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N.C. Utilities Commission

October 18, 2013

VIA COURIER

Mrs. Gail L. Mount, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603-5918

Re: Docket No. E-100, Sub 136

Dear Mrs. Mount:

Enclosed for filing in the above-referenced docket on behalf of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power ("DNCP"), are an original and thirty (30) copies of the *Rebuttal Testimony of Bruce E. Petrie, Public Version* and *Rebuttal Testimony of Robert J. Trexler*.

Also enclosed is one extra copy of each to be file-stamped and returned with our courier. Should you have any questions please do not hesitate to contact me. Thank you for your assistance in this matter.

Very truly yours,

Andrea R. Kells

Andrea R. Kells

ARK:asm

Enclosures

JK
Full Dist.

B. Hinton

FILED

OCT 18 2013

Clerk's Office
N.C. Utilities Commission

REBUTTAL TESTIMONY OF BRUCE E. PETRIE ON BEHALF OF DOMINION NORTH CAROLINA POWER BEFORE THE NORTH CAROLINA UTILITIES COMMISSION DOCKET NO. E-100 SUB 136 REDACTED VERSION

Q. Please state your name, business address, and position of employment.

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am the Manager of Generation System Planning for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include forecasting total system fuel and purchased power expenses, and forecasting the Company's long term avoided costs. A statement of my background and qualifications is attached as Appendix A.

Q. Have you filed other documents or comments in this proceeding?

A. Yes. I prepared Section III of the Company's Comments, Exhibits and Avoided Cost Schedules, filed in this docket on November 1, 2012. In addition, I filed direct testimony on August 9, 2013 and have participated in responding to data requests of other parties to this proceeding.

Q. What is the purpose of your testimony in this proceeding?

A. I will respond to the direct testimony of Mr. John R. Hinton and Mr. Kennie D. Ellis filed on behalf of the Public Staff, the direct testimony of Mr. Don C. Reading filed on behalf of the Renewable Energy Group ("REG"), and the direct testimony of Mr. Karl Rábago filed on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. What did Mr. Hinton conclude about the inputs used in the Company's avoided energy cost estimate?

A. Mr. Hinton testified that the inputs used to calculate avoided energy costs by all of the utilities involved in this proceeding were reasonable and were consistent with the inputs and assumptions used by the utilities in their IRPs. Hinton Testimony at p. 6. I agree with this assessment as it relates to the Company. I have not reviewed the inputs and assumptions used by DEC and DEP but have no reason to doubt his conclusion with respect to those companies.

Q. Did Mr. Hinton testify about the avoided capacity cost estimates filed by DNCP in this proceeding?

A. Yes. Mr. Hinton's testimony focused on the Company's estimated installed costs of a CT.

Q. What are the Company's estimated costs of a CT used for this proceeding.

A. As discussed in more detail in my direct testimony, the Company's nominal installed cost of a CT is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, exclusive of financing costs, and was based on the installed costs of a CT contained in the Company's 2012 IRP.

Q. What did Mr. Hinton say about the Company's estimated cost of a CT used for this proceeding.

A. He testified that he was "comfortable with DNCP's projected installed costs of a CT…." Hinton Testimony at p. 10. However, Mr. Hinton also testified that he believed that DNCP's installed CT cost estimate should include "land cost" even though the Company intends to install CTs at brownfield sites. *Id.* at p. 28.

Q. Do you agree with Mr. Hinton that the estimates of installed CT costs should include land costs, even if the Company's next CT build is expected to be on a brownfield site?

A. No. As I discussed in my direct testimony, the Company's 2012 IRP shows the addition of 400 MW of CT capacity in both 2021 and 2022. *See* Dominion North Carolina Power's and Dominion Virginia Power's Report of its Integrated Resource Plan at 6, Fig. 1.4.1, Docket No. E-100, Sub 137 (Aug. 31, 2012). The Company has multiple existing brownfield sites available where there is adequate land and where the site configuration would allow the addition and build-out of at least 800 MW of CT units. Accordingly, the Company would install the 800 MW of CTs included in the IRP on such brownfield sites. Because the CTs will be installed on brownfield sites, the Company will neither incur nor avoid any land or other greenfield related cost for the CTs.

Q. Is an installed CT cost based upon a brownfield installation consistent with the Company's 2012 IRP?

A. Yes, the Company's installed CT cost estimate was premised on a brownfield installation because that is in fact where the Company plans to install any new CTs.

Q. Has the Public Staff stated its position as to whether consistency between a utility's IRP and the inputs to its avoided cost estimates is important?

A. Yes. In its Reply comments in this proceeding, the Public Staff stated "[i]t is important that the projected CT costs used in the utilities' respective IRPs and generation expansion plans be consistent with the CT costs and assumptions used in the determination of their avoided cost rates." Public Staff Reply Comments at 4. Further, speaking in this instance of energy costs, in his direct testimony Mr. Hinton testified that "it is important that the inputs used in the avoided costs model and the inputs used in the IRP model be consistent." Hinton Direct at 6-7.

Q. Do you agree that consistency with the IRP is important?

A. Yes. The Company agrees that, absent an after-the-fact discovery of error or a demonstrated change in circumstances from those contemplated in an IRP, the inputs and assumptions of the IRP should be used in the determination of avoided cost rates. The Company's installed cost estimate of a CT is consistent with its 2012 IRP. The Public Staff's proposed modification to the Company's installed cost estimate is not.

Q. Would inclusion of land and other greenfield related costs for a CT on a brownfield site be consistent with PURPA?

A. No. Avoided costs are defined under PURPA as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013). Further, avoided costs must be "just and reasonable to the electric consumer of the electric utility and in the public interest" and an electric utility is not required to "pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a) (2013).

Because the Company would not incur any land costs associated with CTs on a brownfield site, the avoided land costs for such CTs are $0. Requiring the Company's ratepayers to bear costs that are not in fact avoided is not just and reasonable. In other words, requiring the Company to pay capacity rates that include an allowance for land costs that are not avoided will result in the Company paying more than its avoided costs for capacity in violation of PURPA.

Q. Could the Company's plans to install CTs at brownfield sites change, and if so, would that result in the avoided cost capacity rates in this proceeding being too low?

A. In theory, yes. However, it is also possible that the Company will not need or install all of the CTs identified in the 2012 IRP, which would result in the avoided cost rates approved in this proceeding being too high. The point is that in calculating estimates of avoided cost, the Company uses the best information available at the time of the estimate. And when relying on estimates for long-term avoided cost purchases, "the rates for such purchases do not violate [FERC's PURPA regulations] if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. § 292.304(b)(5) (2013).

Q. Have you quantified the increased costs to the Company and its ratepayers of the use of greenfield CT costs?

A. I quantified those impacts in detail on pages 6 through 8 of my direct testimony. In summary, use of a greenfield CT in lieu of a brownfield CT would increase the installed cost of a CT by $43/kW over the Company's estimate, which would result in an increase in capacity rates by approximately 12.2% above the Company's forecasted avoided cost of capacity.

Q. On page 28 of his testimony, Mr. Hinton states that in Docket No. E-100, Sub 87, the Commission required DNCP and DEC to include the cost of land in their calculation of CT costs. Does the Commission decision in that case require the inclusion of land and other greenfield related costs in this proceeding?

A. No. As explained in more detail in my direct testimony at pages 4 and 5, and in the Company's Reply Comments filed in the Sub 87 proceeding, *DNCP Reply Comments* at 2, Docket No. E-100, Sub 87 (Feb. 2, 2001), DNCP's CT installed cost estimates were based on the Ladysmith CT units 1-2 being installed at a greenfield site. As the Commission noted in the Order in that proceeding,

> NC Power . . . agreed land costs should be included in the

> calculations in cases where land costs could actually be avoided. However, the [C]ompany pointed out that new capacity is sometimes added at existing sites where land costs cannot be avoided.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2000, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 12, Docket No. E-100, Sub 87 (Apr. 6, 2001). The Commission adopted "NC Power's agreement to include land costs in its capacity credits, and conclude[d] that NC Power should be required to include the capital costs of land in its calculation of capacity credits for purposes of this proceeding." *Id.* at 12-13 (emphasis added). As discussed above, the Company has multiple existing sites available to install the 800 MW of CTs identified in its 2012 IRP and the Company would install those CTs on brownfield sites. This is exactly the circumstance that the Company described in Docket E-100, Sub 87: when new capacity will be added at existing sites, "land costs cannot be avoided." This is analogous to prior Commission decisions holding that the Company was not required to offer capacity credits to QFs during periods when the Company in fact had no capacity needs.[1] In those cases, the Commission recognized that no capacity credit should be offered where no capacity costs were avoided. Here, the

[1] *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1998,* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 6, 16, Docket No. E-100, Sub 81 (July 16, 1999); *see also See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1996,* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 8, 21-22, Docket No. E-100, Sub 79 (June 19, 1997), *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 1994,* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 8, 27, Docket No. E-100, Sub 74 (June 23, 1995) ("1994 Biennial Order").

Commission also should not require DNCP to pay for land and other greenfield related costs that will not be avoided.

Q. On pages 28-29 of his testimony, Mr. Hinton refers to the CT cost study by the Brattle Group. Do you have any comments about the appropriateness of using that study or any other generic third party study in this avoided cost proceeding?

A. I do not think it is appropriate to rely on the Brattle Report to set avoided cost rates in this proceeding. The purpose of this proceeding is to make utility-specific determinations of the costs that will be avoided by each utility through the purchase of energy and capacity from QFs based on the particular circumstances and plans of each utility. The Brattle Report is simply not an estimate of DNCP's, or any other North Carolina utility's, cost to install a CT, but rather a generic study based on data, given its August 2011 submittal date, that is well over two years old.

Q. What was Mr. Hinton's ultimate recommendation to the Commission with respect to the Company's installed CT cost?

A. On page 30 of his testimony, Mr. Hinton recommended that an installed cost of $650 per kW be used for this proceeding. He also testified that installed CT cost estimates in the range of $625 to $675 per kW were reasonable.

Q. Do you agree with Mr. Hinton's recommendation?

A. No. Mr. Hinton's recommended CT installed cost of $650 per kW does not reflect the Company's installed cost per kW.

Q. **Regarding the testimony of Mr. Don Reading on behalf of the Renewable Energy Group, do you have any comments about his recommendation for the CT capital cost?**

A. On page 31 of this testimony, Mr. Reading recommended that the Commission direct the Company to recalculate its avoided cost rates using a CT capital cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This figure is the installed capacity cost estimate for the installation of a CT at a greenfield site that the Company prepared in response to a Public Staff data request.

Q. **Do you agree with Mr. Reading's recommendation?**

A. No. For the reasons I discussed earlier with respect to Mr. Hinton's testimony, the appropriate installed CT capital cost for use in this proceeding is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2013 dollars, which is the installed cost of a CT on a brownfield site.

Q. **On page 30 of his testimony, Mr. Reading stated that the Company's installed CT cost did not include AFUDC and financing costs. Is Mr. Reading correct?**

A. Mr. Reading is correct that AFUDC and financing costs are not included in the installed CT figure, but such costs are accounted for in the Company's calculation of avoided capacity costs. Like other components of the avoided capacity costs such as the PAF, AFUDC and financing costs are accounted for separately by the Company's calculations and are indeed included in the final avoided capacity cost rates. Because financing and AFUDC costs are accounted for elsewhere in the Company's model, including them in the installed CT figure would result in double counting of those costs.

Q. Did Mr. Reading's testimony address the issue of the appropriate Performance Adjustment Factor ("PAF") for solar QFs?

A. Yes. On pages 32 through 36 of his testimony, Mr. Reading essentially restates the comments and arguments made by REG in its initial comments filed in this proceeding, with one additional discussion discussed below. *See* Renewable Energy Group Initial Comments (February 7, 2013) ("*REG Initial Comments*"). My direct testimony in this proceeding set out the Company's position of the appropriate PAF for solar QFs and responded to the comments and arguments of REG in the REG Initial Comments. *See* Direct Testimony at pages 9 – 21. Because the REG Initial Comments and Mr. Reading's testimony on the PAF issue are essentially identical, to avoid unnecessary duplication, I adopt pages 9 through 21 of my direct testimony in rebuttal to the testimony of Mr. Reading on the PAF issue.

Q. You mentioned that there was one additional discussion. Please explain.

A. On page 35 of the his testimony, Mr. Reading noted that (1) SB 3 has been in effect for five years, (2) 2012 was the first year that utilities were subject to an increase in the REPS requirement, and (3) SB 3 was not modified in the 2013-2014 legislative session.

Q. Do these developments affect the Company's position on the appropriate PAF for solar and wind QFs?

A. No. These developments do not justify raising the PAF to 2.0 for solar and wind QFs.

Q. Regarding the testimony of Public Staff Witness Mr. Kennie Ellis, do you have any comments about his recommendation that DNCP offer Option B type avoided cost rates?

A. Yes. The Company is not opposed to adding an Option B type rate offering, in addition to its existing rate offerings, so long as the PAF used in the Option B rate offering is 1.2. The Option B on-peak hours definition is consistent with customers' current demand patterns, and covers those hours when the system is most likely to experience its peak load. The Company notes, however, that as customer demand patterns change (for example, with increasing penetration of distributed solar generation), adjustments to the on-peak hours definition may be appropriate. If the Company adds an Option B type rate offering, and subsequently concludes that such a change is required, it would bring the issue to the Commission's attention in its biennial filings.

Q. Have you reviewed the testimony of Mr. Karl Rábago on behalf of the NC Sustainable Energy Association?

A. Yes.

Q. What does Mr. Rábago recommend with respect to rates at issue in this proceeding?

A. Mr. Rábago recommends that the Commission adopt a PAF for solar QFs of 2.0. *See* Rábago Testimony at 25-26.

Q. Do you agree with Mr. Rábago's recommendation?

A. No, as discussed on pages 9 through 21 of my direct testimony, the Company does not believe that a PAF of 2.0 for solar or wind QFs is appropriate.

Q. Does Mr. Rábago make any other recommendations in his testimony?

A. Mr. Rábago appears to recommend that the Commission abandon the peaker methodology of determining avoided costs, at least at it relates to solar QFs.

Q. What does Mr. Rábago recommend that the Commission use in lieu of the peaker methodology?

A. A "value of solar" ("VOS") analysis.

Q. What is a VOS analysis?

A. Generally, as described by Mr. Rábago, a VOS is an evaluation of the costs and benefits of distributed solar generation. Mr. Rábago believes that the results of a VOS are a better indicator of the "full avoided costs" of distributed solar generation.

Q. Did you believe that the VOS approach is an appropriate way for the Commission to determine avoided costs.

A. No. As I testified earlier, avoided costs are defined under PURPA as "the incremental *costs* to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013) (emphasis added).

The VOS as described by Mr. Rábago provides compensation to QFs not only for the costs that are avoided by utilities but also for perceived benefits of solar QFs. These benefits include items such as "reputational community participation," recognition of financial risks associated with "future control regimes" and "societal benefits" such as job growth, and increased local tax revenues. This Commission has consistently held that "uncertain and unquantifiable costs such as those associated with environmental externalities should not be taken into account in calculating avoided cost rates . . . ." *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2006,* Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 22-23, Docket No. E-100, Sub 106 (Dec. 19, 2007) ("2006 Biennial Order").

While some of the items mentioned by Mr. Rábago may have value to an individual or a locality (e.g., job growth associated with a solar facility or increased local tax revenues) or value to society generally, they are simply not costs that are avoided by a utility through the purchase of energy and capacity from a solar QF. The Company, for instance, does not avoid any "reputational community participation costs" as a result of the purchase of energy and capacity from a QF.

In sum, the types of value adders discussed by Mr. Rábago are not properly included in the calculation of avoided cost pursuant to PURPA. Other avenues exist for local, state and federal entities, if they choose, to compensate QFs for these types of intangible or unquantifiable benefits, as currently evidenced by the various tax benefits, renewable energy credits and other incentives for QFs that produce these sorts of benefits.

Q. Has the Commission provided any guidance on the appropriateness of including compensation for compliance with future environmental control cost?

A. Yes, in Docket E-100, Sub-74, the Commission held that:

> [U]tilities should not be required to include environmental compliance costs in their respective avoided cost calculations that are unknown or uncertain in nature for purposes of this proceeding. Quantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility.

1994 Biennial Order at 24.

Similarly, in Docket No. E-100, Sub 106, the Commission rejected the arguments that avoided cost rates should include an allowance for general "environmental impacts that may be caused by generating plants." 2006 Biennial Order at 23. The Commission held that under PURPA, rates paid to a QF must equal the monetary costs a utility avoids by obtaining power from a QF. *See id.* at 23-24 ("Environmental externality costs . . . cannot be properly included in avoided costs.").

Q. Do DNCP's avoided cost rates represent the full avoided cost of QF power?

A. Yes. The peaker methodology utilized by the Company does identify and include the quantifiable costs that the utility can actually avoid by the purchase of energy and capacity from a QF. The Company's avoided cost calculations include recognition of energy, capacity, line losses, and known and quantifiable emissions such as sulfur dioxide and nitrogen oxide.

Q. Did Mr. Rábago perform a VOS for this proceeding or draw upon any North Carolina-specific VOS in this testimony on which the Commission could rely?

A. No. Mr. Rábago testified that none of the VOS studies he analyzed for this testimony included specific data from a North Carolina electric utility's service territory. In addition he testified that he was not aware of any published VOS study results in North Carolina.

Q. Did Mr. Rábago include any VOS studies in his testimony?

A. Yes. Exhibit-KRR-3 to his testimony is a VOS performed for New Jersey and Pennsylvania, which indicated that the VOS for that area could be $200 to $300/MWh. Rábago Testimony at p. 13. In addition, Mr. Rábago included as Exhibit-KRR-2 to his testimony a Rocky Mountain Institute ("RMI") report entitled "A Review of Solar PV Benefit and Cost Studies" that summarized 15 VOS and other studies addressing distributed solar generation benefits and costs (the "RMI Report").

Q. Did you review the studies and summaries included in Mr. Rábago's testimony?

A. Not in great detail because they did not relate to North Carolina or this proceeding and as I discussed above, I believe that the VOS approach in general is inconsistent with PURPA. I do note however, that the executive summary of the RMI Report stated the following:

> Methods for identifying, assessing and quantifying the benefits and costs of DPV and other DERs are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees and pricing structures for DPVs and other DERs.

RMI Report at page 5.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BACKGROUND AND QUALIFICATIONS
OF
BRUCE E. PETRIE

I graduated from Clarkson University in 1983 with a Bachelor of Science degree in Mechanical Engineering. From 1983 to 1986 I worked for Babcock and Wilcox designing tools for nuclear power plant maintenance. In 1988 I earned a Master of Business Administration degree from Virginia Tech.

I worked for Niagara Mohawk Power Corporation from 1988 through 1998 in generation planning, fuel procurement, and wholesale power marketing, and then at Old Dominion Electric Cooperative from 1998 until 2001 as a power supply analyst. I joined the Company in April 2001 as an electric pricing and structuring analyst. My responsibilities included the pricing and structuring of wholesale electric transactions, project financial analysis, and analytical support to the Energy Supply group.

In October 2007, I was promoted to Manager of Generation System Planning. I am currently responsible for the Company's mid-term operational forecast (PROMOD model) and forecasting of the Company's long term avoided costs.

REBUTTAL TESTIMONY
OF
ROBERT J. TREXLER
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 136

Q. Please state your name, business address, and position of employment.

A. My name is Robert J. Trexler, and my business address is 701 East Cary Street, Richmond, Virginia 23219. My current position is Director of Regulation for Dominion North Carolina Power ("DNCP" or the "Company"). Prior to October 1, 2013, I was the Director of Power Contracts for the Company. My responsibilities as Director of Power Contracts included the negotiation (including restructuring) and day-to-day administration of the Company's non-utility generation power purchase contracts. A statement of my background and qualifications is attached as Appendix A.

Q. Have you filed other documents, comments or testimony in this proceeding?

A. Yes, I sponsored Sections I, IV and VI of the Company's Comments, Exhibits and Avoided Cost Schedules, filed in this docket on November 1, 2012. In addition, I filed direct testimony on August 9, 2013 and have participated in responding to data requests of other parties to this proceeding.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to describe Article 6 of DNCP's Agreement for the Sale of Electrical Output to Virginia Electric and Power

Company with regard to the Company's Schedule 19-FP (the "Schedule 19-FP PPA") and to respond to the affidavit of Mr. Erik Stuebe and the testimony of Mr. John E. P. Morrison with respect to Article 6 of the PPA. In addition, I will respond to certain aspects of Mr. Morrison's testimony on the relationship of QF financing and avoided costs.

Q. Please describe Article 6 of the Schedule 19-FP PPA.

A. Article 6 of the Schedule 19-FP PPA deals with a situation in which a regulatory body with jurisdiction, such as this Commission, the Virginia State Corporation Commission ("VSCC") or the Federal Energy Regulatory Commission ("FERC"), issues an order (a "Disallowance Order") that (1) prohibits rate recovery of payments made to a QF, and/or (2) requires the Company to refund to its ratepayers payments already made to a QF (the "Regulatory Disallowance Clause"). In the event of such a Disallowance Order, the Regulatory Disallowance Clause provides that rates under the Schedule 19-FP PPA will be reset on a prospective basis at the levels that the Company is allowed to recover in rates. Further, if a Disallowance Order requires the Company to refund to ratepayers previous payments to a QF, then the QF is similarly required to refund the Company those amounts.

Q. Does the Regulatory Disallowance Clause give this Commission or the Company the right to disallow recovery of avoided costs rates or adjust the rates approved by this Commission in this proceeding?

A. No, the Regulatory Disallowance Clause does not itself give the Commission or the Company the right to disallow recovery of or adjust avoided costs payments made pursuant to Schedule 19-FP, and the Company would contest any such disallowance. Further, Article 6 does not give the Company the right to seek a Disallowance Order. The Company believes that QFs should receive full payments under a PPA and the Company should receive full rate recovery of those payments. Article 6 simply recognizes that neither the Company nor a QF can control the actions of a regulatory body and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful.

Q. Is the Regulatory Disallowance Clause a new addition to DNCP's Schedule 19 Contracts?

A. No, the Commission has approved standard Schedule 19 PPAs containing a clause similar to the Regulatory Disallowance Clause since at least 1997.[1]

Q. Has the Commission recently ruled on the reasonableness of the Regulatory Disallowance Clause?

A. Yes, in the previous biennial proceeding, Docket No. E-22, Sub 127, the Commission held that, based on the record in that proceeding, DNCP's inclusion of the same Regulatory Disallowance Clause in its Schedule 19-DRR PPA was "reasonable and should be allowed."[2]

[1] *See, e.g., In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1996*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 23, Docket No. E-100, Sub 79 (June 19, 1997) (approving the standard contracts proposed by DNCP as reasonable).

[2] *See In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2010*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 22, Docket No. E-100, Sub 127 (July 27, 2011).

Q. Why does the Company believe that the inclusion of the Regulatory Disallowance Clause is reasonable and necessary?

A. Basically, the Company believes that inclusion of the Regulatory Disallowance Clause is a matter of fundamental fairness.

Q. Please explain.

A. The Company's purchase of energy and capacity from QFs is not optional. Currently, pursuant to PURPA, and the rules, regulations and orders of this Commission, the VSCC and FERC, the Company has a mandatory obligation to purchase energy and capacity from QFs of 20 MW or less at the Company's avoided cost.[3] Without the Regulatory Disallowance Clause, if there were a Disallowance Order, the Company would be required to continue making full payments to the QF but would not be compensated for the portion of those payments in excess of the Disallowance Order amount. The Company believes there is no principled reason that the burden of the disallowance of legally compelled payments should be borne by the Company and its shareholders.

Q. Does the fact that the Commission will have expressly approved the Schedule 19 rates in this proceeding have any bearing on the need for a Regulatory Disallowance Clause?

A. No, but it does tend to lessen the risk of a Disallowance Order. There is precedent for the proposition that a regulatory commission cannot revise avoided cost rates that it has previously reviewed and approved. *See, e.g., Freehold Cogeneration Associates v. Bd. of Regulatory Commissioners of New Jersey*, 44 F.3d 1178, 1194 (3d Cir. 1995), *cert. denied*, 516 U.S. 815 (1995) (holding that once a state regulatory commission approved a power purchase agreement between a QF and a utility on the ground that the agreement's rates were consistent with avoided cost, the commission was preempted by PURPA from reconsidering its approval). However, the possibility still exists that avoided cost rates approved by one regulatory body could be rejected by another regulatory body. While the Company certainly would resist such a result, it is a possibility, and has occurred before as I discuss below.

Further, the Company notes that in North Carolina, avoided cost rates for QFs larger than five MW are not reviewed and approved by the Commission and therefore do not enjoy the relative assurance of Commission-approved rates. Accordingly, any decision by the Commission to require removal of Article 6 from the Schedule 19 PPAs would not and should not apply to contracts that are not eligible for Schedule 19 (e.g., those contracts pertaining to QFs larger than five MW).

[3] The Company has been relieved of its obligation to purchase energy and capacity from QFs with a net capacity of greater than 20 MW. *See Virginia Electric and Power Company,* 124 FERC ¶ 61,045 (2008).

Q. Does the Company believe that the risk of the issuance Disallowance Order is substantial?

A. No. The Company believes that the possibility of a Disallowance Order is remote under existing law and precedent. Presumably, QFs and their lenders are also aware of the relatively low risk of a Disallowance Order and therefore can be reasonably certain of the return on their investment.

Q. If the risk of a Disallowance Order is remote, then why does the Company believe that the inclusion of a Regulatory Disallowance Clause is nonetheless necessary and reasonable?

A. Because, while remote, the risk of a Disallowance Order is real. In 1993, this Commission disallowed North Carolina rate recovery of a portion of the Company's avoided cost payments to three Virginia QFs because it concluded that the avoided cost payments ordered by the VSCC exceeded DNCP's avoided costs. *See Ex rel. Utilities Commission v. North Carolina Power*, 338 N.C. 412, 416, 450 S.E.2d 896, 898-899 (1994), *cert. denied,* 516 U.S. 1092 (1996) ("*Utilities Commission v. North Carolina Power*"). Similarly, the VSCC has disallowed recovery of a portion of payments to QFs when it subsequently determined that the avoided costs under the QF contracts erroneously included costs that were not in fact avoided costs. *See Hopewell Cogeneration Limited Partnership v. State Corporation Commission*, 249 Va. 107, 118-119, 453 S.E. 277, 284 (1995), *cert. denied,* 516 U.S. 817 (1995).

Q. Have you reviewed the affidavit of Mr. Erik Stuebe and the testimony of Mr. Morrison as they relate to the Regulatory Disallowance Clause?

A. Yes.

Q. What does Mr. Stuebe say about Article 6 of the Schedule 19-FP PPA?

A. Mr. Stuebe states that Ecoplexus, Inc. ("Ecoplexus") has multiple five MW solar QF projects under development in the Company's North Carolina service territory and that he has been involved in attempting to secure financing for these projects. Mr. Stuebe further states that he has sought financing from two lenders for these Ecoplexus projects, one of whom has previously financed Ecoplexus projects in other states.

Mr. Stuebe states that the two lenders that he has approached have declined to finance Ecoplexus' proposed QFs because of Article 6 of the Schedule 19-FP PPA. Further, he states that based on this experience, "Article 6 constitutes a barrier to finance." Affidavit of Erik Stuebe at 2, Docket No. E-100, Sub 136 (Sept. 27, 2013).

Q. Do you have comments on Mr. Stuebe's statements?

A. Yes. First, two lenders do not constitute the universe of potential lenders or sources of financing to Ecoplexus' proposed facilities. The Company has entered into a number of QF contracts containing Article 6 and those QFs have seemingly managed to finance their facilities, which I will discuss further below. Finally, I am aware of no requirement under PURPA that the Company or this Commission modify their respective avoided cost policies based on the demands of a QF's lenders, which I also will discuss further below.

Q. What does Mr. Morrison say about Article 6 of the Schedule 19 PPA?

A. Mr. Morrison, chief operating office of Strata Solar, LLC ("Strata") a large QF solar developer, testified that the Regulatory Disallowance Clause created uncertainty that "is a barrier to financing a QF project, as investors are unwilling to overlook the asserted right of DNCP to modify rates and collect a refund." Direct Testimony of John E. P. Morrison at 11, Docket No. E-100, Sub 136 (Sept. 27, 2013) ("Morrison Testimony"). In addition, Mr. Morrison testified that in Order No. 69, FERC stated that "in order to be able to evaluate the financial feasibility of a [QF], an investor needs to be able to estimate, with reasonable certainty, the expected return on potential investment before the construction of a facility. *Id.* at 12 (citation omitted). Mr. Morrison believes that the Regulatory Disallowance Clause "creates unnecessary uncertainty regarding an investor's expected return on a potential investment, in what appears to [him] to be a violation of Order No. 69." *Id.*

Mr. Morrison also asserted that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA. *See id.*

Finally, Mr. Morrison testified that Strata has not developed solar facilities in the Company's service territory because of the Regulatory Disallowance Clause. *See id.*

Q. Do you agree with Mr. Morrison's assertion that the Regulatory Disallowance Clause gives the Company the right to modify rates and collect a refund?

A. No. The Company is not "asserting a right" to modify rates paid to QFs. As I explained above, the Regulatory Disallowance Clause does not give the Company, or the Commission, the right to modify PPA rates. The clause simply recognizes that neither the Company nor a QF can control the actions of a regulatory body and allocates the burdens of a Disallowance Order equitably if such an order is issued and held to be lawful.

Q. Do you have any comments on Mr. Morrison's statement with regard to Order No. 69?

A. Yes. I agree with Mr. Morrison's general proposition that a QF investor, like any other investor "needs to be able to estimate, with **reasonable certainty**, the expected return on potential investment before the construction of a facility." (emphasis added). However, I am unaware of any provision in PURPA that requires that QF investors, unlike other investors, be entitled to absolute certainty of a return on their investment. Moreover, I believe that an investor in Schedule 19-FP QF has a "reasonable certainty" with respect to its investment, because, as I discuss above, under existing law and precedent, the possibility of a Regulatory Disallowance Order is remote.

Finally, if the QF and its lenders will not accept the remote but real risk of a Disallowance Order, why should the entire risk be shifted to the Company and its shareholders? The Company must comply with the legal mandate to purchase power from QFs. The Company must also comply with a Disallowance Order that is held to be lawful. There is no principled reason or basis in PURPA for the Commission to impose the entire burden of a Disallowance Order on the Company and its shareholders under those circumstances.

Q. Do you agree with Mr. Morrison that the Regulatory Disallowance Clause is inconsistent with the right of a QF under 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of a PPA?

A. No. Under the Schedule 19 PPA, a QF is entitled to receive fixed rates over the term of the PPA. Absent the occurrence of a breach of the PPA by the QF, the QF's entitlement to those rates would be affected only if there is a Disallowance Order that is found to be lawful after appeal by the Company and the QF. To be found lawful, a court would almost certainly have to find that a disallowance was not barred by 18 C.F.R. § 292.304(d)(2).

Q. Do you have any comment on Mr. Morrison's testimony that Strata has not developed any solar facilities in the Company's service territory?

A. Yes. Although to my knowledge, Strata has not built a solar facility in the Company's North Carolina service territory, in September and October of this year, two Strata affiliates have filed CPCN applications for solar facilities in the Company's service territory that states that the developer intended to sell power to the Company.[4] Further, the Company has been in discussions with Strata concerning a possible PPA for a solar facility larger than 5 MW in the Company's North Carolina service territory.

Q. Mr. Morrison testified that the Regulatory Disallowance Clause discourages QF development in the Company's North Carolina service territory. Do you agree?

A. No. In the last two years, the Company has entered into five Schedule 19 contracts with QFs, of which three have entered commercial operation and two have started construction. Each of these contracts contained the Regulatory Disallowance Clause at issue in this proceeding. In addition, the Company has entered into a PPA with a 20 MW QF that also contains a provision similar to the Regulatory Disallowance Clause. Perhaps more significantly, so far this year, at least 44 QF projects, representing over 370 MWs of nameplate capacity, have filed applications for certificates of public convenience and necessity for facilities in the Company's North Carolina service territory; nearly all of which are for solar facilities. A list of these QFs is provided at Exhibit RJT-1 to this rebuttal testimony. In short, even with the inclusion of Article 6 in the Company's Schedule 19 and non-Schedule 19 PPAs, there appears to be strong and active interest in the development of QFs in the Company's North Carolina service territory.

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[4] *See In the Matter of Williamston West Farm, LLC For a Certificate of Public Convenience and Necessity and Registration as a New Renewable Energy Facility,* Application at 3, Docket No. SP-2971, Sub 0 (Sept. 18, 2013), *In the Matter of Application of Parmele Farm, LLC For a Certificate of Public Convenience and Necessity and Registration as a New Renewable Energy Facility,* Application at 3, Docket No. SP-3024, Sub 0 (Oct. 3, 2013).

Q. On pages 4 through 7 of this testimony Mr. Morrison emphasizes that under PURPA a utility is required to purchase energy and capacity at the utility's full avoided costs in order to encourage the development of QFs. Do you agree?

A. I am not a lawyer, so I cannot speak to Mr. Morrison's legal analysis, but I agree with the general proposition that FERC determined that a requirement that utilities purchase QF power at avoided costs would encourage the development of QFs. Utilities, however, are not required to pay more than avoided costs to encourage QF development.

Q. What are avoided costs?

A. Avoided costs are defined under PURPA as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (2013).

Q. Is a utility required under PURPA or FERC's regulations implementing PURPA to pay QFs more than its avoided cost in order to encourage the development of QFs?

A. No. The FERC regulations implementing PURPA provide that an electric utility is not required to "pay more than the avoided costs for purchases." 18 C.F.R. § 292.304(a) (2013).

Q. Did you review Mr. Morrison's testimony on the importance of the internal rate of return (IRR) in financing QF projects?

A. Yes. On pages 10 and 11 of his testimony, Mr. Morrison stated that IRRs in the range of 8% to 12 % are necessary to attract investors. Further, Mr. Morrison testified that based on his experience, the avoided costs rates approved in Docket No. E-100, Sub 127 produced an IRR in that range, but "[a] 20% decrease in rates, as proposed by the Utilities will drop IRRs below that threshold." Morrison Testimony at 10-11.

Q. What did Mr. Morrison predict would be the result if the Commission adopted the avoided cost rates proposed by the Utilities in this proceeding?

A. He stated that he believed that many QF developers would cease to do business in North Carolina. Further, he noted some QF developers, including Strata, were investigating development opportunities in other states in light of utilities' proposed avoided cost rates. Morrison Testimony at 11.

Q. Do you have any comment on Mr. Morrison's prediction?

A. I take Mr. Morrison at his word that Strata would consider abandoning North Carolina solar development if the Utilities' avoided cost rates approved by the Commission do not provide an IRR acceptable to Strata. As I testified above, however, CPCN filings in the Company's North Carolina service territory in the past year indicate strong QF interest in the rates proposed by the Company in this proceeding.

Q. **In light of the threat that QF developers would abandon North Carolina, would it be appropriate for the Commission to augment the Utilities' actual avoided costs to reach an IRR level satisfactory to QF developers?**

A. No. The purpose of this proceeding is solely to objectively determine the utilities' avoided costs pursuant to and in accordance with PURPA. The rate of return required by QF developers is not an avoided cost and is not relevant to the determination of avoided costs. As the Commission has succinctly stated: "[a] utility is obligated to pay QFs the utility's avoided cost, but it is not obligated to any more than that in order to make a particular QF proposal economically viable." *In the Matter of Economic Power & Steam Generation, LLC v. Virginia Electric and Power Company,* Order on Arbitration at 6, Docket No. SP-467, Sub 1 (June 18, 2010).

Q. **Does this conclude your rebuttal testimony?**

A. Yes, it does.

Solar Photovoltaic CPCN Filings in DNCP N.C. Service Territory since January 1, 2013

Docket	Applicant	Filing Date	Max Capacity, kW (AC)
SP-751 Sub 7	SunEnergy I, LLC	1/9/2013	18,000
SP-2465 Sub 0	GEENEX, LLC	1/24/2013	20,000
SP-2465 Sub 1	GEENEX, LLC	1/24/2013	
SP-2515 Sub 0	Williamston Solar, LLC	2/22/2013	1,990
SP-2545 Sub 0	Wonnie Brown Jr.	3/6/2013	6
SP-751 Sub 8	SunEnergy1, LLC	3/20/2013	20,000
SP-2665 Sub 2	Fresh Air Energy - II, LLC	4/22/2013	5,000
SP-751 Sub 10	SunEnergy1, LLC	5/15/2013	5,000
SP-2767 Sub 0	Albert J Larose	6/6/2013	4
SP-2665 Sub 5	Fresh Air Energy - II, LLC	6/10/2013	5,000
SP-2665 Sub 10	Fresh Air Energy - II, LLC	6/10/2013	19,990
SP-2665 Sub 11	Fresh Air Energy - II, LLC	6/10/2013	19,990
SP-2665 Sub 13	Fresh Air Energy - II, LLC	6/10/2013	20,000
SP-751 Sub 12	SunEnergy1, LLC	6/19/2013	12,000
SP-2665 Sub 17	Fresh Air Energy-II, LLC	6/25/2013	19,990
SP-2804 Sub 0	Williamston Alpha SDP, LLC	6/26/2013	5,000
SP-2823 Sub 0	Jamesville Alpha SDP, LLC	7/8/2013	10,000
SP-2824 Sub 0	Ahoskie Alpha SDP, LLC	7/8/2013	20,000
SP-2825 Sub 0	Seaboard Alpha SDP, LLC	7/8/2013	10,000
SP-751 Sub 13	SunEnergy 1, LLC	7/9/2013	20,000
SP-751 Sub 14	SunEnergy 1, LLC	7/9/2013	5,000
SP-751 Sub 15	SunEnergy 1, LLC	7/22/2013	5,000
SP-751 Sub 16	SunEnergy 1, LLC	7/22/2013	5,000
SP-751 Sub 17	SunEnergy 1, LLC	7/22/2013	5,000
SP-751 Sub 18	SunEnergy 1, LLC	7/22/2013	12,000
SP-751 Sub 19	SunEnergy 1, LLC	8/14/2013	12,000
SP-751 Sub 21	SunEnergy 1, LLC	8/19/2013	5,000
SP-2910 Sub 0	SolNCPower1, LLC	8/20/2013	5,000
SP-2910 Sub 1	SolNCPower1, LLC	8/20/2013	5,000
SP-2910 Sub 2	SolNCPower1, LLC	8/20/2013	5,000
SP-2943 Sub 0	Tarboro Solar, LLC	8/29/2013	4,990
SP-2910 Sub 3	SolNCPower1, LLC	9/3/2013	5,000
SP-751 Sub 22	SunEnergy 1, LLC	9/5/2013	5,000
SP-751 Sub 23	SunEnergy1, LLC	9/17/2013	5,000
SP-2910 Sub 4	SolNCPower1, LLC	9/17/2013	5,000
SP-2971 Sub 0	Williamston West Farm, LLC	9/18/2013	4,975
SP-2363 Sub 3	Carolina Solar Energy II, LLC	9/19/2013	4,990
SP-2993 Sub 0	Aulander Solar, LLC	9/26/2013	4,990
SP-2994 Sub 0	Woodland Solar, LLC	9/26/2013	4,990
SP-2995 Sub 0	Winton Solar, LLC	9/26/2013	4,990
SP-2996 Sub 0	Garysburg Solar, LLC	9/26/2013	4,990
SP-2498 Sub 1	Jakana Solar LLC	9/27/2013	4,990
SP-2515 Sub 1	Bethel Solar, LLC	9/30/2013	4,990
SP-2538 Sub 1	Bethel Solar, LLC	9/30/2013	4,990
SP-3024 Sub 0	Parmele Farm, LLC	10/3/2013	4,975

	Count	Max Capacity, kW (AC)
Total CPCN Filings	**44**	**370,830**
Total CPCN Filings of 5,000 kW or Less	**30**	**136,860**

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
ROBERT J. TREXLER

I am the Director of Regulation for Virginia Electric and Power Company in Richmond, VA, where I have a responsibility for negotiation and administration of the Company's wholesale and large customer sales contracts. I have a B.S. degree in Electrical Engineering from The Pennsylvania State University. I joined Dominion Virginia Power in January 1986, and have held various positions since joining the Company. Those positions have included engineering and planning positions within various departments in the electric transmission and distribution side of the Company. I joined Dominion Virginia Power's Capacity Acquisition group in January 2002, where I have coordinated the Company's solicitations for non-utility generation and administered a number of the Company's contracts with non-utility generators ("NUGs") and wholesale customers until I became Manager of Wholesale Power Contracts in December, 2007. In that position, I managed the activities of a number of contract administrators managing the Company's Wholesale Power Sales contracts. In April, 2010, I became Director of the Power Contracts Group, where I oversaw both the administration and operational aspects of the Wholesale sales and NUG power purchase contracts. On October 1, 2013, I became Director of Regulation.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Rebuttal Testimony of Bruce E. Petrie, Public Version and Rebuttal Testimony of Robert J. Trexler*, as filed today in Docket No. E-100, Sub 136 has been served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 18th day of October, 2013.

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