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June 20, 2014

Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603 – 5918

Re: NCUC Docket No. E-100, Sub 140
Redacted Rebuttal Testimony

Dear Ms. Mount:

In connection with the above-referenced docket, enclosed for filing on behalf of NCSEA is the REDACTED Rebuttal Testimony of R.T. Beach. Please ensure that this redacted version is posted to the Commission's website.

Should you have any questions or comments, please do not hesitate to call me. Thank you in advance for your assistance and cooperation.

Kind Regards,

/s Charlotte Mitchell

4834-3108-3547, v. 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2014

REBUTTAL TESTIMONY

OF

R. THOMAS BEACH

ON BEHALF OF

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

June 20, 2014

Q: PLEASE STATE FOR THE RECORD YOUR NAME, EMPLOYER AND POSITION.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A: I am testifying on behalf of NCSEA.

Q: HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A: Yes. On April 25, 2014, I caused to be pre-filed in this docket direct testimony consisting of 41 pages plus three exhibits. On May 30, I caused to be pre-filed in this docket response testimony consisting of 21 pages.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the following issues: 1) DEC/DEP's and DNCP's proposals to modify the hours over which to compensate QFs for capacity value; 2) the Public Staff's position that the costs of carbon emission control are not sufficiently certain to be included in the avoided cost calculation; 3) DEC/DEP's position that avoided transmission capacity costs should not be included in the avoided cost calculation; and 4) the net peaker methodology proposed by the utilities.

Option B On-Peak Hours

Q: DEC/DEP WITNESS SNIDER'S TESTIMONY STATES THAT YOU ADVOCATE FOR THE USE OF THE CURRENT STANDARD TARIFF OPTION B ON-PEAK HOURS AS THE PERIOD OVER WHICH TO COMPENSATE QFS FOR CAPACITY.[1] IS THIS STATEMENT ACCURATE?

A: No, it is not. I previously testified that the Option B structure is a reasonable means to compensate solar QFs for the capacity which they provide.[2] However, my recommendation is that the current on-peak period in Option B should be modified as follows: the current DEC summer on-peak period of 1 p.m. – 9 p.m. should be changed to 11 a.m. – 7 p.m., and the current DEP summer on-peak period of 1 p.m. – 9 p.m. should be modified to noon – 8 p.m. As Figures 2 and 3 in my direct testimony illustrate, these revised periods would align more accurately with the utilities' system peaks in recent years, thus providing greater benefits to the utility and ratepayers. I tested the alignment of these peak periods by looking at the on-peak period that captures the highest percentage of the top 700 load hours for DEC and the top 1,040 hours for DEP, matching the number of hours in an eight-hour on-peak period on weekdays in the summer months for each utility (June to September for DEC, April to September for DEP).[3]

Q: DEC/DEP WITNESS SNIDER RECOMMENDS A MUCH MORE SIGNIFICANT MODIFICATION TO THE OPTION B HOURS: HE SUGGESTS THE USE OF

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1 Supplemental Direct Testimony of Glen A. Snider for DEC/DEP, p. 25, ll 3-5.

2 Direct Testimony of R. T. Beach for NCSEA, p. 38, ll 16-19.

3 As noted in my direct testimony, for DEC an on-peak period of 11 a.m. to 7 p.m. captures 69% of the top 700 peak load hours, compared to just 63% for a 1 p.m. to 9 p.m. on-peak period. An on-peak period of noon to 8 p.m. for DEP captures 59% of the top 1,040 peak load hours, compared to 58% for a 1 p.m. to 9 p.m. on-peak period. *See* Direct Testimony of R. T. Beach for NCSEA, p. 39, ll 5-9.

AN ON-PEAK PERIOD OF 2 P.M. TO 7 P.M. ON WEEKDAYS IN THREE SUMMER MONTHS (JUNE – AUGUST), PLUS 6 A.M. TO 9 A.M. ON WEEKDAYS IN THREE WINTER MONTHS (DECEMBER – FEBRUARY). HOW DO YOU RESPOND TO THIS PROPOSAL?

A: DEC/DEP witness Snider indicates that the narrower set of hours proposed is based on "historic load trends" and best aligns with the utilities' projected need for capacity. The analysis presented in witness Snider's testimony is limited to using data from a single year (2013) and to a definition of peak hours as those falling within 5% of either the summer or winter seasonal peak.[4] I have the following concerns with this analysis:

1. DEC and DEP are summer-peaking utilities,[5] and, for this reason, it is inappropriate to modify Option B to include an on-peak period in winter months that has equal weight as the summer on-peak period.
2. Load conditions can vary from year to year, and thus any analysis of an appropriate on-peak period should consider load data from multiple years.
3. The selection of an on-peak period should examine a range of possible periods, and determine which one best captures when the utility expects to experience peak demands.
4. The on-peak period selected should be used for both energy and capacity rates, and should be reasonably consistent with the on-peak periods used in the utilities' retail rate schedules.

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4 Supplemental Testimony of G. Snider for DEC/DEP, at 19-22.

5 *See* Testimony of Kennie D. Ellis for the Public Staff, p. 13, l 17 (indicating that "DEC, DEP and DNCP are all summer peaking systems").

The modest modifications I have recommended to the Option B hours for the payment of capacity credits are based on analysis that takes into account the foregoing concerns.

Q: ARE DEC AND DEP SUMMER-PEAKING UTILITIES?

A: Yes, they are. A large majority of the peak load hours for DEC and DEP occur in the summer months of June – September, and this majority grows larger as one narrows the sample to look at only the highest demand hours. I examined the top 1,000, 700, 500, and 100 load hours for DEC and DEP in each year from 2006-2012, and calculated the percentage of these hours which occur during June to September. These results are presented in **Tables 1 and 2**.

Table 1: *Percent of DEC's Top Load Hours Occurring in June to September*

Period	Top 1000 Load Hours	Top 700 Load Hours	Top 500 Load Hours	Top 100 Load Hours
2006	72%	80%	93%	100%
2007	73%	80%	93%	100%
2008	65%	72%	85%	97%
2009	60%	67%	74%	83%
2010	65%	75%	85%	90%
2011	67%	75%	88%	96%
2012	63%	69%	80%	86%
2013	61%	69%	86%	100%
Average	**66%**	**73%**	**86%**	**94%**

Table 2: *Percent of DEP's Top Load Hours Occurring in June to September*

2006	66%	73%	87%	100%
2007	68%	78%	90%	96%
2008	60%	66%	75%	86%
2009	53%	58%	60%	52%
2010	57%	63%	73%	72%
2011	61%	65%	78%	88%
2012	58%	62%	73%	74%
2013	55%	61%	71%	77%
Average	**60%**	**66%**	**76%**	**81%**

Typically, fewer than 100 hours each year have loads that are within 5% of the annual system peak load. These tables show that, on average, 87% of the top 100 load hours occur during the summer—specifically, 94% for DEC and 81% for DEP. Although the utilities occasionally experience winter storms which result in periods of high demand, these episodes clearly are less frequent, and result in appreciably lower peak demands on average, than the peak demands which result from hot weather conditions in the summer.

This conclusion is reinforced when one looks at the combination of the two utilities. It is appropriate to combine the demands of the two utilities given their geographic adjacency, DEC/DEP witness Snider's testimony that there are few transmission constraints between their service territories,[6] and their common ownership. When DEC's and DEP's loads are combined, 98% of the hours with loads within 5% of the annual system peak occur in the summer months. In 2012, all of the hours with loads within 5% of the system peak fell in the summer months of June to September. **Figures 1 and 2**, below, provide an illustration of this analysis, using 2012 data. These figures indicate load levels on the summer and winter peak days in 2012. Figure 1 shows that the combined DEC/DEP

[6] Supplemental Testimony of G. Snider for DEC/DEP, at 16, ll 3-4.

loads on the 2012 summer peak day which were above 95% of the system peak fell between noon and 7 p.m. Figure 2 shows that there were no loads on the winter peak day that came within 5% of the system peak.

Figure 1: *Load Profile on the Day of the 2012 Annual Summer Peak Combined Load*

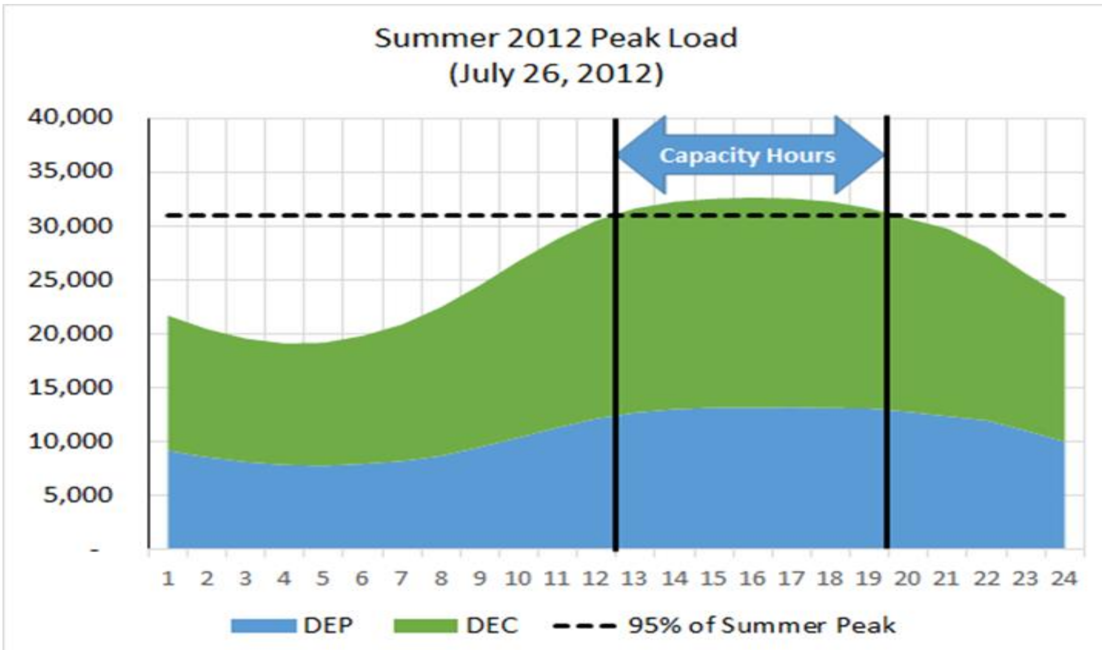
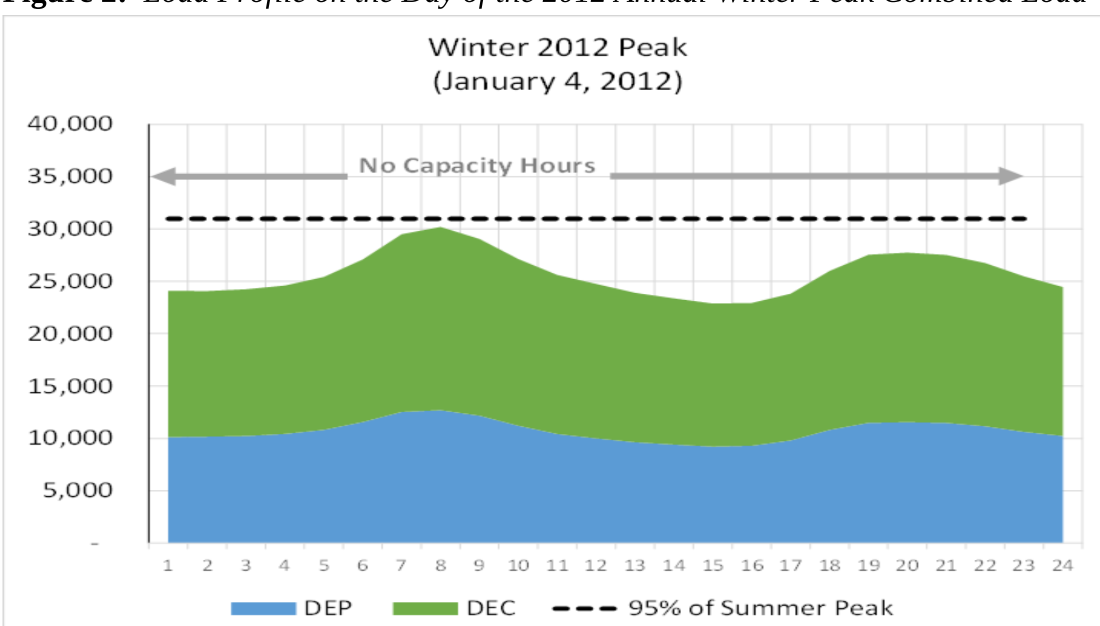


Figure 2: *Load Profile on the Day of the 2012 Annual Winter Peak Combined Load*



I also have reviewed an analysis of the number and percentage of loads within 5% of the combined DEC/DEP peak for all hours from 2006 to 2013. The following **Table 3** provides a summary of these results, which show that 98% of loads within 5% of the system peak occur in the summer months of June to September.

Table 3: *Number and % of Loads Within 5% of the Combined DEC/DEP System Peak*

	2006	2007	2008	2009	2010	2011	2012	2013	**Average**
June to September	38	41	11	91	91	72	31	52	**46**
Annual Total	38	41	14	96	96	72	31	52	**47**
As %	100%	100%	79%	95%	95%	100%	100%	100%	**98%**

My conclusion from this analysis is that it is reasonable to continue the Option B structure which includes a peak period focused on the summer months of June to September.

Q: GIVEN THAT THE LARGE MAJORITY OF DEC'S AND DEP'S PEAK LOAD HOURS OCCUR DURING THE SUMMER, WHY WOULD IT BE PARTICULARLY UNFAIR TO ADOPT THE SET OF ON-PEAK HOURS FOR OPTION B WHICH DEC/DEP RECOMMEND?

A: The on-peak period proposed by DEC/DEP has 37% of its hours during the winter months. As a result, if capacity credits are allocated equally to all on-peak hours (which is unclear in DEC/DEP's proposal[7]), the DEC/DEP proposal would result in 37% of the utilities' avoided capacity costs being attributed to winter demands, when, as shown in Table 3 above, only 2% of the utilities' peak demands within 5% of the system peak

[7] DEC's current avoided cost rates allocate 78% of avoided capacity costs to the summer, and 22% to the winter, but it is not clear if DEC proposes to continue this practice.

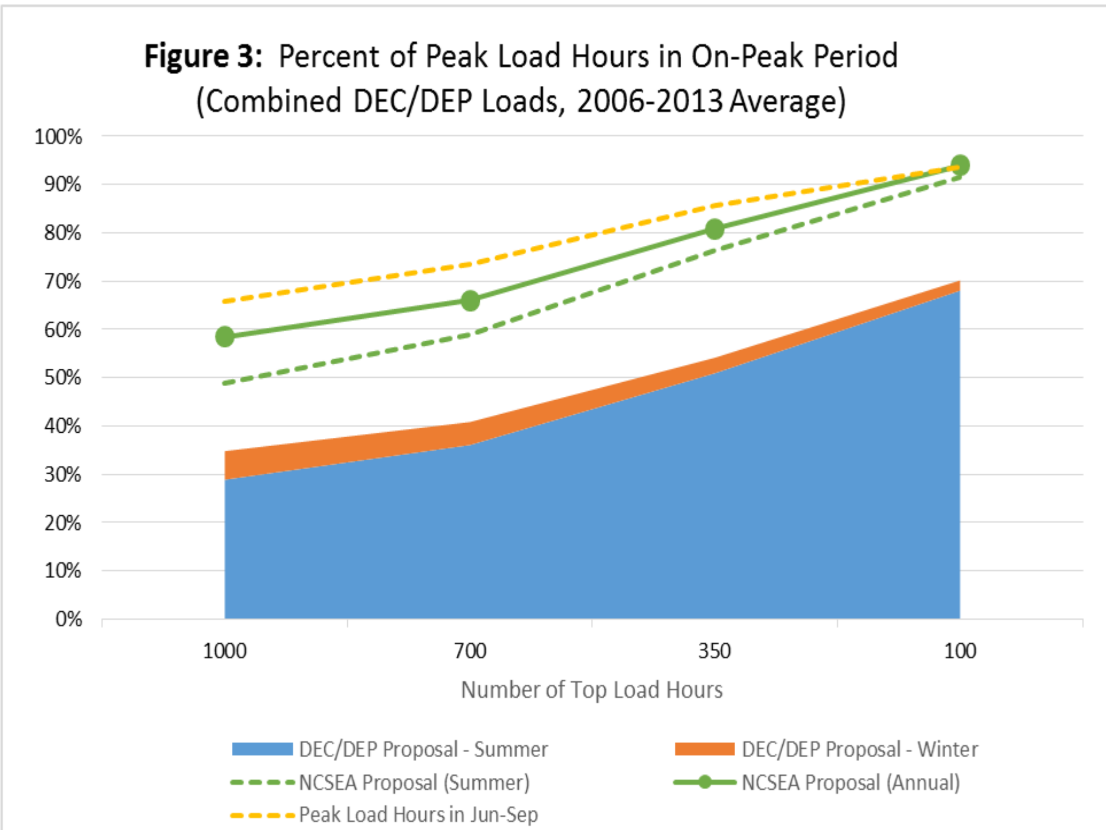
actually occur during the winter. This structure would fail to represent the utilities' avoided costs accurately and would discriminate against solar QFs whose output will be lower from 6 a.m. to 9 a.m. on winter mornings than output during hot, sunny summer afternoons when loads are more likely to be closer to the system peak.

Q: YOU HAVE OBSERVED THAT THE CHOICE OF AN ON-PEAK PERIOD SHOULD LOOK AT MULTIPLE YEARS, AS WELL AS AT A RANGE OF POSSIBLE PERIODS. PLEASE COMMENT ON THE DEC/DEP PROPOSAL IN THIS REGARD.

A: The analysis presented in DEC/DEP witness Snider's testimony looked only at a single year (2013) and calculated the percentage of hours within 5% of the seasonal peak that fell into DEC/DEP's recommended period. DEC/DEP did not examine other recent years, and they did not examine whether there were other periods which might capture even more top load hours. The Commission should adopt a peak period based on an analysis that considers loads in multiple years and that analyzes a number of possible on-peak periods covering a range of top load hours. For example, looking at combined DEP and DEC loads from 2006 to 2012 and at a range from the top 100 load hours to the top 1,000 load hours, we found that DEC/DEP's recommended on-peak period captures from 35% of the top 1,000 load hours to 70% of the top 100 hours.[8] In contrast, my proposal for a summer on-peak period of 11 a.m. to 7 p.m. during June to September (plus the existing Option B non-summer hours) for DEC does a better job of including the peak

[8] The percentage of top load hours included in the peak period grows as the number of top load hours shrinks, because the very highest peak load hours do tend to be more focused on the peak period.

load hours, capturing from 58% of the top 1,000 hours to 94% of the critical top 100 hours. Thus, my recommended on-peak period includes an additional 24% to 27% of top load hours as compared to the DEC/DEP recommendation. These results are shown in **Figure 3** below, and use data for the years 2006-2013. The figure shows that the NCSEA on-peak period captures 98% of the top 100 load hours that fall in the summer months of June to September, while the DEC/DEP proposal includes only 73% of such hours.



Q: HOW DID THE PUBLIC STAFF RESPOND TO YOUR PROPOSAL RELATED TO THE OPTION B HOURS?

A: On page 16, lines 17-20 of his testimony, Public Staff witness Ellis testified that my "proposed tailoring of the on-peak hours to better fit utility peak load appears to have merit and warrants further consideration."

Q: DNCP WITNESS PETRIE PROPOSES TO CHANGE THAT UTILITY'S OPTION B PERIODS, INCLUDING MOVING THE SUMMER ON-PEAK PERIOD FROM 1 P.M. TO 9 P.M. IN JUNE – SEPTEMBER TO 2 P.M. TO 7 P.M. IN JUNE – AUGUST, PLUS NARROWING THE WINTER ON-PEAK HOURS. HAS DNCP ADEQUATELY JUSTIFIED THIS PROPOSAL?

A: No, it has not. The DNCP testimony includes no analysis showing that this proposed change better aligns with DNCP's peak load hours in recent years. Absent such a showing, the Commission should reject this proposal.

Inclusion of Carbon Emission Control Costs in Avoided Costs

Q: PLEASE RESPOND TO PUBLIC STAFF WITNESS HINTON'S TESTIMONY THAT THE COSTS OF CARBON EMISSIONS CONTROL ARE NOT SUFFICIENTLY CERTAIN TO BE INCLUDED IN AVOIDED COSTS.

A: Public Staff witness Hinton testifies that the "costs of carbon emissions control are not sufficiently certain to be included in avoided costs."[9] I suspect that all parties will agree that there are uncertainties associated with the future costs of controls on carbon emissions, as well as the timing of when such controls will be required. However, all parties also appear to recognize that some level of costs associated with mitigating carbon

[9] Testimony of J. R. Hinton for the Public Staff, p. 20, ll 8-10.

emissions is inevitable. For example, the utilities include such costs in their integrated resource planning scenarios, and there appears to be agreement that carbon costs will influence the choice of future generation expansion plans.[10] In fact, witness Hinton points out that the "inclusion of carbon is one of the primary reasons the least cost algorithms select new nuclear generation over alternative generation units."[11]

Therefore, as evidenced by the planning undertaken by the utilities, while the future cost of carbon emissions control is uncertain, it will not be zero and is likely to be significant. The problem with the Public Staff's and the utilities' position is that it responds to uncertainty about future carbon costs by defaulting to an assumption that those costs will be zero, which is inconsistent with the assumptions used for resource planning in the IRPs. Public Staff witness Hinton characterizes the IRP carbon cost assumptions as used for "arriving at the least cost plan"; he tries to distinguish this from the instant proceeding, which is "for the purpose of calculating rates." [12] However, unlike retail rates, the rates established in this proceeding are long-term wholesale procurement rates based on avoided costs calculated by modeling the IRP preferred plan. The costs assumed in that preferred plan should not be excluded from avoided costs if the resulting avoided cost rates are not to discriminate against QFs. Furthermore, IRPs and avoided cost rates are designed for the same purpose: to guide resource procurement – the IRPs guide the procurement of utility resources, and avoided cost rates regulate the procurement of QFs. Consistent assumptions need to be used in both processes, to avoid

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10 Supplemental Testimony of G. Snider for DEC/DEP, p. 27, ll 13-15; Testimony of J. R. Hinton for Public Staff, p. 21, ll 11-14.

11 Testimony of J. R. Hinton for Public Staff, p. 21, ll 12-14.

12 Testimony of J. R. Hinton for Public Staff, pp. 21-22.

biasing procurement toward either type of resource. Indeed, on many other avoided cost issues, the parties, including the utilities and the Public Staff, recognize that it is important for there to be consistency between IRP and avoided cost assumptions.[13] Carbon costs should be no different.

Q: HOW DO YOU RESPOND TO THE POINTS MADE BY DEC/DEP WITNESS BOWMAN REGARDING THE INCLUSION OF COSTS ASSOCIATED WITH FUTURE CARBON REGULATIONS IN THE AVOIDED COST CALCULATION?

A: In opposing the inclusion in the avoided cost calculation of the costs associated with the regulation of carbon dioxide emissions, DEC/DEP witness Bowman characterizes such costs as speculative and takes the position that, "in the case of costs associated with potential future carbon regulations, the regulations may not ever be implemented or they may be implemented later than currently anticipated, or the costs of compliance may be substantially lower than anticipated." [14] However, as discussed above, the utilities are sufficiently convinced that such regulations will be implemented that they use the anticipated costs in major generation planning decisions.

Finally, witness Bowman's concerns regarding the inclusion of future costs making the "process unworkable"[15] are unfounded. DEC/DEP have already quantified the anticipated cost of carbon dioxide emissions regulation and have used those costs in the

[13] Testimony of J. R. Hinton for Public Staff, at p. 8, ll 14-19; *see also* Supplemental Testimony of G. Snider for DEC/DEP, p. 26, ll 1-2.
[14] Supplemental Direct Testimony of G. Snider, p. 11-12.
[15] Supplemental Direct Testimony of K. Bowman, p. 31, ll 7-8.

IRP process. Utilizing the costs already selected and employed by the utilities in the IRP process would avoid the morass that witness Bowman predicts in her testimony.

Q: DO YOU HAVE ANY ADDITIONAL CONCERNS RELATED TO DEC/DEP'S CHARACTERIZATION OF CERTAIN ENVIRONMENTAL COSTS THAT YOU WISH TO BRING TO THE COMMISSION'S ATTENTION?

A: Yes. DEC/DEP witness Snider states that certain external costs, including "speculative future potential environmental costs," are not avoidable utility costs. Rather, witness Snider appears to characterize environmental costs – including carbon costs – that the QF allows the utility to avoid as external benefits that are in addition to avoided costs and that are captured as the cost of Renewable Energy Certificates ("RECs").[16] He goes on to state that the "inclusion of externalities in the avoided cost calculation would essentially circumvent the legislative intent of the cap on REC payments by artificially including these externalities as part of the utilities' avoided costs."[17] However, "Renewable Energy Certificate" under North Carolina statutory law means:

> [A] tradable instrument that is equal to one megawatt hour of electricity or equivalent energy supplied by a renewable energy facility, new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission. **A "renewable energy certificate" does not include the related emission reductions, including, but not limited to, reductions of sulfur dioxide, oxides of nitrogen, mercury, or carbon dioxide.**[18]

Although I am not a lawyer, the statute seems to me to provide clearly that a REC does not include carbon dioxide emission reductions, or reductions of certain other specified

[16] Supplemental Direct Testimony of G. Snider, p. 11.
[17] Supplemental Direct Testimony of G. Snider, p. 12, ll 2-4.
[18] N.C. Gen. Stat. § 62-133.8(a)(6)(emphasis added).

criteria pollutants. Therefore, witness Snider's argument that avoided emissions costs are included in the REC fails. As a REC clearly does not include emission reductions, the costs of reducing carbon emissions that the QF allows the utility to avoid should be included in the avoided cost calculation.

Q: TABLE 2 OF YOUR DIRECT TESTIMONY SHOWS THE IMPACTS ON DEC'S AVOIDED COST ENERGY RATES IF THE CARBON COSTS FROM ITS IRP ARE INCLUDED. DO YOU HAVE ANY FURTHER INFORMATION TO CONFIRM THOSE NUMBERS?

A: Yes. DEC has provided a simplified calculation of the annual increase in its avoided cost energy rates if the assumed carbon costs from its 2012 IRP are included, in its CONFIDENTIAL response to Public Staff Data Request 3, Question 4 in this proceeding.

[BEGIN CONFIDENTIAL]

[redacted]

CONFIDENTIAL

[redacted]

[redacted]

[END CONFIDENTIAL]

Using the discount rate that DEC assumes in its current avoided cost rates, the 5-, 10-, and 15-year levelized values for the increases that DEC estimates are the same as the increases that I have calculated and presented in Table 2 of my Direct Testimony. I calculated the values in Table 2 using the full output data from DEC's production cost model runs; DEC's simpler estimate has arrived at the same result.

Q. BEYOND CONSISTENCY WITH THE IRP, IS THERE ANOTHER JUSTIFICATION FOR THE INCLUSION OF CARBON EMISSIONS COSTS IN THE AVOIDED ENERGY CALCULATION?

A. Yes. As testified by Public Staff witness Kirsch, "QF power creates environmental benefits by displacing the electrical energy that would otherwise be produced by resources that are more polluting."[19] Public Staff witness Kirsch also testifies that "QFs can help utilities avoid the costs of paying for certain emissions or for the credits that

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[19] Direct Testimony of L. Kirsch for the Public Staff, p. 16, 11 14-15.

offset those emissions."[20] Kirsch points out that to the extent that utilities do not yet pay for their emissions, QFs do not help utilities avoid costs, even though QF power may provide an environmental benefit. Kirsch acknowledges, however, that in such a scenario, the QF is being undercompensated when he testifies that "[b]y mandating that QFs be paid utilities' avoided costs, PURPA thus may pay to QFs only a portion of the environmental benefits that they create."[21] Thus Public Staff witness Kirsch highlights the fact that QFs are undercompensated for environmental benefits they provide.

Q. PLEASE RE-STATE YOUR RECOMMENDATION REGARDING THE INCLUSION OF COSTS ASSOCIATED WITH CARBON DIOXIDE EMISSIONS REGULATION IN THE AVOIDED COST CALCULATION.

A. The costs which the utilities themselves have assumed in their IRPs as the costs of carbon dioxide emissions regulation should be included in the calculation of avoided energy costs, for the following three reasons:

1. Renewable QFs provide environmental benefits, including displacing the electrical energy that would otherwise be produced by resources that are more polluting, for which they are currently undercompensated.
2. The utilities take the cost of carbon dioxide emissions regulation into consideration in the resource planning process to justify their own generation decisions.

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[20] Direct Testimony of L. Kirsch for the Public Staff, p. 17, 11 4-7.
[21] Direct Testimony of L. Kirsch for the Public Staff, p. 17, 11 7-9.

3. Regulation of such emissions in the near future, and the associated work to meet carbon dioxide reduction targets, is likely to occur within the 15-year term of a power purchase agreement entered into during the 2014 biennium. Accordingly, it is unreasonable to assume zero costs over this period for mitigation of carbon emissions.

Avoided Transmission Capacity Costs

Q: DOES DEC/DEP WITNESS SNIDER HAVE A VALID CRITICISM THAT YOUR RECOMMENDATION ON AVOIDED TRANSMISSION CAPACITY COSTS "DOES NOT DIFFERENTIATE BETWEEN TRANSMISSION PEAK CAPACITY REDUCTIONS AND REDUCTIONS IN TRANSMISSION CIRCUIT UTILIZATION"[22]?

A: No. I do agree with witness Snider that transmission capacity additions are driven by the peak loadings on transmission circuits. But my recommendation is based on the fact that solar PV systems located on the distribution system that are generating at times of peak demand on the transmission system will reduce peak loads on transmission circuits because the solar output will serve local distribution loads and avoid the need for upstream transmission capacity to do so. This makes transmission capacity available to serve other customers, to meet load growth, or to fulfill service requests for wholesale transmission. My direct testimony explains this clearly on pages 23-26 and discusses how solar can be assumed to reduce transmission peak loadings, just as solar can provide reliable generating capacity to serve peak demand. In support of my position, I cite

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[22] Supplemental Direct Testimony of G. Snider for DEC/DEP, p. 26, ll 21-22.

Itron's impact evaluation studies from the California Solar Initiative, which confirm that distributed PV generation at times of peak demand will provide additional peak capacity on the transmission system. Similarly, Minnesota has recognized that distribution-level solar will avoid peak capacity-related transmission costs, and has included such avoided transmission costs in its adopted value of solar.

Net Peaker

Q. PUBLIC STAFF HAS OPPOSED DNCP'S PROPOSED "NET PEAKER" METHOD, IN WHICH DNCP WOULD REMOVE THE VALUE OF THE ENERGY BENEFITS OF A PEAKER FROM THE AVOIDED CAPACITY COSTS.[23] PLEASE COMMENT ON THE GROUNDS FOR PUBLIC STAFF'S OPPOSITION.

A. I agree with Public Staff witness Hinton that it is difficult to establish the point at which a combustion turbine peaker is run to provide energy benefits, as opposed to simply being a source of capacity. Even if a peaker is purely a source of capacity, it would be expected to run for a certain number of hours; otherwise, it would not be needed for capacity. Thus, this adjustment should only be made if the utility can show that the new peaker will run for a significant number of hours (for example, at a capacity factor of 8% or higher, which is equivalent to running at full output for the number of hours in the Option B summer on-peak period).

[23] Testimony of J. R. Hinton for Public Staff, at pp. 19-20.

I also concur with Public Staff witness Hinton that it is difficult to know whether the output of a production cost model accurately forecasts the hourly market prices or locational marginal prices ("LMPs") of the markets in which the peaker would sell energy. If the Commission adopts a net peaker concept, and continues to use production cost modeling to set avoided energy rates, the Commission should adopt DEC/DEP's method of capping energy prices in the production cost runs at the operating costs of the peaker, including the peaker's start-up and variable operating and maintenance costs. Alternatively, because DNCP operates in the PJM market, the Commission could consider directing DNCP to use PJM's Net Cost of New Entry (Net CONE) capacity price, which already includes the net peaker adjustment. The use of the PJM Net CONE capacity price would have the benefit of being a public, transparent source for the long-term avoided capacity cost, which appears to be a particularly contentious avoided cost parameter in these proceedings.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing **REBUTTAL TESTIMONY OF BEACH** upon the parties of record in this proceeding, or their attorneys, by electronic mail.

This 20th day of June, 2014.

/s Charlotte A. Mitchell

4843-5048-8347, v. 1