast integrated transmission system with interfaces with PJM-East, PJM-West, and AEP with greater access to generation resources, load diversity, and improved reserve sharing across the region. Witness Hinton disagreed with Dominion's argument that there is no capacity value associated with incremental QF generation. He therefore recommended, like DEC and DEP, that the Commission require Dominion to provide a capacity credit based on the first indicated need in its IRP.

NCSEA witness Johnson testified in opposition to the Utilities' proposal to include payments for avoided capacity only for those years when the utility's IRP shows a capacity need. Witness Johnson testified that Dominion's proposal results in the payment of no avoided capacity rate and that the DEC and DEP proposal results in an approximate 60% reduction in the avoided capacity rate from the 2014 rate. He further testified that the Commission rejected this same proposal by DEC and DEP in the 2014 biennial avoided cost proceeding, observing that: 1) DEC and DEP justified their proposal in 2014 on the same or similar bases on which they justify the 2016 proposal; and 2) that the Commission should reject the proposal again, as it did in 2014. In addition, witness Johnson testified that the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of "incremental cost" and "avoided cost." He also testified that the use of zeros is inconsistent with the concept of "ratepayer indifference," and it leads to undue discrimination against QFs. Witness Johnson testified that, in general, the goals of PURPA are best promoted when PURPA is implemented in a way that focuses on long run incremental cost, rather than a short run measure of cost that excludes capacity costs. More specifically, he testified that QF avoided cost rates should reflect the full long run cost of building and operating the utilities' generating facilities, including years when new generating units are not being added. He further testified that because of economies of scale, electric utilities typically find it cost effective to construct large generating facilities, at multi-year intervals. He testified that if the utility has a capacity need of 100-MW per year over a 6-year period, it will not add a 100-MW plant every year but instead will add a 600+ MW plant in a single year. Under these circumstances, Johnson argued that economic theory tells us there are long run capacity costs present in every year; they are not zero in some years and present in others. Put a different way, Johnson testified that given reality of how electric utilities add new generating capacity, even during years when "zero" capacity is planned, the long run cost of capacity is the same, or nearly the same as it is during other years, when a new block of capacity is scheduled to be placed into service. With respect to discrimination against QFs, NCSEA witness Johnson testified that PURPA specifically states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers." He explains that under rate base regulation, the utilities are allowed to recover the cost of new generating capacity as they are completed and put into commercial operation, even though some of the capacity is being added prior to the time it is required (due to lumpiness). He testified that since the utility is allowed to recover

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its capacity costs during the "zero" years just after a new capacity addition and its reserve margin is higher than the required minimum, to avoid discrimination, the QF should be treated the same.

SACE witness Vitolo testified in response to the Utilities' proposal to eliminate capacity payments in years when the utility's IRP shows no need for capacity. He testified that the use of a dollar-per-kilowatt cost of a CT under the peaker methodology and the making of a capacity payment in every year are "inextricably linked." This link, he testified, results from the assumption that the utility's generating system is operating at equilibrium and that generation capacity payments will be made for all years in which the QF is in service. He further testified that the concerns expressed in the Sub 140 proceeding are still applicable today. Those concerns, he testified, prompted the Commission to reject the same proposal in the Order on Inputs. Witness Vitolo also testified in response to Dominion's proposal to eliminate capacity payments, arguing that, for similar reasons the Commission should reject this proposal as well.

As amended by HB 589, G.S. 62-156(b)(3) provides that a future capacity need shall only be avoided in a year where the utility's most recent IRP has identified a projected capacity need to serve system load and the identified need can be met by the type of resource being used by the small power producer to generate electricity.

Discussion and Conclusions

With regard to QFs that are small power producers, the Commission concludes that G.S. 62-156(b)(3) requires that, when calculating avoided capacity rates using the peaker method, a utility's standard offer to purchase should include a capacity credit for those years when the utility's most recent IRP demonstrates a need for capacity. The Commission further concludes that Duke witness Snider's proposal to provide levelized capacity payments for the full term of the ten-year standard offer, including capacity payments in years prior to the utility's first capacity need reflecting a lower annual payment to account for those initial years in which there is no avoidable capacity costs, is a reasonable means of implementing this directive. More specifically, this tends to support PURPA's directive to encourage QF development by providing more revenue to the QF earlier in the term of the standard contract. Therefore, the Commission will require the Utilities to include this methodology in their respective standard offer to purchase tariffs as part of the compliance filing required by this order.

Based upon the foregoing and the entire record herein, the Commission determines that this avoided capacity payment methodology is also appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. While the Commission has previously considered and rejected similar proposals in past avoided cost proceedings, the Commission finds that the changed economic and regulatory circumstances facing QFs and utilities now justifies accepting this change. PURPA requires that QFs be fairly and reasonably compensated for the incremental capacity and energy costs that, but for the capacity and energy provided by the QF, the utility would be required to generate or purchase elsewhere to serve its

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customers, but PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need. Changes experienced in the marketplace for QF-supplied power in North Carolina challenge many of the assumptions regarding the application of the peaker method, as well as threaten to obligate customers to pay for capacity well in excess of what may actually be avoided. While the Utilities' IRPs all continue to show additional need for capacity, the mere presence of QF capacity, including solar nameplate capacity, does not always translate into an avoidance of capacity needs by the utility. FERC's regulations implementing PURPA provide that states shall consider a number of factors in determining avoided costs, including the availability of capacity or energy from a QF during the system daily and seasonal peak loads (including dispatchability, reliability, and the individual and aggregate value of energy and capacity from QFs), as well as the relationship of the availability of energy and capacity from the QF to the ability of the utility to avoid costs. 18 C.F.R. 292.304(e). These factors are largely consistent with the directives in G.S. 62-156, and the Commission concludes that the operating characteristics of a QF resource must be considered in evaluating whether the QF can help to avoid the utility's planned capacity addition. In considering these characteristics and the other factors, the Commission concludes that the record in this proceeding demonstrates that the capacity value provided by additional solar PV does not necessarily help the utilities to offset or avoid their next capacity need. Solar QFs may provide some seasonal capacity benefit, but may also create other operational challenges due to its non-dispatchability and intermittency that offset the capacity benefits.

In light of these specific directives to consider dispatchability, reliability and other factors in determining avoided costs, the Commission is not persuaded by SACE witness Vitolo and NCSEA witness Johnson's arguments that inclusion of no capacity value in avoided capacity rates when the utility's IRP does not show a need is discriminatory under PURPA. As discussed in detail above, the testimony of the Utilities' and the Public Staff's witnesses demonstrates that the decision to allow a utility to add its owned generation resources to its portfolio and recover the costs is too different from the PURPA must-purchase requirement to make this a useful analogy.

However, the Commission agrees with NCSEA witness Johnson that the appropriate analysis of capacity needs should be conducted over the long run, and the use of zeroes in the early years will have the effect of lowering the avoided cost rates for the entire period. The Commission finds that this outcome may provide avoided cost rates that more accurately reflect the cost being avoided by the Utilities, in light of the amount of current and pending growth from QFs in North Carolina. As Public Staff witness Hinton testified, by including a capacity credit only in those years in which the IRP has established a capacity deficiency, the risk of overpayment by ratepayers is reduced, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. Further, the Commission agrees with witness Johnson that the Utilities should focus on improving the rate design in ways that are responsive to the specific concerns that have been identified to ensure that the change in policies being adopted in this proceeding do not adversely impact other small power producers, including wind, methane from landfills, hog or poultry waste, and non-animal

biomass, for problems that are specifically related to solar energy. As discussed in other sections of this order, the Commission concludes that an avoided cost rate based on the characteristics of the QF-supplied power may also be appropriate going forward in future proceedings, and, therefore, will require the Utilities to include proposed rates and data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings in the next biennial avoided cost proceeding.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witness Petrie; Public Staff witness Hinton; NCSEA witness Johnson; and SACE witness Vitolo.

Summary of the Testimony

Duke Witness Snider testified in support of Duke's proposal to reduce the PAF multiplier for non-hydro facilities from 1.20 to 1.05 to align the PAF with the operational characteristics of a CT. Witness Snider testified that the PAF is intended to make up for a QF's unavailability during the on-peak period when QFs are paid for capacity by increasing the rate the QF is paid during peak hours to account for hours in which it does not operate. Witness Snider acknowledged that Duke's resources are sometimes unavailable, and it follows that the QFs replacing those resources should not be penalized for the same level of unavailability. He further testified that when using the peaker methodology to calculate avoided cost rates, the resource a QF is replacing is a CT. He then testified that DEC's and DEP's CT fleet performs at greater than 95% starting reliability, and as such, no PAF greater than 1.05 is warranted. Witness Snider acknowledged that the Commission declined to adopt a similar proposal in the Sub 140 proceeding, noting that the Commission determined that the arguments presented in that proceeding to modify the PAF were insufficient "at that time," and found "widespread QF development under the existing framework without adverse impacts to ratepayers." Witness Snider testified that since Sub 140, both DEC and DEP have experienced an unprecedented "surge" in solar QFs exposing customers to $1 billion in overpayments for energy and capacity. He testified that the approximately $1 billion in overpayments only accounts for QFs that are currently delivering power and does not include approximately 1,100 MW (of 5 MW and less QFs) that are in development or under construction and remain eligible for the avoided cost rates that were calculated in Sub 140 or Sub 136. He also testified that Duke is unaware of any other jurisdiction, except DEC's and DEP's stipulated avoided cost rates in South Carolina (which are derived from the rates calculated in Sub 140), that have recently explicitly or implicitly provided for a PAF multiplier in setting avoided capacity rates.

Witness Snider also responded to the Public Staff witnesses' testimony, recommending a PAF of 1.16 based on an average availability factor of 86.33%. He states that the Public Staff's focus on "availability" is appropriate, but their calculation has a critical flaw that leads to substantial overstatement of a just and reasonable PAF. In support of his argument he first defined a generator's "availability factor" as the amount

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of time that it is able to produce electricity over a certain period, divided by the amount of time in the period. He understands the time period used in the Public Staff's calculations based on annual data, testifying that witnesses Hinton and Metz are testifying that the average availability factor for certain DEC, DEP, and Dominion baseload and intermediate units was about 86% during the period 2011-2016. Further, wtiness Snider testified that the numerator of the availability factor reflects (i.e., is reduced by) the amount of time that a unit is out of service for planned maintenance, and, thus, the annual availability factor measures how much a unit is available across an entire year which includes these planned outages such as nuclear refueling outages. He further testified that planned maintenance is typically conducted during off-peak shoulder periods when electricity demand is low. As such, he argued that using the annual availability factor for the Companies' generating fleet is not relevant to the intended purpose of the PAF, which applies only to on-peak periods. He further stated that, by definition, off-peak periods have very low loss of load risk even with the planned maintenance outages, and that of greater importance, QFs do not have to produce a single MWh in off-peak hours to receive their full capacity payment. His criticism is that the Public Staff's use of off-peak planned maintenance from utility generation effectively increases the proposed PAF they are recommending for QFs, and testified that this would imply that an acceptable operational practice would be to schedule a nuclear unit refueling outage during peak demand periods. He testified that this is obviously not representative of prudent utility operating practice, and that, in fact, the Companies strive to take outages, planned or not, during lower load or off-peak periods when capacity is not needed. He summarized, stating that any availability metric used to support a PAF must focus solely on the peak availability and not annual availability, and that it is mathematically incorrect to base a PAF on annual availability of utility generation which includes off-peak outages as a measure of on-peak performance for a QF.

Further, witness Snider noted that utility reserve margins are based on on-peak availability of greater than 95%. He testified that imposing an assumed 86% peak availability would result in a significant increase in the Companies' reserve margin requirement and significant increase in costs to consumers to build or buy greater amounts of capacity in order to provide reliable service. In responding to witness Johnson's contention that utilities are not held to the high standard of 95% availability, witness Snider testified that Duke manages its generation fleets to achieve a very high level of on-peak reliability and does not believe the Commission would accept less. In conclusion, witness Snider testified that if the Commission believes that the PAF should be based on a system availability metric, as the Public Staff recommends, then it should be based on a metric that represents the reliability of the system during peak demand periods. Therefore, he recommended using the Equivalent Forced Outage Rate (EFOR) which represents the reliability of a unit or generating fleet during periods between planned maintenance intervals which means that it is a better indicator of the reliability of the unit or fleet during peak demand periods when performance is critical. He noted that similar to the CT starting reliability data, the EFOR data from the 2016 resource adequacy studies again supports a PAF less than, and certainly no greater than 1.05.

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In addressing the characteristics of QF-supplied power, witness Snider further testified that if a solar QF, or any other QF for that matter, was truly dispatchable, then the Companies would be open to a demand rate that would allow the dispatchable QF to receive capacity payments consistent with other dispatchable capacity resources Duke purchases outside of PURPA. He noted that it is the very non-dispatchable nature of QF power that requires the QF to operate across the peak to receive a full capacity payment. Witness Snider testified that if the QF were dispatchable, capacity would be based upon dispatch performance like other generation outside of PURPA. He suggested this is a key point that is often lost in the comparison of non-QF capacity and QF capacity. According to witness Snider, PURPA specifically envisions issues like intermittency and dispatchability to be factored into the rate structure and valuation.

Dominion witness Petrie testified that, consistent with its proposal not to make a capacity payment to QFs for the duration of the standard offer contract, Dominion did not propose any adjustments to the PAF. Witness Petrie agreed, however, that the PAF issue merits reevaluation in this proceeding, and testified that, to the extent that the Commission directs the Utilities to offer capacity rates to QFs in this proceeding, a PAF of 1.05 would be appropriate. He testified that, since the peaker method determines avoided capacity costs based on the installed cost of a peaking CT unit, the peak hours availability of a peaking CT should be the basis for the PAF. He testified further that, if a QF cannot operate at a level of availability similar to or better than a CT during peak periods, and does not provide the same level of reliability as a CT, the QF should not be entitled to rates based on the avoided cost of a full CT. Specifically, he testified that if a QF is assumed to defer the need for a CT with 95% availability during peak hours, the QF should not receive the same capacity payment if it is only available 83% (or less) of the time. Witness Petrie testified that witness Johnson's testimony demonstrates precisely this distinction in availability and reliability between a solar facility and a CT. He also testified in response to witness Vitolo's assertions that the year-round availability of all fleet units is not the correct metric to use for this purpose, because it includes maintenance and planned outages that are purposely scheduled to occur during non-peak conditions. The appropriate measure for the PAF, witness Petrie concluded, is the availability of a CT during summer and winter peak hours, resulting in a PAF of 1.05. For the same reasons, witness Petrie disagreed with the Public Staff witnesses' recommendation of a 1.16 PAF.

Witness Petrie recognized that the Commission declined to accept this proposal in the 2014 biennial proceeding. He noted, however, that in making that decision, the Commission stated that there had been widespread QF development under the existing framework without adverse impacts to utility ratepayers. Witness Petrie testified that, as Dominion has shown, this is no longer true, because circumstances have changed since 2014, and utility customers are being adversely impacted.

Public Staff witness Hinton provided a brief history of the PAF, stating that in the early stages of PURPA implementation, the Commission approved a capacity credit adjustment based on the utilities' reserve margin of 20%, which was subsequently replaced with the PAF. The Commission has consistently recognized in its avoided cost

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orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive capacity payments that the Commission had determined constituted the utility's avoided capacity costs. More specifically, according to witness Hinton, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate on all peak hours throughout the year in order to receive the full capacity payment to which it is entitled. Witness Hinton testified that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constituted the utility's avoided capacity costs. More specifically, witness Hinton noted that the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate all on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled.[5] According to witness Hinton, using a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83% of the on-peak hours. Further, witness Hinton notes that the Commission has previously concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83% of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Witness Hinton stated with respect to the argument that the starting reliability of a CT should be used to establish the PAF, the Commission has specifically rejected the use of a CT for this purpose, most recently in the Sub 140 proceeding. In that proceeding, the Commission concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are just a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. Witness Hinton testified that the Public Staff agrees with the Commission's previous conclusions that if a QF's availability is similar to that of the utility's baseload fleet, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

Witness Metz testified that he does not agree entirely with Duke's proposal of 1.05 PAF. He testified that while he agrees that a 1.2 PAF may no longer be appropriate for use in calculating avoided cost rates, he does not agree that the appropriate PAF is the one that matches the reliability of a CT. Witness Metz noted that the peaker methodology uses a CT as a proxy for the pure capacity value of generation versus the energy value, but it is not meant to imply that all QF capacity calculations should be based on the characteristics of a CT. Witness Metz recommended that the Commission approve a PAF value of 1.16, which he notes is reflective of a broader plant availability factor average of 86.33%

[5] See e.g., Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127, 11-12 (2011).

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Witness Metz testified that his calculation was based upon plant performance data filed by the Utilities in monthly Commission Baseload Power Plant Performance Reports, SNL data, and responses to Public Staff data requests. He noted that when data was not available for particular units, he made assumptions based on historical performance of the unit using capacity factors. Witness Metz stated that his calculation is similar to that made by the Public Staff in prior avoided cost proceedings. Further, he noted that his calculation included intermediate generating units in addition to baseload units, as well as some operating characteristics based on known information about certain generating facilities. Witness Metz recommended that the Commission consider this revised PAF calculation based on the historic weighted availability factors of the utilities' baseload and intermediate generating units as a refinement and update to the Public Staff's previous PAF calculations.

NCSEA argues that the proposed reduction is unreasonable and should be rejected. NCSEA witness Johnson testified that under the peaker method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units and, hence, witness Johnson opined that the availability of all types of generating units (intermediate and baseload) must be considered, contrary to the narrower viewpoint initially expressed by Duke. Further, NCSEA witness Johnson testified that while the precise calculation of the PAF may be disputed, QFs must be treated in a non-discriminatory manner, consistent with the treatment afforded the electric utilities. He testified that this is important because QF rates are supposed to leave customers financially indifferent between purchases of QF power and the generation of the same amount of output by the utility. NCSEA witness Johnson further testified that reducing the PAF to 1.05 would have the effect of requiring a QF to generate at full capacity during 95% of the on-peak hours in order to receive full payment of the avoided capacity costs. Johnson testified that a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on-peak hours due to the fact that many on-peak hours occur before the sun rises or after the sun sets.

Witness Vitolo argued that the Commission should reject the proposal by DEC and DEP to reduce the PAF from 1.2 to 1.05. Witness Vitolo testified that the resource the QF is replacing is not a CT. He noted that the peaker method assumes that the utility's fleet is in equilibrium and therefore "the quantitative result is not biased by the choice of one particular technology over another."[6] Further, according to witness Vitolo, the only specific role for a combustion turbine in the peaker method is to estimate the avoided capacity cost for a new unit. Witness Vitolo opines that there is no expectation that the QF will avoid the utility procurement of a specific generator technology or type. Witness Vitolo testified that in any given hour, the QF could be displacing a peaking unit, a mid-range unit, or even a baseload unit – demonstrating that the QF's availability should be compared to the utility's entire fleet. Witness Vitolo recommended that the Commission maintain current policy by requiring the Companies continue to use a 1.20 PAF for

[6] Citing, Laurence D. Kirsch, Direct Testimony on behalf of the Public Staff, Docket No. E-100, Sub 140 (April 25, 2014), Page 23, Line 6.

non-hydro renewable QFs. He noted that the availability standard implied by a 1.20 PAF better aligns with the expected availability of units in a utility fleet.

Discussion and Conclusions

In its Sub 100 Order, the Commission concluded that the availability of a CT is not determinative for purposes of calculating a PAF, because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed cost of any avoided generating unit. [7] The Commission reiterated this conclusion in the Order on Inputs, finding that despite the widespread development of QFs, the existing framework was not resulting in adverse impacts to utility ratepayers. The parties in this proceeding agree with basic notion that a PAF is appropriately included in the avoided capacity methodology and that something other than the availability of a CT should be considered in calculating a PAF. The parties dispute what metrics should be considered in developing the appropriate PAF.

Unlike in the Sub 140 proceeding, the Commission has found in this order that the circumstances facing QFs and utilities in North Carolina have changed. As relevant to the calculation of the PAF, this change is evidenced, in part, by the Utilities' increased operation of combined-cycle (CC) units as baseload and intermediate generation, their use of coal plants as intermediate and peaking generators, as well as the Utilities' increased use of CTs. In addition, in this proceeding the parties' evidence and arguments address the appropriate PAF to be included in the avoided capacity methodology with greater precision than past proceedings.

The resolution of this issue focuses the Commission's attention on the requirement that avoided cost rates must be non-discriminatory. See Order No. 69 at 12,222-12,223. As relevant to calculating the PAF, the witnesses testified that this requires the Commission to make a fair comparison between the performance of utility-owned generation resources and QFs. The witnesses agree that the appropriate comparison should focus on generating unit "availability" and that an evaluation of availability should be based upon an informed discussion of utility system planning and load forecasting. In other words, the appropriate analysis is of the utility's broader fleet availability. The parties' dispute centers on what is the appropriate method to be used in developing the PAF for analyzing "availability" across the utility's fleet.

The Commission agrees with witness Snider that the Public Staff's witnesses use of availability factor is flawed because it includes planned outages that a utility intentionally schedules for off-peak shoulder periods when electricity demand is low. Further, as utility reserve margins are based on on-peak availability of greater than 95%, an assumed 86% availability would result in a significant increase in the Utilities' reserve margin requirements. That result would be inconsistent with the reserve margins

[7] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 100, at 22, issued September 29, 2005.

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accepted as reasonable in the Commission's recent order accepting Duke's IRPs.[8] In addition, as witness Snider testified, it follows that this approach would, on a theoretical level, contemplate the Duke utilities planning for 5,000 MW of generation unavailable during any given peak hour. As witness Snider testified, the Commission would be unlikely to find this an acceptable manner for Duke to carry out its statutory obligations to provide reliable power to its North Carolina ratepayers. For these same reasons, the Commission is not persuaded by the testimony of SACE witness Vitolo.

Rather than availability factor, the Commission agrees with witness Snider that a more reasonable approach is to develop the PAF based on equivalent forced outage rate (EFOR) for several reasons. First, this makes a fair comparison between on-peak reliability of all generation resources and a reasonable expectation of QF availability during on-peak hours. Second, EFOR represents the reliability of a unit or generating fleet during periods between planned maintenance intervals, making it a better indicator of utility generating fleet performance during the on-peak hours. Third, this avoids raising problematic issues of accepting higher reserve margins for planning based on lowering expectations of on-peak performance reliability. In this regard, use of the EFOR in calculating the PAF tends to harmonize the Commission's approach to calculating avoided capacity payments with the Commission's approach to long-term planning analysis. Fourth, Duke's uncontroverted testimony is that North Carolina is the only state that applies a pure capacity multiplier similar to a PAF. Finally, and more broadly, holding QFs to the same high performance standards during on-peak periods incentivizes efficient behavior for both utilities and QFs, and tends to support the public interest by insuring ratepayers are provided adequate, reliable, and cost-effective service.

The Commission carefully considered the testimony of NCSEA witness Johnson expressing concern with the Utilities' use of "arbitrary, overly broad, on-peak time periods" to produce the Option A and Option B rate schemes. The Commission is inclined to agree with witness Johnson that avoided capacity calculations could send better price signals to incentivize QFs to better match the generation needs of utilities, and that proper incentives could drive QFs to adopt new technologies such as solar PV that tracks the sun or incorporates storage. Therefore, the Commission will require the Utilities to consider refinements to the avoided capacity calculation as suggested by witness Johnson and to address these refinements in their initial filings in the next avoided cost proceeding. This should include consideration of a rate scheme that pays higher capacity payments during fewer peak-period hours to QFs that provide intermittent, non-dispatchable power, based on each utility's costs during the critical peak demand periods.

Based upon the foregoing and the entire record herein, the Commission determines that the availability of a CT is not determinative for calculating the PAF, and that calculation of the PAF should be based on a methodology that uses a system availability metric that represents the reliability of the system during peak demand periods. The Commission concludes that a PAF of 1.05 should be utilized by DEC, DEP,

[8] See Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, issued June 27, 2017.

and Dominion in their respective avoided cost calculations for all QFs except hydroelectric facilities without storage capability. The Commission further determines that EFOR and similarly focused equivalent availability are appropriate peak season reliability indicators. In the interest of harmonizing the Commission's avoided cost proceedings and other routine filings such as power plant performance reports, the Commission determines that equivalent availability may be the more appropriate metric. As such, the Commission will require the Utilities to address the PAF and to support their recommendations for PAF calculations based on evidence of peak season equivalent availabilities for the utility fleets in total in its initial filings in the next biennial proceeding established to review avoided cost rates.

Finally, the Commission considered issues raised in DEC and DEP filed Schedules PP-H and PPH-1, respectively, setting forth avoided cost rates available to run-of-the-river QF hydro facilities without storage capability and reflecting the terms and conditions of the Hydro Stipulation. By these schedules, DEC and DEP would continue to use a 2.0 PAF to calculate the avoided cost rates for these QFs with the same hour options that these QFs had in 2014 under DEC's Schedule PP-H and DEP's Schedule CSP-29. The Hydro Stipulation, which the Commission approved in the Order on Inputs, provides that DEC and DEP would include and incorporate the foregoing in their proposed avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31, 2020.

No party introduced any evidence disputing that the avoided cost rates shown on DEC's PP-H and DEP's PPH-1 were inconsistent with the Hydro Settlement, and no party introduced any evidence indicating that the Commission should reconsider its prior approval of the Hydro Stipulation. In contrast to the Commission's implementation of the standard offer contract, the amendments to G.S. 62-2(27a) and 62-156 do not speak to the PAF. Thus, the Commission's historic reliance on this as state policy supporting the encouragement of the development and economic feasibility of small hydroelectric generating facilities is not undermined with regard to the PAF. Further, the Commission notes that there is no evidence of an alternative PAF for run-of-the-river hydro QFs in this proceeding, and the Commission finds that prudential considerations support not undoing the Hydro Stipulation at this time. Considerations of regulatory certainty lend further support to allowing the Hydro Stipulation to continue, at least through the end of the two-year period that is covered by this biennial proceeding.

Based on the foregoing and the entire record herein, the Commission finds that the 2.0 PAF included in Schedule PP-H and PPH-1 are consistent with the Hydro Stipulation and should be approved. The Commission further finds it appropriate to require the Utilities to address this issues in its initial filings in the next biennial avoided cost proceeding.

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EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 9

The evidence supporting this finding of fact is found in the testimony of Duke witness Snider, Public Staff witness Hinton, NCSEA witness Johnson, and SACE witness Vitolo.

Summary of the Testimony

Duke witness Snider testified in support of Duke's proposal to change the seasonal allocation weightings that are an input into determining the avoided capacity rates. Witness Snider testified that Duke commissioned resource adequacy studies that were presented in their 2016 IRPs. He testified that the high penetration of solar resources that have connected to Duke's transmission and distribution systems in the past 2-3 years, along with the high volume of solar resources currently in the interconnection queue, was one driver of the studies, and the significant load response to cold weather experienced in 2014-2015 winter periods was the other. Witness Snider testified that, in the past, the Companies' annual peak demands were projected to occur in summer. In addition, the Companies' generating fleets, especially gas-fired CTs and CC units, have greater output during winter periods compared to summer periods. Thus, summer load and resources have driven the timing need for new resource additions, and a summer reserve margin target provided adequate reserves in both the summer and winter periods and was sufficient for overall resource adequacy.

Witness Snider testified, however, the load and resource balance has changed dramatically in the past two to three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. He further testified that solar resources contribute significantly more to the summer afternoon peak than they contribute to winter morning peak. Therefore, witness Snider stated, the 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. As such, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources now drive the timing and need for new capacity additions.

Witness Snider testified that the Companies increased their minimum planning reserve margin target in the 2016 IRP due to the surging solar penetration and significant winter load response. Solar resources contribute approximately 45% of their nameplate rating at the time of the summer peak, which occurs in the afternoon hours. He noted that the Companies' winter peaks occur in the early morning hours around 7:00 am when solar has no output. The Companies' 2016 IRP reflect a 5% capacity contribution from solar for winter resource planning purposes. Thus, as solar resources increase, the Companies' summer reserve margins increase compared to winter reserves. Witness Snider testified that higher solar penetration is one of the drivers of the shift to winter capacity planning and why the Companies must now plan new resource additions to satisfy minimum winter reserve margins. Planning to a 17% winter reserve margin with growing summer resources will result in an increasing summer reserve margin over time. Witness Snider

demonstrated also that the disparity will continue to grow as solar penetration increases. Witness Snider next testified that 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk now occurs during the winter period and about 20% during the summer period, and that this 80/20 winter/summer seasonal weighting was incorporated into the Companies' avoided cost rates in this proceeding.

Public Staff witness Hinton expressed concern that Duke's proposed seasonal allocation factors overly emphasized winter periods. He noted the significant winter peaks in 2014 and 2015, but said that the summer peak remained considerable and cautioned against an overemphasis on winter peaks at this time. Witness Hinton recommended that the Commission make a smaller change in the seasonal allocation factor than that proposed by Duke, to 60% winter and 40% summer, and revisit the issue once there is more information and confidence regarding the utilities' emphasis on winter planning.

NCSEA witness Johnson testified that he had reviewed DEC's and DEP's hourly load data from 2006-2015 and determined that 86.5% of the most extreme system peaks occurred from June through September, while the remaining 13.5% occurred in the winter months of December through February. He concluded that rather than shift seasonal allocation toward winter, these data support a stronger allocation toward summer. He recommended that the Commission create three sets of months: June through September; December through February; and the remaining months for allocating capacity seasonally. In the alternative, Dr. Johnson proposed that the Commission retain the current 60% summer and 40% winter allocation.

SACE witness Vitolo expressed concern about using the Astrapé studies as a basis for the seasonal allocation, as the 36 weather years (1980-2015) in the studies were developed using five years of historical weather and load data that included the polar vortex years of 2014 and 2015. Dr. Vitolo stated that this could overstate winter peaks. He also noted that the studies did not account for any investments Duke may make to meet wintertime reliability challenges. He pointed out that the Astrapé studies are for use in 2019, and do not pertain to 2017 or 2018. He recommended that the Commission assign 80% of capacity to summer and 20% to winter for 2017 and 2018.

In his rebuttal testimony, Duke witness Snider noted the differences between being winter peaking and winter planning. He testified that the shift to winter planning is driven by the impact of solar generation. He did not refute NCSEA witness Johnson's calculations of peaks based on the hourly load data, but contended that the calculations failed to consider reserve capacity. In response to the testimony of Public Staff witness Hinton, witness Snider testified that the shift to winter planning is not due to the load forecast, but due to penetration of solar resources and winter load variability. Witness Snider noted that the Astrapé studies modeled 36 weather years using the last five years' weather and load data to develop weather and load relationships. Witness Snider stated that the impact of Duke's proposed change in seasonal allocation of capacity payments to QFs would be approximately one percent, and have no effect on baseload QFs.

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Discussion and Conclusions

The parties' recommended allocations for seasonal capacity range from 80% winter and 20% summer, as proposed by Duke, to 20% winter and 80% summer, as calculated by SACE witness Vitolo. The Commission determines that the evidence on this issue demonstrates that a shift toward winter peak demands and winter seasonal loss of load risk is appropriate for purposes of seasonal allocation of capacity payments in this case. These changes, which have been influenced by the increased amount of solar-powered QFs interconnected to Duke's electric systems, justify an adjustment to the seasonal capacity allocation input to calculating avoided cost rates.

The Commission finds that a high penetration of solar resources that have connected to the Companies' transmission and distribution systems in the past two to three years, along with the high volume of solar resources currently in the interconnection queue have driven Duke's resource adequacy studies; the significant load response to cold weather experienced in 2014-2015 winter periods has been the other driver. The Commission determines that for purposes of this case it is appropriate to rely on the resource adequacy studies for purposes of seasonal allocation of capacity payments.

The Commission finds that Duke's load and resource balance has changed in the past two to three years, driven primarily by the high penetration of solar resources and the significant load response to cold weather experienced during the 2014 and 2015 winter periods. Duke's solar resources contribute significantly more to the summer afternoon peak than they contribute to winter morning peak. Duke's 2016 resource adequacy studies demonstrated that the loss of load risk is now heavily concentrated during the winter period. As such, a summer reserve margin target will no longer ensure adequate reserve capacity in the winter, and winter load and resources presently drive the timing and need for new capacity additions.

The Commission finds that solar resources presently contribute approximately 45% of their nameplate rating at the time of the summer peak, which occurs in the afternoon hours. The Companies' winter peaks occur in the early morning hours around 7:00 a.m. when solar has insignificant output. The Companies' 2016 IRP reflect a 5% capacity contribution from solar for winter resource planning purposes.

Duke's 2016 resource adequacy studies showed that approximately 80% or more of the loss of load risk presently occurs during the winter period and about 20% during the summer period. The Commission determines this substantial loss of load risk justifies the 80% winter, 20% summer allocation for establishing rates in this case.

The Commission agrees that Duke's winter capacity planning is distinct from winter peaking. The impact of the addition of solar resources on that planning requires DEC and DEP to "plan" on a winter peak reserve margin criteria as a result of existing and anticipated solar on the system. Regardless of when the peaks occur, the resource adequacy studies showed a need for both Companies to shift to winter capacity planning because Duke's summer peaks occur late in the afternoon when solar has some energy

contributions as compared to winter where very little solar is available at the time of peak. As a result, summer peak loads are net of solar output compared to winter peak loads.

As an alternative to Duke's proposed change, witness Hinton recommended that DEC and DEP adjust the seasonal weighting to 40% for summer and 60% for non-summer. In support of this recommendation, witness Hinton stated, "it was somewhat of an uninformed judgement call …. In the IRP, we clearly address issues with the reserve margin study and I had concerns personally with their load forecasting. … I just felt it was appropriate not to make such a large change in the seasonal allocation until we have more information." The Commission is not persuaded that this "uninformed judgment call" justifies the allocation advanced by the Public Staff at this time for the purposes of this case. The Commission is also unpersuaded by witness Vitolo's criticisms of the Companies' resource adequacy studies regarding the use of historical weather data. Witness Snider's testimony that the resource adequacy studies not only include five years of weather and load data, as asserted by witness Vitolo, but the recent temperature and load relationships were applied to 36 historic weather years that were included in the study, sufficiently outweigh witness Vitolo's criticisms. The Commission is likewise not persuaded by witness Johnson's argument that historic summer peak load data does not support Duke's seasonal weightings. Witness Snider's testimony that high penetrations of solar have a significant impact on summer versus winter loads net of solar contributions and his testimony regarding the associated impact on reserves and loss of load risk sufficiently address the concerns expressed by witness Johnson in his testimony.

Based upon the foregoing and the entire record herein, the Commission determines that Duke's proposed seasonal allocation weightings of 80% for winter and 20% for summer are appropriate for use in weighting capacity value between winter and summer, and should be used in calculating DEC and DEP's avoided capacity rates in this proceeding. In reaching this finding, the Commission expressly reserves judgment on the parties' arguments regarding winter peaking versus winter planning and whether the reserve margins referenced herein are appropriate for the Duke utilities' integrated resource planning. See Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147, at 14-15 and 21-23, issued June 27, 2017.

As with other determinations in this case, the issue of system planning is dynamic, and conditions may change in the future. Therefore, the Commission will be receptive to revisiting this issue in future avoided cost cases.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 10

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Snider; Dominion witnesses Gaskill and Petrie; Public Staff witness Hinton; NCSEA witnesses Johnson and Strunk; Cypress Creek witness McConnell; and SACE witness Vitolo.

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Summary of the Testimony

By its initial statement, Duke argues that DEC and DEP's customers are obligated to pay excess long-term costs due to the recent trend in declining energy markets over the past several years where actual incremental system marginal energy costs have been significantly lower than prior forecasts in earlier avoided cost filings. For non-hydroelectric QFs, Duke proposed to mitigate the longer-term commodity price forecast risk through the modified Schedule PP 10-year avoided cost rate structure that included biennially resetting avoided energy rates.

Witness Bowman testified that Duke's proposal to adjust avoided energy rates every two years was consistent with PURPA's requirement that avoided cost rates be just and reasonable to customers, in the public interest, and not discriminatory to QFs. She argues that this means avoided cost rates should not exceed the incremental costs of alternative energy that the utility would generate or purchase from another source. Witness Bowman further argued that if contracts extend for many years, the forecasted avoided cost rates become increasingly inaccurate. She noted that PURPA does not prescribe a minimum or maximum term for a "long-term" contract, and that different states offer differing terms. She contrasted South Carolina, which has a maximum 10-year fixed long-term contract, with Georgia, which has a maximum 5-year fixed long-term contract,[9] and noted that Tennessee, Alabama, and Mississippi have all approved minimum standard offer terms of one year, and that the Idaho Public Utilities Commission recently approved a two-year fixed contract term for wind and solar QFs larger than 100 kW.

Duke witness Snider also testified in support of the proposed 10-year maximum term standard contract with capacity rates fixed over the term and energy rates readjusted as part of the Commission's biennial avoided cost proceedings. He testified that approximately 1,600 MW of utility-scale QF solar generators are now interconnected and delivering power to DEC/DEP under prior Commission-approved avoided cost rates, and an additional 1,100 MW of proposed solar QFs either in development or under construction have also taken the steps required to "lock in" to the Sub 136 and Sub 140 standard avoided cost rates that the Commission previously approved. Witness Snider testified that these growing risks associated with the long-term financial obligations under existing PURPA standard offer contracts has driven Duke's proposed modifications to its Schedules PP and PP-3 rate design in this proceeding. He argues that development of these additional solar QFs inevitably means that Duke's financial obligation under PURPA and customers' exposure to overpayments could increase significantly in the future.

Witness Snider then testified that entering into long-term fixed price contracts without regard to changing commodity market conditions had caused the citizens and businesses of North Carolina to pay for QF generation at this substantially higher cost. Overpayment in energy rates to the QFs is driven primarily by the significant decline in

[9] The Commission notes that the Georgia Power Company's Solar Purchase Schedule SP-2 was discontinued for new customers in July 2016. Public Staff witness Hinton testified during the hearing that authorized fixed-term standard offer available in Georgia Power's service territory to QFs 100 kW or less is now two years. (Tr. Vol. 3 at 95; Tr. Vol. 8 at 143).

fuel commodity prices over the last several years. Witness Snider testified that in general, 10-year levelized gas prices had fallen approximately 40% and coal prices had fallen approximately 16% for that same period as compared to those used in calculating Duke's avoided energy cost in the 2014 Sub 140 proceeding. He asserted that if energy rates were recalculated more regularly, they would better align with future fuel commodity prices. Therefore, to mitigate the potential harm to Duke's customers of long-term overpayments in excess of actual future avoided costs, Duke proposed modifications to their proposed standard offers to balance the QF's interests for fixed long-term contracts while limiting the significant fuel commodity forecast price risk for Duke's customers going forward. Witness Snider testified that adjusting energy rates at reasonable, periodic intervals throughout the duration of a long-term contract is an effective way to reduce customers' exposure to overpayments.

Witness Snider also contrasted the PPAs that Duke enters into outside of PURPA with those under PURPA. Duke's PPAs outside of PURPA generally do not include long-term commodity price risks. DEC and DEP also seek to procure energy or build new generation based on a need that is typically defined in DEC's or DEP's IRPs. When DEC or DEP solicit offers for new energy or capacity, the Commission reviews the prudence of the proposed resource options by assessing the economics and the risks with the objective of procuring the least cost, least risk assets for customers. Further, when a PPA is negotiated outside of PURPA, the energy payment terms are generally linked to a real time fuel price index, and, as such, DEC and DEP minimize the risk of the customer paying beyond market energy prices. Witness Snider concluded that Duke's proposed modification to the standard offer structure better aligns the level of risk imposed upon customers in PURPA contracts with those in non-PURPA ones.

Witness Bowman further testified that Duke's proposed 10-year contract term with the 2-year avoided energy adjustment was developed in response to the concerns raised by the Public Staff and other intervenors. She testified that Duke appreciates the Public Staff's and other parties' concerns that small QFs and their potential investors require certainty in terms of the avoided cost rates to be offered to determine whether to develop a project. She noted that the FERC's PURPA regulations have long provided a method through the forecast information required to be filed with the Commission pursuant to 18 C.F.R. § 292.302 for QF investors to evaluate the utility's longer-term need for capacity and the forecasted cost of energy. As testified in Order No. 69, this data can be used by QFs and their investors in evaluating the utility's future avoided costs. Although witness Bowman testified that she was not an expert in contract terms and conditions that the financial community would deem reasonable to allow QFs to attract capital, she understood that numerous considerations, including a QF developer's balance sheet, management team experience and creditworthiness, as well as avoided cost-specific considerations including price, contract tenor, the cost of capital, all come into play in determining whether an investment can attract debt and/or equity capital. PURPA largely exempts QFs from state regulatory authority over their rates and business operations so that neither Duke, the Public Staff, nor the Commission has any clear insights into a QF developer's business or the level of profit deemed reasonable to attract equity capital.

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Witness Bowman also disputed testimony from intervenors that the Windham decision prohibited Duke's proposed 2-year updates of avoided energy rates in an otherwise fixed 10-year PPA. She agreed that the FERC found in Windham that PURPA's directive to encourage QFs suggests that a LEO should be sufficiently long to allow QFs reasonable opportunities to attract capital from potential investors. Witness Bowman argued, however, that Windham arose in the context of rates offered by a Connecticut utility in the ISO-New England organized market and, further, that the FERC did not specify a particular number of years for such LEOs, leaving the proper term to the discretion of the State Commissions. She noted that Alabama was the only jurisdiction outside of an organized wholesale market to consider the FERC's recent Windham decision in setting forecasted avoided cost rates under PURPA. Further, she testified that in early March 2017, the Alabama Public Service Commission (Alabama PSC) approved Alabama Power Company's (Alabama Power) standard rate offer for QFs with a design capacity above 100 kW, which offers Alabama Power's forecasted energy and capacity rate over a one-year term with an "evergreen provision" under which avoided cost pricing updates annually consistent with the updated avoided energy pricing submitted by Alabama Power.[10] The Alabama PSC held that the rate structure was consistent with PURPA and with prior FERC guidance that a long-term contract is one year or longer under PURPA.[11] Witness Bowman testified that she is unaware of any state in the Southeast with a contract term of more than 10 years under PURPA. For these reasons, witness Bowman testified that Windham should not materially change the Commission's analysis of Duke's proposed standard offer structure.

Witness Bowman also disputed witness Vitolo's assertion that the Commission had previously denied a similar biennial reset of the avoided energy rate for Dominion in the 2010 Sub 127 avoided cost proceeding on the ground it was inconsistent with the FERC's J.D. Wind Orders. Witness Bowman asserted that Duke's proposal in this proceeding was in response to the current economic and regulatory circumstances. She also noted that Dominion had used the biennial reset method from 1989 to 2010 prior to the Commission directing it to transition to fixed, levelized avoided energy rates. Additionally, witness Bowman disagreed that PURPA or the FERC's regulations prohibited such a biennial reset, and noted that the Commission had allowed Dominion to offer its 2-year fixed energy rate during 2010-2011. Finally, she testified that prohibiting this option perpetuates North Carolina's status as an outlier that significantly encourages QF development compared to other southeastern states, such as Alabama, Arkansas, Florida, Kentucky, Louisiana, Maryland, and Virginia. Witness Bowman cited NCSEA witness Johnson's testimony that these states offer shorter-term variable rates, rather than fixed, long-term rates.

Witness Bowman also disputed SACE witness Vitolo's claim that QF fixed contracts should match the recovery period of Duke's own PV and other generating assets. She distinguished QF contracts from utility-owned ones in multiple ways. First,

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[10] Alabama Power Company, Petition for Approval of Rate CPE – Contract for Purchased Energy, Docket No. U-5213 (March 7, 2017).

[11] Id.

utility resource additions are driven by need, which the Utilities establish through an extensive IRP and CPCN application process. In contrast, the PURPA must-purchase requirement mandates QFs be reimbursed for selling power to Duke whether or not the power is needed. Next, witness Bowman noted that utility load-following generator resources are dispatchable. She also testified that because the Utilities were not locked into long-term fixed contracts, they can pass lower fuel and other operating cost savings to customers. A utility, however, cannot dispatch or back down a QF when more economic alternatives are available, so she argues that customers ultimately pay for potentially higher-cost QF energy produced by a QF. Long-term contracts exacerbate this inefficiency. She testified that QFs do not actually advocate for a longer cost recovery period based upon actually recovering their cost of service, but only to extend the period of guaranteed revenue (and profit) out into the future.

Dominion Witness Gaskill also responded to witness Vitolo's concern that QF solar projects are treated differently than utility projects because utility-sponsored projects depreciate capital over their lives. Witness Gaskill noted several differences between rate regulated utilities and QFs with respect to how they are organized, regulated, financed, and how they obtain cost recovery. Utilities operate under cost-of-service rate recovery, which differs significantly from how independent power producers, like QFs, recover their costs. If a utility builds a solar facility and places it into rate base, all of the benefits, including fuel savings, revenue from renewable energy credits (RECs), and investment tax credits are passed on to customers. Witness Gaskill contrasted this with QFs, which are paid the marginal costs for both capacity and energy and retain all other revenue streams from RECs and tax credits.

Witness Snider agreed that Public Staff witness Hinton's suggestion to link available energy rates to a publicly available composite fuel index was a reasonable alternative to the 2-year reset of energy payments. He argued that this accomplished the goal of minimizing the risk of overpaying QFs for the energy that they provide. Witness Snider agreed to further evaluate incorporating this proposal in its rate design in the next biennial proceeding. As an interim measure, however, and in response to specific concerns raised by the intervenors that the 2-year update to energy rates was too risky and unpredictable for QFs 1 MW and less to obtain financing, witnesses Bowman and Snider offered a "compromise proposal" in their rebuttal testimony. The compromise proposal would allow QF developers the option to "fix" the underlying 2-year avoided energy rate filed with the Schedules PP for the duration of the 10-year contract. Witness Snider noted that the 2-year fixed Schedule PP annualized energy rates were only slightly below the fixed 10-year Schedule PP-H annualized energy rates. He viewed this as an acceptable, albeit imperfect, allocation of longer term risk forecast between QFs and Duke's customers at this time. Additionally, he testified that Duke viewed this compromise offer as an interim rate design to be considered with the Public Staff's other alternative options, such as linking avoided energy rates to a fuel index, in the next biennial proceeding.

Public Staff witness Hinton testified that Dominion's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with

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PURPA's goals of encouraging QFs. He noted that in Windham the FERC recently elaborated on this requirement more fully, as follows:

> [T]he Commission has long held that its regulations pertaining to legally enforceable obligations "are intended to reconcile the requirement that the rates for purchases equal to the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments, by necessity, on estimates of future avoided costs" and has explicitly agreed with previous commenters that "stressed the need for certainty with regard to return on investment in new technologies." Given this "need for certainty with regard to return on investment," coupled with Congress' directive that the Commission "encourage" QFs, a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors.[12]

Witness Hinton testified that he does not think offering a standard offer contract with a two-year reset on the avoided energy rates would provide sufficient "certainty with regard to return on investment" to provide a QF with a reasonable opportunity "to attract capital from potential investors." He noted that larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, but that resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which could make obtaining financing difficult or impossible.

Witness Hinton acknowledged, as noted by Duke witness Bowman, that Georgia Power offers fixed two-year energy rates and only pays for avoided capacity when the IRP shows a need, similar to Duke's proposal. However, witness Hinton noted that there is little QF development in the states that offer two-year energy rates, and that the development in those states is largely in response to legislative mandates for solar power. Witness Hinton agreed that QF contracts contain risks that are ultimately borne by the utility customer. However, he further testified that these risks need to be viewed in the context of a utility's long-term commitment to build plants, whereby such decisions as the building of Cliffside Unit 6 and the Richmond County CC units were based upon forecasts that are also uncertain, resulting in ratepayers bearing the same type of forecast risk from utility plants as they do from QFs.

Witness Hinton described other options to reduce forecast risk that might be considered, such as linking available energy rates to a publicly available composite fuel index or establishing a band or collar on the amount of adjustment that energy rates could vary from some indicative pricing. He stated that these options may provide QFs with additional certainty, while reducing ratepayers' risk of overpayment. Lastly, witness Hinton noted that the Public Staff was already proposing a number of other adjustments

[12] T. Vol. 8, p. 75, citing Windham at 8.

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to the rate and terms under the standard offer in this docket that would more appropriately reduce the risk of overpayment by customers.

NCSEA argues that Duke's proposed two-year reset of avoided energy rates results in disruptive uncertainty and links the future revenue stream – which is critical to the economics and financing of a QF -- to the future course of volatile fuel prices and other variables that are unknowable and unpredictable from the perspective of the QF and their investors, likely discouraging investment in QFs. NCSEA witness Strunk testified that providing fixed prices for a term that is sufficient to provide a reasonable amortization of sunk investment costs for a long-lived asset has been key to the financing of new independent power production facilities. He testified that reducing the PPA term and including two-year energy price resets would raise the price that a QF requires to be viable for two reasons: (1) the QF's cost of capital will increase as its investors bear more risk; and (2) investors will seek shorter amortization periods for capital investments, which in turn translate to higher short-term cash flow requirements. He stated that reducing the term of the PPA therefore increases the near-term costs for the QF, decreases the possibility that those costs could be recovered under avoided cost pricing, and reduces the likelihood that the facility will actually be developed. This reduction of the time period over which fixed rates apply will lead lenders to view the effective PPA coverage period as only two years, even though Duke is proposing a 10-year PPA term. He indicated that lenders will significantly discount the revenues available beyond that two-year period, and as a result, it is unlikely that project debt could be obtained in reasonable quantities for terms longer than two years.

NCSEA witness Johnson testified that under the current avoided cost tariff structure in North Carolina, a QF benefits from a fixed revenue stream that aligns well with its fixed costs, but under DEC's and DEP's proposal to provide for a two-year reset, avoided energy rates will suddenly become highly unpredictable. He testified that "not only will the future revenue stream depend on the future course of volatile fuel prices, but it will fluctuate with those prices in ways that are fundamentally unknowable and unpredictable from the perspective of the QF and their financiers, because it will depend on the outcome of litigated proceedings every two years." Witness Johnson testified that most non-PURPA sellers of power are burning fuel, so their use of a pricing structure that recognizes fuel price changes is appropriate. He noted, however, that this approach shifts the fuel price risk to the customer. Witness Johnson testified that he did not think it was reasonable to apply a similar pricing arrangement to generators that do not consume fuel.

Cypress Creek argues that financing parties would view a ten-year PPA with a two-year readjustment to the avoided energy rate no more favorably than they would a two-year contract, which would not be financeable. Cypress Creek witness McConnell testified that rates fixed over the term of the contract are critical to securing financing, stating that "fixed rates for a fixed period of time create financeable contracts," and that what creates value in the contract is having a set avoided cost rate for a set period of time. He further testified that without these fixed rates, lenders are unwilling to bet on what the avoided cost rates will be going forward. Witness McConnell also testified that in a regulated market, a 10-year contract with a two-year reset for energy prices would be viewed as

more or less equivalent to a two-year contract, and would likely not be financeable in the current environment.

SACE witness Vitolo testified that Duke's proposed change in the energy payment schedule is not appropriate since the lack of set avoided energy payments over the life of the contract would jeopardize project financing and likely discourage QF development contrary to the policy goals of PURPA. He also noted that this change would reduce the rate stability provided by decoupling some generation from variable fuel prices. He testified that in J.D. Wind FERC held that QFs are entitled to receive long-term avoided contracts or other legally enforceable obligations "with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." Witness Vitolo further testified that changing the payment every two years would differ significantly from how the utilities treat their own assets. He argues that a utility decision to build or purchase a generating asset nearly always includes a long-term obligation to pay for that capital asset, and that integrated resource planning and decisions to invest capital in new generators are also substantially influenced by long-term forecasts of costs, particularly fuel. In support of his argument, he noted that in the Order on Inputs, the Commission observed:

> While witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC'S and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts. Order on Inputs at p. 20.

Dr. Vitolo also discussed the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, issued on July 27, 2011, in Docket No. E-100, Sub 127, stating that the Commission rejected Dominion's proposal to continue to offer variable avoided energy rates for QFs larger than 100 kW that would be updated every two years. The Commission determined that an avoided energy rate that "is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate," and required the utility to begin offering fixed long-term, levelized avoided energy rates for QFs entitled to standard contracts in the following biennial proceeding.

Discussion and Conclusions

The Commission notes that a QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's J.D. Wind Orders. FERC's intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation. See Order on Inputs at p. 19-20. In addition, G.S. 62-133.8(d) provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility "… shall be of sufficient length to stimulate development of solar energy." See id. at 20. Further, in Windham, FERC reiterated

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Order No. 69 requires certainty with regard to return on investment and, thus, a legally enforceable obligation must be long enough to allow QFs reasonable opportunities to attract capital from potential investors. Windham at 3-4. Subsequent FERC actions or inactions in allowing states to approve short-term fixed rates in standard offer PURPA PPAs must also be acknowledged in resolving the issues in this case.

The Commission agrees with Duke witness Snider that PURPA does not require the Commission to establish avoided cost rates at levels high enough to attract financing; rather, the avoided cost rate must be equal to the avoided costs. However, the question of whether Duke's proposed two-year reset in avoided energy rates complies with PURPA is a question as to the form in which the rates are offered, not the appropriate level of the rate.

The Commission determines, for purposes of this case, that Duke's proposed two-year reset in the avoided energy rate component of the standard offer rate should not be adopted at this time. While some larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, the proposed two-year energy rate reset for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing more difficult than a longer term, fixed-rate PPA.

The Commission notes that in addition to providing the basis for electric power purchases from QFs by a utility, the Commission-determined avoided costs are utilized in, among other applications, the determination of the cost effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs, the determination of the incremental costs of compliance with REPS for cost recovery purposes; and in some ratemaking, such as determination of stand-by rates. In these contexts, it is appropriate for the rates to be reflective of the utilities' actual forecasted rates over a longer term, not based on a short-term forecast that is fixed for the duration of a longer term.

The Commission recognizes that the parties have raised the concept of linking the avoided energy rate fuel cost component to a published composite index or establishing a band or collar on the adjustment amount. The Commission determines that this concept deserves additional study in a future proceeding. This concept tends to provide additional certainty to QFs, while mitigating the risk of inaccurate avoided energy rates in the future. Thus, the Commission will allow the Utilities to propose this change in a future biennial avoided cost proceeding, provided that the proposal includes sufficient supporting information and otherwise demonstrates compliance with PURPA's requirements.

Based upon the foregoing and the entire record herein, the Commission finds that Duke's proposal to adjust avoided energy rates every two years should not be adopted in this case. Instead, the Commission finds Dominion's proposal to provide fixed ten-year energy prices as part of its standard offer rates is reasonable and consistent with PURPA's goals of encouraging QFs. Therefore, the Commission will require Duke to file

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revised avoided cost rate schedules, power purchase agreements, and terms and conditions, reflective of this conclusion, as part of the compliance filing required by this order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11 AND 12

The evidence supporting these findings of fact is found in the testimonies of Duke witness Snider, Dominion witness Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

As a method to mitigate longer-term commodity price forecast risk, Duke proposes to modify its Schedule PP 10-year avoided cost rate to include avoided energy rates that are reset every two years based on the avoided energy cost methodology and inputs approved in the Commission's biennial avoided cost proceedings. As reflected in the preceding section, the Commission concludes that it is inappropriate to approve this proposal in this proceeding. This leaves unresolved the question of what fuel forecast is appropriately included in the Utilities' calculation of avoided energy costs as an input to its 10-year, fixed avoided energy rate.

Duke witness Snider testified that, for purposes of calculating longer-term avoided energy rates, Duke relied upon 10 years of forward market natural gas pricing data followed by a transition to Duke's fundamental natural gas forecast of spot prices in year 11. He testified that this methodology is consistent with Duke's approach to forecasting future natural gas commodity prices in DEC and DEP's respective 2016 IRPs filed on September 1, 2016, in Docket No. E-100, Sub 147. Witness Snider responded to the testimony of Public Staff witness Hinton and NCSEA witness Johnson, who both recommended that the Commission require Duke to rely more heavily upon fundamental forecast data in setting DEC's and DEP's Schedule PP-H rates.[13] He first provided context for Duke's more recent reliance on natural gas forward market data, testifying that by 2014, changes in the United States natural gas markets and the rapid increase in natural gas production due to technology advancements had created longer range options for purchasing natural gas. At this time, Duke began requesting quotes for 10-year purchases of natural gas forwards from various brokerage firms based upon these longer range forward market options. Since the Sub 140 proceeding in 2014, Duke developed its 2015 IRP updates and 2016 biennial IRPs based upon 10 years of forward market price data transitioning to fundamental forecast-derived data in year 11.

[13] By necessity of Duke's proposal to reset avoided energy costs every two years, Duke did not propose a long term forecast input as a component of its other rate schedules. Therefore, in this section, reference is made the Schedule PP-H because that is the only rate schedule where Duke proposed a long-term fixed rate. For purposes of discussion, the Commission assumes that had Duke proposed a fixed rate under the other schedules, it would have included a similar input. Similarly, as the Commission has found a 10-year fixed rate to be an appropriate term for the standard offer contract, discussion of the proposed 15-year term under Schedule PP-H will, by necessity, serve for the purposes of discussion of this issue, but the conclusions reached in this section apply equally to Duke's other rate schedules.

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Witness Snider then testified regarding the historic 10-year levelized natural gas forecast assumptions from Duke IRPs and avoided cost proceedings dating back to 2012 to show that prices had dropped 40% since 2012, and to show how fundamental price forecasts were lagging the market prices in response to the recent structural changes in the natural gas market. He testified that fundamental forecasts take significant time to develop and are often only released by research firms once or twice per year; therefore, fundamental forecast data can be well over a year old by the time avoided cost rates go into effect. Witness Snider then emphasized the significant impact that relying on stale or lagging natural gas fundamental forecast data can have on forecasted avoided costs in this proceeding, pointing out that Duke's fundamental forecast natural gas price estimates are at least $1.00/MMBtu higher than the actual market prices starting in 2020. Witness Snider also testified that the Commission's mandate in Sub 140, requiring Duke to rely upon fundamental natural gas commodity price data after year five of the long-term avoided costs rates has been the main driver along with the continuing decline in natural gas commodity prices of the current disconnect between Duke's current actual marginal system operating costs and the significantly higher avoided energy rates approved in the Phase II Order proceeding that became effective in March 2016.

Witness Snider also responded to witnesses Hinton and Johnson's arguments regarding forward markets lacking liquidity 10 years into the future. He testified that market liquidity is demonstrated by Duke having recently completed a 10-year purchased forward gas contract, executed April 5, 2017, for 2,500 MMBtu/day of natural gas forwards through 2026. He testified to his experience that long-dated forward contracts are liquid and transactable and may be purchased over-the-counter directly with large financial institutions and other firms rather than traded on the NYMEX. Witness Snider also testified that this forward market transaction provides a tangible price point for the natural gas market over the equivalent period of the 10-year PP-H hydro rate, and that the 10-year levelized price of this purchased gas is approximately 6% lower than the forward market prices used in establishing Duke's November 2016 proposed avoided cost rate and approximately 20% lower than the 5-year market plus 5-year fundamental forecast blend of 10-year prices recommended by Public Staff witness Hinton.

Witness Snider also testified that he disagreed with witness Hinton's assertion that reliance upon fundamental forecast data is more appropriate than use of actual market prices. He testified that QF purchase power transactions similarly represent significant forward purchased power obligations on behalf of customers, totaling more than $3 billion dollars today. Duke may either purchase fuel or purchase power, or both, to satisfy future customer energy needs, and PURPA requires customers to be held indifferent between the two. Witness Snider testified that use of fundamental price forecasts, rather than a transactable gas price, leads to avoided energy rates that are inconsistent with this indifference standard that is a bedrock principle of PURPA. Witness Snider also testified that, consistent with the Commission's prior direction in the Sub 140 Phase II Order, Duke's fuel forecasting methodology of using 10 years of forward market data with a blending to fundamentals starting in year 11 is the same methodology used in both the 2015 IRP and 2016 IRP filings for DEC and DEP. Third, witness Snider also testified that witness Hinton's recommendation to rely upon fundamental forecast data was in conflict

with witness Hinton's own alternative recommendation to consider offering QFs avoided energy rates based on a composite commodity price index. He testified that the gas commodity price index is a market-based price, and a QF's ability to enter into a hedging transaction to fix their future revenues under this structure could only occur at the prevailing forward market price for natural gas and not at fundamental forecast-derived price levels that are different from the market price. Witness Snider testified that by offering QFs a transactable forward price above the prevailing natural gas market, the implicit result of witness Hinton's position would be to subsidize QFs while transferring significant price risk to North Carolina consumers.

Witness Snider also addressed witness Hinton's assertion that Duke and Dominion's fundamental forecasts were more comparable than Duke's reliance on 10 years of market prices. Witness Snider testified that at any point in time only a single forward market exists for natural gas, while a wide range of fundamental price forecasts are available, as shown by the deviation between Duke's and Dominion's fundamental forecasts. During the hearing, witness Snider testified to the difference between a transactable market-based forward price versus a longer-term spot forecast of commodity price beyond the liquid market. He testified that accuracy and appropriateness were key considerations that support relying upon forward market price data in a transactable market versus fundamental forecast spot pricing. With regard to accuracy, witness Snider emphasized that only a single transactable market price exists while multiple spot forecast prices may exist based upon differing fundamental forecasts. Further, reliance on lagging or "stale" fundamental forecast pricing has proven to be inaccurate over the past few years and has led to a systematic overpayment to QFs. He testified that Duke had also addressed liquidity concerns with Duke's use of long-term forward commodity price quotes, as raised in Sub 140, by actually transacting in the forward market to accurately show the actual 10-year forward market price of natural gas. With regard to appropriateness, witness Snider testified that fundamental forecasts are intended to act as a guide to future spot prices beyond the liquid transactable curve, but are never intended to be used as a transactable price in the presence of a transactable market. He also testified how relying on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage of the market prices and result in QF generators flocking to a region to take advantage.

Witness Snider also testified that contracting for QF power is also a forward market transaction committing the utility to purchase from a QF at a fixed price years into the future, and that the utility can either buy the power or buy the commodity and should be indifferent between the two. DEP's recent natural gas forward transaction procured equivalent gas to approximately 50 MW of solar QF generation at a six percent lower levelized price than the forward market commodity price used in Duke's rates filed in November. Witness Snider also identified that PURPA allows the QF the option to select pricing at the time energy is delivered if the QF believes the future spot price will be higher than the transactable forward market.

During examination by Public Staff, witness Snider agreed that NYMEX and the Intercontinental Exchange are exchange markets where shorter term natural gas futures

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are traded. However, he testified that the commodity market has evolved where long-dated future natural gas trading is occurring through bilateral transactions with numerous financial institutions, and Duke's experience is that a very liquid, long-dated market exists where quotes and transactions with multiple counter-parties can occur at a market price 10 years into the future. Witness Snider testified that Duke's continued and consistent reliance on 10 years of forward market data in their last four regulatory filings, including IRP and biennial avoided cost filings, as well as the April 5, 2017 10-year forward market transaction has demonstrably demonstrated a liquid and transactable market.

Dominion witness Petrie described the methodology used to calculate avoided energy cost rates under its proposed Schedule 19-FP and Schedule 19-LMP. Witness Petrie testified that the avoided energy cost rates proposed in this case for its Schedule 19-FP were calculated using the peaker method, and that, as in previous proceedings and discussed above, energy rates under Schedule 19-LMP are based on the hourly PJM DOM Zone Day-Ahead LMP expressed in dollars per MWh. He described the peaker method as it applies to energy as determining avoided energy costs based on the forecasted marginal energy costs of the system in each hour. Witness Petrie testified that Dominion uses the PROMOD production cost model to derive avoided energy cost rates for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in Dominion's North Carolina service area where QFs are located, plus a fuel hedging benefit. He stated that Dominion uses the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP.

Witness Petrie also testified that, consistent with Commission directives issued in the 2014 biennial proceeding, as well as with the price forecasting methodology contained in its 2016 and prior IRPs, for purposes of determining avoided energy costs in this proceeding Dominion maintained its approach of using estimated forward market prices for fuel, PJM power, and emission allowance for the first 18 months of the forecast period, a blend of forward market prices and ICF commodity price forecast as of early October 2016 for the next 18 months, and exclusively ICF commodity price forecast for the remainder of the term (starting in October 2019). He stated that this approach is consistent with the directive of the Commission's Phase 2 Order issued in the 2014 biennial proceeding that the Utilities calculate avoided energy rates using commodity forecasts constructed in a manner consistent with their IRPs. He clarified that the order did not require that the same price forecast itself must be used.

Witness Petrie testified that in determining the rates it is proposing in this case, Dominion used the same Black-Scholes Model option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 biennial proceeding. He also noted that, while Dominion believes there are likely costs associated with integration of distributed solar generation, it did not include solar integration costs in its production cost modeling. Witness Petrie noted the Public Staff's support for Dominion's fuel price forecasting approach, and disagreed with witness Johnson's suggestion that Dominion should use either the 2017 Energy Information Administration (EIA) forecast or

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the fundamental commodities forecast used to prepare its 2016 IRP for purposes of this case. He testified that, because the commodity prices for the 2016 IRP were developed by ICF in December 2015, Dominion used updated, October 2016 data for fuel and power prices in preparing its initial filing. He noted that, as standard offer prices are updated only every two years, QFs that establish an LEO late in the biennial period receive avoided cost rates that can be several years old by the time they commence operations, and that witness Johnson's proposal that Dominion base its avoided energy rates on forecasts that are an additional year older should, therefore, be rejected because it would exacerbate this disparity between contracted rates and actual avoided costs. Witness Petrie advised that using the 2017 EIA forecast for this purpose would also be inappropriate, as it would directly contradict the Commission's directives in the 2014 biennial proceeding and Dominion's use of ICF-developed prices for its IRP and avoided cost purposes in compliance with those directives.

Witness Petrie also testified that witness Johnson's long-term natural gas price trend line does not reflect current natural gas market fundamentals, and that it appears to discount the fact that technology improvements continue to create production benefits resulting in reduced long-term natural gas prices. He testified that witness Johnson's gas price data lends too much weight to the years 1990-2008 when natural gas prices were rising and not enough weight to the downward trend in prices from 2009-2016.

In response to witness Vitolo, witness Petrie testified that no generator is available 100% of the time, regardless of whether the unit is utility-owned and regardless of the type of energy source. He testified further that Dominion's assumption of 85% availability in calculating standard offer avoided energy rates reflects the availability of a baseload unit, and that this approach is consistent with the theory behind the peaker method as it pertains to the calculation of avoided system energy costs from a typical QF. He cited the Commission's statement in the 2004 avoided cost proceeding that the peaker method theory is that, if the utility's generating system is operating at equilibrium (that is, at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost, and that it will also equal the cost of a baseload plant. He noted that this modeling approach has been used by Dominion and accepted by the Commission for many years, including in the previous biennial proceeding.

Witness Petrie also disagreed with witness Vitolo's apparent concern that Dominion may be under estimating the energy rates due to a mismatch between the PROMOD modelling and the energy rate calculation. Witness Petrie clarified that Dominion correctly divided the total dollar savings produced by the model by 744,600 MWh, consistent with the 85% availability, and that the system cost savings in the numerator was, therefore, consistent with the QF energy production in the denominator.

On cross examination by SACE, witness Petrie agreed that in using the PROMOD model to calculate avoided energy costs, Dominion modeled the "with QF" scenario using a 100-MW generator with zero production costs, and ran this scenario assuming some outages. He testified that when the 100-MW block of energy is added, the model shows

how much the production cost declines by adding that block. He testified the block has 85% availability and that the 15% unavailability is spread evenly throughout all hours of the year, including on- and off-peak hours. He also confirmed his response to a discovery request that reiterated this explanation.

Public Staff witness Hinton testified that he reviewed the coal and natural gas price forecasts used by the utilities and found most of the inputs to be reasonable, except for Duke's use of ten-year forward prices to develop its price forecast for natural gas. Witness Hinton testified that these concerns were similar to those expressed by the Public Staff in the 2014 proceeding and in the 2016 IRP regarding DEC's and DEP's over-reliance on long-term forward prices for their fuel forecasts. Witness Hinton testified that in their 2014 IRPs, DEC and DEP incorporated five years or less of forward price data before transitioning their fuel forecast to a long-term fundamental natural gas price forecast. In their 2015 IRP updates, however, they made changes to this approach by extending the period on which they relied on forward price data to ten years. Witness Hinton testified that the Public Staff and other parties advocated in the 2014 Proceeding that DEC and DEP return to their previous use of forward prices for no more than five years of the forecast before transitioning to a fundamental forecast developed by energy economists and gas analysts who estimate the future demand and supply of natural gas. Witness Hinton illustrated the difference between DEC's and DEP's previous use of five years of forward prices by graphically contrasting DEC's natural gas price forecasts incorporated in the 2012 and 2014 IRPs with DEC's gas price forecast using ten years of forward prices that were initially proposed but ultimately rejected by the Commission. In addition, witness Hinton indicated that comparing Dominion's forecast from 2017 to 2031 with that of DEC and DEP, as well as noting the similarity in their predicted fuel prices in 2031, illustrates the impacts that result from the use of forward prices over the planning period.

Witness Hinton further testified that in its Phase II Order, the Commission ordered DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts constructed in a consistent manner with those utilized in their 2014 IRPs. Further, the Commission found that to the extent the utilities wished to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, that those changes should first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations. Witness Hinton stated, however, that DEC and DEP's proposed avoided cost rates in this proceeding again used ten years of forward prices and then shift to their traditional fundamental forecast for years 11 through 15.

Witness Hinton testified that the Public Staff supports the use of forward prices as a component in the development of a long-term price forecast. He asserted that the use for up to five years is reasonable and appropriate because the market for these contracts is relatively liquid. With regard to ten-year futures, however, witness Hinton indicated that the market is relatively illiquid, meaning the number of natural gas price investors willing to make buy and sell decisions on future prices beyond five years out in the future is much smaller and less transparent. Witness Hinton further testified that fundamental price forecasts and forward price-based forecasts are different and have different applications.

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In addition, he testified that traders in futures are more likely to respond to temporary conditions, as compared to fundamental price forecasts that are based on future demand and supply conditions, providing a more measured response to expected changes in the natural gas market.

Witness Hinton testified that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations as was used in their 2014 IRPs, or the same methodology approved by the Commission in the 2014 proceeding. He noted that in the Order on Inputs, the Commission emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. In Phase Two, the Public Staff recommended the use of up to five years of forward prices in combination with a long-term price forecast, and the Commission ordered DEC and DEP to incorporate the natural gas price forecasts that are constructed in a consistent manner with the forecasts utilized in their 2014 IRPs. The Public Staff restated its view that an overreliance on forward price data can call into question the reasonableness of the long-term forecasts.

Witness Hinton testified that he found Dominion's reliance on forecasts from ICF International, Inc. (ICF), the same source utilized for its 2016 IRP, along with Dominion's use of three-year forward prices before transitioning to a fundamental price forecast, to be reasonable. He disagreed, however, with Duke's use of ten-year forward prices, and instead, recommended that the Commission direct DEC and DEP to recalculate their avoided energy rates using no more than five years of forward natural gas prices before transitioning to their long-term fundamental price forecast. He stated that this approach would be consistent with the Commission's directive in the 2014 proceeding that DEC and DEP utilize natural gas price forecasts that are constructed in the same manner as the forecasts utilized in their 2014 IRPs, and is also consistent with the Public Staff's comments in the 2016 IRP proceeding.

NCSEA argues that Duke's overreliance on forward market data is not reasonable. In addition, NCSEA argues that Dominion used unreasonably low fuel prices in constructing its fuel forecast for this proceeding, as compared to the fuel prices used in its 2016 IRP forecast. In support of its position, NCSEA witness Johnson testified that Duke goes to considerable effort and expense to develop its own, comprehensive, fundamental forecast of the entire US energy sector, which it updates periodically for use by both the parent and its subsidiaries. This proprietary forecast reflects Duke's view of the long-term outlook for the energy sector, which it uses to make long-term investment decisions by all of its electric utilities. Witness Johnson testified that forward market data is useful for short term forecasts, because it can easily and frequently be updated, as commodities traders respond to changes in the weather and minute-by-minute and day-to-day changes in supply and demand conditions in the commodities markets. In essence, he argues, forward market data is particularly useful for dealing with, and hedging against, fluctuations in commodity prices over the near-term future, but, it is not as useful, nor as appropriate, to use it for long-term planning purposes. Witness Johnson

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further testified that fundamental forecasts, as well as the forecast Dominion used in its 2016 IRP, seem reasonable, and both are reasonably consistent with the most recent long term fundamental forecast of natural gas prices that was published in March 2017 by EIA. Witness Johnson testified that it would be reasonable for the Commission to rely on the 2017 EIA forecast—a publicly available fundamental forecast—as a benchmark for judging the reasonableness of the fuel forecasts that DEC, DEP and Dominion use to calculate avoided energy costs. Additionally, Johnson testified that it would be reasonable for the Commission to require Dominion to use either the 2017 EIA forecast or the fundamental forecast it used in preparing its 2016 IRP. Witness Johnson also recommended that the Commission again reject the use of forward market data for anything more than the near-term future and direct DEC and DEP to reconstruct their fuel forecasts using a blend of forward market data and fundamentals data.

Discussion and Conclusions

The issue of establishing a long-term avoided energy rate poses difficulties because it of necessity relies upon projections of natural gas prices anticipated to occur for as far as 10 years into the future. As past experience has shown, predictions of future energy prices seldom accurately coincide with what those prices turn out to be. The primary dispute among the parties involves the method of projecting natural gas prices beyond the first five years of the relevant planning period. Duke and the Public Staff agree that it is appropriate to rely upon forward market gas pricing data for the first five year projections. Duke's witnesses' testimony supports reliance on such forward market price data for the years six forward also because, in Duke's experience and observation, the market is sufficiently fluid and robust to provide the most reliable predictions. The Public Staff, on the other hand, supports continued reliance on fundamental forecasts, arguing that after year five the current market is not so robust as to supplant the predictions of market analysts.

The Commission finds merit in some of the arguments each party raises but determines for purposes of this case not to agree completely with any but, in the Commission's expert judgment, to adopt a method relying on market data for eight years and fundamental forecasts thereafter.

The Commission agrees with Duke that lagging fundamental forecast pricing has proven to be inaccurate over the past few years and has led to overpayment to QFs. The Commission is concerned that undue reliance on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage. Based on structural changes in the natural gas market, the Commission is also concerned that fundamental forecasts take significant time to develop and are only released by research firms once or twice per year.

On the other hand, the Commission shares the concerns expressed by the Public Staff that 10-year futures are less liquid based on existing transactions in the market so as to authorize exclusive reliance on them as advocated by Duke. While the parties differ on their assessment of the liquidity of the market with respect to 10-year futures, the Commission is satisfied that at the present time the number of such transactions is sufficiently fewer to prevent the Commission from relying completely on this method for

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establishing energy prices in this case at this time and will continue to monitor the liquidity in the market in future avoided cost proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Holeman, Public Staff witness Metz, and NCSEA witness Johnson.

Summary of the Testimony

Duke witnesses Bowman and Holeman testified in support of Duke's proposal to amend the standard offer terms and conditions applicable to purchases of electricity from QF generators under Schedule PP and Schedule PP-H in order to more clearly define the circumstances that constitute an "emergency condition" during which DEC and DEP may curtail energy injections from QFs into the utility's electric system. Duke asserts that under FERC's regulations, absent contractual agreement otherwise, a QF selling power pursuant to a long-term contract may be curtailed and purchases discontinued only during "system emergency" conditions. Duke's proposed amended terms and conditions would expressly include any circumstance that requires imminent action by Duke to comply with North American Electric Reliability Corporation (NERC)/SERC Reliability Corporation (SERC) regulations or standards as an emergency condition.

Duke Witness Holeman testified at length regarding DEC's and DEP's independent BA responsibilities to manage system operations and maintain compliance with mandatory NERC/SERC reliability regulations within their separate BAAs. Witness Holeman recounted the history of NERC's current regime of over 100 mandatory and enforceable reliability standards, which evolved out of EPAct's response to the catastrophic 2003 northeast blackout. Witness Holeman testified that he is directly responsible for ensuring Duke's ongoing compliance with the NERC reliability standards.

Specific to DEP's growing experience managing the increasing levels of unscheduled or uncontrolled and non-dispatchable solar QF energy being injected into the BA, witness Holeman testified how DEP and DEC will be increasingly challenged to maintain compliance with the mandatory NERC BAL-001, BAL-002, and BAL-003 reliability standards. He testified that the "BAL" 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. Witness Holeman further testified that the BAL-001-2 standard was updated effective July 1, 2016, and now requires BAs to provide reserves for restoring resource-to-demand balance within 15 minutes following a sudden loss of a designated load following generating unit or disturbance event on the BA. In addition, he testified that a BA's failure to comply with the BAL reliability standards could result in system emergencies and reliability failures

such as unscheduled power flows, unnecessary and automatic firm load shedding, or in a worst-case scenario, cascading outages across the interconnection.

Witness Holeman also testified that DEP's system operators currently have no dispatch control and no day-ahead planning control over the variable energy injections into the BA from solar QF generators. He further testified that by 2018, the DEP system is projected to have 2,200 MW of solar generation injecting unscheduled and unconstrained energy into the BA, and DEP system operators will increasingly be required to manage reliability in a reactive operational mode, with very limited forecast situational awareness of these variable and intermittent solar energy injections into the BA. Witness Holeman presented examples of how the growing levels of unscheduled solar QF energy being injected into the DEP BA is requiring system operators to manage both operationally excess and deficit in energy situations to maintain proper frequency in order to avoid potential BAL Standard violations. He testified that if the BA experiences too much unscheduled solar QF energy relative to real time load, the system operator must ramp down load following generating resources to the LROL of its Security Constrained Unit Commitment, which, if exceeded, can then require DEP to mitigate operationally excess energy in order to maintain proper frequency. He further testified that growing solar QF energy injections can also increase the risk of a deficit in energy relative to real-time demand in the BA, causing frequency to drop below the scheduled frequency. He also testified that, for example, if a change in weather or other event suddenly caused large volumes of solar QF energy to drop off the system, or in the late afternoon period as the solar energy drops off, and DEP was unable to ramp up its load-following generating resources fast enough, or if DEP were to lose a sizable network generating resource, then there would be a deficit of energy on the DEP system. Under these conditions, witness Holeman testified, DEP's system would be operating with compromised reliability and be at risk of violating the BAL-001 standard if the BA operated in these conditions for greater than 30 minutes. Witness Holeman further testified that these excess and deficit energy reliability impairments are directly correlated with significant amounts of unscheduled solar generation being injected into the BA, without the BA operator having operational control over the facilities. He argued that the ability to curtail solar QFs, as provided in Duke's proposed amended terms and conditions, will provide some measure of improved operational control during a potentially imminent system emergency situation.

Witness Holeman also responded to testimony of other witnesses by further testifying about the impacts to system reliability and risks of non-compliance with NERC's reliability standards, including the more rigorous operating contingency requirements to be imposed on BAs in the upcoming BAL-002 standard, effective January 1, 2018. Witness Holeman also highlighted the very steep up- and down-ramping requirements that DEP's load following generating units will face as 2,200 MW of solar QF penetrations come online in 2018, as well as the high likelihood of operational curtailments of QFs that will be required in real time to ensure compliance with NERC's reliability standards and to avoid risks to reliable electric service, as additional QFs continue to come online. Witness Holeman also testified the risks and limits of the hourly, as-available non-firm, curtailable transmission paths underlying the Joint Dispatch Agreement between DEC

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and DEP, which he emphasized is not a tool for DEP and DEP system operators to use to manage balancing, regulating, or operating reserve requirements. Witness Holeman addressed NCSEA witness Johnson's testimony that it was feasible for the DEP BA to rely on the DEC BA's pumped storage assets to manage DEP's system reliability long-term operational commitments and NERC reliability obligations, stating that it is not a long-term sustainable solution as DEC and DEP are independent BAs with separate obligations to comply with NERC's reliability standards. Witness Holeman also testified that DEC and DEP are currently in the process of developing an operating procedure document for the management of system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis, and committed to share the document with the Public Staff as soon as it is completed and to file such procedures with the Commission after discussions with the Public Staff.

In concluding his testimony, witness Holeman testified to his 31 years of experience as a system operator and emphasized the significant challenge facing DEP and DEC system operators in the planning horizon under the current operational tool set to ensure system reliability and security as the 2,200 MW of QF solar projected to be online in early 2018 will be the largest aggregate generating resource in the Carolinas. Witness Holeman also highlighted the need for fair, non-discriminatory operating procedures that will provide DEP more centralized operational control to better manage the intermittency and uncertainty increasingly caused by the growing levels of utility scale solar.

Witness Bowman also addressed witness Johnson's recommendation that the Commission mandate DEC and DEP to enter into take or pay arrangements with QFs that result in customers paying for QF solar power that is simply "discarded" or not used to meet system load. She testified that witness Johnson provides no evidence that any other public service commission has ever approved a take or pay contract in its implementation of PURPA, and that mandating such a proposal in North Carolina based upon current economic and regulatory circumstances would be completely unjust and unreasonable. Witness Bowman also cited Order No. 69, arguing that nothing in PURPA requires customers to pay QFs for unused or unneeded energy or capacity.

Public Staff witness Metz testified that he agreed with witness Holeman that must-take energy from PURPA QFs is causing potential concerns within the DEP BA. He also agreed with witness Holeman that the utilities' limited ability to control PURPA QF solar generation creates challenges for BAs trying to match generation with load while staying within the limits required by NERC. Witness Metz stated that DEC and DEP already have language in their negotiated contracts that allows for a limited amount of curtailment each year through the use of a "Dispatch Down" instruction, but curtailment due to system emergencies does not count toward the limit. According to witness Metz, the Public Staff believes that the Federal Code already allows the utilities to curtail QFs when faced with an imminent violation of a NERC BAL Standard because an imminent violation of a NERC BAL Standard constitutes a system emergency as defined by 18 C.F.R. 292.101(b)(4). Witness Metz further testified that the Public Staff is in

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discussions with Duke about filing its processes and procedures for curtailing QFs in a non-discriminatory fashion.

NCSEA witness Johnson testified that the issues described by witness Holeman were legitimate, but viewed them as "growing pains." He testified that he was troubled by Duke's solution of "declaring a system emergency when solar energy is displacing some of Duke's less flexible generating resources." Witness Johnson testified that the proposal forces the QFs to shoulder too much risk because there is no limitation on how often an emergency can be declared or how much revenue a QF will lose. Witness Johnson stated that two other options to help with the excess energy problem are for Duke to modify how it utilizes its pumped storage generation and to negotiate "Take or Pay" contracts with some of the solar QFs.

Discussion and Conclusions

A "system emergency" is "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. 292.101(b)(4). During any system emergency, a utility may discontinue purchases from a qualifying facility if such purchases would contribute to such emergency. 18 C.F.R. 292.307(b)(1). The disputed issue here is whether an imminent violation of NERC standards is within the definition of system emergency, and whether it is appropriate to allow a utility to discontinue purchases or curtail output from a QF during a system emergency. If the Commission concludes that it is, Duke argues that it would be appropriate to amend the terms and conditions included in its standard offer contract documents.

The Commission finds persuasive witness Holeman's testimony regarding the new and unique technical and operational circumstances facing utilities. As he testified, this task has grown more complicated because of the presence of solar-powered QFs interconnected to the Duke electric systems, and particularly DEP's system in eastern North Carolina. In addition, he testified Duke's responsibilities as BAAs to comply with increasingly complicated and rigorous reliability standards issued by NERC and SERC. His testimony is largely consistent with, and supported by, the testimony of Public Staff witness Metz.

The Commission rejects witness Johnson's argument that the operational challenges facing the Utilities in managing their electric systems are mere growing pains. For reasons discussed below, the Commission also rejects his proposal to require use of the DEC's pumped storage generation to mitigate operational challenges experienced in the DEP East BA, and the notion of including a take-or-pay provision in the standard contract offer. The Commission agrees with witness Bowman that a take-or-pay provision would introduce uncertainty about compliance with the limits of PURPA's requirements, expressed in Order No. 69, that utilities are not required to pay for energy and capacity in excess of their system needs. See Order No. 69, at 12,219. While the Commission recognizes that allowing curtailment or discontinuance of QFs purchases shifts some risk to QFs, the compliance filing required by this order and the availability of arbitration before

the Commission serve as a sufficient protection against this risk. Moreover, the Commission expects the Utilities to observe the standards of good faith in all their dealings with QFs, including the exercise of curtailment or discontinuance of QF purchases.

As witnesses Bowman and Holeman testified, DEP and DEC continue to operate as separate BAAs and utilities, and each is responsible for its own independent resource planning and operations, as directed under the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, issued on June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986.[14] As witnesses Holeman and Metz testified, the JDA is an opportunistic, economic, incremental-cost energy transfer tool, which relies on hour-by-hour, as-available, non-firm, curtailable transmission and does not reduce availability of firm transmission for long-term wholesale transactions of other network transmission customers. They further testified that relying on the JDA to manage operationally excess energy poses significant system operational risks of transmission curtailment and that the JDA was not designed as a long-term solution to manage operationally excess energy supplied by solar-powered QFs. The Commission is not inclined to compound the complexities of operating the electric system by requiring use of the JDA in this manner. Therefore, the Commission agrees with the Duke and Public Staff witnesses on this issue, and finds that it is inappropriate to approve witness Johnson's proposal.

Based on the foregoing and the entire record herein, the Commission determines that system emergency includes a condition where the Utilities' system operators are operating their load-following generating fleets at LROL and are confronted with circumstances that require immediate action to comply with mandatory NERC/SERC reliability standards, including, but not limited to, the BAL standards. Thus, the Commission concludes that an imminent violation of NERC/SERC standards is a system emergency. The Commission is persuaded that the NERC/SERC reliability standards were established to avoid conditions on a utility's system which are likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property, and that the number and volume of solar-powered QFs on Duke's electric systems makes these conditions more likely to occur with more frequency. Thus, the Commission further determines that in a system emergency, it is appropriate to allow the

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[14] See, e.g., DEC/DEP Regulatory Condition No. 4.1, which provides that "DEC and DEP acknowledge that the Commission's approval of the merger and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA never being interpreted as providing for:

(a) A single integrated electric system
(b) A single BAA, control area, or transmission system
(c) Joint planning or joint development of generation or transmission
(d) DEC or DEP to construct generation or transmission facilities for the benefit of the other
(e) The transfer of any rights to generation or transmission facilities from DEC to DEP to the other, or
(f) Any equalization of DEC's and DEP' production costs or rates."

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Utilities to curtail QF generated power or, in extreme conditions, to discontinue purchases from QFs, if the purchase of that power would contribute to the emergency condition.[15] The Public Staff argues that there is no need to amend the standard offer contract terms and conditions because the Utilities curtailment authority is based in FERC's regulations, but the Commission cannot identify any evidence that allowing the amendment to the terms and conditions will cause any discriminatory harm to QFs. Therefore, the Commission concludes that Duke's proposed amendment to the terms and conditions should be approved.

Duke and the Public Staff's witnesses also testified that the development of operating procedures to manage system emergency curtailments of QFs and other non-QF generators on a similarly situated, non-discriminatory basis is underway. Duke committed to share this document with the Public Staff and file it with the Commission. The Commission determines that establishing non-discriminatory and transparent system emergency curtailment operating procedures is appropriate and justified by the requirements of PURPA. The Commission further determines that it is appropriate to require Duke to file its planned system emergency curtailment operating procedures as part of the compliance filings required by this order. In addition, the Commission determines that it is appropriate, as proposed by the Public Staff, to require the Utilities to file quarterly reports with the Commission documenting each instance where a utility is faced with, or declares an imminent violation of a NERC Standard or any other type of system emergency, that causes or potentially causes the utility to curtail QFs. These reports shall include the following information: (1) whether the utility curtailed any QF(s); (2) the procedures leading up to the decision to curtail the QF(s); (3) how the utility determined which QF(s) to curtail; (4) the duration of the curtailment; (5) the duration of the system emergency; and (6) any other documentation required to be sent to any other state or federal agencies due to occurrence of a system emergency.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 16

The evidence supporting these findings of fact is found in the testimony of Dominion witnesses Gaskill and Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

Dominion witnesses Gaskill and Petrie testified in support of Dominion's proposal to adjust its avoided energy rates to reflect the locational energy value its North Carolina service area as opposed to the entire DOM Zone. Dominion witness Petrie testified that, as in past avoided cost proceedings, energy prices under Dominion's proposed Schedule

[15] While this finding is specific to the standard offer terms and conditions, the Commission also determines that Duke's inclusion of dispatch down and similar contractual provisions in the non-standard offer PPAs with larger QFs is consistent with this determination. The Commission encourages the Utilities to continue to evaluate requiring enhanced contractual rights that will more effectively provide utility system operators scheduling and operational control rights over deliveries of energy by QFs to assure continued reliable electric service in North Carolina. This evaluation and the exercise of these rights in the negotiated contract setting should be consistent with the Commission's findings and conclusions in this order.

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19-LMP are based on the hourly PJM Interconnection, L.L.C. (PJM) Dominion Zone (DOM Zone) Day Ahead Locational Marginal Price (LMP) expressed as $/MWh. Witnesses Gaskill and Petrie testified that LMPs reflect the value of energy at specific locations, or nodes, on the grid. As a result, areas that need additional generation to meet load will realize higher LMPs, which provide incentive for generation to locate in that place, while conversely, areas where generation is not valuable due to lack of congestion or losses will realize lower LMPs. Further, witness Petrie testified that the average of the Day Ahead LMP values in the billing month, divided by 10 to derive a cents per kWh price, is applied to the QF's total net generation during the billing month. Witness Petrie further testified that the LMPs in North Carolina were over 4% lower than those for the DOM Zone, and were likely to be even lower as compared to the DOM Zone in the future due to the future solar development in its North Carolina service territory.

Witness Petrie testified that power price inputs to and outputs from the PROMOD model Dominion Energy North Carolina uses to calculate avoided energy costs are expressed at the DOM Zone level, not at the nodal (local) level. He noted that the DOM Zone is an aggregate pricing point in the PJM energy market, and represents the average of LMPs of all nodes within the DOM Zone. Witness Petrie offered data, calculated using the average day-ahead LMPs at six North Carolina nodes selected due to their geographic diversity and proximity to QF development, showing that on-peak energy prices for Option B were 4.4% lower in Dominion Energy North Carolina's North Carolina service area than in the DOM Zone during the 2014-2016 time period, and 4.8% lower during off-peak periods. Energy prices for Option A were 4.7% lower during both on- and off-peak periods during this time. He testified that this LMP disparity is typical for grid locations with an oversupply of generation relative to customer demand. He stated that, all things being equal, Dominion's North Carolina LMPs are likely to be even lower in the future as additional distributed solar comes onto its system, leading to additional losses and congestion issues.

Witness Petrie testified that to account for this difference, Dominion adjusted the PROMOD model results to reflect the locational value of energy for QF deliveries in the North Carolina service area to ensure that the avoided energy rates Dominion and its customers pay are as accurate as possible. The adjustment reduced Option B on-peak rates by 4.4% and off-peak rates by 4.8%, and reduced Option A on- and off-peak rates by 4.7%, consistent with the historical data.

Witness Gaskill testified that, while Dominion's fuel rates are based on the total system cost of energy, its system cost of energy is fundamentally derived from the LMPs where the load and generation are located. He further testified that Dominion's total system energy cost is equal to the net of (1) the cost to supply load, and (2) generation energy revenues and costs. He demonstrated through several examples that, if additional generation is added (or load is reduced) in a location with low LMPs, it has less effect on lowering net system costs than generation that is added to a location with high LMPs. He testified that the avoided cost of added generation or load reduction is equal to the LMP at the bus where the generation or load reduction occurs.

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Witness Gaskill also testified that lower LMPs indicate that additional generation in this area is less valuable than generation in other areas of the DOM Zone, and that the discounted value of generation in this area must therefore be incorporated into the forecasted avoided energy price, because that is the actual value PJM gives to this generation. He stated that Dominion Energy North Carolina's proposal to adjust avoided energy rates to reflect the locational energy value of its North Carolina service area would result in rates that better reflect its actual avoided cost for QFs in this area. He testified that, if Dominion Energy North Carolina does not make this adjustment, customers will pay rates that exceed the marginal energy costs that QFs in its North Carolina service area actually avoid. Finally, witness Gaskill testified that Dominion's proposed LMP adjustment is consistent with the peaker method, because the underlying theory behind the peaker method is that the long-run avoided energy cost is equal to the marginal costs of the utility's system in each hour and, as shown by his example, the LMP where the generation is located directly translates into the marginal cost avoided for the utility system.

No party contested Dominion's proposal to continue to offer Schedule 19-LMP as an alternative to Schedule 19-FP or raised any issue with the proposed Schedule 19-LMP.

Public Staff witness Hinton stated that this proposal was reasonable based on Dominion's showing that the LMPs in North Carolina had consistently been lower than those in the DOM Zone.

NCSEA argues that, conceptually, using LMP data to help refine rates is reasonable, as LMPs may be relevant to the problem of how best to encourage QF power to be generated where it is most valuable. NCSEA witness Johnson indicated that he did not oppose the proposal on a conceptual level as it sent appropriate price signals. However, he argued that there were a number of issues that should be investigated before adoption by the Commission, including the amount of and the reasons for the difference between the LMPs. Further, he testified that additional granularity and further refinement to Dominion's approach may be warranted before the Commission authorizes Dominion to implement this proposal, in the interest of transparency and ensuring that the method for accounting for locational value results in encouraging QFs to locate where the QF can provide value to the utility and its ratepayers. Witness Johnson further testifies that, with additional study and data analysis, detailed location-specific information could be developed that considers: 1) proximity to load centers and other factors which influence line losses; 2) opportunities to reduce congestion on distribution lines, substations, and transmission lines which could postpone or avoid upgrades to these facilities within the relevant planning horizon; and 3) opportunities to improve local reliability.

Dominion witness Gaskill testified in response to witness Johnson that Dominion had already provided in testimony and discovery information that should address most of the concerns raised by Dr. Johnson. Witness Gaskill noted that Dominion would also be

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able to develop more granular prices for negotiated contract avoided energy rates based on the specific location of the QF.

Discussion and Conclusions

The Commission finds persuasive the testimony of Dominion witnesses Petrie and Gaskill that LMPs reflect the underlying supply and demand, and associated local congestion and marginal losses, across the electric system. The Commission agrees that as supply increases, LMPs decrease, and as demand increases, LMPs increase; and thus, the avoided cost of added generation or load reduction is equal to the LMP at the location where the generation or load reduction occurs. The Commission is also persuaded by witness Gaskill's testimony that the utility's marginal system cost of energy, which is the measure of avoided energy cost under the peaker method, is fundamentally derived from the LMPs associated with the location of load and generation. The Commission recognizes, as testified to by witnesses Petrie and Gaskill, that as more generation is added to Dominion's North Carolina service area, a location that is saturated with narrowly concentrated distributed generation, the congestion and marginal losses costs increase, reflecting the re-dispatch cost to enable this generation to "flow" to locations where it is needed to serve load. This result is demonstrated by witness Gaskill's rebuttal exhibit, which shows on-peak congestion between Dominion's North Carolina nodes and the DOM Zone during 2016 of $1.84/MWh, which he estimates would result in $2 million annually in congestion costs for North Carolina QFs under contract. Such significant added cost supports using the LMPs associated with the locations where QFs are generating to correctly calculate avoided cost rates. In addition, the Commission is persuaded by Dominion's testimony that as more generation is added to this area relative to load, the disparity between North Carolina LMPs and DOM Zone LMP is likely to increase.

Dominion's proposed use of North Carolina LMPs is supported by Public Staff witness Hinton's testimony citing data showing that the LMPs for North Carolina nodes have been consistently lower than the DOM Zone average LMPs. Further, NCSEA witness Johnson agreed with the principle of reflecting local LMPs in avoided cost pricing. The Commission determines that witness Gaskill sufficiently addressed witness Johnson's proposed questions for the purposes of this proceeding. However, the Commission determines it is appropriate to monitor the impact of this adjustment and to require Dominion to address this issue in the next biennial avoided cost proceeding. Finally, the Commission determines that witness Johnson's recommendation to use LMP data to refine the QF rates is helpful, and agrees that additional granularity and further refinement of this approach is appropriate. Therefore, the Commission will direct Dominion to address the questions raised by witness Johnson in its initial filings in the next biennial avoided cost proceeding. The Commission does not agree with witness Johnson that these questions should be answered before approving Dominion's proposed change.

Based upon the foregoing and the entire record herein, the Commission determines that Dominion's proposal to adjust its avoided energy cost rates to account

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for the lower locational value of generation in its North Carolina service area, as compared to DOM Zone LMPs overall, is appropriate. The Commission concludes that Dominion's proposed adjustment will allow those rates to better reflect its actual avoided system energy cost, as required by PURPA and FERC's implementing regulations. Therefore, Dominion's proposed LMP adjustment to avoided energy cost rates should be approved.

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

The evidence supporting these findings of fact is found in the testimonies of Dominion Energy witnesses Gaskill, Public Staff witnesses Metz and Hinton, NCSEA witness Johnson, and SACE witness Vitolo.

Summary of the Testimony

Dominion witness Gaskill testified in support of Dominion's proposal to eliminate the 3% adder associated with line loss avoidance from the avoided energy rate methodology for the standard offer contract. He testified that, when deployed effectively, distributed solar generation can avoid line losses, because when load on a particular circuit exceeds the generation interconnected to that circuit, solar or other generation at that location can often directly serve the load on that circuit and avoid transmission and transformer losses that would otherwise be associated with serving that load. He further testified that the 3% adder was established under the assumption that QF distributed generation would be less than load on interconnected circuits, thereby permitting line losses arising from centrally-located generation to be reduced or eliminated.

Witness Gaskill testified that this assumption is no longer true because losses are generally only avoided when the substation load exceeds the local distributed generation on a substation bus. Otherwise, he stated, excess generation flows in reverse, or "backflows," onto the transmission grid to travel to serve load on a different circuit. In those cases, he testified, an increase in system line losses can actually occur, since the distributed generation must pass through two transformers (distribution to transmission to distribution) to reach the load that needs it. He further testified that the volume of distributed solar generation on the North Carolina portion of Dominion's system has reached the point that it either is or will soon exceed the load requirement on most circuits, and that, when that happens, backflow occurs. In addition, he testified that, when backflow occurs, many of the benefits and avoided costs attributed to distributed generation—scalability, mobility, and resulting reduced congestion and improved reliability—are lost. In particular, no line losses are avoided.

Witness Gaskill made reference to an exhibit that included data showing that backflow already occurs most of the time on some of Dominion's North Carolina substations and part of the time on other substations. Specifically, he offered data showing hourly load flow from September 2015 through September 2016 on Dominion's 33 distribution transformers that have interconnected distributed solar facilities. That data shows that 11 of those transformers are experiencing a predominantly constant backflow, indicating that the energy delivered from the distributed generation connected at these

substations exceeds the load at those locations. Of the remaining 22 transformers, 18 are "neutral," meaning they either have a mix of forward and reverse flows or that there is only a small amount of excess load remaining, such that the interconnection of additional distributed solar at these transformers will tip the scales, resulting in power backflow, and not result in additional line loss savings at these locations. Only four transformers still showed a clear margin of load over currently interconnected distributed solar generation and, thus, the ability to host additional distributed solar without resulting in backflow. Witness Gaskill noted, however, that the addition of just one or two more 5-MW projects at these locations will eliminate this margin. He also noted that the data did not include distributed solar generation that commenced operations since September 2016, or the remaining approximate 600 MW of distributed solar generation in Dominion's interconnection queue that has not yet commenced operations. He testified that, when this generation is connected, the backflow on Dominion's substations will increase substantially.

In light of the foregoing, witness Gaskill recommended that the 3% line loss adder should be eliminated for future QFs eligible for the standard offer. Without this change, he stated, customers will pay for losses that are not actually avoided. He noted that the data presented shows that customers are in many cases already paying for a loss adder under 2012 and 2014 biennial period contracts where no actual losses are being avoided. He argued that, while QFs already receiving the line loss adder may continue to receive it as specified in their contracts, future QFs should not be paid for losses that are not actually avoided. Witness Gaskill clarified that, for QFs not eligible for the standard offer, Dominion may calculate project-specific loss percentages, either positive or negative, depending on each project's specific interconnection location.

SACE witness Vitolo disagreed with Dominion's line loss analysis. Witness Vitolo agreed that increasing backflow from a substation that is already backflowing will not necessarily result in line loss avoidance at that specific time, but contended that, to the extent that a substation receives positive flow from the transmission system at any half-hour, an operating local distribution generator will avoid transmission line losses at that time. He asserted that as long as there are hours in a year when the transmission grid sees a net reduction of total demand, there will be line loss avoidance. Witness Vitolo contended that based on his own analysis of power flows at the 33 Dominion transformers, only one of those transformers showed a majority of half-hours with backflow. He opined that each of the other 10 substations labeled "negative" in Dominion's analysis experienced positive flow during most of their hours, and claimed that line losses would be avoided with additional solar generation added to all but one of the substations. Witness Vitolo claimed based on his analysis that eliminating the line loss adder would be inappropriate. He recommended that the Commission direct Dominion to calculate line loss avoidance with enough granularity to compensate renewable QFs for the value they provide in avoiding line loss and that, if such calculations are not feasible, it should continue to apply the 3% line loss adder. (T. Vol. 7 at 57-60)

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NCSEA witness Johnson agreed that due to the backflow issue at the substations in certain areas that line losses are not avoided as much as in the past, but that the utilities do not take into account other benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs savings from not having to upgrade the transmission system itself. Witness Johnson stated that in the Sub 140 proceeding, the Commission decided it should not include other cost and benefits of distributed solar in the avoided cost calculation until future studies and calculation methods have further developed.

Public Staff witness Metz provided the history of the line loss adder, stating that it first appeared in the avoided cost rate schedules of North Carolina Power (now Dominion), filed in Docket No. E-100, Sub 53, in 1987. The rate was last increased from 2.7% to 3% in the 2008 avoided cost proceeding. Witness Metz testified that the Pubic Staff agrees with Dominion's proposal to eliminate the line loss adder from the standard offer contract based on the number of substations already experiencing power backflows and the number projected to experience power backflows in the future. Witness Metz then stated that the Public Staff does not believe DEC or DEP should eliminate the line loss adder from their standard offer contract at this point, but should continue to evaluate the issue and include their findings in a study, or equivalent, during the next avoided cost proceeding.

Dominion witness Gaskill responded to the testimony of the other witnesses, emphasizing witness Metz's recognition of the forward-looking nature of this proceeding. He testified that, while many Dominion substations already realize significant reverse flow, any avoided line loss that remains at this point will continue to diminish in the future as additional distributed generation is interconnected. He also emphasized that it is inappropriate to continue to pay for avoided line losses when the evidence is clear that the typical QF that signs a standard contract pursuant to this proceeding will likely not avoid any line losses. Witness Gaskill further testified that witness Vitolo's claim that only one of the 33 transformers experienced backflow during a majority of the time was incorrect. He testified that witness Vitolo's analysis included hours, including nighttime hours, when no solar QF generation would be producing. He also noted that witness Vitolo did not account for the fact that QF generation was incrementally added over the course of the year, which explains why the data would show more hours with backflow late in the year than early in the year, and did not recognize that the focus should be the state of the flow as it exists today and will exist in the future. He presented an example of one transformer at which reverse flow clearly increased at the point in time at which new generation was added, such that by the end of the time period studied, that transformer was experiencing reverse flow during nearly all daylight hours. Witness Gaskill also noted that, since the line flows presented in his direct exhibit only accounted for distributed generation that was operational at that time—293 MW as of September 2016—considering that the capacity of projects with PPAs or LEOs that have not yet come online exceeds 600 MW, the flows presented in the exhibit included only approximately half of the QF generation that has committed to sell to Dominion. He stated that many of the transformers identified as "neutral" or "positive" in his exhibit will soon experience predominately reverse flow as these additional QFs commence operations. Finally,

witness Gaskill testified that because in this proceeding Dominion is proposing rates and terms for the standard offer, it must derive a rate that applies to the average QF all across its North Carolina service area. As the amount of QF generation committed to Dominion already exceeds average on-peak load, the average QF going forward will not avoid additional line losses and will, in some cases, add to such losses. Since the avoided cost rates set in this case are forward-looking, the data clearly shows that most QFs subject to these rates will not avoid additional line losses.

In response to witness Johnson's testimony, witness Gaskill noted that Dominion has incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, including for avoided energy, capacity, line losses, and congestion. He testified that it is only now, in the absence of those benefits as QF generation has exceeded load and those benefits are reduced or eliminated, that Dominion has proposed to reduce or eliminate the associated costs from its standard avoided cost rates. He noted that Dominion shares Public Staff witness Hinton's concern regarding the uncertainty of integration costs, but because its integration costs studies have not yet quantified those costs, it has not proposed to include any integration costs into its avoided cost rates at this time. Witness Gaskill further testified that, with respect to QFs not eligible for the standard offer, Dominion can evaluate the line loss characteristics of a specific circuit to which a QF plans to interconnect, and model that location with and without the additional generation to estimate the difference in line loss and determine whether avoided line loss should be reflected in the rate. In addition, witness Gaskill testified that line losses are avoided when a distribution level QF allows the utility to avoid transmitting generation across the transmission line, through the transformer to the load. He testified that if the QF does not serve load on that circuit, it nevertheless reverse flows, and line losses are not avoided and may in fact increase. He further testified that on Dominion's North Carolina system, the majority of circuits where QFs are interconnecting either are or will soon experience reverse flow, such that any line loss avoidance for new QFs will be zero or even negative, meaning the QF is actually contributing to, rather than avoiding, line losses. He opined that it would require a large amount of load growth in a short period of time for QFs that will interconnect in Dominion's service area under this proceeding to avoid line losses, and that he did not foresee that occurring. He confirmed that part of a discovery response, which he did not prepare, stated that Dominion has not quantified system losses associated with QFs in its North Carolina territory during times when backflow was and was not occurring over the past two years. He clarified that, as the purpose of the standard offer is to apply to all small QFs, Dominion has decided to consider the average across its North Carolina system to be zero, even though it is likely that the growing QF solar generation may actually be adding to line losses. He testified that this cannot be a QF-specific determination, since it is for the standard offer projects.

Witness Gaskill's testimony also included examples of transformer data from his line loss exhibit. He examined one transformer that he had labeled as "positive," meaning that generally load was being offset by generation at that location, and noted that the location had 10-15 MW of load, with another 13 MW of new generation in the queue to come online. He testified that once that new generation interconnects, the flow will shift to "neutral" at that location, because the interconnected generation will, when producing,

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offset the load at that location. He testified further that any additional generation interconnected at that location would not avoid any line losses, because all potential avoided line loss is being covered by the existing, soon-to-be interconnected generation at that transformer. In another example, witness Gaskill testified how the Whitakers substation data shows positive load flow during nighttime hours when a solar facility does not generate, but reverse flow when the facility generates during daytime hours. He noted that where a location already sees reverse flow from negative load flow, adding more generation to that location will only increase the reverse flow. He testified that Dominion knows how much generation is in line to be constructed and begin operations, and that once that generation comes online, the vast majority of its substations will indicate predominantly reverse flow when that generation is producing. He testified that, for that reason, Dominion has concluded that across its North Carolina service territory, any additional generation at these locations will not on average avoid line loss, and most locations will incur additional line losses due to increased reverse flow. He noted that, despite its expectation that additional line losses will be incurred, Dominion settled on zero avoided line loss for purposes of its standard avoided cost rates.

Witness Vitolo agreed that the purpose of the line loss adder has been to compensate QFs for line losses that their facilities allow utilities to avoid. He also agreed that, according to FERC, paying for line loss is appropriate where the utility avoids line loss costs it would have incurred but for the QF being at that location. He agreed further that solar QFs can avoid line loss by meeting at least in part the requirements of the load at a particular location, so that the electricity does not need to travel elsewhere on the system. He recognized that backflow can occur and that, depending on the details of the substation and the flow on the transmission grid, increasing backflow from a substation already backflowing will not necessarily result in line loss avoidance at that time. He admitted that in his own line loss analysis, while he removed data points for which the power flow registered as zero, and started his analysis at each substation at the point in time at which backflow started to occur, he did not remove any data points corresponding to non-daylight hours. He agreed that the vast majority of QFs coming online on Dominion's North Carolina system are solar QFs, and that a substantial number of the next 100 QFs to come online will be solar. On cross and redirect, witness Vitolo testified that each of Dominion's substations would present a different picture than the others. However, with respect to an example transformer about which Dominion counsel questioned him, he also agreed that there is a solar correlation associated with the times of day that the example transformer showed a negative power flow (i.e., the negative flow occurred during daylight hours), and he agreed that no negative power flows occurred after 6:00 pm on that day for that transformer.

Discussion and Conclusions

The Commission finds persuasive the testimony of Dominion witness Gaskill and Public Staff witness Metz regarding the impact that distributed generation, and specifically solar-powered QFs, is having on the operation of Dominion's electric system in North Carolina. The Commission agrees with witnesses Gaskill and Metz that line losses are avoided when distributed generation can offset the load at a particular location, thereby

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reducing the flow of power required to travel from the transmission system to the distribution system to serve that load and avoiding the line losses that would be associated with that power flow. The Commission has historically required Dominion to include the line loss adder in the calculation of its avoided energy rates, because line losses are a known and quantifiable benefit of distributed generation. However, the Commission is persuaded that when the distributed generation connected at a particular location exceeds the load requirements at that location, upstream line losses are not actually avoided, because there is no local load being offset. In that case, the power must flow back onto the system, traveling through transformers and onto transmission lines, with the accompanying, and additional, line losses. Dominion's analysis, as presented by witness Gaskill, demonstrates that the majority of its transformers to which QF generation is connected in North Carolina are experiencing reverse power flows during the hours of the day when solar generation would be expected to produce power. Because this analysis did not account for the substantial volume of distributed solar capacity that is currently moving through the interconnection queue or under construction, the Commission agrees with witnesses Gaskill and Metz, that, once this additional generation is added to these locations, reverse flows will increase, and line losses will likely increase, and not be avoided.

The Commission carefully considered the testimony in opposition to Dominion's proposal, and finds that witness Gaskill's testimony has sufficiently responded to these arguments. For example, witness Gaskill demonstrated that witness Vitolo's criticisms of Dominion's load flow analysis is flawed in that it included nighttime hours, tending to skew the results in favor of a suggestion that these locations are almost all experiencing positive power flows. Witness Gaskill also demonstrated that, while witness Vitolo limited his analysis of each transformer to the period of time during which QF generation was located there (as opposed to looking at power flows that occurred prior to any QF generation being connected), he did not account for the subsequent increases in reverse flows that occurred at several transformers once additional facilities came online. Finally, as witness Gaskill testified, witness Vitolo did not account for the QFs expected to come online in the near-term. This demonstrates the connection between the addition of incremental QF generation and the increased degree of reverse power flow. Witness Gaskill's testimony also sufficiently refuted the arguments of NCSEA witness Johnson that the Utilities do not take into account other benefits, including line losses that can be avoided by not sending the electricity over the transmission system, and costs savings from not having to upgrade the transmission system itself. The Commission agrees with and accepts witness Gaskill's testimony that as the situation developed to the current state of QF generation exceeding Dominion's system load, these savings became reasonably known and quantifiable. The Commission concludes that this is consistent with the Commission's historical approach to calculating the Utilities' avoided costs and that Dominion has proceeded reasonably in this respect as well as in refraining from proposing to include any integration costs into its avoided cost rates until its studies are able to quantify such costs.

Based on the foregoing and the entire record herein, the Commission finds that backflows are occurring with regularity on a number of Dominion's distribution system

circuits, and that based upon the number and aggregate size of QF projects that are seeking to interconnect to Dominion's electric system, backflows are likely to occur more frequently on more distribution circuits in the future. The Commission further determines that this development greatly reduces or eliminates the benefits of the solar QFs line loss avoidances, which historically have been accounted for in Dominion's avoided energy rate through the 3% line loss adder. Therefore, the Commission determines that it is appropriate for Dominion to eliminate the 3% line loss adder from its standard offer avoided cost payments to distribution-connected QFs eligible for the standard offer.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 19

The evidence supporting these findings of fact is found in the testimony of Duke witness Snider, Public Staff witness Metz, and NCSEA witness Johnson.

Summary of the Testimony

Public Staff witness Metz testified that Duke includes a line loss adjustment in DEC and DEP's avoided energy rates. He further testified that while Dominion makes the adjustment after calculating the avoided energy rates, DEC and DEP incorporates the calculation into their avoided energy rates. Witness Metz then testified that neither DEC nor DEP have proposed to eliminate the line loss factors from Duke's calculations, and the Public Staff does not recommend that they do so at this time. However, witness Metz testified that it may be appropriate for DEP to consider such an adjustment in future proceedings given the similar flow conditions to those experienced by Dominion. He further testified that it would be inappropriate to recommend that DEP make this adjustment without more thorough study of this issue. Therefore, he concluded that DEP should continue to evaluate the issue and include their findings in a study, or equivalent, during the next avoided cost proceeding. Finally, witness Metz testified that DEC has not experienced the same power flow conditions, and that it would be inappropriate for DEC to eliminate the adjustment for line losses at this time.

Witness Snider testified that he agreed with Public Staff witness Metz that DEP should consider eliminating the line loss adder in future avoided cost proceedings because of the abundance of distributed generation. He further testified that Duke may also evaluate this issue as part of specific avoided cost characteristics for larger distribution-connected QFs.

Discussion and Conclusions

Based upon the foregoing and the entire record herein, the Commission determines that it is appropriate for DEC and DEP to continue to incorporate the line loss factor in their standard offer avoided energy calculations. The Commission further determines that it is appropriate to require Duke to study the impact of distribution generation on power flows on their distribution circuits and provide the results of that study as a part of their filings in the next biennial avoided cost proceeding.

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EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 20

The evidence supporting this finding of fact is found in the testimony of Duke witness Snider, Dominion witnesses Gaskill and Petrie, Public Staff witness Hinton, and NCSEA witness Johnson.

Summary of the Testimony

Witness Snider testified that while he designed and supported generic avoided cost rates under the peaker method to apply to all QFs eligible for the standard offer, the recent high penetrations of QF solar resources as well as proposed solar QF projects under development had caused Duke to more specifically evaluate the impact of solar QFs on Duke's planning and reliability. He described Duke's 2016 resource adequacy studies and recent shift to winter planning, emphasizing that the load and resource balance has changed drastically in the past two-to-three years, driven in large part by the high penetration of solar. He also noted that Duke may need to consider the ancillary services impact of high levels of must-take solar when considering additional generation resources to satisfy winter reserve margin requirements, and to ensure adequate system ramping capability and operational flexibility. Witness Snider also noted that the generic avoided capacity rates filed in this proceeding tend to over-compensate solar QFs in excess of the capacity actually avoided due to the broad on-peak hour definitions under Options A and B of Schedule PP. Witness Snider testified that Duke intended to evaluate these solar-specific issues in the context of negotiated PPAs with larger QFs and in the next biennial proceeding.

Witness Snider further testified that, given the large increase in solar QFs in the Duke territories, evaluating solar specific avoided cost rates for larger QFs is appropriate. Witness Snider additionally believed that advancing a solar-specific rate in a standard offer filing in a subsequent avoided cost proceeding may be appropriate. With respect to the factors that the Commission should consider regarding a solar QF's specific characteristics and impact on energy value, witness Snider testified that generic QF rates under the peaker method apply to any PURPA QF eligible for the standard offer, and the energy value assumes an equal amount of generic QF generation is available in every hour. Witness Snider noted that generation must be available and dispatchable to meet the dynamic needs of the consumer, which change minute-to-minute. He further testified that a utility system can only accommodate a finite amount of intermittent generation that does not follow load, and that the net impact of a large amount of this type of generation on a given system results in the need for additional operating reserves and other operating adjustments. Witness Snider further testified that Duke was not including the cost of these additional operational adjustments in the calculation of the filed standard offer rates for small QFs in this proceeding. However, he emphasized that the costs for such additional operations are a growing concern and should be analyzed for larger QFs.

Witness Snider outlined how Duke would implement a solar-specific energy rate if directed to do so. He testified that to calculate the energy specific portion of the avoided cost rates for solar QFs, the Companies would perform two production cost runs, one

with, and one without, 100 MW of free solar generation using a general diversified solar profile. He testified that the use of a solar-specific profile could better represent the actual system marginal energy benefits associated with incremental solar generation as opposed to the generic energy rate that assumes equal production in all hours.

Witness Snider disputed Public Staff witness Hinton's claim, that solar off peak rates would increase between 8% and 10% due to the diurnal profile of solar coinciding with higher off peak hours. Witness Snider testified that Duke had analyzed producing an avoided energy rate under the traditional peaker method, but altered to include only a daylight hours solar load shape using a free 100 MW solar load profile to generate the associated energy, rather than a constant 100 MW as traditionally used in calculating the standard offer energy rate design. Based on this analysis, he testified that a solar-specific energy rate that more precisely calculates the energy value of incremental solar based on the load characteristics of a solar resource would result in avoided energy rates that on an annual average would be approximately 10% lower than the rates solar QFs are receiving under the generic small QF standard offer that assumes constant energy production around the clock.

Witness Snider then discussed the factors that led to a lower avoided energy cost rate using a solar-specific profile. First, he noted that the non-coincident nature of the solar shape with Duke's loads contributes significantly to the lower rate. He pointed to his Figures 7 and 8 in his rebuttal testimony. Figures 7 and 8 illustrate that peak load typically occurs between 7 AM and 8 AM in the winter (January) and between 4 PM and 5 PM in the summer (July). The peak for solar output typically occurs between 1 PM and 2 PM in the winter and between 2 PM and 3 PM in the summer. Witness Snider highlighted that on winter mornings, solar generation starts providing energy to the system just as load is decreasing. During winter evening hours, solar output begins to decline just as load is rebounding. He then testified that solar aligns better with load in the summer, but solar output still begins to decline as system demand is growing toward the afternoon peak. Witness Snider pointed out that solar resources are only available on a varying basis in approximately 55% of all hours in the year. In addition, solar generation only moved in the same direction as load about half those hours while moving in the opposite direction the other half. Figures 7 and 8 show that solar is moving in the opposite direction of customer demand during critical peak hours when energy demand is peaking. Witness Snider then addressed Figures 9 and 10 in his rebuttal testimony, which show that as more solar is added to the system, the more non-coincident the solar shape becomes versus the load profile.

Witness Snider further testified that because a solar profile is not coincident with load, it lacks coincidence with Duke's highest marginal cost hours in both winter and summer. Witness Snider's Figures 11 and 12 illustrated that solar is not producing at high levels during the Companies' highest system marginal costs. These Figures also depicted that solar is not fully available during the Option B on-peak hours for non-summer months. Witness Snider testified that the current energy rate structure, which provides solar with a rate based on a flat 100 MW load profile, effectively over-credits solar QFs for energy during the on-peak hours.

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With respect to the capacity value of solar, witness Snider stated that Duke would strive to align the capacity rate paid to solar with the amount of avoided capacity that the solar resource will produce. To that end, the Companies would account for the unique characteristics of a large-utility scale solar-specific QF on the system outside of the standard QF rate offering. Witness Snider noted that a solar QF is intermittent, non-dispatchable, and not capable of following customer load. Moreover, witness Snider continued, during high demand periods, solar is ramping up when peak loads are declining and declining when customer demand is increasing. Witness Snider concluded that, as NCSEA witness Johnson had suggested, using a solar-specific load profile to calculate negotiated QF rates along with a potential change in subsequent biennial avoided cost proceedings will provide more precise price signals to QFs that reflect the specific characteristics of the QF as envisioned by PURPA.

On cross-examination by Cypress Creek, witness Snider testified that Duke views it as appropriate to include costs associated with solar QFs in negotiated PPAs that they do not include in standard offer PPAs. Witness Snider testified that the currently proposed avoided cost rates in the standard offer are technology agnostic, but that it may be appropriate with the larger QFs to account for the specific characteristics of that QF. He clarified that Duke was not proposing to include an ancillary service charge in the standard rates in this proceeding as Duke proposed in Sub 140, Phase I, but he noted that it would be appropriate to consider evaluating, including such ancillary costs, outside of the standard offer. On examination by the Attorney General, witness Snider testified that PURPA contemplates a solar-specific rate, wherein the attributes of that specific technology are included in the rate can be appropriate. Witness Snider also noted that the amount of capacity that a utility could actually avoid building as a result of a generic QF is very different from how much capacity a solar QF avoided. Witness Snider concluded that the standard offer rates, as filed, still paid very well for capacity, even though very little capacity will actually be avoided through additional solar QFs. Thus, witness Snider indicated that if Duke adopted technology-specific avoided cost rates, those are areas that will need to be addressed for large QF negotiations to more appropriately value the QF's capacity and energy.

Witness Petrie testified that in determining the rates it is proposing in this case, Dominion used the same Black-Scholes Model option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 biennial proceeding. He also noted that, while Dominion believes there are likely costs associated with integration of distributed solar generation, it did not include solar integration costs in its production cost modeling.

In response to witness Johnson's testimony, witness Gaskill testified that Dominion has incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, including for avoided energy, capacity, line losses, and congestion. He testified that it is only now, in the absence of those benefits as QF generation has exceeded load and those benefits are reduced or eliminated, that Dominion has proposed to reduce or eliminate the associated costs from its standard avoided cost rates. He noted that Dominion shares Public Staff witness Hinton's concern regarding the uncertainty of

integration costs, but since its integration costs studies have not yet quantified those costs, it has not proposed to include any integration costs into its avoided cost rates at this time.

Public Staff witness Hinton testified that in the Sub 140 proceeding, NCSEA witness Tom Beach proposed that the definition of off-peak hours be aligned with the load profile of solar QFs. The Commission did not adopt this proposal on the basis that it accounted for the benefits but not the costs associated with solar generation. Witness Hinton asked the Commission to view this issue as a modeling or allocation issue where solar generation during off-peak hours is not being properly valued in rates. His calculations indicate that the avoided energy rate for solar would be 8% to 10% higher if the avoided marginal costs from solar generation during off-peak hours were taken into account. Witness Hinton recommended that the utilities submit a solar-only rate.

Discussion and Conclusions

Several parties' witnesses suggested that a "solar-specific rate" would be appropriate for consideration in the next biennial avoided cost proceeding. In Order No. 69, FERC explained that standard rates for purchase may differentiate among QF technologies on the basis of supply characteristics, while also recognizing that administrative efficiency of setting generic standardized avoided costs that do not take into account the specific characteristics of these small QFs is appropriate even if a deviation in value from true avoided costs results.

> [FERC] is aware that the supply characteristics of a particular facility may vary in value from that average rate set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction cost associated with administration of the program would likely render the program uneconomic for this size of [QF]. Order No. 69*,* 45 Fed. Reg. at 12,223.

In describing the avoided costs rates to be paid to larger QFs, FERC also emphasized that a QF's capacity and energy supply characteristics could be taken into account in analyzing whether the QF provided capacity value and in calculating the incremental energy value to be avoided by the QF. Id. at 12,224 (describing the specific capacity value considerations of wind, solar, and biomass QFs). FERC also established specific factors that could affect the rates for purchases from QFs, while emphasizing that the selection of a methodology setting avoided costs is best left to the State Commissions charged with implementing PURPA's must-purchase provisions. Id. at 12,226; see 18 C.F.R. 292.304(e); see also Windham, at ¶6 (recognizing that the value of avoided energy and capacity could be lower for purchases from intermittent QFs than for purchases from firm QFs). Section 62-156(b) incorporates consideration of these factors as a part of the Commission's standards that apply to the standard offer contract rates for each electric public utility.

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Based on the foregoing and the entire record herein, the Commission concludes that it is inappropriate to require the Utilities to develop a separate avoided cost rate for solar QFs in this docket. As witness Hinton notes, the Commission previously rejected this proposal on the grounds that it "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources." Order on Inputs at 62. The Commission reaches the same conclusion here. Further, the Commission concludes that any technology specific rate is contrary to the direction in the federal regulations implementing PURPA and G.S. 62-156(b).

However, the Commission finds merit in the concept underlying the recommendations of witnesses Hinton, Johnson, and Snider, that an evaluation of the Utilities' avoided costs should consider the characteristics of the power supplied by a QF. Considering the factors in G.S. 62-156 and the FERC regulations in the determination of avoided cost rates ensures that the Commission's avoided cost methodology remains true to PURPA's directive that avoided cost rates are to be based on the costs that the utility avoids. Thus, the Commission recognizes that PURPA provides utilities with the ability to consider factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates for purchases from larger QFs, including solar QFs. The Commission also recognizes that in the past the Commission has required utilities to make the standard offer tariff available to QFs based upon the QF's fuel source or technology used to generate electricity, but that issue is distinct from the rate paid to the QF. The Commission concludes that this approach complies with PURPA and G.S. 62-156 and should be continued in future avoided cost proceedings. The Commission further concludes that it would be appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power, if the Utilities' cost data demonstrates marked differences in the value of the energy and capacity provided by these QFs.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate to require the Utilities to calculate avoided energy and capacity costs for purposes of establishing rates available to QFs eligible for the standard offer without regard to the technology the QF uses to generate electricity. The Commission further finds that it is appropriate to require the Utilities to consider and propose additional rate schedules in the next avoided cost proceeding that are based upon a consideration of the characteristics of the power supplied by the QF and not the technology that the QF uses to generate electricity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 21

The evidence supporting these findings is contained in the proposed rates of WCU and New River. WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution. This is the same approach approved by the Commission in Sub 140. No parties filed any comments or objections to WCU's and New River's proposals. DEC is WCU's requirements supplier, and it is indirectly New River's through

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Blue Ridge Electric Membership Corporation (Blue Ridge). The PPA between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis-à-vis Blue Ridge.

As discussed above, amended G.S. 62-156 provides that long-term contracts up to ten years for the purchase of electricity by the electric public utility from small power producers with a design capacity up to and including 1,000 kW (or 1 MW) shall be encouraged to enhance the economic feasibility of these facilities.

The Commission concludes, based upon the foregoing and the entire record herein, that WCU's and New River's rate proposals should be altered to conform with amended G.S. 62-156, namely, that WCU and New River should eliminate the 15-year long-term rate option and with the other changes approved herein with respect to DEC's avoided capacity and energy rates. Therefore, WCU's and New River will be required to file amended schedules reflective of these changes as part of the compliance filing required by this order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-25

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Bowman and Freeman, Dominion witness Gaskill, Public Staff witnesses Lucas and Hinton, and NCSEA witness Harkrader.

Summary of the Testimony

Duke witness Bowman testified that the current standard to establish a LEO, as approved in the Sub 140 proceeding, requires the QF developer to take the following actions: (1) self-certify with the FERC as a QF; (2) obtain a CPCN from the Commission to construct the generator; and (3) indicate its intent to make a commitment to sell the facility's output under PURPA via the use of an approved Notice of Commitment Form. However, witness Bowman also testified that the current process is increasingly imposing unjust and unreasonable purchase obligations on Duke's customers without actually obligating the QF to sell to the utility. She further testified that this results from the QF being able to establish a LEO without actually obligating the QF to sell to the utility, essentially rending the "QF's 'commitment to sell' increasingly meaningless."

Duke witness Freeman testified in support of Duke's proposed changes to the LEO standard. He testified that his recent experience is that the commitment to sell purportedly being made by QFs who submit the Notice of Commitment Form is not meaningful or binding on the QF. Witness Freeman argued that the commitment to sell power under the current LEO standard is being made early in the development process when the QF (1) has no concrete information on the feasibility, cost, or timing of interconnection; (2) is not ready, willing, and able to sell power; and (3) has not begun PPA negotiations with the utility. Witness Freeman further argued that this is not consistent with PURPA's intent that a QF must make a legally enforceable commitment to sell – either through executing

a PPA or under a non-contractual LEO where the utility refuses to enter into a contract – in order to obligate the utility and its customers to purchase the QF's output.

Witness Freeman next testified by describing some of the unique provisions of the North Carolina Interconnection Procedures (NCIP) approved by the Commission in May 2015 that impact whether a QF can make a reasonably informed commitment to sell early in the interconnection and QF development process. He noted changes to the study process, including the elimination of the initial feasibility study so that the System Impact Study (SIS) is now the first study completed. He testified that during the SIS process, the feasibility, grid impacts, and preliminary ballpark cost to interconnect the generator are analyzed. He further testified that as interconnected solar capacity has increased on DEP's rural distribution system, certain proposed points of interconnection either may not be feasible to interconnect additional solar without adversely impacting power quality and reliability, or the proposed generator must be significantly modified (i.e., a reduction in nameplate generator capacity) during the study process to make interconnection to the local distribution system feasible. In addition, he testified that increasingly, significant system upgrade costs are likely to be required, as the average upgrade cost for utility-scale generators exceeded $400,000 in 2016.

Witness Freeman further described the interdependency-driven interconnection processing under NCIP Section 1.8, which prioritizes studying generators whose proposed points of interconnection are not impacted by upgrades required to interconnect lower-queued generators. Currently, there are over 150 "On Hold" interconnection requests in DEC and DEP's North Carolina interconnection queues and 33 different substations where more proposed generators have submitted an interconnection request for study than can even be accommodated by the substation size, transmission, and/or distribution systems. Witness Freeman also identified how the interim interconnection agreement and "dwell period" between the SIS and Facilities Study are designed to allow QFs to continue with project development work, but emphasized that QFs are not required to make any binding commitments to proceed with the generator during the study phase of the interconnection process.

Witness Freeman testified that the first meaningful commitment by a QF developer under the Section 4 Full Study interconnection process occurs where the interconnection customer executes the interconnection agreement (IA) and financially commits to construction of system upgrades so projects later in the study queue (and the utility processing the studies) can rely on the required system upgrades being constructed. He testified that DEC and DEP have treated the 60 calendar day period provided in the NCIP for payment of upgrades as an informal due diligence period where the interconnection customer may terminate the IA without liability if the QF elects not to pay for upgrades under the IA and to terminate the project. Witness Freeman further testified to his recent experience that two to four years could pass between a Sub 140 "LEO date" established early in the QF interconnection and development process and the point in time that a QF begins delivering power to customers. This extended period heightens the risk and likelihood that the LEO-committed avoided cost rates no longer align with Duke's then-

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existing avoided costs, effectively assigning the risk of stale and inaccurate avoided costs to Duke's customers.

Witness Freeman testified that Duke initially proposed modifications to the current Notice of Commitment (NoC) Form intended to modify the current NoC Form to require a utility-scale QF developer proceeding through the Section 4 full study process to make some indicia of commitment by executing and returning a Facilities Study Agreement after the dwell period, thereby committing the project to a detailed engineering and construction Facilities Study. However, witness Freeman then testified that Duke modified its recommendation, and now supports the Commission transitioning the current LEO standard to formalized contracting procedures between larger QFs and the utilities, which will more appropriately align the establishment of a legally enforceable commitment to sell with the date upon which a QF actually agrees in a PPA to commit itself and becomes obligated to deliver power over a specified term. Witness Freeman testified that similar contracting procedures have been adopted in other jurisdictions with significant PURPA activity, including Oregon and Idaho, where a LEO commitment to sell is tied to the QF's commitment to deliver power under a PPA. For example, witness Freeman testified that, in Oregon, a LEO is established when a QF signs a final draft of an executable PPA that includes a scheduled commercial on-line date and information regarding the QF's minimum and maximum annual deliveries, thereby obligating itself to provide power or be subject to penalty for failing to deliver energy on the scheduled commercial on-line date. He argued that adopting similar contracting procedures here could resolve Duke's concerns about the growing harm to customers of stale avoided cost rates, while also providing QFs certainty as to the process for negotiating a definitive PPA. This proposal, he also argued, would better ensure that the QF developer and not Duke's customers is taking on the risk of the QF's non-performance at the time the QF's "commitment to sell" is made. Witness Freeman emphasized that customers should be protected from the risk of the QF's potential non-performance by including reasonable and appropriate liquidated damages (if the QF is late in achieving commercial operation) or termination damages (if the QF elects not to perform) in negotiated PPAs for large QFs. He noted that if the QF and the utility cannot agree to a PPA, the QF could also file a complaint or petition for arbitration with the Commission.

Witness Freeman also testified regarding the expedited Fast Track study process for smaller generators, and stated that Duke supports a streamlined LEO form for small QFs 1 MW or less that are eligible for the standardized avoided cost rates and terms and conditions. The streamlined form would consist of: (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the Company deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to DEC or DEP under then-approved standard avoided cost rates.

Finally, witness Freeman testified regarding potential changes to the process for negotiating PPAs between large QFs and the Utilities. Witness Freeman testified that the proposed contracting procedures are commercially reasonable and will improve the transparency and efficiency of the negotiated PPA process by establishing clear

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milestones and a process for good faith negotiations between the QF and utility. He also testified that the contracting procedures modify the process for a large QF to make a legally enforceable commitment to sell by focusing on the QF's commitment to enter into a PPA as establishing its obligation to deliver energy or capacity over a specified term. Under his proposed contracting procedures, he argues that the decision to make such a commitment is completely within the QF's control, and only where the QF and the utility cannot agree on the terms and conditions of the PPA would the Commission need to get involved to determine whether a non-contractual LEO has been established. Prior to the QF entering into a PPA, he suggests that the utility will provide non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. This approach, he argues, mitigates the risk of stale avoided cost rates as the QF will be provided indicative pricing information needed to evaluate developing the QF, but will not "lock in" avoided cost rates until it actually makes a commitment to deliver power to the utility over a specified term by executing a PPA. Witness Freeman also suggested that the Companies' PPA would continue to include a 60-calendar day "post-execution due diligence period," providing the QF reasonable additional time to ensure it is prepared to make a legally enforceable commitment to sell power over the term specified in the PPA.

Witness Freeman included as an exhibit to his testimony a revised Notice of Commitment Form proposed to be used by QFs smaller than one MW. Witness Freeman also included a Notice of Intent to Negotiate Form and contracting procedures to be used by larger QFs as an exhibit to his testimony and requested that the Commission direct Duke to take input from the Public Staff, Dominion, and other interested parties on the large QF form.

Dominion witness Gaskill described the current requirements for a QF to establish an LEO under the 2014 biennial proceeding orders: receive a CPCN or Report of Proposed Construction; be a QF; and submit a "Notice of Commitment" form, which Dominion calls the LEO Form. Witness Gaskill testified that, while Dominion did not initially recommend changes to the standard for establishing a LEO, he shares many of the same concerns raised by the Duke witnesses. He testified that the current LEO process, while improved in the 2014 biennial proceeding with the determination of a uniform LEO Form and the addition of the QF status requirement, still allows a QF to establish a LEO before it is in a position to truly commit to develop the project and deliver power in a timely manner. He further testified that, in practice, the LEO Form has been used by North Carolina QFs as a means to establish a put-option price, but it has not obligated the QF to actually deliver power to the utility.

Witness Gaskill testified that this situation presents two significant implications, both of which unjustly harm customers. First, he testified that it impairs adequate utility system planning, because Dominion does not know how much QF power will ultimately be constructed and delivered, since it cannot rely on the QF energy and capacity to be available based on an LEO. As a result, he testified that Dominion must, in order to meet its obligation to meet customer requirements, secure short- and long-term capacity without accounting for QFs, thus reducing or eliminating any avoided capacity costs.

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Second, he testified that the current process has created a situation where the LEO, and thus the avoided cost prices, are significantly outdated by the time the QF actually completes construction and begins delivering output. He testified that the result is that customers are paying rates to QFs that established LEOs and therefore qualified for avoided cost rates that, in many cases, were calculated years prior to the QF actually coming online.

Witness Gaskill argued that Duke's proposed LEO process would better align a QF's commitment to the point in time at which it can be reasonably sure whether it will proceed with the project. He agreed that Duke's proposal for small QFs 1 MW or less is a reasonable step to ensure that the QF is in fact progressing in its development. He also agreed that either of Duke's initial proposals for large QFs—establishing the LEO after execution and return of a Facilities Study Agreement, or tying the LEO to the negotiated PPA process—would be an improvement over the current process, because they also better align the LEO with the point in time at which the QF has enough information to actually commit to development. Witness Gaskill testified that witness Lucas' recommendations for the large QF standard would still allow QFs to establish an LEO before they have made any material financial commitments beyond the interconnection fee or actual commitment to delivery output to the utility, but stated that he did not object to these recommendations as they are an improvement over the current process, assuming that the requirement to obtain a CPCN or RPC would remain in place.

Finally, witness Gaskill testified that although Dominion did not submit a modified LEO Form, he believes that the LEO requirements should be uniform for all QFs in the State regardless of the utility to which the QF interconnects. He stated that, once the Commission determines any changes to the requirements for an LEO in this proceeding, Dominion would work with the Public Staff, Duke, and other stakeholders on the appropriate modifications to the LEO Form to implement those requirements.

Public Staff witness Lucas agreed with Duke's streamlined LEO process for small QFs of one MW or smaller. Witness Lucas also proposed to include an additional requirement to the current LEO standard for non-standard QFs. He proposed that in order to establish a LEO, the QF must first be a Project A or B in the interconnection queue. The LEO would be established upon the earlier of (1) the QF's receipt of the utility's SIS, or (2) the passage of 105 days after the QF submits a complete interconnection request to the utility. For QFs that are not a Project A or B at the time the QF submits its interconnection request, the LEO is established upon the earlier of (1) receipt of the utility's SIS for the QF, or (2) 105 days after the QF becomes a Project A or Project B.

Witness Lucas largely agreed that a QF owner lacks the ability to fully evaluate the feasibility of a project until it receives its SIS results. However, witness Lucas pointed out that the timing and control of the interconnection process is also largely up to the utility. Under the NCIP, a utility has 105 days to provide a QF with a SIS. With the current delays in the interconnection queue, he testified that the actual time required for these studies has varied with some projects waiting far longer than 105 days for receipt of the study. Moreover, he testified that the QF has no control over when it will receive its SIS because

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the timing of the study is solely in the hands of the utility. Thus, he concluded that tying the establishment of the LEO to completion of the System Impact Study step of the interconnection process as proposed by Duke would allow the utility to determine if and when a LEO is established. This, witness Lucas testified, would be inconsistent with FERC's decision in FLS Energy, Inc., which held that allowing the utility to control whether or not a LEO is established is contrary to PURPA and FERC regulations.[16]

Witness Lucas also proposed to limit QFs that withdraw a previously submitted NoC from being able to establish a new LEO for two years from the date of withdrawal. He testified that in an environment of rising avoided costs, this would prevent a QF from delaying the establishment of a LEO in order to take advantage of higher rates. Under his proposal, for the two-year time period after a QF has withdrawn its NoC, the QF would be limited to the utility's "as available" energy rates.

Public Staff witness Hinton testified that the Public Staff generally agrees with witness Freeman's testimony regarding the establishment of reasonable contracting procedures that improve the transparency and efficiency of the negotiated PPA process. Witness Hinton recommended Duke provide additional details regarding its proposal, and specifically highlighted his support for certain standards including providing for specific timeframes for both parties to provide information and responses; providing for a standardized contract form with clear delineation of any specific changes or points of negotiation clearly identified; providing for the utility to deliver indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and be able to seek financing; and providing an opportunity for either party to seek informal resolution of disputes or to petition for arbitration with the Commission.

NCSEA cites the federal regulations, FERC's decisions in J.D. Wind and FLS Energy, and the Commission's Order Denying Request for Waivers, issued on June 15, 2005, in Docket No. SP-4158, Sub 0, in support of its opposition to Duke's proposed changes to the standard for establishing a LEO. In short, NCSEA objects to Duke's proposal because it leaves the QF's ability to establish a LEO outside of the QF's control. NCSEA witness Harkrader testified to the unpredictability and inconsistency that plagues the interconnection process and that, in her experience, the interconnection process now takes longer and is less predictable than prior to the May 2015 revisions to the NCIP. She testified that in 2016, her company Carolina Solar Energy II, LLC (CSE) was involved in the interconnection of 12 5-MW_{AC} solar QFs to the grid. Witness Harkrader projects that in 2017, only four 5-MW_{AC} solar QFs developed by CSE will be interconnected. Further, she testified that one interconnection request made by CSE in the summer of 2014 has still not received results from the study process and that CSE has received only one new SIS from the utility for a distribution level QF in North Carolina in the past twelve (12) months.

NCSEA also takes issue with Duke's assertion that a QF cannot make a commitment until it receives the results of the SIS. NCSEA witness Harkrader testified that the QF development process involves many steps that require the QF to make

[16] See, In re: FLS Energy Inc., 157 FERC 61, 211 (December 15, 2016).

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significant commitments, only one of which is interconnection. She testified that: 1) the early stages in the development process involve the identification of a suitable site for the facility, the negotiation for site control with the landowner, the completion of environmental surveying and permitting, the securing of land use approvals, and the securing of regulatory approvals; 2) these early stages can take many months, or longer, to complete; and 3) securing rights to the site and all necessary approvals involves significant costs. She further testified that the interconnection process involves significant commitment on the part of the QF. Specifically, she testified that the interconnection request is typically made very early in the process after site control has been secured. Engineering and design work must be undertaken prior to submitting the interconnection request, and a significant fee, $25,000, in the case of a 5-MW QF, must be paid at the time the interconnection request is submitted. Subsequent to the submittal of the interconnection request, a scoping meeting is held with the relevant personnel for the interconnecting utility, as well as the QF's team of engineers, to discuss the request. From the scoping meeting, the request proceeds to the study process. The process of preparing an interconnection request, submitting to the utility, and holding a scoping meeting with the utility can take several months and involve significant expense, depending on the complexity of the interconnection and the engineering and design resources required. Thus, witness Harkrader testified that significant commitments—in terms of expenditure of time and financial resources and the securing of necessary approvals—are made toward the development of the QF before the interconnection study process is completed. Based upon witness Harkrader's testimony, NCSEA agrees with the Public Staff's proposal to amend the LEO standard, by providing that the LEO could be established at the earlier of the completion of the SIS or 105 days after the date of the submittal of the interconnection request.

Discussion and Conclusions

A QF has the unconditional right to choose whether to sell its power "as available" or pursuant to a LEO at a forecasted avoided cost rate determined, at the QF's option, either at the time of delivery or at the time that the obligation is incurred. 18 C.F.R. 292.304(d). PURPA requires that a utility purchase any energy and capacity made available by a QF. 18 C.F.R. 292.303(a). Use of the term "legally enforceable obligation" is intended to require the QF to make a commitment to sell as well as to prevent a utility from circumventing PURPA's requirements merely by refusing to enter into a contract with the qualifying facility, Order No. 69 at 12,224, or by delaying the signing of a contract, so that a later and lower avoided cost is applicable. Cedar Creek Wind, LLC, 137 FERC ¶ 61,006 at p. 5 (2011). By committing itself to sell to an electric utility, a QF also commits the electric utility to buy from the QF, resulting in either a contract or in a non-contractual, but binding, legally enforceable obligation. J.D. Wind at 25. FERC has held: "the establishment of a LEO turns on the QF's commitment, and not the utility's actions." (emphasis in original). FLS Energy, at 9, citing J.D. Wind at 25[17]. More specifically, "a

[17] In FLS Energy, the QFs at issue had already tendered PPAs at the time they alleged LEOs were established. In FLS Energy, the FERC denied the QF's request to undertake an enforcement action thereby arguably rendering its statements interpreting PURPA's LEO standard dictum.

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requirement for a facilities study or an interconnection agreement, given that the utility can delay the facility study or tendering an executable interconnection agreement, as a predicate for a legally enforceable obligation is inconsistent with PURPA," FLS Energy at 8. The Commission notes that on June 29, 2016, FERC held a technical conference to review PURPA,[18] and that Congress is conducting an examination of PURPA that might result in legislation proposing modifications of this 1978 statute.[19]

The Commission acknowledges the testimony of Duke witness Freeman and Public Staff witness Lucas, that delays in the interconnection queue have allowed QFs to establish a LEO well before the date the QFs are able to generate power. The Commission agrees that this delay can expose the utility to a risk of being obligated to pay avoided cost rates that deviate from the utility's actual avoided costs and that delays in the interconnection queue have added to this risk. The Commission agrees with the Public Staff that the appropriate refinement to the standard for establishing a LEO is one that brings the LEO date into closer alignment with the date the QF is able to deliver power to the utility.

Therefore, the Commission finds it appropriate, for the purposes of this case, to add an additional requirement to the current LEO standard for QFs larger than one MW, as a step in the direction of reducing the impact of paying QFs on the basis of stale rates. For these QFs, a LEO is established when (1) the QF has self-certified with FERC as a QF, (2) the QF has made a commitment to sell the QF's output to a utility under PURPA using the approved NoC Form, (3) the QF has filed a report of proposed construction or been issued a CPCN pursuant to G.S. 62-110.1, and (4) the QF has submitted a completed interconnection request pursuant to the NCIP. For a QF that has been designated as an A or B project in the interconnection queue, the date on which the LEO is established shall be the earlier of (1) 105 days after the submission of the interconnection request, or (2) upon the receipt of the system impact study from the public utility. For a QF that has not been designated as an A or B project at the time of its interconnection request, the date on which the LEO is established shall be the earlier of (1) 105 days after the project has been designated as an A or B project, or (2) upon the receipt of the system impact study from the public utility. In either case, where the QF has or has not been designated an A or B project, the 105-day period as part of establishing a LEO will remain in effect until the Commission issues a final order in Docket No. E-100, Sub 101. If, by final order issued in that docket, the Commission alters the NCIP's 105-day-deadline for providing a QF with the results of the utility's system impact study, that altered deadline shall be substituted for the 105-day standard approved in this order. If, prior to the expiration of the 105 days or the substituted date from Docket No. E-100, Sub 101, the utility anticipates being unable to deliver the results of the system impact study to the QF, then the utility may petition the Commission for an extension of

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[18] See Implementation Issues Under the Public Utility Regulatory Policies Act of 1978; Supplemental Notice of Technical Conference, 81 Fed. Reg. 43593 (July 5, 2016).

[19] See Powering America: Reevaluating PURPA's Objectives and its Effects on Today's Consumers Before the Subcomm. on Energy of the H. Comm. on Energy and Commerce, 150th Cong. (2017).

that deadline and a delay in the establishment of the QF's LEO. In the proceeding on such a petition, the utility shall bear the burden of proof to justify any requested extension and delay, and the length thereof. The Commission shall address such petitions on an expedited basis and determine the appropriate deadline extension and LEO date on a case-by-case basis. This procedure places the timing of the LEO under the supervision and control of the Commission with appropriate safeguards to prevent the utility from unilaterally delaying the establishment of the LEO so as to prevent the QF from obtaining a valid PPA. The Commission concludes that these refinements fully comply with PURPA's requirements by establishing the LEO based on the QF's commitment and independent of the utility's actions. The Commission further concludes that these changes, in conjunction with the other changes approved in this order, tend to mitigate the lag time between the date the LEO is established and the date the QF delivers power to the utility, which in turn, supports PURPA's goal of setting avoided cost rates that reflect the utility's avoided costs.

For QFs with a generating capacity less than one MW and eligible for the standard offer contract, the Commission agrees with witness Freeman that changes to streamline the process are appropriate. For these QFs, a LEO is established when (1) the QF submits a report of proposed construction to the Commission pursuant to G.S. 62-110.1 and Commission Rule R8-65; (2) the QF submits a Section 2 or Section 3 Interconnection Request; and (3) the QF has made an indication of intent (i.e., a notice of commitment) to sell the QF's output to the utility under then-approved standard avoided cost rates. These proposals were generally supported by the Public Staff witnesses, and no parties opposed or requested changes to the NoC Form included as an exhibit to witness Freeman's testimony.

The Commission also acknowledges the Duke witnesses related concerns of "stale rates" and a QF establishing a LEO without making a true commitment to sell power to the utility. The concern they expressed is that the rates for which a QF is eligible at the time it establishes a LEO may no longer be representative of the utility's current avoided costs at the time the QF begins delivering power to the utility. Public Staff witness Lucas agreed with many of these concerns and proposed a modification to the NoC to limit a QF to "as available" energy rates for a period of two years should a QF withdraw its NoC Form. In addition, witness Lucas pointed to a provision in Duke's current standard contract terms and conditions that limits eligibility to QFs that begin delivering power within 30 months of establishing a LEO and the automatic termination provisions in the current NoC Form as providing a utility's ratepayers with protection against stale rates. The 30-month provision was first approved in the 2012 avoided cost proceeding (Docket No. E-100, Sub 136) and no party has proposed a change or requested Commission review of that provision in this proceeding. The Commission finds that the Public Staff's proposal to limit a QF that withdraws its commitment to sell to "as available" rates for the two years following the withdrawal to be an appropriate protection against stale rates. Therefore, the NoC Form should be revised to reflect the consequences of withdrawing a previously submitted NoC Form. The Commission concludes that this revision, the existing 30-month provision in the standard contract terms and conditions, and the

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existing automatic termination provisions in the NoC, provide appropriate incentives to QFs to make a commitment to actually deliver power to a utility.

Finally, the Commission finds it appropriate, as recommended by the Public Staff, to establish a forum to develop procedures for the negotiation of non-standard PPAs. In addition, the Commission finds that the issues discussed in this section merit further consideration. Therefore, the Commission will require the Public Staff to convene a working group that includes Duke, Dominion, and other interested stakeholders with the goal of developing consensus around proposed revisions to the NoC Form, procedures for streamlining the negotiated PPA process, and refinements to the standard for establishing a LEO that require a QF to make a more meaningful commitment to actually deliver power to the utility. The participants jointly, if consensus is reached, or individually, if not, should bring these matters to the Commission's attention in an appropriate proceeding, for example, the next biennial avoided cost proceeding or the interconnection stakeholder effort underway in Docket No. E-100, Sub 101.

Based upon the foregoing and the entire record herein, the Commission finds it appropriate to refine its standards for establishing a LEO as described in this section. The Commission will require the Utilities to solicit input on the revised NoC Form, make revisions to the form consistent with this order and the input received, and to file a revised form with the Commission as a part of the compliance filing required by this order.

IT IS, THEREFORE, ORDERED as follows:

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

2. That Dominion shall continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's Sub 106 Order. Dominion shall revise Schedule 19-LMP to provide that the energy price that it will pay pursuant to that rate schedule is the LMP at the PJM-defined nodal location nearest to where the energy is delivered.

3. That DEC, DEP, and Dominion shall offer QFs not eligible for the standard long-term levelized rates the following three options: (1) if the utility has a Commission-recognized active solicitation, participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be

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

4. That DEC, DEP, and Dominion shall calculate avoided capacity rates using the peaker method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need;

5. That DEC and DEP shall recalculate their avoided energy rates using forward natural gas prices for no more than eight years and fundamental forecasts for the remainder of the planning period;

6. That DEC, DEP, and Dominion shall, in future avoided cost proceedings, propose commodity price forecast methodologies that are consistent with those proposed in the utility's most recently filed IRP;

7. That DEC and DEP should recalculate their avoided capacity rates using seasonal allocation weightings of 80% winter and 20% summer;

8. That DEC, DEP, and Dominion, shall use a PAF of 1.05 in their avoided cost calculations for all QFs other than hydroelectric QFs with no storage capability and no other type of generation;

9. That DEC, DEP, and Dominion, shall use a PAF of 2.0 in their avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation;

10. That Dominion shall eliminate the line loss adder of 3% from its standard offer avoided cost payments to solar QFs on its distribution network;

11. That DEC and DEP shall continue to include the line loss adder in their avoided cost calculations, but shall study the effects of QFs on their distribution grid to determine the extent of backflow at substations;

12. That DEC, DEP, Dominion, WCU, and New River shall, within 30 days of the date of this order, make a compliance filing in this docket that includes the following:

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a. Revised schedules applicable to the purchase of power from QFs, in redline and clean versions, that comply with the rate methodologies and contract terms approved in this order;

b. Supporting calculations for the revised rate schedules applicable to the purchase of power from QFs;

c. Revised purchase power agreements and terms and conditions, in redline and clean versions, that comply with the contract terms and conditions approved in this order for the standard offer contract for purchase of power from QFs;

d. A short and plain explanation of the standard for a QF to establish a LEO, as approved in this order, and a description of how the utility will make this information available to QFs and the general public, including publication on the utility's website; and

e. Revised Notice of Commitment Forms that comply with the changes approved in this order.

13. That the revised rate schedules, purchase power agreements, and terms and conditions required to be filed by ordering paragraph 12 shall become effective and be implemented 15 days after being filed unless a party files with the Commission specific objections as to the accuracy of the revisions or supporting calculations;

14. That DEC, DEP, and Dominion shall, within 90 days of the date of this order, file with the Commission procedures stating how they would curtail electric output from QFs on a nondiscriminatory basis when the utility is faced with a system emergency;

15. That DEC, DEP, Dominion, and the Public Staff shall, within 90 days of the date of this order, convene a working group that includes other interested parties to discuss and develop streamlined contracting procedures for QFs contracting to sell capacity greater than one MW, further refinements to the Commission's LEO standard, and any other related issues, and, after considering the input of this working group, jointly or individually file with the Commission proposed forms and contracting procedures, or otherwise bring proposals to the Commission's attention through an appropriate proceeding;

16. That, in addition to their cost data and any other usual and appropriate matters, DEC, DEP, and Dominion shall, in their initial filings in the Commission's next biennial proceeding established to determine avoided cost rates for electric utility purchases from QFs, address the following issues consistent with the discussion and conclusions in this order: a continued evaluation of capacity benefits of QF generation, whether the utilization of a 2.0 PAF as approved in the Hydro Stipulation should continue as provided in that agreement, the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations, hourly CT

operational data and marginal cost data on a season-specific basis, and consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable;

17. That WCU and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved ten-year, long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed ten-year avoided capacity rates; and

18. That the proposed schedules, supporting calculations, and purchase power agreements and terms and conditions, except as specifically addressed in this order, are approved and shall be implemented.

ISSUED BY ORDER OF THE COMMISSION.

This the 11th day of October, 2017.

NORTH CAROLINA UTILITIES COMMISSION

Linnetta Threatt

Linnetta Threatt, Acting Deputy Clerk

Commissioners Bryan E Beatty and Don M. Bailey did not participate in this decision.

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