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December 20, 2013

VIA ELECTRONIC FILING

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Docket No. E-100, Sub 136
Proposed Order of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.

Dear Ms. Mount:

Please find enclosed for filing in the above-referenced docket Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities. An electronic copy is being emailed to briefs@ncuc.net.

Portions of the proposed order contain confidential information about the Companies' combustion turbine costs. Such information designated by the Companies as confidential qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3). If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to ratepayers. Information clearly marked as confidential shall be considered confidential filed under seal, and the Companies respectfully request that the Commission treat this information as confidential and protect it from public disclosure pursuant to N.C. Gen. Stat. § 132-1.2. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress
Associate General Counsel

Enclosures
cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s Proposed Order Establishing Standard Rates and Contract Terms for Qualifying Facilities has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 20th day of December, 2013.

Kendrick C. Fentress

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	**DUKE ENERGY CAROLINAS, LLC**
Biennial Determination of Avoided	)	**AND DUKE ENERGY PROGRESS,**
Cost Rates for Electric Utility	)	**INC.'S PROPOSED ORDER**
Purchases from Qualifying Facilities -	)	**ESTABLISHING STANDARD RATES**
2012	)	**AND CONTRACT TERMS FOR**
	)	**QUALIFYING FACILITIES**

HEARD: Tuesday, February 12, 2013, at 9:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, October 29, 2013 at 1:00 p.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, October 30, 2013 at 9:00 a.m. Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown Bland, Presiding; Chairman Edward S. Finley, Jr., Commissioners Lucy T. Allen (February hearing only), Lorinzo L. Joyner (February hearing only), Bryan E. Beatty, William T. Culpepper, III (February hearing only), Jerry C. Dockham (October hearings only), James G. Patterson (October hearings only) and Susan Rabon

APPEARANCES:

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BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission's (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the 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 the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power 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 which 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. The relevant FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state regulation, the 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 the FERC's rules.

The Commission has implemented Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also results from the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute provides that, "no later than March 1, 1981, and at least every two years thereafter," the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" as used in G.S. 62-156 is more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding other types of renewable resources.

On June 18, 2012, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing* (Scheduling Order). The Scheduling Order made Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP); New River Light & Power Company (New River), and Western Carolina University (WCU) parties to this proceeding to establish the avoided cost rates each is to pay for power purchased pursuant to the provisions of Section 210 of PURPA, the associated FERC regulations and G.S. 62-156. The Scheduling Order also required each electric utility to file proposed rates and proposed standard form contracts.

The Scheduling Order stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules rather than a full evidentiary hearing. DEP, DEC, DNCP, New River and WCU were required to file their statements and exhibits by November 1, 2012. Other persons desiring to become parties were initially required to seek permission to intervene and to file their comments, statements, and exhibits by January 7, 2013; this deadline was subsequently extended to February 7, 2013. All parties were allowed to file reply comments by February 13, 2013 and proposed orders by March 13, 2013. The Commission scheduled a public hearing for February 12, 2013, solely for the purpose of taking non-expert public witness testimony. Finally, the Commission required DEP, DEC, DNCP, New River and WCU to publish notice and submit affidavits of publication no later than the date of the hearing.

On June 25, 2012, DEP filed confidential avoided cost data and on November 1, 2012, DEP, DEC, DNCP, WCU and New River filed statements, comments and/or exhibits in accordance with the Commission's June 18, 2012 order. DNCP subsequently filed corrected comments, exhibits and avoided cost schedules on November 5, 2012.

The North Carolina Sustainable Energy Association (NCSEA), the Public Works Commission of Fayetteville (FPWC), and Carolina Utility Customers Association, Inc. (CUCA) filed petitions to intervene, all of which were granted. The Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR), Renewable Energy Group (REG), North Carolina Electric Membership Corporation (NCEMC) and Southern Alliance for Clean Energy (SACE) subsequently filed petitions to intervene, which were also granted.

On November 1, 2012, DEP also filed a Motion to Suspend Availability of Previously Approved Long-Term Rates. The motion sought authorization to make available to QFs the currently approved variable rates in Schedule CSP-27 during the period of time between December 1, 2012 and the date that the Commission issues an order setting rates in this docket. On November 6, 2012, NCSEA filed a brief in opposition to DEP's motion, and on November 8, 2012, the Commission requested comments on DEP's motion. On November 21, 2012, REG, NCSEA, EWP LLC, and the Public Staff filed comments, and on December 5, 2012, DEC and DEP filed joint reply comments, and the Public Staff and REG also filed reply comments.

On December 21, 2012, after considering comments filed by the Public Staff and other intervenors, the Commission issued an order granting DEP's motion to suspend availability of rates subject to conditions and requiring that DEP offer their proposed long-term fixed avoided cost rates subject to true-up pending a final order establishing rates in this docket.

On December 21, 2012, the Public Staff filed a motion to extend deadlines for intervenor comments, reply comments and proposed orders, which the Commission granted on December 28, 2012, allowing comments to be filed on February 7, 2013, reply comments on March 15, 2013 and proposed orders on April 15, 2013. On February 7, 2013, the Public Staff, NCSEA and REG filed initial comments.

On or before February 12, 2013, all electric utilities filed Affidavits of Publication of the Notice of Hearing, and the public hearing was held in the Commission's hearing room as scheduled. Seven public witnesses gave testimony at that hearing. In addition, several consumer statements of position were filed in this docket.

On March 14, 2013, DEC and DEP filed a joint motion for extension of time to file reply comments, which the Commission granted on March 15, 2013. Subsequently on March 22, 2013, the Public Staff filed a motion for a further extension of time to file reply comments, which the Commission granted on March 25, 2013, allowing reply comments to be filed on March 28, 2013.

On March 28, 2013, reply comments were submitted by the Public Staff, DNCP, and jointly by DEP and DEC. NCSEA also filed a motion asking the Commission to schedule an evidentiary hearing and to direct that DEC's and DNCP's proposed fixed long-term avoided cost rates go into effect on a temporary basis, subject to true-up following the Commission's final order in this proceeding. In response to the reply comments and request for an evidentiary hearing, on April 1, 2013, the Commission suspended the deadline for proposed orders and gave all parties the opportunity to file comments on the request for an evidentiary hearing. On April 8, 2013, DEC, DEP, and DNCP filed comments in opposition to calendaring an evidentiary hearing.

On May 14, 2013, the Commission issued an order directing DEC and DNCP to offer their proposed long-term fixed avoided cost rates subject to true-up pending a final order establishing rates in this docket. DEC subsequently filed its avoided cost rates in compliance with this order on June 13, 2013, and DNCP filed its avoided cost rates on August 15, 2013.

On June 6, 2013, the Commission issued an order scheduling an evidentiary hearing on September 10, 2013, and establishing the procedural schedule. On June 26, 2013, the Public Staff filed a motion to revise the procedural schedule, to postpone the hearing and extend the related filing dates. On July 1, 2013, the Commission granted the motion, rescheduling the hearing for 9:30 a.m. on October 29, 2013. On August 1, 2013, to avoid potential confusion, DEP filed its interim schedule CSP-27B in compliance with the Commission's December 21, 2012 order, which had not required the filing of revised rates pending the Commission's final order in this docket.

On August 6, 2013, DEP and DEC submitted a joint motion for extension of time to file testimony, which the Commission granted on August 8, 2013. On August 9, 2013, DNCP filed the direct testimony and exhibits of Bruce E. Petrie and Robert J. Trexler. On August 13, 2013, DEC and DEP jointly filed the direct testimony and exhibits of Kendal C. Bowman, Glen A. Snider and Theodore P. Pintcke. On September 27, 2013, REG filed the direct testimony of John E.P. Morrison and Don C. Reading and the affidavit of Erik Stuebe; the Public Staff filed the direct testimony of Kennie D. Ellis and John R. Hinton; NCSEA filed the direct testimony and exhibits for Karl R. Rabago. On October 18, 2013, DEC and DEP jointly filed the rebuttal testimony of Mr. Snider and Ms. Bowman; DNCP filed the rebuttal testimony of Mr. Petrie and Mr. Trexler; and NCSEA filed a report which provided additional support for Mr. Rabago's testimony. On October 25, 2013, DNCP, DEC and DEP filed a joint motion to strike NCSEA's October 18, 2013 correspondence and report. NCSEA responded to the joint motion on October 25, 2013, and on October 28, 2013 the Commission denied the motion to strike.

Having received from DEC and DEP on October 28, 2013, an oral notice of a settlement with the Public Staff and a request to delay the hearing to allow time to file the settlement agreement, the Commission issued an order rescheduling the hearing to begin at 1 p.m. on October 29, 2013. On October 29, 2013, the Public Staff, DEC and DEP jointly filed a Stipulation of Settlement. On that date, DNCP and the Public Staff also jointly filed a Stipulation of Settlement Agreement. The evidentiary hearing was held as scheduled on October 29, 2013. DEC and DEP subsequently on November 14, 2013, filed a letter clarifying that the evidence presented at the hearing strongly supports the settlement agreement and that Mr. Snider's summary of his rebuttal testimony was not intended to indicate a lack of support.

On November 27, 2013, DEC and DEP filed a Late-Filed Exhibit, responding to inquiries made at the evidentiary hearing. On December 2, 2013, DEC and DEP filed a revision to its November 27, 2013 Late-Filed Exhibit in order to correct a typographical error. Following the hearing, proposed orders were filed by the parties on December 20, 2013.

Various filings were made and orders were issued which are not discussed in this order but are included in the record of the proceeding.

Based on the foregoing, all of the parties' comments and other filings, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DEC should be required to offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5MW or less capacity, and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5MW or less capacity. The standard levelized rate options of 10 and 15 years should 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. DEC should offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3MW or less capacity.

2. DEP should be required to offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5MW or less capacity, and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5MW or less capacity. The standard levelized rate options of 10 and 15 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility or 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. DEP should offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3MW or less capacity.

3. DEC, DEP, and DNCP should offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (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 Commission-recognized active solicitation underway, it should offer QFs not eligible for

the standard long-term levelized rates the option of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings, or (2) contracting with the utility to sell power at negotiated rates. 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 standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is a Commission order approving a solicitation, it will be assumed that there is no Commission-recognized 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. The Peaker Method is generally accepted and used throughout the electric industry and is reasonable for use in this proceeding.

5. DEP should include in its QF rate schedule a new schedule that is consistent with DEC's Option B.

6. The performance adjustment factor (PAF) of 2.0 should be utilized by DEC, DEP, and DNCP in their respective avoided cost calculations for run-of-river

hydroelectric QFs with no storage capability and no other type of generation. DEC and DEP should use a PAF of 1.2 for all other QFs.

7. DEC and DEP should not include costs associated with hedging in their avoided energy cost rates.

8. The contract clause currently in DEC's avoided costs standard contract should be amended to make clear that the rate portion of long-term contracts are not subject to revision by subsequent Commission action.

9. DEC and DEP shall recalculate their avoided capacity rates using an installed CT cost of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** and shall refile such recalculated avoided cost rates in accordance with the provisions of this Order.

10. DEP may continue to include a Reduction-in-Energy Charge in its standard contract terms and conditions.

11. DEP should amend Section 11 of the Terms and Conditions of its standard avoided cost contract to reflect the lower Monthly Facilities Charge that DEP proposed in Docket No. E-2, Sub 1023. DEP should also amend existing agreements with QFs under its standard avoided cost contracts that contain a Monthly Facilities Charge to reflect the new Monthly Facilities Charge on a going forward basis.

12. The provisions of DEC's Schedules PP-N, PP-H and DEP's CSP-29 that make the fixed, long-term rates reflected therein available to customers under contract with DEC or DEP, respectively, as of November 1, 2014 are appropriate.

13. In light of the changes in the size and nature of the QF industry in North Carolina, it is appropriate for the Commission to solicit comments from the parties on

the need for a proceeding outside of the biennial avoided cost process to assess the current avoided cost process and related policies and the potential scope of such a proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

No party to this proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell 5MW or less or the availability of 5-year levelized rate options to all other qualifying facilities contracting to sell 3MW or less capacity. The Commission has consistently concluded in prior avoided cost proceedings that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next and that, in doing so, it must balance the need to encourage QF development on the one hand, and the risks of overpayments and standard costs on the other. The Commission continues to believe that its decisions in the most recent avoided cost proceedings strike an appropriate balance between these concerns. The Commission, therefore, concludes that DEC and DEP should each continue to offer long-term levelized rate options of 5-, 10-, and 15-year terms to hydro QFs contracting to sell 5MW or less and to QFs contracting to sell 5MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass, and that they should offer their 5-year levelized rate options to all other QFs contracting to sell 3MW or less capacity. With these limitations, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments and should continue to be made available.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 3

No party to this proceeding recommended a change with respect to the rates to be made available to QFs not eligible for the standard long-term levelized rates. The Commission concludes that DEC and DEP should continue to be required to offer QFs not eligible for the standard long-term levelized rates the optional contracts and rates derived by free and open negotiations or, when explicitly approved by Commission order, participation in the utilities' competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission.

The Commission has previously 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 costs, 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. Because arbitration may be be less time consuming and extensive for the QF than the previously available complaint process, the Commission concludes that the arbitration option should be preserved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The Commission has repeatedly affirmed that the Peaker Method is appropriate for calculating DEC's and DEP's avoided cost rates. No party in this proceeding has proposed that DEC or DEP be required to use a method of determining avoided costs other than the Peaker Method. However, NCSEA presented the direct testimony of Karl R. Rabago, sole employee and principal of Rabago Energy, LLC who opined on the

Peaker Method. In his direct testimony, NCSEA witness Rabago criticized the Peaker Method, and the Commission takes this opportunity to address these criticisms.

Witness Rabago opined that the Peaker Method does not reflect the full value of generating resources such as solar because it does not reflect the full range of benefits conferred by solar QFs. (Tr. Vol. 2, pp. 167-69) He further suggested that the true value of solar generation is better captured through a Value of Solar (VOS) study that would reflect a comprehensive assessment of the benefits of solar. (Tr. Vol. 2, p. 167) Witness Rabago noted, however, that he was not proposing a specific avoided cost value for solar generation based on VOS studies, other than an increase in the PAF. (Tr. Vol. 2, p. 184) Witness Rabago further testified that the alleged benefits reflected in VOS studies include social benefits, customer benefits and environmental benefits (Tr. Vol. 2, pp. 199-200), which are not the types of benefits that are appropriately considered in an avoided cost context. The Commission notes that the VOS studies to which witness Rabago referred include benefits such as general environmental benefits, economic benefits such as job creation, and general societal benefits such as the reputational benefit to customers of installing solar generation at their homes or businesses. Witness Rabago acknowledged that externalities such as environmental and societal benefits are not properly included in avoided cost calculations. He also noted that the industry does not yet possess the analytical rigor to assess such benefits accurately. (Tr. Vol. 2, p. 225) Nevertheless, witness Rabago maintained that VOS analyses provided a fuller avoided cost assessment than traditional avoided cost methodologies.

On October 28, 2013, NCSEA submitted a North Carolina-based VOS study conducted by Crossborder Energy ("Crossborder"), and witness Rabago testified regarding the Crossborder study during his direct testimony (See, e.g., Tr. Vol. 2, pp. 187, 189, and 229). The Crossborder study was submitted on the same day that rebuttal testimony of DEC, DEP and DNCP were due to be filed and well-after the time for NCSEA to file its direct testimony had passed.

In response to questions by Chairman Finley, witness Rabago acknowledged that he was not involved in the development of the Crossborder study. (Tr. Vol. 3, p. 11) Witness Rabago testified that he had spoken with the individual responsible for the Crossborder study once, and only exchanged a few emails with him. (Tr. Vol. 3, p. 16) Witness Rabago also acknowledged that the Crossborder study was developed for NCSEA. (Tr. Vol. 3, p. 9) Witness Rabago stated that the Crossborder study was not, to his knowledge, published or peer reviewed. (Tr. Vol. 3, p. 11)

In her rebuttal testimony, witness Kendal C. Bowman, Vice President Regulatory Affairs and Policy North Carolina for DEC and DEP, argued that VOS studies of the type described by witness Rabago are not appropriate for avoided cost calculations. Witness Bowman noted that many of the benefits associated with the VOS studies do not relate to a specific utility's avoided costs, but rather are associated with general societal benefits allegedly produced by solar generation. (Tr. Vol. 3, p. 119)

Witness Bowman also noted that witness Rabago had acknowledged that such VOS studies were outside the scope of the present proceeding when he stated in his pre-filed direct testimony that PURPA is not "designed…to fully address all of the issues" encompassed by a VOS study. (Tr. Vol. 3, p. 120) Further, witness Bowman noted that none of the VOS studies referred to by witness Rabago in his direct testimony had been conducted based on the value of solar generation in North Carolina and, therefore, did not provide meaningful information regarding the costs DEC and DEP avoid when purchasing power from QFs. (Tr. Vol. 3, p. 121) Further, in the absence of a VOS study specifically conducted for the purposes of determining the value of solar in North Carolina, it is not possible to test the accuracy and reasonableness of the assumptions and the analysis underlying the quantification of the alleged benefits of solar.

The Commission has consistently approved the Peaker Method and has recognized that it is a widely accepted methodology for calculating the costs avoided by a utility when it purchases power from a QF. No party or witness, including witness Rabago, has provided any specific recommendation regarding changes to the Peaker Method or alternative methods that should be used.

Based on the evidence presented, the Commission is not persuaded by witness Rabago's specific criticisms of the Peaker Method. For example, witness Rabago suggests that traditional avoided cost calculations do not fully capture the risk of costs associated with environmental regulation. However, under the Peaker Method, utilities include environmental compliance costs in the calculation of avoided energy rates. Moreover, witness Rabago's concerns that traditional avoided cost calculations do not fully compensate QFs for mitigating risks associated with fuel cost volatility are unpersuasive. Our avoided cost process accounts for the potential volatility in natural gas prices by establishing new avoided cost rates every two years. A QF that believes that such volatility could adversely affect its compensation from utilities, therefore, can opt for shorter-term power sales agreements to take advantage of the frequent resetting of avoided cost rates.

With regard to witness Rabago's assertion that VOS studies more accurately reflect the costs a utility avoids by purchasing power from solar QFs, the Commission finds that assertion to be unsupported by the evidence presented in this docket. The Commission is not convinced that VOS studies provide a better assessment of a utility's avoided costs when it purchases power from a solar QF. Even Witness Rabago concedes that VOS studies generally include benefits of solar generation that would not be appropriate to apply in the context of calculating a utility's avoided cost. Witness Rabago did not cite a single instance of a regulatory body using a VOS study in the context of setting a utility's avoided cost rate, and the Commission is unaware of any such instance. Moreover, it must be borne in mind that the purpose of the avoided cost process is to determine the specific costs avoided by particular utilities when purchasing power from QFs. Accordingly, the extent to which a particular type of QF generation may provide alleged benefits to society in general is not relevant to the avoided cost calculation process. Consequently, the VOS studies as presented by witness Rabago do not appear to provide a more appropriate means of determining a utility's avoided cost.

Witness Rabago's direct testimony was predicated primarily on VOS studies conducted in states other than North Carolina. However, avoided cost calculations are intended to be utility specific. Thus, VOS studies conducted outside of North Carolina have no probative value in the context of the current proceeding. The only VOS study purporting to assess solar generation in North Carolina is the Crossborder study, which was not filed with Mr. Rabago's direct testimony, and was filed at the same time DEC, DEP, and DNCP filed their rebuttal testimony. Witness Rabago conceded that he had no role or input in the development of the Crossborder study. The individuals who actually conducted the Crossborder study did not provide any testimony or backup for the assumptions and conclusions in the Crossborder study. Therefore, the Crossborder study was not subject to discovery, nor were the individuals who were responsible for it subject to cross-examination in this proceeding. Although the Commission allowed the Crossborder study to be entered into evidence by NCSEA, it cannot be afforded any meaningful weight in this proceeding.

Based upon the foregoing, the Commission concludes that the Peaker Method remains a reasonable and appropriate approach for DEC and DEP to establish their avoided cost rates.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

In his direct testimony, Public Staff witness Kennie D. Ellis, an engineer in the Electric Division of the Public Staff, testified that DEP and DNCP should be required to offer an avoided cost rate schedule similar to the Option B rates offered by DEC. Witness Ellis noted that DEC offers an Option A and an Option B in its avoided cost rate schedules. (Tr. Vol. 3, p. 27) The primary difference between these rate options is that DEC's Option B uses a narrower definition of on-peak hours. (Tr. Vol. 3, p. 29) As a result, Option B reflects a much smaller number of on-peak hours than DEC's Option A and, therefore, QFs have to run fewer hours in order to receive avoided capacity rate payments equivalent to 100% of the purchasing utility's avoided capacity costs. Witness Ellis further noted that he believed that the Option B approach to avoided cost rates has value to the utility and its customers by encouraging QFs to maximize their generation during specified critical on-peak hours. (Tr. Vol. 3, pp. 31-32)

Prior to this proceeding, DEP did not offer an Option A and Option B in its avoided cost rate schedules. Rather, it offered only a single option, which used a definition of on-peak hours that is more similar to DEC's Option A than it is to DEC's Option B. In her rebuttal testimony, DEC/DEP witness Bowman opined that DEP did not need to adopt a new schedule similar to DEC's Option B because DEP's avoided cost rate schedule used a definition of on-peak hours that was consistent with the definition of on-peak hours in DEP's time of use rate schedule. (Tr. Vol. 3, pp. 115-16) This was the same approach that produced DEC's Option B. That is, DEC's Option B uses a definition of on-peak hours that is consistent with DEC's time of use rates. Accordingly, witness Bowman indicated that conceptually, DEP's avoided cost rate schedule is already comparable to DEC's Option B. (*Id.*) Witness Bowman also noted that immediate adoption of Option B would be problematic for DEP due to a need to change the metering for small QFs to accommodate a new definition of on-peak hours. (Tr. Vol. 3, pp. 115-16). Nevertheless, on October 28, 2013, DEP and DEC entered into a stipulation with the Public Staff under which DEP agreed to file a new avoided cost rate schedule that utilizes the same definition of on-peak hours that is used in DEC's rate schedule Option B.

Based upon the foregoing, the Commission concludes that DEP should file a new rate schedule utilizing the definition of on-peak hours that is used in DEC's rate schedule Option B. Using a narrower definition of on-peak hours encourages QFs to operate and provide power when it is most needed by the purchasing utility and its customers. Furthermore, by substantially reducing the number of on-peak hours, the new rate schedule will benefit QFs by reducing the number of hours that the QFs have to operate in order to obtain 100% of the purchasing utility's avoided capacity costs through avoided capacity payments. The availability of an Option B-type rate schedule also mitigates concerns raised in this proceeding regarding the ability of solar and wind QFs to obtain capacity payments due to the intermittent nature of their operations. If the necessary changes in metering are not complete when DEP files its Option B-type rate schedule, DEP should also include in the filing a date by which the metering changes will be finalized. As discussed elsewhere in this Order, several parties expressed concern that QFs such as solar and wind QFs that can only operate intermittently, and have little control over when they do operate, have difficulty obtaining avoided capacity payments. However, by providing these QFs with the option of an avoided cost rate schedule that uses a much narrower definition of on-peak hours, this concern is mitigated. The availability of such a rate schedule option substantially increases the amount of capacity payments that such QFs will receive by reducing the number of on-peak hours over which the utility's avoided and capacity costs are spread. Accordingly, the Commission concludes that DEP should file a new rate schedule using the same definition of on-peak hours as is used in DEC's rate schedule Option B.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

NCSEA and REG argued in this case for the use of a PAF of 2.0 for solar and wind QFs, as opposed to the PAF of 1.2 that is currently applicable to such QFs. DEP, DEC and DNCP all opposed increasing the PAF for solar and wind QFs. The Public Staff did not support the institution of a PAF of 2.0 for solar and wind QFs and recommended instead that DEP and DNCP be required to adopt an avoided cost rate schedule similar to DEC's Option B. The parties' positions and the Commission's conclusion on this issue follow.

<u>REG'S POSITION</u>

REG offered the testimony of Don C. Reading, Ph. D., of Ben Johnson Associates in support of its recommendation that PAF for solar and wind QFs should be increased to

2.0. Witness Reading made four arguments for this position. First, REG witness Reading testified that the Commission has already applied a 2.0 PAF for run-of-river hydroelectric QFs and that like such hydroelectric QFs, solar and wind QFs have no control over their energy sources and no storage capability. (Tr. Vol. 2, p. 57) Consequently, witness Reading suggested that such facilities are at a disadvantage because the QFs can only obtain capacity payments for operation during on-peak hours and have limited control over when they operate. (*Id.*)

Second, witness Reading also noted that DEC has constructed a solar facility and has placed at least a portion of that facility in rate base. (*Id.*) Witness Reading noted that a utility is able to recover the full cost of constructing its own solar facilities, even though they have capacity factor similar to solar QFs. (Tr. Vol. 2, p. 58) Witness Reading argued that this puts solar QFs at a disadvantage compared to utility-built solar facilities because with a PAF of 1.2, solar QFs must produce power during 83% of on-peak hours to obtain full avoided capacity payment. (*Id.*)

Third, witness Reading also opined that allowing a 2.0 PAF for solar and wind QFs would be consistent with the state policy encouraging such generation as illustrated by the provisions of Senate Bill 3. (*Id.*) Finally, witness Reading noted that providing a PAF of 2.0 for solar and wind QFs would be consistent with the recent FERC decision in *California Pub. Utilities Comm'n*, Docket No. EL10-64-002 and related cases (collectively referred to as the "*CPUC*"). (*Id.*) Such decisions suggest that a state commission may take into account a particular type of QF capacity when setting avoided cost rates if that particular type of capacity allows the purchasing utility to avoid particular types of costs. (*Id.*)

On cross-examination by counsel for DEC/DEP, witness Reading agreed that there had been a considerable percentage increase in solar generation in North Carolina since 2007. (Tr. Vol. 2, p. 71) Witness Reading also noted, however, that the percentage increase was affected by the fact that the starting point was a very low number. (*Id.*) He opined that on an installed MW basis, the amount of solar generation in North Carolina is still quite low compared to the amount of utility-owned generation. (*Id.*)

With regard to run-of-river hydroelectric QFs, witness Reading agreed on cross-examination that a policy reason behind the 2.0 PAF for such facilities may have been to help small hydro facilities deal with extended (i.e., 2 to 3 year) drought conditions that limit their ability to produce electricity. (Tr. Vol. 2, pp. 79-80) Witness Reading also acknowledged that the number of North Carolina sites suitable for run-of-river hydro generation are limited. (Tr. Vol. 2, p. 80) He also noted that there were fewer such limitations of siting solar generation. (Tr. Vol. 2, p. 81)

REG also presented the testimony of John E. P. Morrison, Chief Operating Officer for Strata Solar, a developer of solar generation headquartered in Chapel Hill, North Carolina. In his direct testimony, witness Morrison argued that the purpose of PURPA and related North Carolina statutes is to encourage the development of QFs, such as solar facilities in North Carolina. (Tr. Vol. 2, pp. 110-111) He took issue with DEC/DEP witness Bowman's assertion that the amount of proposed solar generation in the DEC and DEP interconnection queues demonstrates that such facilities are being adequately encouraged because, in his experience, not all of those projects will be developed. (Tr. Vol. 2, pp. 111-12) In that regard, he argued that the cost of obtaining a spot in the interconnection queue is very low. (*Id.*) Witness Morrison also opined that the avoided cost rates proposed by DEC and DEP were too low to encourage the development of QFs and that if the Commission accepted these rates that many QF developers would stop doing business in North Carolina. (Tr. Vol. 2, pp. 114-15)

NCSEA'S POSITION

NCSEA witness Rabago testified that he agrees with the legal argument presented in REG's comments that the reasoning applied by the Commission in previous dockets to support a PAF of 2.0 for run-of-river hydroelectric QFs should also apply to solar and wind QFs that do not have control over their fuel sources. (Tr. Vol. 2, p. 177) Witness Rabago also observed that because traditional avoided cost calculations do not, in his opinion, fully capture the benefits provided by solar QFs, VOS studies are a more appropriate way to capture the full avoided costs of such facilities. (*Id.*) However, in the absence of an appropriate VOS study for North Carolina, witness Rabago recommended that the Commission adopt a PAF of 2.0 for solar QFs as the least disruptive proxy for avoided cost rates based on a VOS study. (Tr. Vol. 2, p. 178) Witness Rabago did not provide any quantification of the level of compensation that a VOS study would show solar QFs in North Carolina should receive in avoided cost payments. Nor did witness Rabago attempt to show how the results of a VOS study would relate to the compensation solar QFs would receive if the PAF is increased to 2.0. Rather, witness Rabago testified that, because he believed that a VOS would show that solar QFs are providing more benefits to purchasing utilities than the Peaker Method reflects, increasing the PAF for solar QFs to 2.0 would be a form of "rough justice." (Tr. Vol. 2, p. 230)

PUBLIC STAFF'S POSITION

Public Staff's position on this matter was provided by witnesses Ellis and John R. Hinton, Director of the Public Staff's Economic Research Division, who testified as a panel with witness Ellis. In his direct testimony, witness Ellis described the history behind the development of the PAF. (Tr. Vol. 3, pp. 24-26) In particular, witness Ellis noted that the purpose of the PAF was to give QFs the opportunity to obtain payments equal to 100% of the purchasing utility's avoided cost without having to maintain 100% capacity factor during all on-peak hours. (Tr. Vol. 3, p. 26) However, witness Ellis did not recommend the utilization of a 2.0 PAF for solar and wind QFs. Rather, he recommended that DEP and DNCP be required to adopt an avoided cost rate schedule similar to DEC's rate schedule Option B as an appropriate alternative to increasing the PAF for solar and wind QFs.

On redirect, witness Ellis explained that DEP's and DNCP's adoption of an Option B was a better option for ratepayers than increasing the PAF for solar QFs. (Tr. Vol. 3, p. 90) In that regard, he stated that it would be better for QFs to be available for 83% of the more narrowly defined on-peak hours of Option B rather than for 50% of the larger on-peak period defined in non-Option B rate schedules. (*Id.*)

In response to questions from Commissioner Brown-Bland, both witness Ellis and witness Hinton suggested that further study should be undertaken before the Commission changes its PAF policy. (Tr. Vol. 3, pp. 92-93) They referred to the potential impact on ratepayers, the operational impact of installing significant solar generation, and the manner in which solar generation is operated and sized as areas that require additional study. (*Id.*) Witness Hinton also observed that, with regard to a comparison between run-of-river hydroelectric QFs that receive a PAF of 2.0 and solar and wind QFs that receive a PAF of 1.2, the very limited opportunities to develop new hydroelectric generation in North Carolina distinguishes such generation from solar and wind resources. (Tr. Vol. 3, p. 97)

DEC/DEP POSITION

In her direct testimony, DEC/DEP witness Bowman stated that DEC and DEP oppose the proposal to increase the PAF for solar and wind QFs. She observed that a PAF is a multiplier applied to avoided cost capacity rates paid to QFs to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of avoided capacity payments. (Tr. Vol. 1, pp. 102-03) She noted further that solar and wind QFs currently enjoy the benefit of a PAF of 1.2 and that an increase in the PAF for solar and wind QFs to 2.0 could constitute an effective 67% increase in capacity payments received by solar and wind QFs. (Tr. Vol. 1, p. 63) Witness Bowman further testified that the policies underlying Senate Bill 3 do not warrant an increase in the PAF for solar and wind QFs. (Tr. Vol. 1, pp. 103-04) She acknowledged that Senate Bill 3 reflects a state policy in favor of encouraging solar and wind generation in North Carolina, but noted that the General Assembly had structured Senate Bill 3 to limit the cost that customers are required to pay in furtherance of that policy. Specifically, Senate Bill 3 limits the costs incurred by utilities, (and ultimately recovered from their customers) to meet the requirements of that legislation based on costs incurred "in excess of the utilities' avoided cost." (*Id.*) Given that Senate Bill 3 restricted the costs that customers would incur based on the utility's avoided cost rates, witness Bowman concluded that it would be inconsistent with the intent of Senate Bill 3 to attempt to encourage the development of such QFs by effectively increasing the avoided cost rate that they receive. (Tr. Vol. 1, p. 105)

Witness Bowman also testified that the increase in the number of proposed solar and wind projects in North Carolina suggested that increasing the PAF for such QFs was unnecessary to encourage the development of such facilities. (*Id.*) In that regard, witness Bowman noted that as of March 28, 2013, there were more than 1,650 MWs of proposed solar generation facilities and approximately 200 MWs of proposed wind facilities in the utility's interconnection queues. (*Id.*) She further noted that between March 28, 2013, and October 18, 2013, those figures had grown such that the amount of solar and wind generation in the utility's queues was 2,300 MWs and 300 MWs, respectively. (*Id.*) Witness Bowman argued that such figures demonstrated that the utility's avoided cost rate structures – including the application of a 1.2 PAF for solar and wind QFs – was more than adequate to satisfy the State's policy in favor of encouraging the development of new solar and wind projects. (*Id.*)

Witness Bowman further testified that increasing the PAF for solar and wind QFs would result in higher rates for utility customers. (Tr. Vol. 1, p. 126) To illustrate this point, witness Bowman observed that for every 1,000 MWs of solar QFs that execute 15-year contracts, the application of a PAF of 2.0 would impose an incremental cost of $150 million on DEC's and DEP's customers. (*Id.*) She noted that this estimate was conservative given that 1,000 MW represents only a portion of the solar projects currently in DEC's and DEP's interconnection queue and that it was based on the avoided capacity rates proposed by DEC and DEP, not the higher rates recommended by other parties. (*Id.*)

On cross-examination by counsel for NCSEA, witness Bowman acknowledged that North Carolina has adopted a policy of encouraging the development of solar generation. (Tr. Vol. 1, p. 121). She also agreed that in previous orders in biennial avoided cost proceedings, the Commission had observed that use of a different PAF for hydroelectric facilities did not change a utility's avoided cost, but rather changed the manner in which those avoided costs are paid to QFs. (Tr. Vol. 1, p. 123) Nevertheless, witness Bowman stated that a PAF is a modifier that increases avoided cost rates over and above the Commission-established avoided capacity rates.

On cross-examination, witness Bowman also agreed that DEC currently has some solar generation in its rate base as a result of a pilot program, most of which is roof-top solar. (Tr. Vol. 1, p. 125) Witness Bowman also acknowledged that DEC and DEP were considering adding more solar generation if it was consistent with their least-cost obligation to customers. (Tr. Vol. 1, pp. 134-35) Witness Bowman further agreed that DEC and DEP can fully recover the cost of constructing solar facilities, assuming perfect ratemaking and that the utilities' solar facilities would likely have an equal capacity factor of about 18%. (Tr. Vol. 1, p. 131)

On redirect, witness Bowman explained that she viewed providing an Option B avoided cost rate schedule available to QFs was a superior alternative to increasing the PAF for solar and wind QFs to 2.0. (Tr. Vol. 1, p. 150) While Option B and a PAF of 2.0 both ultimately increase the capacity payments a QF receives, Option B has a stronger nexus to PURPA. (*Id.*) Witness Bowman explained that the narrower definition of on-peak hours encourages QFs to operate during hours when utilities most need the capacity, thereby benefiting the utilities and their customers. (*Id.*)

Witness Bowman also clarified under Option B and a PAF of 1.2, a QF could operate at about a 17% capacity factor and receive capacity payments equivalent to 100% of a utility's avoided capacity costs. (Tr. Vol. 1, pp. 156-57) She noted that under Option B there are 1,860 on-peak hours, which constitutes 20% of the 8,760 hours in the year. (*Id.*) Operating 83% of these on-peak hours equates to an annual capacity factor of approximately 17%. (*Id.*) Witness Bowman further noted that in the 2008 biennial avoided cost proceeding, NCSEA had taken the position that it no longer supported the implementation of a 2.0 PAF for renewable QFs other than run-of-river hydroelectric QFs. (Tr. Vol. 1, p. 162) She testified that NCSEA had opined that there were better policy alternatives to encouraging the development of renewable QFs, such as the provision of renewable energy certificates (REC) and REC pricing. (*Id.*) Witness Bowman also observed that in the 2008 proceeding, the Commission found that it was not appropriate to consider the policy initiatives suggested by NCSEA in the context of an avoided cost proceeding. (Vol. 1, p. 163)

In her rebuttal testimony, witness Bowman noted that increasing the avoided capacity rates to certain QFs to compensate for their inability to operate reliably and consistently during peak periods is illogical and violates the underlying principles of PURPA. (Tr. Vol. 3, p. 117) She also noted that such an increase would be inconsistent with Senate Bill 3, in which the General Assembly established a specific framework to encourage the development of such solar and wind generation, including limits on the cost that consumers must pay to achieve that goal. (Tr. Vol. 3, pp. 117-18)

Also in her rebuttal testimony, witness Bowman questioned whether witness Rabago's reliance on VOS studies justified his recommendation to increase the PAF for solar QFs to 2.0. Witness Bowman noted that in his filed testimony, witness Rabago had not included any VOS study applicable to North Carolina, and in fact, conceded that he was not aware of whether any such study has ever been done. (Tr. Vol. 3, pp. 121) She concluded, therefore, that it is speculation what such a study would show and whether it would support any increase in a PAF. (*Id.*) Further, Witness Bowman noted that witness Rabago made no attempt to explain how such a VOS study, if one existed, would support an increased PAF for solar QFs. (Tr. Vol. 3, p. 122) He provided no quantification or analysis that would link the alleged benefits shown by a VOS study to an increase in the PAF. (*Id.*)

DEC and DEP also presented testimony from Glen A. Snider, Director of Integrated Resource Planning for DEC and DEP. In his direct testimony, witness Snider explained that avoided capacity payments are intended to compensate a QF based on the cost of the capacity that a purchasing utility avoids by purchasing power from the QF. (Tr. Vol. 1, p. 225) Witness Snider reasoned, therefore, that avoided capacity payments should be commensurate with the power that a QF can provide during on-peak hours. (*Id.*) Accordingly, witness Snider took issue with the position that the PAF should be increased for solar and wind QFs to compensate for such generation as if it operated consistently and reliably during peak periods. (Tr. Vol. 1, p. 226) Witness Snider suggested that such an approach is inconsistent with PURPA, in that it seeks to pay QFs higher capacity rates because they are unable to reliably provide capacity to the purchasing utility. (Tr. Vol. 1, p. 225) He further opined that such an approach is not consistent with the purpose of the PAF, which is to account for ordinary outages that all generation is subject to from time-to-time, not to make up for inherent operational limitations that prevent facilities from operating reliably during peak periods. (Tr. Vol. 1, p. 227) To this point, witness Snider noted that DEC and DEP do not take full credit for the nameplate capacity of solar and wind generation in calculating their reserve margins. Solar and wind generation are assigned a capacity credit of approximately 40% and 15% of their nameplate ratings, respectively. (Tr. Vol. 1, p. 226)

Although the Commission has provided a 2.0 PAF for run-of-river hydroelectric facilities, witness Snider stated that such facilities are distinguishable from solar and wind QFs. (Tr. Vol. 1, p. 238) Specifically, witness Snider observed that the 2.0 PAF for hydroelectric QFs was adopted pursuant to a specific North Carolina statutory policy encouraging the continued operation of run-of-river hydroelectric facilities. (*Id.*) Further, witness Snider noted that the amount of run-of-river hydroelectric generation in the State is relatively small and finite due to the limited number of sites that are suitable for such hydroelectric facilities. (*Id.*) Conversely, there are few limits on the amount of solar generation that can be installed in North Carolina. (*Id.*)

Mr. Snider also disputed the suggestion that increasing the PAF for solar and wind QFs to 2.0 was necessary to put such QFs on par with similar facilities constructed by utilities such as DEC and DEP. (Tr. Vol. 1, p. 228) Witness Snider noted that the cost recovery processes applicable to public utilities is entirely different than the avoided cost process. (*Id.*) For example, public utilities are limited to recovering their actual costs. (*Id.*) Therefore, a public utility may recover the full cost of installing a solar or wind facility through base rates, but would be allowed to charge very little for fuel and variable O&M expenses because such facilities have so few expenses of that nature. (Tr. Vol. 1, pp. 228-29) Conversely, a QF receives payments based on the purchasing utility's avoided cost, regardless of what the QF expends and, therefore, may be entitled to payments well in excess of their actual cost to operate their facilities. (*Id.*)

Finally, Mr. Snider noted that there appears to be little need to increase the PAF for solar and wind QFs to encourage the development of such facilities. (Tr. Vol. 1, p. 229) He observed that the State is experiencing historic levels of QF interest, particularly from developers of solar QFs. (*Id.*) These developers presumably are aware of the State's current avoided cost rate structure, including the 1.2 PAF applicable to such facilities. (*Id.*) Therefore, witness Snider concluded that it is reasonable to assume that QF developers view this rate structure as providing them a fair opportunity to earn an adequate return on their investment. (*Id.*)

On December 2, 2013, in response to a Commission request, DEC and DEP submitted a late-filed exhibit to provide certain information requested by the Commission at the hearing. This exhibit showed that since January 2011, DEC and DEP had received interconnection requests from 689 projects, representing 3,435 MW. (DEC/DEP Late-Filed Exhibit at 1) The exhibit also showed that 222 of these projects have become operational, representing approximately 200 MW. (DEC/DEP Late-Filed Exhibit at 1) The exhibit also noted, however, that the growth of the proposed projects has accelerated dramatically in recent months. Through the first ten months of 2013, the number of projects in the DEC and DEP interconnection queues has doubled and the associated amount of MW represented by the queued projects has tripled. (DEC/DEP Late-Filed Exhibit at 2) The exhibit also demonstrates that since 2007, DEC and DEP have entered into only four power purchase agreement with new hydroelectric facilities and the combined capacity of these facilities is approximately 5 MW. (DEC/DEP Late-Filed

Exhibit at 2-3) With regard to new solar facilities, the exhibit reveals that DEC and DEP have entered into contracts with three projects under the rates proposed in this proceeding, which have a combined capacity of 62 kW. (DEC/DEP Late-Filed Exhibit at 3) Finally, the exhibit indicates that DEC has contracts with only 2 solar QFs with a capacity greater than 5 MW and DEP has no contracts with solar QFs of that size. (DEC/DEP Late-Filed Exhibit at 3-4)

DNCP'S POSITION

DNCP opposes the use of a 2.0 PAF for solar and wind QFs. DNCP offered the testimony of Bruce Petrie, Manger of Generation System Planning for DNCP. DNCP witness Petrie provided direct testimony that applying a 2.0 PAF to solar and wind QFs is illogical because it provides a premium to resources that do not operate reliably during peak periods. (Tr. Vol. 1, p. 299) Witness Petrie testified that solar facilities produce only 20% to 40% of their maximum output during 4 p.m. to 5 p.m. period, when utilities usually experience their system peak load. (Tr. Vol. 1, pp. 300-01) He also noted that because of this misalignment of solar output and peak hours, PJM only gives solar resources a capacity credit of 38% of the installed MW value. (Tr. Vol. 1, p. 301) He further noted that these issues also apply to wind resources, which typically only produce 10% to 20% of their installed capacity during the system peak hour and only receive capacity credit of 13% of their installed capacity by PJM. (Tr. Vol. 1, p. 302)

Witness Petrie also opined that the presence of solar or wind generation in a utility's rate base does not warrant the use of a 2.0 PAF. (Tr. Vol. 1, p. 303) Witness Petrie argued that under PURPA, a utility's avoided cost is determined based on the alternative cost of power that the utility avoids by purchasing from a QF, not the cost of resources included in the utility's rate base. (Tr. Vol. 1, p. 303)

Witness Petrie also disagreed that the policies underlying Senate Bill 3 justified increasing the PAF for solar and wind QFs. (Tr. Vol. 1, p. 304) Although Senate Bill 3 requires North Carolina utilities to obtain a certain amount of their electric power from renewable resources, witness Petrie noted that it does not mandate a specific rate to be paid for energy from such renewable resources. (*Id.*) Rather, Senate Bill 3 provides a mechanism for utilities to recover their costs if they have to pay more than their avoided cost for such power. (*Id.*) Witness Petrie concluded that the provisions of Senate Bill 3, therefore, were distinguishable from G.S. 62-156, which the Commission cited in support of instituting a 2.0 PAF for run-of-river hydroelectric QFs. (*Id.*)

Witness Petrie further stated that since the passage of Senate Bill 3, the renewable energy sector has grown in North Carolina. (Tr. Vol. 1, p. 305) Citing information produced by NCSEA, Witness Petrie noted that in 2012 the clean energy sector included over 1,100 North Carolina companies, accounted for 15,200 full-time employees, and generated $3.7 billion in revenue in North Carolina. (*Id.*) He, therefore, concluded that Senate Bill 3's policy goal of encouraging the development of renewable resources was working and further incentives in the form of an increased PAF for solar and wind QFs was not needed. (*Id.*)

Finally, witness Petrie testified that FERC's decisions in the *CPUC* cases do not support an increase of the PAF for solar and wind QFs. (Tr. Vol. 1, p. 306) Witness Petrie explained that the *CPUC* cases arose in the context of a California law that required utilities in that state to enter into ten-year contracts with non-utility generators that meet stringent efficiency and emission standards at prices established by the

California Public Utilities Commission. (*Id.*) FERC concluded that the California Commission did not have the authority to set rates for non-QF wholesale power contracts. (*Id.*) However, FERC found that, under PURPA, California could establish a multi-tiered avoided cost structure that takes into account a state-imposed obligation to purchase power from particular sources. (Tr. Vol. 1, p. 307) Witness Petrie argued that FERC's decision is inapposite to the present case because this Commission has not adopted such a multi-tiered avoided cost structure and that no evidence has been presented in this proceeding that would support the creation of such multi-tiered avoided cost rates. (Tr. Vol. 1, p. 308)

On cross-examination by NCSEA's counsel, witness Petrie stated that DNCP believes that a 2.0 PAF for solar QFs could result in capacity payments in excess of the purchasing utility's avoided costs because solar is only 38% effective in avoiding the utility's capacity (i.e., purchasing the output of a 100MW solar capacity provides 38 MW of capacity credit from PJM). (Tr. Vol. 2, pp. 10-11) Witness Petrie acknowledged that this reasoning may also mean that the 2.0 PAF for run-of-river hydro QFs also results in capacity payments in excess of avoided capacity costs. (Tr. Vol. 2, p. 11)

On cross-examination, witness Petrie also acknowledged that DNCP is in the process of developing solar facilities and that such facilities would likely have an annual capacity factor similar to the capacity factor typical for solar QFs (i.e., approximately 18% to 20%). (Tr. Vol. 2, p. 12) Witness Petrie noted, however, that DNCP currently does not have any solar generation in its rate base. (*Id.*)

In his rebuttal testimony, witness Petrie took issue with the relevance of the VOS studies cited by NCSEA witness Rabago. (Tr. Vol. 3, p. 245) Witness Petrie noted that the VOS studies included among the benefits of solar generation such things as "reputational community participation," avoidance of financial risks associated with "future control regimes" and "societal benefits" such as job growth and increased local tax revenues. (Tr. Vol. 3, p. 246) Although such items may have value, witness Petrie argued that they do not represent costs that utilities avoid by purchasing the output of QFs. (*Id.*) Further, witness Petrie noted that this Commission has previously ruled that unknown and uncertain environmental costs are not properly included in avoided cost calculations. (Tr. Vol. 3, p. 247)

COMMISSION CONCLUSION

The Commission has traditionally used a PAF in calculating avoided capacity cost rates for utilities using the Peaker Method. The PAF adjustment recognizes that a generating facility cannot be in operation at all times, and therefore, increases the capacity rates and thus allow a QF to experience a reasonable number of outages and still receive payments equal to the utility's avoided capacity costs. If a utility's avoided capacity rates were set only at the utility's avoided costs without a PAF, a QF would not receive full capacity payments unless it operated 100% of the on-peak hours throughout the year.

Until the 1996 avoided cost proceeding in Docket No. E-100, Sub 79, the Commission approved a PAF of 1.2 for the calculation of avoided cost rates for all QFs. In its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* issued on June 19, 1997, ("Sub 79 Order") approving avoided cost rates in that docket, the Commission approved a PAF of 2.0 for hydroelectric QFs with no storage capability and no other type of generation, which allows such QFs to recover their full capacity payments if they operate 50% of the on-peak hours. The 1.2 PAF used by the Commission in previous cases (for QFs other than run-of-river hydroelectric facilities) reflected the Commission's judgment that if a unit is available and operates 83% of the time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs.

At the outset, it is important to clarify the purpose of the PAF. As the Commission has observed in previous avoided cost proceedings, the PAF allows QFs to operate less than 100% of on-peak hours to receive the full capacity payments to which it is entitled. *See* Sub 79 Order, p. 19. A QF, however, is not entitled to full capacity payments (i.e., payments equal to the purchasing utility's avoided capacity costs) regardless of how it operates. Rather, a QF is entitled to full capacity payments if it operates with reasonable reliability and availability during on-peak hours. The PAF was not intended to ensure full capacity payments to QFs that are not reasonably available during on-peak hours or to make up for operational deficiencies of certain types of generation. Further, the PAF is not intended as a mechanism to ensure the profitability of specific QFs or particular QFs. REG witness Morrison expressed general concern that without higher avoided cost rates many QF developers would cease to do business in North Carolina. However, the Commission's recent experience in terms of applications for new solar facilities suggests that there is still strong interest building new solar facilities in the State. Even if current avoided cost rates make it more difficult for certain QFs to be commercially successful, the PAF is not intended to guarantee the commercial success of such projects.

The PAF must be evaluated in the context of PURPA's underlying principle that the rates paid to QFs shall not exceed the incremental cost of self-generated power or purchased power that the purchasing utility would incur but for the purchase of power from a QF. *See* 19 C.F.R. 292.101(b)(6). In other words, the rates paid to a QF cannot exceed the purchasing utility's avoided cost. Applying a PAF for the purpose of providing capacity payments to a QF in excess of the capacity value that it provides or to ensure the QF's profitability would not be consistent with the underlying principles of PURPA.

Finally, the Commission notes that DEP and DNCP have agreed to offer avoided cost rate schedules comparable to DEC's Option B. As explained by Public Staff witness Ellis, DEC's Option B uses a narrower definition of on-peak hours than DEC's Option A and the avoided cost rate schedules initially proposed by DEC and DNCP in this proceeding. As noted by witness Bowman, under an Option B-type rate schedule, a QF can operate at a 17.6% annual capacity factor and still receive capacity payments equivalent to 100% of the purchasing utility's avoided capacity costs. Although the availability of an Option B-type rate schedule from all of the State's utilities does not guarantee that every QF will receive capacity payments equal to 100% of the capacity of a new combustion turbine (i.e., the basis for capacity costs under the Peaker Method), it clearly mitigates concerns that intermittent resources such as solar and wind QFs may not be able to obtain capacity payments commensurate with the capacity value that they provide. Moreover, as between requiring that an Option B rate schedule be available to QFs and simply increasing the PAF for solar and wind QFs, the Commission finds that

Option B is the better alternative because it encourages and compensates QFs for operating during the hours when the purchasing utility most needs capacity.

Viewed against that background, and based on a careful review of all of the arguments presented in this proceeding, the Commission concludes that the recommendations made to increase the PAF for solar and wind QFs have not been sufficiently supported and that the PAF for such QFs should continue to be 1.2.

The proponents of increasing the PAF for solar and wind QFs to 2.0 offer five arguments in support of their position: 1) the intermittent nature of solar and wind generation makes it difficult for such QFs to obtain capacity payments equivalent to 100% of the annual capacity cost of a CT; 2) the 2.0 PAF helps to put solar and wind QFs on par with solar and wind generation built by the utilities; 3) solar and wind QFs are similarly situated with run-of-river hydro QFs that currently receive a PAF of 2.0 in that they are all intermittent resources and are all supported by State policies; 4) providing a 2.0 PAF for solar and wind QFs is consistent with FERC's decisions in the *CPUC* cases; and 5) a 2.0 PAF for solar QFs is a reasonable proxy for the higher avoided cost payments that such QFs would receive if avoided cost rates were set based on a VOS study.

With regard to the argument that the intermittent nature of solar and wind generation warrants a 2.0 PAF, as noted above, the PAF is not intended to compensate for such operational deficiencies. The challenges that solar and wind generation face in terms of reliable and consistent output is evident in the fact that DEC and DEP do not take full credit for the nameplate capacity of solar and wind facilities calculating their reserve margins. Similarly, PJM provides 48% and 13% capacity credit for solar and wind generation, respectively. This suggests that such QFs are less able to provide capacity value than traditional generating facilities, which does not support the suggestion that the capacity rates for solar and wind QFs be increased by 67%.

As to the argument that the 2.0 PAF places solar and wind QFs on equal footing with similar facilities developed by public utilities and included in their rate base, the Commission does not find the argument persuasive. First, two of the three electric public utilities in this State (DEP and DNCP) currently have no solar generation in their rate base and there is no evidence that any of the utilities have any wind generation in their rate base. Further, although DEC has a small amount of solar generation in its rate base, that solar generation is the result of a pilot program instituted by DEC and consists mostly of roof top solar installed on customers' buildings. As referred to in this proceeding, North Carolina has instituted policies supporting the development of solar generation. DEC and the other utilities in the State, therefore, should be encouraged to engage in activities like DEC's pilot program. That policy goal, however, would not be advanced by a rule under which the inclusion of solar or wind generation in rate base necessarily leads to a 67% increase in the capacity payments made to QFs of that type. To the contrary, such a rule actually may serve to discourage further development of solar generation by the utilities.

Additionally, the Commission agrees with the arguments made by DEC, DEP, and DNCP that there are vast differences between the cost recovery process for utilities and the avoided cost process. Although the Commission has previously indicated that the presence of solar and wind generation in utility rate base is a factor to be considered in setting the PAF for such QFs, it is not an outcome determinative factor. There are numerous significant differences between the avoided cost and utility cost recovery processes. For example, a utility may be entitled to recover from its customers its prudently incurred cost of building and operating a solar facility, but such recovery is limited to the utility's actual costs. Consequently, a utility may recover its cost to construct such a facility, but will receive little in terms of "energy" costs (i.e., fuel and variable O&M costs) because solar facilities incur virtually no energy costs for the utility to recover. Conversely, a solar QF receives capacity payments **and** energy payments from the purchasing utility and the energy payments comprise the bulk of payments that the QF receives. Moreover, those payments are based on the purchasing utility's avoided costs, regardless of the costs the QF incurs to install and operate its facility. Further, unlike a public utility, a QF is not constrained in terms of earning a Commission-approved reasonable return on its investment or the recovery of expenses it actually incurs.

The Commission recognizes that in past proceedings it has observed that the presence of a certain type of generation in a utility's rate base is a factor to be considered in assessing the PAF for QFs of that type. However, since only one utility has any solar generation in its rate base, and that is a small amount of solar generation from a pilot program, and given the State's policy of encouraging renewable resource development, the Commission concludes that the presence of solar generation in a utility's rate base is not sufficient grounds to increase the PAF for solar and wind QFs to 2.0.

REG and NCSEA also argue that solar and wind QFs are similar to run-of-river hydroelectric QFs in that they are intermittent resources with limited ability to control when they operate. They suggest, therefore, that the rationale upon which a 2.0 PAF has been approved for run-of-river hydroelectric QFs should also apply to solar and wind QFs. The Commission disagrees. First, the decision to allow run-of-river hydroelectric QFs to have a PAF of 2.0 was predicated primarily upon a specific State policy in favor of the continued operation of these facilities. In the 1996 biennial avoided cost proceeding, the Commission held that a 2.0 PAF should be used for run-of-river hydroelectric QFs "based on the statewide policy of encouraging hydro generation as expressed in G.S. 62-156." Sub 70 Order at 19. This state policy was not simply to encourage the development of new run-of-river hydroelectric facilities (particularly since the feasibility of developing new facilities of that type is greatly constrained by the limited number of suitable sites), but rather to provide support for the continued operation of existing run-of-river hydroelectric facilities. Further, as noted in the past, run-of-river hydroelectric QFs are "unique" in that "their ability to operate is beyond the control of their operators because their fuel is essentially stream flow, which is influenced by rainfall." *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 100 at 22 (September 29, 2005). Thus, run-of-river hydroelectric facilities can be subject to extended periods of operational limitations due to prolonged drought conditions. The Commission also is mindful that small run-of-river hydroelectric generation provides a minor portion of the State's electric supply. There is no realistic prospect that the amount of such generation will increase appreciably due to the limited number of sites in North Carolina that are suitable for small hydroelectric facilities. Thus, the economic impact of increasing the PAF for run-of-river hydroelectric QFs on electric consumers in North Carolina is nominal and not likely to increase. Given these particular circumstances, the Commission has allowed run-of-river hydroelectric facilities to receive a PAF of 2.0.

The Commission has considered the arguments of REG and NCSEA and concludes that the circumstances applicable to solar and wind QFs are not entirely analogous to those that support a 2.0 PAF for hydroelectric facilities. Although run-of-river hydroelectric, solar and wind generation are all intermittent, the nature of their intermittency is different. Solar and wind QFs are dependent upon the sun and wind, respectively, to produce electricity, but they are not at risk for the type of protracted operational limitations that can affect run-of-river hydroelectric QFs. North Carolina has adopted policies supporting solar and wind generation. However, rather than simply providing a general policy directive (as was the case with small hydroelectric facilities), the General Assembly has specified in Senate Bill 3 how solar and wind generation are to be encouraged and, more importantly, established limits on the cost that customers should bear in furtherance of that policy objective. Senate Bill 3 (G.S 62-133.8) requires electric utilities and other electric power suppliers to obtain a certain percentage of their electrical supply from renewable resources and even provides a specific amount that is to be obtained from solar generation. However, Senate Bill 3 also imposes limits on the amount that the utilities are required to spend and recover from its customers to fulfill these requirements. G.S. 62-133.8(h)(3)-(4). For purposes of this proceeding, it is significant that these cost limits are set based on a utility's "incremental cost," which is defined as cost "in excess of the utility's avoided costs." G.S. 62-133.8(h)(1)(a). Thus, while it was appropriate to address the previously adopted State policy supporting small hydroelectric facilities through an increased PAF, the Commission does not find that the same approach is appropriate as a means of advancing the policies of Senate Bill 3. To the contrary, increasing avoided cost payments to solar and wind QFs by raising their PAF would undercut and disrupt the specific cost constraints set forth in Senate Bill 3.

A final distinction between run-of-river hydroelectric QFs and solar and wind QFs is the magnitude of the impact that a change in PAF has on consumers. In this regard, the Commission notes that Section 210 of PURPA requires that the rates paid to QFs must be "just and reasonable to the electric consumers of the [purchasing utility]." As noted above, the impact on consumers of a 2.0 PAF for small run-of-river hydroelectric QFs is limited and unlikely to grow. This is demonstrated by the fact that DEC and DEP have entered into contracts with only 5 MW of new hydroelectric facilities since 2007.

Conversely, there are fewer limits on the development of solar and wind facilities. Currently, DEC and DEP have over 3,000 MW of proposed solar and wind projects in their interconnection queues. Further, as noted in DEC's and DEP's late-filed exhibit, the growth of the number of projects in the queue has accelerated. Through the first 10 months of 2013, the number of solar projects in the queue has doubled and the associated MW represented by the queued projects has tripled. Witness Morrison argued that the amount of projects in the utilities' interconnection queue does not necessarily reflect the amount of projects that will come to fruition. That may be true, but even a portion of those projects is several order of magnitude greater than the amount of new run-of-river hydroelectric generation reasonably expected to be developed in North Carolina. Moreover, Mr. Morrison's argument fails to consider that, if the Commission establishes a 2.0 PAF for solar and wind QFs, the increased PAF will apply to more than just projects that are currently queued. It will apply to every new solar and wind QF year after year and to any existing QFs that execute a new power sales agreement until the PAF is changed. The Commission notes that the unrebutted testimony of DEC and DEP estimates that for every 1,000 MW of solar QF capacity, a 2.0 PAF will impose incremental costs on the purchasing utility and its customers of $150 million over the life of a 15-year power purchase agreements and that this figure was calculated based on DEC's and DEP's proposed avoided capacity rates and their initially filed rate schedules. That estimate would be higher if it were calculated based on the higher avoided capacity rates to which DEC and DEP have agreed and used an Option B rate schedule for DEP. Thus, while one can debate the precise impact that increasing the PAF for solar and wind QFs may have, there is no question that such a change would impose a substantial economic burden on consumers.

With regard to the *CPUC Cases*, the Commission concludes that the principles set forth in these decisions do not warrant an increase in the PAF for solar and wind QFs. These decisions provide that a state commission may establish avoided cost rates that differentiate among types of QFs based on differences in the costs that they allow a utility to avoid. They do not require that state commissions adopt such a multi-tiered structure for avoided costs. Moreover, no party has recommended that the Commission do so in this proceeding and no evidence has been presented that would support the adoption of such a multi-tiered approach. Further, nothing in the *CPUC Cases* diminishes the fundamental principle that rates paid to QFs should be based on actual costs avoided by the purchasing utility. To the contrary, FERC made clear in the context of "adders" to avoided cost rates that such measures are permissible only if they are based on an "actual determination of expected costs … that the QFs will permit the purchasing utility to avoid." *CPUC*, 133 FERC at 15. Nothing presented in this proceeding suggests that the incremental increase of the PAF proposed for solar and wind QFs reflects actual costs that these types of facilities will allow utilities to avoid. Accordingly, we find the *CPUC Cases* inapposite to the issue before us in this docket.

Finally, the Commission finds witness Rabago's arguments in favor of increasing the PAF for solar and wind QFs to be unpersuasive. Essentially, witness Rabago argues that a VOS study would show that solar QFs provide greater benefits than are captured in avoided cost rates calculated pursuant to the Peaker Method. He, therefore, concludes that in the absence of a VOS study conducted for North Carolina utilities, that the Commission should adopt a 2.0 PAF as a proxy for the supposed excess benefits provided by solar QFs. For the reasons discussed below, the Commission does not accept this argument.

Witness Rabago assumes that VOS studies appropriately measure the costs that a solar QF allows the purchasing utility to avoid. As explained previously in this Order, the Commission does not agree. Witness Rabago's description of VOS studies suggests that they incorporate a number of alleged benefits of solar generation that cannot be included in avoided costs, including general societal benefits such as job creation, general environmental benefits, and even reputational benefits for individuals who install solar facilities on their property. Even if that were not the case, witness Rabago has not presented a single VOS study upon which this Commission could discern the benefits that solar QFs confer upon DEC, DEP, or DNCP. His direct testimony was predicated exclusively on VOS studies conducted outside of North Carolina.

At hearing, witness Rabago adopted the Crossborder study, which purports to be a North Carolina-based VOS study. However, he conceded that he had no involvement the development of that study and had limited knowledge of the company that produced it. Further, NCSEA presented no testimony from the individuals who were responsible for the Crossborder study. Consequently, neither the other parties nor the Commission were able to examine the reasonableness and relevance of the methodology and numerous assumptions underlying this study. On the surface, the Crossborder study presents a number of issues that would have to be analyzed and assessed before it could be accepted as valid for any purpose. For example, Crossborder conducted its own forecast of natural gas prices, made assumptions regarding the need and cost of firm gas pipeline capacity and calculated cost of CT capacity. However, the record contains no support or back-up for those calculations and assumptions. Moreover, the Crossborder study, like other VOS studies described by witness Rabago, appears to incorporate factors that are not appropriate for avoided cost purposes, including the cost of compliance with future environmental requirements, general mitigation of fuel prices, and economic development. Accordingly, given the record in this case, we cannot give meaningful weight to the Crossborder study nor can we conclude that the Crossborder study, or any of the VOS studies cited by witness Rabago, justifies the imposition of a 2.0 PAF for solar QFs.

Finally, we note that in addition to the foregoing, witness Rabago does not provide any evidence to explain how increasing the PAF for solar QFs to 2.0 relates to the results one would expect from a VOS study. Even he admits that increasing the PAF for solar QFs in the absence of a properly conducted and supported VOS study is nothing more than "rough justice." The Commission cannot base its decision on such a speculative foundation, particularly when the decision would impose significant incremental costs on the State's electric customers.

In considering the issues presented concerning the PAF, the Commission observes that the issue of whether to alter its PAF policy is complex and the ramifications of such a change can have substantial impacts to electric consumers. Accordingly, having carefully reviewed and considered the evidence presented in this docket, the Commission concludes that the PAF for run-of-river hydroelectric QFs should remain at 2.0 and the PAF for all other QFs should remain at 1.2.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 7

In its Initial Comments, NCSEA argued that DEC and DEP should be required to include natural gas hedging costs in its calculation of its avoided energy costs. (NCSEA Initial Comments at 35-39) NCSEA argued that DEP had requested recovery of approximately $50 million of hedging costs in its 2012 fuel case. (*Id.* at 36) NCSEA further argued that, because the Commission has found it prudent for DEP to hedge its gas purchases in order to reduce price volatility for its customers, it is reasonable to expect DEP to continue to incur hedging costs during the 15- to 20-year period for which gas prices are projected for purposes of this proceeding. (*Id.*) NCSEA, therefore, concluded that failure to include hedging costs could distort the utilities' avoided cost calculations such that they no longer represented the utilities' avoided energy costs. (*Id.* at 37) NCSEA acknowledged that currently DEC did not have a natural gas hedging program, but noted that DEC was considering instituting a long-term gas hedging program based on DEC's recent testimony in its 2012 REPS rider proceeding, Docket

No, E-7, Sub 1020. (*Id.* at 36, footnote 25) Based on the foregoing, NCSEA recommended that the Commission require DEC and DEP incorporate a projection of natural gas hedging costs into their calculations of overall avoided energy costs. (*Id.* at 39)

In their Joint Reply Comments, DEC and DEP responded to NCSEA's arguments regarding hedging costs. (DEC/DEP Joint Reply Comments at 31-33). With regard to DEC, they noted that DEC has no hedging program at this time and that, therefore, there was no basis upon which to include such costs in DECs avoided energy costs calculation. (*Id.* at 32) Further, DEC and DEP pointed out that their practice was to base their avoided costs on current information. (*Id.*) For example, DEP had calculated its avoided capacity rates based on a return on equity (ROE) of 12.75%, which was DEP's approved ROE at the time that the proposed avoided cost rates were filed in this docket. (*Id.* at 4) DEP took that approach even though it was highly likely that DEP's allowed ROE established in DEP's then-pending rate case would be substantially lower than 12.75%. (*Id.*) DEC and DEP, therefore, concluded that the proper approach to setting avoided costs is to use the best available current information and that the Commission should not require DEC to include in its avoided energy rates hypothetical hedging costs associated with a hedging program that does not currently exist. (*Id.* at 32)

With regard to DEP, DEC and DEP argued in their Joint Reply Comments that the hedging costs incurred by DEP should not be included in DEP's avoided energy calculations because they do not reflect costs that can be avoided by purchasing power from a QF. DEC and DEP explained that DEP's hedging program does not cover all of the natural gas it uses to produce energy. (*Id.*) Rather, DEP attempts to hedge its base load and intermediate use of natural gas. Accordingly, DEP hedged 40% of its gas burn during the 12-month period ending March 31, 2011, and 49% of its gas burn during the 12-month period ending March 31, 2012. (*Id.* at 32-33) DEC and DEP pointed out that under the Peaker Method avoided energy costs are based on a utility's marginal energy costs. (*Id.* at 32) Because DEP's natural gas hedging program is not focused on such marginal use of natural gas, it should not be included in the calculation of DEP's avoided energy costs. (*Id.* at 33)

Neither NCSEA nor any other party filed testimony on the issue of whether DEC or DEP should be required to include hedging costs in their avoided energy cost calculations.

On cross-examination by NCSEA's counsel, DEC/DEP witness Snider acknowledged that DEP had incurred hedging costs of $50 million in 2011 and $70 million in 2012. (Tr. Vol. 1, p. 242) Witness Snider also testified that, while DEP expects its hedging costs to move towards zero of the next few years, it would be reasonable to expect that DEP would continue to incur some level of hedging costs over the next few years. (Tr. Vol. 1, p. 242-43) Witness Snider also agreed that the Commission had directed DEC to develop a natural gas hedging strategy to be filed with the Commission by the end of 2013 (Tr. Vol. 1, p. 244) On redirect, witness Snider explained that DEP hedges only a small percentage of its natural gas consumption and that it does not hedge the gas that is burned to produce marginal energy. (Tr. Vol. 1, p. 251-52) Witness Snider also noted that hedges are used to lock in natural gas costs for a two-to-three year period and that hedging losses occur if future natural gas prices prove to be lower than projected. (Tr. Vol. 1, p. 252) Because the energy rates received by

QFs are based on similar projections as DEP uses in its hedging program, the same over-estimation of future gas prices that produce hedging losses also produce higher avoided energy rates that are paid to QFs. (*Id.*)

In assessing this issue, the Commission notes that the only evidence presented at the hearing on the inclusion of natural gas hedging costs in avoided cost rates was provided by witness Snider on behalf of DEC and DEP. The Commission has taken into account the comments filed by the parties on this issue, but the weight given to those comments is mitigated by the fact that the comments are not sworn testimony subject to cross-examination.

After consideration of all of the evidence presented on this issue, the Commission concludes that natural gas hedging costs should not be included in DEC's or DEP's avoided energy cost calculations. With regard to DEC, it is undisputed DEC did not have a long-term hedging program at the time it filed its proposed avoided cost rates in this docket and that DEC still does not have such program. The Commission, therefore, concludes that DEC should not be required to include speculative and hypothetical hedging costs in its avoided energy rate calculations. Although DEC may initiate a hedging program in the future, absent unusual circumstances, avoided cost rates should be based on a utility's actual costs as of the time that the avoided costs are calculated. In that regard, the Commission notes that the avoided cost rate process is designed to address the changing nature of utility costs by resetting avoided cost rates every two years. Thus, changes in relevant factors can be incorporated into a utility's calculation of its avoided cost rates with minimal delay.

As to DEP, based on the evidence presented in this proceeding, the Commission concludes that DEP's natural gas hedging costs were properly excluded from DEP's avoided energy cost calculations. Although witness Snider acknowledged that DEP currently incurs costs to hedge its natural gas purchases and that it expects to incur such costs for the next few years, the Commission is persuaded that these costs are not properly a part of DEP's avoided energy costs. Witness Snider explained that the purpose and intent of DEP's hedging program is to hedge only a portion of DEP's natural gas burn. This is consistent with DEC's and DEP's Joint Reply Comments, which states that DEP only hedges base load and intermediate gas burn associated with the operation of DEP's combined cycle generating facilities. Under the Peaker Method, DEP's avoided energy costs are calculated based on its marginal energy cost (i.e., the highest cost energy on DEP's system). Thus, the fuel that DEP is hedging is not the fuel that is producing the energy that makes up DEP's avoided energy costs.

Moreover, in order for any cost to be included in a utility's avoided cost rates, the cost must be capable of being avoided by the utility's purchase of power from a QF. However, when a utility purchases energy from a QF, the purchase displaces the marginal energy that the utility would have otherwise generated or purchased from another source. Such purchases, however, do not meaningfully impact the purchasing utility's base load and intermediate generation, which is the type of generation to which DEP's hedging program is directed. Accordingly, it does not appear that DEP's QF purchases actually reduce the amount of natural gas that DEP hedges, and therefore, would not allow DEP to avoid such hedging costs.

For the foregoing reasons, the Commission concludes that neither DEC nor DEP are required to include natural gas hedging costs in the calculation of the avoided energy rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In his pre-filed direct testimony, REG witness Morrison testified that certain language that had been included in previous versions of Section 2 of DEC's standard QF contract has been omitted in the version filed in this proceeding. (Tr. Vol. 2, pp. 116-17) The language in question pertains to the effect of changes made by the Commission to DEC's rate schedules and service regulations. Section 2 of DEC's Terms and Conditions provides that those rate schedules and service regulations are subject to change by the Commission and any such changes "shall immediately be made a part [of the QF contract], and shall nullify any prior provision in conflict therewith." (*Id.*) Previously, DEC's Terms and Conditions also included language that limited the reference to changes in rate schedules to "variable rates only." Witness Morrison questioned the omission of the foregoing language because it suggests that DEC intends for long-term fixed rates to be subject to change by subsequent Commission action. (*Id.*)

DEC/DEP witness Bowman stated in her rebuttal testimony that the omission of the foregoing language should not suggest that DEC intends for long-term fixed rates to be subject to change by subsequent Commission action. DEC instead agrees that once a QF signs a long-term fixed rate contract, the QF is entitled to those rates for the life of the contract. (Tr. Vol. 3, pp. 126-27) Witness Bowman noted that the previous language in Section 2 was over-broad and appeared to suggest that even non-rate terms and provisions in long-term fixed rate contracts were immune from Commission-authorized changes. (*Id.*) To address this issue, witness Bowman stated that DEC proposed to amend Section 2 of its Terms and Conditions to include the following language:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges), and all non-rate provisions.

(Tr. Vol. 3, p. 127)

On redirect by REG's counsel, REG witness Morrison confirmed that the foregoing language resolved REG's concerns regarding Section 2 of DEC's standard terms and conditions. (Tr. Vol. 3, p. 144) He further confirmed that the only contractual issues that remained between REG and the other parties related to the Reduction-in-Contract-Energy-Charge in DEP's standard terms and conditions and the regulatory disallowance provision in DNCP's standard terms and conditions.

The Commission finds that the language proposed by DEC adequately addresses the issue raised by witness Morrison and directs DEC to include this language in its standard terms and conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

Under the Peaker Method, a utility's avoided costs are determined based on the utility's marginal cost of energy and the capital cost associated with new simple-cycle combustion turbine (CT) capacity. Accordingly, a primary component of avoided capacity rates is the estimated cost of installing new CT capacity. DEC, DEP, REG and the Public Staff offered testimony on this issue. DEC and DEP offered the direct and rebuttal testimony of witness Snider and the direct testimony of Theodore P. Pintcke, a Vice President and Senior Project Director of Black & Veatch. REG presented the direct testimony of witness Reading and the Public Staff presented the direct testimony of witness Hinton. NCSEA offered no testimony on the issue of the appropriate installed CT costs to be used in DEC's and DEP's avoided capacity rates, but raised various issues in its filed Comments. The Commission notes that DEC, DEP, REG and the Public Staff also addressed this matter in their respective filed comments. SACE presented no evidence on this issue.

The record in this proceeding demonstrates that determining the cost of new CT capacity involves numerous assumptions and estimates, including the cost of new CT equipment, amount of contingency to include in the project cost estimate, the number of units assumed to be constructed, how much the inclusion of additional units affects the cost of the capacity (i.e., the effect of economies of scale from siting multiple CTs at a single site), the model of the CT assumed in the cost estimate, and the assumed MW rating of the CTs. Not surprisingly, therefore, there was considerable divergence in the CT costs that the parties proposed to be used to calculate DEC's and DEP's avoided capacity rates.

DEC and DEP proposed to use installed CT costs of **[BEGIN CONFIDENTIAL]** **and** **[END CONFIDENTIAL]** as the basis for their respective avoided capacity rates based primarily on CT cost studies prepared by Burns & McDonnell and Sargent & Lundy. (Tr. Vol. 1, p. 196). DEC/DEP witness Pintcke opined that a lower installed CT cost of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]** would be more in line with the current market for CTs. (Tr. Vol. 1, p. 29) Public Witness Hinton recommended that DEC and DEP both be required to use a CT cost of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]** based primarily on his assessment of CT costs submitted by DNCP in this proceeding and a CT cost study conducted by The Brattle Group for the purpose of establishing capacity costs in the PJM market. (Tr. Vol. 3, p. 66-67). Finally, REG witness Reading proposed that DEC and DEP be required to calculate their avoided capacity rates based on CT costs of **[BEGIN CONFIDENTIAL]** **and** **[END CONFIDENTIAL]**, respectively. (T. Vol. 2, pp. 45 and 50) Witness Reading's recommendation was based primarily on his position that the capacity costs identified in DEC's and DEP's previously filed Integrated Resource Plans and reserve margin studies should be the basis for the capacity cost calculation in this proceeding.

On October 28, 2013, prior to the commencement of the hearing in this matter, DEC, DEP, REG and NCSEA entered into a stipulation under which they agreed that DEC and DEP would both use an installed CT cost of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]** to calculate their avoided capacity rates. The stipulating parties also agreed that they would enter their pre-filed testimony on the CT cost issue into the record, but would waive any cross-examination pertaining to this matter. The Commission accepted the entry of the stipulation among DEC, DEP, the Public Staff, REG and NCSEA into the record without objection. (Tr. Vol. 1, p. 70). Counsel for SACE indicated that it was not taking a position on the stipulation. (Tr. Vol. 1, p. 81-82)

In light of the agreement among all of the parties who have taken a position on this issue and the fact that the stipulated CT costs fall within the range of CT costs proposed by these parties, the Commission concludes that the stipulation regarding CT costs should be accepted. Therefore, DEC and DEP shall recalculate their respective avoided capacity rates using an installed CT cost of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]**.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this Finding of Fact is found in the direct testimony of REG witness Morrison and the rebuttal testimony of DEP and DEC witness Bowman.[1]

REG witness Morrison testified that DEP should eliminate the provision in its Terms and Conditions providing a Reduction-In-Contract-Energy-Charge if "the [s]eller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak energy level." Witness Morrison described the Reduction-In-Contract-Energy-Charge (or "provision") as unnecessary and unduly punitive to QFs. In support, he argued that the utilities do not pay a QF unless electricity is generated by and received from a QF. Charging a small QF when production is off by 20% (or falls below 80%) "unfairly enriches" the electric utility at the expense of the QF. Moreover, the provision causes hardships for QFs relying on variable resources, such as hydro, wind, and solar, to access capital on reasonable, workable terms. Witness Morrison noted that the DEC Standard Contract did not contain this provision. Thus, he concluded that DEP should remove the Reduction-In-Contract-Energy-Charge from its Terms and Conditions for the Purchase of Electric Power. (Tr. Vol. 2, pp. 117-18).

In her rebuttal testimony, witness Bowman explained that the Reduction-In-Contract-Energy-Charge is intended to ensure balanced, levelized QF contracts throughout the life of the contract. DEP includes this provision, according to Ms. Bowman, because long-term levelized rates tend to overpay the QF in early years and underpay the QF in later years. Generally, however, avoided energy costs increase over

[1] At the evidentiary hearing in this matter, counsel for DEC and DEP notified the Commission that DEC, DEP and REG had agreed to waive cross-examination of each other's witnesses with respect to the Reduction-of-Contract-Energy-Charge testimony and to request that the Commission determine this issue on the basis of the pre-filed testimony and the pleadings thus far. (Tr. Vol. 1, pp. 15-16)

time. Witness Bowman testified that when avoided energy rates are levelized over the life of a contract, the utility pays a QF more than the utility's avoided cost in the early years of the contract, which is offset by the expectation that the levelized rate will be less than the utility's avoided cost in later years. Thus, Ms. Bowman opined, from a QF's perspective, the early years of the contract are more profitable than the later years.

Witness Bowman further testified that while a QF's costs to operate will likely increase over time, it receives the same payment for each kwh of energy it produces in the first year of a levelized rate contract as it does in the fifteenth year. As a result, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes and could disappear over the life of a long-term levelized rate contract. Given these economics, witness Bowman asserted that it would be unfair to DEP and its customers for a QF to underperform during the later part of its contract, having already reaped the excess benefits of the levelized rates in the contract's early years. Witness Bowman concluded that the Reduction-In-Contract-Energy-Charge prevents this situation by adjusting the contract to maintain the expected balance of economic benefits to both parties if the QF's performance falls materially short of its obligation. (Tr. Vol. 3, pp. 127-29)

Witness Bowman also disputed REG witness Morrison's characterization of the Reduction-In-Energy-Charge as punitive to QFs. She testified that the provision had been a part of DEP's Terms and Conditions since 1987, and DEP had never applied it in a punitive manner. Witness Bowman further stated that DEP has never had to resort to a Reduction-In-Contract-Energy-Charge to resolve a performance issue and that no party had ever objected to it before this proceeding. (Tr. Vol. 3, pp. 129-30)

Witness Bowman also countered witness Morrison's claim that the Reduction-In-Contract-Energy-Charge is unfair to QFs using intermittent resources such as solar and wind. According to witness Bowman, the provision is not triggered by a QF's failure to meet hourly, daily, monthly, or seasonal goals. The Reduction-In-Contract-Energy-Charge is only invoked if a QF fails to meet its contracted-for energy targets over a 12-month period. It is based on a 12-month average of the QF's output, which gives the QF the benefit of any periods in which it produced energy in excess of the contracted-for amounts. In addition, witness Bowman explained that a QF does not even need to perform up to its contractual representations, because the Reduction-In-Contract-Energy-Charge only comes into play after the QF has operated for two years and if the QF's output for a 12-month period falls below 80% of its contract energy level. This gives the QF time to work out any initial start-up issues and to assess the actual operating capability of its facility to determine whether it can meet its contractual obligations. (Tr. Vol. 3, pp. 130-31)

The Commission notes that the full text of the provision at issue is as follows:

> After the first two years of operation of the Facility, if Seller's average energy generation in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak Energy level, the Company may invoke a Reduction-in-Contract-Energy-Charge and establish a new Contract Energy level for on-peak and off-peak energy periods, respectively.

(Tr. Vol. 3, p. 128) As witness Bowman explained, long-term levelized rate QF contracts create a tension between encouraging QF development and the risk of overpaying QFs. Levelized rates tend to overpay QFs in the early years of their contracts and underpay them in later years. Consequently, a QF's incentive to incur the costs of operating and maintaining a facility diminishes over the life of a long-term levelized rate contract. The Commission agrees with the arguments of DEP on this issue and concludes that it would be unfair to DEP and to DEP's customers for a QF to underperform during the latter part of its contract, having already reaped the benefits of levelized rates in the early years.

The Commission also disagrees that the Reduction-In-Contract-Energy-Charge is unfair to solar or wind powered QFs. As noted by witness Bowman, the Reduction-in-Contract-Energy-Charge is only triggered by the QF's failure to meet contracted energy targets over a 12-month period and not by a failure to meet an hourly, daily, monthly, or even seasonal production goal. Moreover, the calculation called for in the Reduction-In-Contract-Energy-Charge is based on a 12-month average, giving the QF the benefit of any periods where it produced energy in excess of its contracted for amounts. The QF is not called upon to predict with precision its hour-to-hour or day-to-day energy production; the provision merely requires that, over the long-term, the QF's facility perform at least at 80% of its represented capability.

The Commission further notes that REG did not present any evidence of the Reduction-In-Contract-Energy-Charge being imposed punitively on a wind or solar QF or support for its assertion that it hindered wind and solar QFs in accessing capital. In fact, the evidence showed that DEP had never resorted to the Reduction-In-Contract-Energy-Charge to resolve a performance issue with a QF, indicating that this provision has never been used punitively and that it is not burdensome to QFs contracting with DEP.

For the foregoing reasons, the Commission rejects REG's proposal to remove the Reduction-In-Contract-Energy-Charge from DEP's Terms and Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

In its Initial Comments, REG observed that, in DEP's then-pending base rate case in Docket No. E-2, Sub 1023, DEP had proposed to lower the Monthly Facilities Charge applicable to small generator interconnections. REG noted, however, that Section 11 of PEC's Terms and Conditions filed in this proceeding did not reflect this change in the Monthly Facilities Charge. (REG Initial Comments at 13-14). REG, therefore, questioned how the proposed change in the Monthly Facilities Charge would be administered. (*Id.*)

In the Joint Reply Comments filed by DEC and DEP, DEP stated that it had filed proposed Terms and Conditions that reflect the lower monthly carrying charge rate under the non-contributory and contributory plans, in page 117 of 120 of Exhibit B to its base rate case application. (DEC/DEP Joint Reply Comments at 44) DEP committed that this change would become effective upon approval by the Commission at which time PEC would apply the new rates to all contracts that contain the Monthly Facilities Charge, regardless of when the contracts were executed. (*Id.*)

The Commission notes that it has issued a final order in Docket No. E-2, Sub 1023, which approved, among other things, DEP's proposal to lower its Monthly Facility Charge applicable to small generator interconnections. Accordingly, the Commission concludes that, consistent with DEP's commitment, DEP should amend Section 11 of the Terms and Conditions of its standard avoided cost contract to reflect the Monthly Facilities Charge that DEP proposed in its most recent base rate case. Further, the Commission directs that DEP amend existing agreements with QFs under its standard avoided cost contracts that contain a Monthly Facilities Charge to reflect the new Monthly Facilities Charge on a going forward basis.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

In its Initial Comments, the Public Staff argued that provisions in DEC's and DNCP's current tariffs, as well as DEP's proposed provision, limiting the availability of long-term avoided cost rates to QFs that are under contract with them on or before November 1, are inconsistent with the Commission's recent Arbitration Orders, dated June 8, 2010, in Docket No. SP-467, Sub 1, involving Economic Power and Steam, LLC and dated January 26, 2011, in Docket No. E-22, Sub 966, involving EPCOR USA North Carolina, LLC (EPCOR). The Public Staff stated that, based on FERC precedent, the Commission previously had determined that a QF has the option of either selling energy on an "as available" basis or selling energy and capacity pursuant to a legally enforceable obligation ("LEO") over a specified term. If the QF chooses the latter, it may choose a rate calculated at the time the obligation is incurred. The Public Staff concluded that the Commission had held in its Arbitration Orders that prerequisites for an LEO to have occurred or to have been created were: (i) the QF having a certificate of public convenience and necessity ("CPCN") and (ii) the QF having made it sufficiently clear to the utility that it wanted to commit itself to sell its output pursuant to an LEO over a specified term. As such, the Public Staff argued that the tariffs proposed by DEC, DEP and DNCP were inconsistent with Arbitration Orders because they limited the availability of their long-term fixed rates to QFs under contract with them by November 1, 2014.

The Public Staff also cited the Commission's December 21, 2012 order in this docket in support of its position. The Public Staff asserted that in that order, the Commission determined that for QFs that had filed an application for a CPCN or had filed a report of proposed construction ("RPC") before December 1, 2012, the long-term avoided cost rates on DEP's existing tariff would remain available until such time as the Commission approved new, long-term avoided cost rates. For QFs that had not filed by the stated deadline, the proposed avoided cost rates would become available, subject to true-up if the Commission approved higher rates.

Based on the foregoing, the Public Staff urged the Commission to approve the following standard – QFs that file their applications for CPCNs or RPCs no later than the November 1 filing date of the new, proposed avoided costs (or actual filing date, if later) are entitled to any of the avoided cost rate options in the currently-approved avoided cost rate schedules, including the long-term options (assuming they are otherwise available). The Public Staff echoed these arguments in its Reply Comments.

REG also objected to DEP's proposal to suspend the long-term fixed rates in its proposed Schedule CSP-29 in its Initial Comments. REG cited the EPCOR arbitration in which the Commission determined that a LEO arises when the QF: (1) commits itself to sell its output to a utility and (2) has a CPCN in hand. Thus, REG asserted, a QF has the right to the currently-approved avoided cost rate at the moment it has committed to sell its output to the utility and has a CPCN in hand. REG argued that the suspension of approved rates is inconsistent with these rights and, therefore, requested that the Commission disallow the practice, or, in the alternative, allow an exemption for QFs that have a LEO, along with a true-up for those QFs that elect to proceed with the proposed rates if higher rates are approved.

In their Joint Reply Comments, DEP and DEC argued that suspension of the long-term avoided cost rates reflected on proposed Schedules PP and CSP-29 was reasonable. Consistent with DEC's avoided cost rates approved since 2006, DEC's proposed Schedules PP-H and PP-N include a provision providing for the interim suspension of DEC's standard long-term fixed rates during the period beginning November 1 of the next avoided cost proceeding (in this case, 2014), during which the new proposed rates will be pending. DEP's proposed tariff CSP-29 also included similar language for the interim suspension of standard long-term, fixed rates beginning on November 1, 2014. Both DEC's and DEP's variable rates will remain in effect for QFs after November 1, 2014, until the Commission has approved new long-term rates in the next biennial proceeding. As DEC has explained in previous avoided cost proceedings, the intent of this contractual language is to allow long-term avoided cost rates offered to QFs to more closely align with the DEC's and DEP's actual avoided costs, instead of avoided costs that may have been approved in the previous avoided cost proceeding. Suspending the long-term rates after DEP and DEC file proposed new long-term rates avoids the potential for QFs to attempt to "lock in" at currently authorized long-term rates if the avoided costs have declined compared to rates approved in the previous avoided cost proceeding. DEC and DEP explained that, consistent with this past practice, QFs will have the option under both DEC's and DEP's avoided cost rates to convert from the variable contract rate to the long-term fixed rates once the Commission has approved the new long-term fixed rates. DEC and DEP observed that the Commission had considered this issue in its 2010 Avoided Cost Order and agreed with DEC's arguments. DEC and DEP argued that the Commission should adopt this same reasoning here.

The Commission notes that, as described by DEC and DEP, it has reviewed this issue in previous avoided cost proceedings, most recently in Docket No. E-100, Sub 127. In its July 27, 2011 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, in Docket No. E-100, Sub 127 (Sub 127 Order), the Commission discussed this issue and referenced its prior decision in the 2006 avoided cost proceeding. In that 2006 proceeding, the Commission approved the contested provision in DEC's Schedule PPs and noted that it was intended to prevent QFs from taking advantage of the differences between the existing rates and the proposed rates for the following biennium. The Commission then again approved DEC's proposed provision suspending the long-term rates, stating that it agreed with the arguments put forth by DEC and the reasoning stated in the 2006 avoided cost proceeding. Sub 127 Order, pp. 12-19. The Commission does not find any reason to alter its prior decisions here.

Moreover, the Commission is not persuaded by the Public Staff's arguments on this issue. The Public Staff previously cited the Arbitration Orders in the Sub 127 proceeding to suggest that it was inconsistent with PURPA to end the availability of the approved long-term avoided cost rates when new ones were proposed. In those Arbitration Orders, the Commission indicated that a QF must have a CPCN in hand as a prerequisite to establishing a LEO, in addition to committing to sell its output to the utility. Furthermore, as described by the Public Staff, the Commission issued its *Order on Motion to Suspend Avoided Cost Rates*, in this docket and Docket No. E-7, Sub 127 on December 21, 2012 (Suspension Order). Pursuant to the Suspension Order, QFs that had both: (1) filed an application for a CPCN or an RPC on or before December, 1, 2012, and (2) established an LEO with DEP prior to the issuance of an order approving the new long-term rates in this docket, remained eligible to enter into contracts at the then current CSP-27 long-term rates. This Suspension Order, however, was limited only to DEP's long-term rates at issue in this proceeding; it did not resolve the question of whether the provisions providing that the long-term rates in DEC's and DEP's proposed tariffs were available to QFs that signed purchase power contracts with the utilities before November 1, 2014, were appropriate. Thus, for the reasons put forth by DEC and DEP, the Commission approves the provisions of DEC's Schedules PP-N, PP-H and DEP's CSP-29 that make the fixed, long-term rates reflected therein available to customers under contract with DEC or DEP, respectively, as of November 1, 2014.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

This Commission began setting avoided cost rates pursuant to PURPA in 1981 in Docket E-100, Sub 41. Since that time, various changes have been made to the avoided cost process, but much of the process has remained unchanged. The QF industry in North Carolina, however, has undergone significant changes during that time. As witnesses Petrie notes, renewable generation and related industries have become a significant business sector in North Carolina. (Tr. Vol. 1, p. 305) Thus, the avoided cost process that was established when the QF industry was in its nascent stage is still being applied to a business sector that is more mature and sophisticated. The Commission also recognizes that in the early stages of PURPA QFs often tended to be co-generators, using steam from industrial processes to generate electricity. Currently, renewable QFs, such as solar and biomass generation, are more prevalent. As evidenced by the testimony of witnesses Rabago and Snider, such generation carries its own peculiar costs and benefits. (Tr. Vol. 1, pp. 226-27; Tr. Vol. 2, pp.160-62) To date, however, the Commission has not had the opportunity to fully assess the nature of the particular characteristics of these newer technologies in the context of setting avoided cost rate proceedings. The Commission has also seen an unprecedented increase in the number of proposed QF projects in the state. (Tr. Vol. 1, p.105; Tr. Vol. 3, p 125) While the parties in this docket may not agree fully on the precise magnitude of the increase in QF activity in North Carolina, there is no doubt that as the amount and significance of QF generation increases the impact of avoided cost rate decisions on the State's electric consumers increases as well. Public Staff witnesses Ellis and Hinton testified that consideration of even the single issue of whether to amend the Commission's PAF policy was complex and would require careful study. (Tr. Vol. 3, pp. 92-94) They further noted that a separate proceeding would be an appropriate forum for addressing such an issue. (*Id.*)

In light of the foregoing, the Commission concludes that it should consider initiating a separate docket to assess our QF-relate policies (including the establishment of avoided cost rates). The Commission finds that such a proceeding may help it determine whether changes are needed to better conform its policies to the current realities of the QF industry and its impact on the State's utility's and consumers. Therefore, the Commission will require each of the parties in this proceeding to file comments within thirty (30) days of this order stating whether the party believes that a docket to assess the Commission's QF regulations is necessary and, if so, what the scope and purpose of such a docket should be.

IT IS, THEREFORE, ORDERED AS FOLLOWS:

1. DEC shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5MW or less capacity, and (b) non-hydroelectric qualified facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5MW or less capacity. The standard levelized rate options of 10 and 15 years should 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. DEC should offer its standard five-year levelized rate option to all other qualifying facilities contracting to sell 3MW or less capacity.

2. DEP shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5MW or less capacity, and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5MW or less capacity. The standard levelized rate options of 10 and 15 years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility or 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. DEP shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3MW or less capacity.

3. DEC, DEP, and DNCP shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (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 Commission-recognized active solicitation underway, it shall offer QFs not eligible for the standard long-term levelized rates the option of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings, or (2) contracting with the utility to sell power at negotiated rates. 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 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 shall be determined by motion to, and order of, the Commission. Unless there is a Commission order, it will be assumed that there is no solicitation underwriting. 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. The performance adjustment factor (PAF) of 2.0 shall be utilized by DEC, DEP, and DNCP in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation.

5. The performance adjustment factor (PAF) of 1.2 shall be utilized by DEC, DEP, and DNCP in their respective avoided cost calculations for all QFs, other than hydroelectric facilities with no storage capability and no other type of generation.

6. The rate schedules and standard contract terms and conditions proposed in this proceeding by DEC and DEP shall be approved except as otherwise discussed herein. The utilities shall be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within twenty days after the date of this Order. Those rate schedules and standard contracts shall be allowed to go into effect ten days after they have been filed unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that ten-day period.

7. Within twenty days of the issuance of this Order, DEP shall file a new avoided cost rate schedule that utilizes a definition of on-peak hours that is consistent with DEC's Option B. In the event that the implementation of metering changes to accommodate the new rate schedule prevents the rate schedule's immediate implementation, DEP shall include in its filing a detailed description of the work required to implement the new rate schedule and a schedule of when such work is to be completed.

8. DEC and DEP shall not include costs associated with natural gas hedging in their avoided energy cost rates.

9. Section 2 of Terms and Conditions in DEC's avoided cost standard contract shall be amended in accordance with the provisions of this Order to make clear that the rate portion of long-term contracts are not subject to revision by subsequent Commission action.

10. DEC and DEP shall recalculate their avoided capacity rates using an installed CT cost of **[BEGIN CONFIDENTIAL]** **[END CONFIDENTIAL]** and shall refile such recalculated avoided cost rates in accordance with the provisions of this Order.

11. DEP may continue to include a Reduction-in-Contract-Energy-Charge in its standard avoided cost contracts.

12. DEP shall amend Section 11 of the Terms and Conditions of its standard avoided cost contract to reflect the lower Monthly Facilities Charge that DEP proposed in Docket No. E-2, Sub 1023. DEP shall also amend existing agreements with QFs under its standard avoided cost contracts that contain a Monthly Facilities Charge to reflect the new Monthly Facilities Charge on a going forward basis.

13. Within thirty days of the issuance of this Order, each of the parties in this proceeding shall file comments stating whether the party believes that a separate proceeding docket to assess the Commission's avoided cost processes and related policies is necessary and, if so, what the scope and purpose of such a docket should be.

ISSUED BY ORDER OF THE COMMISSION

This the __ day of _______, 201_.

NORTH CAROLINA UTILITIES COMMISSION