KEYES, FOX & WIEDMAN LLP

May 30, 2014

Via Electronic Filing

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

Re: NCUC Docket No. E-100, Sub 140
ADDITIONAL DIRECT TESTIMONY OF J. RICHARD HORNBY ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE

Dear Ms. Mount,

Attached for filing in the above-referenced docket is the ***Additional Direct Testimony of J. Richard Hornby on Behalf of The Alliance for Solar Choice***. Please do not hesitate to contact me if you have any questions. Thank you for your assistance with this matter.

With best regards,

/s/ Thadeus B. Culley
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Attachments

cc: Service List for Docket No. E-100, Sub 140

CERTIFICATE OF SERVICE

I hereby certify that all persons on the service list for Docket No. E-100, Sub 140 have been served true and accurate copies of the foregoing ***Additional Direct Testimony of J. Richard Hornby on Behalf of The Alliance for Solar Choice*** by hand delivery, first class mail deposited in the U.S. Mail, postage pre-paid, or email transmission with the party's consent.

Dated May 30, 2014, at Cary, North Carolina.

/s/ Thadeus B. Culley
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ADDITIONAL DIRECT
Biennial Determination of Avoided Cost	)	TESTIMONY OF J. RICHARD
Rates for Electric Utility Purchases from	)	HORNBY ON BEHALF OF
Qualifying Facilities — 2014	)	THE ALLIANCE FOR SOLAR
	)	CHOICE

May 30, 2014

ADDITIONAL DIRECT TESTIMONY OF J. RICHARD HORNBY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge, MA 02139.A.

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have over thirty years of experience in the energy industry, primarily in utility regulation and energy policy. Since 1986, as a regulatory consultant I have provided expert testimony and litigation support on natural gas and electric utility resource planning, cost allocation and rate design issues in over 120 proceedings in the United States and Canada. During that period my clients have included staff of public utility commissions, state energy offices, consumer advocate offices, environmental groups and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the Natural Gas Program and subsequently, as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT) and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my resume to this testimony as Exhibit___(JRH-1).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I have testified in a Duke Energy Save a Watt case (Docket No. E-7, Sub 831) and in a case regarding a request by Progress Energy for a performance incentive for its delivery of efficiency programs (Docket No. E-7, Sub 831).

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of I am testifying on behalf of The Alliance for Solar Choice ("TASC"). TASC is an organization founded by companies that comprise the majority of the nation's rooftop solar industry, including SolarCity, Sunrun, Sungevity, Verengo Solar, Demeter Power Group, and Solar Universe.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony has two purposes. It addresses whether the methodologies the Commission has historically relied upon to determine avoided cost, and the methodologies other parties proposed in their April 25 direct testimonies, capture the full avoided costs of Qualifying Facilities (QFs) under Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). My testimony also compares the valuation methodologies proposed by those other parties to the methodological framework Ms. Anne Smart presented, in her direct testimony, for evaluating the full range of benefits associated with distributed solar electric generation facilities.

Q. **WHAT DATA SOURCES DID YOU RELY UPON TO PREPARE YOUR TESTIMONY AND EXHIBITS?**

A. My testimony is based upon the Direct Testimonies and Exhibits other parties filed on April 25, responses to data requests in this proceeding, and the various studies listed in TASC's Exhibit AS-1.

II. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE FIRST MAJOR CONCLUSION AND RECOMMENDATION FROM YOUR REVIEW OF THE DIRECT TESTIMONIES OF OTHER PARTIES.

A. My first major conclusion is that the categories of costs utilities avoid by purchasing electric energy from qualifying facilities do not represent or reflect the full range of benefits associated with distributed solar electric generation facilities. Based upon that conclusion, I support the recommendation made by Ms. Smart that the Commission initiate a proceeding to develop and adopt a standard method for determining the benefits of distributed solar generation in North Carolina.

Q PLEASE SUMMARIZE THE SECOND MAJOR CONCLUSION AND RECOMMENDATION FINDING FROM YOUR REVIEW OF THE DIRECT TESTIMONIES OF OTHER PARTIES.

A. My second major conclusion is that certain of the methodologies and input assumptions Duke Energy Carolinas and Duke Energy Progress ("DEC/DEP") and Dominion North Carolina Power ("Dominion" or "DNCP") have proposed for estimating the costs they will avoid by purchasing electric energy from QFs do not capture the full avoided costs that will result from those purchases and are therefore not reasonable. Based upon that conclusion, I recommend the following changes.

- Avoided generation capacity costs. Consistent with North Carolina's tradition and familiarity, I recommend that the North Carolina utilities continue to use the peaker method to quantify avoided capacity costs. I also recommend that they use a set of comprehensive, transparent and verifiable input assumptions including land, construction and materials, infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and weighted average cost of capital.
- Avoided energy costs. I recommend that the North Carolina utilities continue to use a production cost method to determine their avoided energy cost for each hour. However, the Commission should require North Carolina utilities that are planning resource additions in the

absence of purchases from QFs to include the net fixed costs of new resources in their avoided energy costs. That is, net of avoided capacity costs per the peaker method, North Carolina utilities should develop avoided energy costs that are QF technology-specific, given the differences in generation profile by QF technology.

- Avoided Environmental costs. Each utility should calculate its avoided energy costs using, at a minimum, the Reference Case projection for carbon costs used in its most recent Integrated Resource Plan.
- Avoided energy losses. I recommend that both DEC/DEP and DNCP adjust their capacity and energy credits for solar QFs upward by 3.3% to reflect avoided line losses. I recommend that DNCP undertake a study to understand how distributed PV reduces line losses within DNCP's North Carolina service territory.
- Avoided transmission and distribution (T&D) costs. For avoided transmission capital investments, I recommend that DEC include $0.010 per kWh, that DEP include $0.007 per kWh, and that DNCP include an avoided transmission capacity cost of $0.009 per kWh. For avoided distribution capital investments, I recommend that DEC, DEP, and DNCP use a value of 0.0025/kWh for solar QFs. Finally, I recommend that DEC/DEP and DNCP both continue to collect and analyze data and that both utilities study these avoided cost issues so that the avoided cost paid to PURPA QFs is appropriate as both the

physical system and our understanding of that system continue to evolve.

- Avoided Energy Market Costs. North Carolina utilities who participate in PJM's wholesale energy and capacity markets have the potential to benefit from the suppression in prices in those wholesale prices that will result from their purchases from QFs. The value of those price suppression benefits can be significant.
- Ancillary services and grid support. The Duke Energy PV Study indicates that North Carolina utilities can make a smooth transition to a high-PV energy mix. In addition, the Study acknowledges the limitations of its analyses. I recommend that the Commission consider those two factors when deciding whether it is reasonable to allow an adjustment for solar integration costs. If the Commission does approve an adjustment, I recommend that it be no greater than the $1.43/MWh recommended by Mr. Beach.

III. DISTRIBUTED SOLAR GENERATION BENEFITS EXCEED THE COSTS UTILITIES AVOID BY PURCHASING ELECTRIC ENERGY FROM QFS

Q. ARE DISTRIBUTED SOLAR GENERATION FACILITIES ALWAYS QUALIFYING FACILITIES?

A. No. First, it is important to understand the difference between the two types of facilities. A distributed solar generation facility is a photovoltaic (PV) installation typically located at or near the point of retail electricity use, and as such typically connected to the local utility's distribution grid. PURPA defines QFs as cogenerators and small power facilities up to 80 MW.

A distributed solar generation facility may be, but need not be, a QF. For example, in North Carolina solar PV generators of up to 1 MW are eligible to participate in the state's net metering program and net usage against production rather than electing to sell all exported electricity at wholesale as QFs. Thus, a solar PV facility owner within the Duke, Progress, or Dominion service territory could participate in North Carolina's net metering program rather than PURPA.

Q. WHY DO YOU MAKE A DISTINCTION BETWEEN DISTRIBUTED SOLAR GENERATION FACILITIES AND QUALIFYING FACILITIES?

A. There are several reasons for making this distinction. First, making the distinction between distributed solar generation facilities and qualifying facilities is significant in light of the expanded scope of the preliminary phase of the biennial avoided cost proceeding, which seeks party input on how the Commission should think about broader distributed solar generation issues. This broader consideration has implications beyond the Commission's use of these proceedings to implement PURPA by determining the rates that jurisdictional utilities must pay to QFs pursuant to PURPA. Under the broader consideration of distributed solar generation that has been scoped within this preliminary part of this biennial proceeding, it is appropriate for the Commission to consider categories of value associated with distributed solar generation that go beyond what would be traditionally considered under PURPA. In that regard, understanding the distinction between distributed solar generation facilities that are QFs and those that are not QFs helps parties understand that the costs utilities avoid by purchasing from QFs are only a sub-set, or portion, of the full set of benefits of distributed solar generation facilities.

Second, it is important to take into consideration both the "technological" and "distributed" characteristics of distributed solar generation facilities for purposes of determining an avoided cost rate through this proceeding. The values of certain types of utility avoided costs will vary depending on the characteristics of the generation technology, e.g. a solar QF versus a wind QF versus a hydroelectric QF, and with the location at which the QF connects to the utility, i.e. at the transmission level or at the distribution level. It is consistent with PURPA to reflect these QF characteristics in an avoided cost rate.

Q. ARE THE BENEFITS OF DISTRIBUTED SOLAR GENERATION GREATER THAN THE COSTS UTILITIES AVOID BY PURCHASING ELECTRIC ENERGY FROM QFS?

A. Yes. The benefits of distributed solar generation include the costs that utilities avoid by purchasing from QFs as defined by PURPA plus additional costs that society avoids and additional benefits that society receives.

Q. WHAT CATEGORIES OF BENEFITS CAUSE THE VALUE OF DISTRIBUTED SOLAR GENERATION TO EXCEED THE AVOIDED COST RATE FOR PURCHASES FROM QFs?

A. Various studies have quantified at least fourteen benefits of distributed solar generation, as named and defined by Ms. Smart in Exhibit AS-1. In Column A of Exhibit JRH-2 I list those fourteen benefits. However, current PURPA regulations only allow utilities to consider eight of those fourteen benefits as costs they can avoid by obtaining energy and capacity from QFs. Column B of Exhibit JRH-2 identifies those eight types of avoided costs to utilities as (i) avoided energy costs (electricity generation), (ii) avoided environmental costs, (iii) avoided capacity costs (generation), (iv) avoided and deferred capacity costs for transmission and distribution, (v) avoided energy losses, (vi) fuel price hedging, (vii) energy market impacts (supply induced price effects) and (viii) ancillary services and grid support**.** The six additional types of benefits that cause the value of distributed solar generation to exceed the avoided cost rate for purchases from QFs are avoided renewable costs, health benefits, security and resiliency of grid, environmental and safety benefits, effects on economic activity and employment and visibility benefits.

I did not include avoided renewable costs as one of the costs North Carolina utilities could avoid by purchasing energy from QFs for two reasons. First, the quantity of renewable energy North Carolina utilities are obligated to acquire each year is expressed as a percent of their retail sales. Utility purchases from QFs do not reduce that annual quantity obligation. Second, PURPA requires utilities to purchase energy from QFs, it does not require them to purchase the renewable energy credits (RECs) that may be associated with the energy from those QFs.

Q. IS YOUR POSITION THAT, BY PURCHASING FROM QFS, EACH NORTH CAROLINA UTILITY WILL ALWAYS BE ABLE TO AVOID EACH OF THE EIGHT TYPES OF AVOIDED UTILITY COSTS?

A. No. The eight types of avoided utility costs I list in column B of Exhibit JRH-2 represent the full range of costs that utilities in North Carolina have the potential to avoid by purchasing from QFs. The extent to which a specific North Carolina utility will be able to avoid each of those eight types of costs will vary by utility and by the point in time at which the utility prepares its projection of avoided utility costs.

Q. IS THERE GENERAL CONSENSUS AMONG THE PARTIES TO THIS PROCEEDING THAT NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID EACH OF THE EIGHT TYPES OF AVOIDED UTILITY COSTS YOU HAVE IDENTIFIED?

A. The parties disagree on the appropriate methods for calculating various types of costs, as I discuss later in my testimony. However, I believe that the parties may generally agree that North Carolina utilities have the potential to avoid each of the eight types of avoided utility costs, i.e., that these are the correct eight types of costs to analyze. However, since some parties have not addressed certain of the types of costs explicitly I do not know with certainty that there is there general consensus on consideration of these eight types of costs.

I present my assessment of the positions of the parties regarding consideration of each of the eight types of avoided utility costs in column C of Exhibit JRH-2. There does appear to be general consensus that, by purchasing from QFs, North Carolina utilities have the potential to avoid four of the eight types of avoided utility costs, i.e., energy generation costs, avoided environmental costs (of emissions subject to existing regulations), generation capacity costs and capacity costs for transmission and distribution. Not all parties have presented an explicit position on whether, by purchasing from QFs, North Carolina utilities have the potential to avoid the other four types of utility costs, i.e., energy losses, energy market impacts, fuel price hedging and ancillary service costs.

Q. IS THERE EVIDENCE TO SUPPORT YOUR POSITION THAT ALL NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID THOSE FOUR TYPES OF AVOIDED UTILITY COSTS?

A. Yes. In the next section of my testimony I present evidence supporting my position that, by purchasing from QFs, North Carolina utilities have the potential to avoid costs related to energy losses, energy market impacts, fuel price hedging and ancillary service costs.

Q. IS IT IMPORTANT THAT THE COMMISSION APPROVE METHODS FOR QUANTIFYING THE ADDITIONAL SIX BENEFITS YOU HAVE CATEGORIZED AS AVOIDED COSTS / BENEFITS TO SOCIETY?

A. Yes. It is important that the Commission approve methods for quantifying avoided renewable costs, health benefits, security and resiliency of grid, environmental and safety benefits, effects on economic activity and employment and visibility benefits. Those additional six types of avoided costs / benefits because they will be critical inputs to other proceedings, such as any future consideration of the costs and benefits of net metering in North Carolina. The combined value of those six benefits may be material in such a determination.

Estimates of the avoided costs / benefits to society of distributed solar generation will be critical inputs to future proceedings on net metering in North Carolina. The Commission has an open docket related to net metering (Docket No. E-100, Sub 83). The Commission recognized "the potential magnitude of the impacts on generation, transmission, and distribution systems of both smaller distributed and utility-scale solar photovoltaic projects that are proposed to be constructed in North Carolina" in its February 21, 2014 Order in Docket No. E-100, Sub 136. Because "the Commission has determined that the most efficient path forward in this proceeding is to consider these issues prior to the filing of new proposed rates," the consideration of and eventual approval of a method for quantifying the avoided costs / benefits to society is important.[1]

Exhibit 2 of Mr. Beach, witness for the North Carolina Sustainable Energy Association (NCSEA), referred to as "The Crossborder Study" estimates

[1] Schedule Order E-100 Sub 140, February 25 2014, page 2.

the combined value of several of those benefits, specifically renewable costs, fuel diversity, price mitigation benefits, grid security, and economic development (collectively referred to as "Avoided Renewables Costs") to be as high as 2.2 cents per kWh, depending on the type of PV solar installation and the North Carolina utility.[2] Moreover that estimate does not include estimates of the value of the health benefits or the visibility benefits of distributed solar generation in North Carolina.

Q. DID ANY OF THE PARTIES SUBMIT TESTIMONY ON METHODS FOR QUANTIFYING THE REMAINING SIX BENEFITS YOU HAVE CATEGORIZED AS AVOIDED COSTS / BENEFITS TO SOCIETY?

A. Ms. Smart is the only witness who submitted testimony on methods for quantifying the avoided costs / benefits to society. Dr. Brown, witness for Staff, commented on the applicability of including those benefits in the calculation of costs utilities avoid by purchasing from QFs.

Q. DID DR. BROWN MAINTAIN THAT NORTH CAROLINA WOULD NOT RECEIVE SOME OR ALL OF THOSE SIX ADDITIONAL BENEFITS FROM DISTRIBUTED SOLAR GENERATION?

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[2] NCSEA Witness Beach, Exhibit 2, page 6, Table 2 and Table 3.

A. No. Dr. Brown's position is simply that none of the six avoided costs / benefits to society should be included in the calculation of utility avoided costs under PURPA. Dr. Brown does not state that North Carolina would not receive those benefits nor did he state that the benefits to society could not be quantified.

Q. DOES DR. BROWN MAINTAIN THAT IT IS THEORETICALLY POSSIBLE FOR DISTRIBUTED SOLAR GENERATION TO HAVE AN ADVERSE IMPACT ON GRID OPERATION SAFETY, SECURITY, RELIABILITY, AND RESILIENCY?

A. Yes. Dr. Brown makes a number of general assertions regarding the potential detrimental impact of distributed solar generation on grid operation safety, security, reliability, and resiliency.

Q. **DID DR. BROWN PRESENT OR CITE ANY PROJECTIONS OF DETRIMENTAL IMPACTS DISTRIBUTED SOLAR GENERATION IN NORTH CAROLINA MIGHT THEORETICALLY HAVE ON GRID OPERATION SAFETY, SECURITY, RELIABILITY, OR RESILIENCY?**

A. No. Dr. Brown's testimony does not present any projections of detrimental impacts distributed solar generation in North Carolina might have on grid operation safety, security, reliability, or resiliency. In addition, his testimony does not either critique, or present any citations, from the Duke Energy Photovoltaic Integration Study: Carolinas Service Areas (Duke

Energy PV Study)[3], the Crossborder Study, or any other North Carolina specific analysis of possible impacts of distributed solar generation in North Carolina on grid operation safety, security, reliability, or resiliency. Finally, his testimony does not either critique, or present any citations, from recent studies on the impacts of distributed solar generation on grid operation safety, security, reliability, or resiliency in other states with higher levels of solar penetration than North Carolina.

Q. IN RESPONSE TO DATA REQUESTS DID DR. BROWN PRESENT OR CITE ANY PROJECTIONS OF DETRIMENTAL IMPACTS DISTRIBUTED SOLAR GENERATION MIGHT HAVE IN NORTH CAROLINA?

A. No. In Public Staff responses to TASC Data Requests1.2 to 1.15, Dr. Brown did not present, or cite any projections by others, of detrimental impacts distributed solar generation might have in North Carolina.

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[3] DEC/DEP Witness Snider Exhibit 1.

IV. METHODS FOR ESTIMATING COSTS UTILITIES MAY AVOID BY PURCHASING ELECTRIC ENERGY FROM QFS

Q. DO ALL PARTIES AGREE ON THE METHODS FOR ESTIMATING EACH OF THE EIGHT TYPES OF COSTS YOU HAVE CATEGORIZED AS AVOIDED COSTS TO UTILITIES?

A. No. The parties disagree on the methods which should be used to calculate five of the eight types of avoided costs, as well as on the input assumptions which should be used to make certain of those calculations. The five types are avoided energy costs (electricity generation), avoided environmental costs, avoided energy losses, avoided capacity costs (generation) and avoided capacity costs for transmission and distribution. The witnesses for DEC/DEP, and for DNCP, do not discuss methodologies for calculating avoided costs attributable to energy market impacts (supply induced price effects, fuel price hedging or ancillary services and grid support.)

In this section of testimony I discuss the types of costs on which the parties disagree and present recommendations on the appropriate methodology for each type of cost. My testimony focuses primarily on the methods proposed by witnesses for Staff, DEC/DEP and DNCP. Exhibit

JRH-3 presents a synopsis of the methods those parties proposed for each of the eight types of avoided costs.

Avoided Capacity Costs for Generation

Q. WHAT METHOD DO NORTH CAROLINA UTILITIES CURRENTLY USE TO CALCULATE THE COSTS OF GENERATING CAPACITY THEY CAN AVOID BY PURCHASING FROM QFS?

A. By purchasing from QFs North Carolina utilities can avoid the costs of acquiring electric generating capacity from other resources. North Carolina utilities currently use the peaker method to calculate those avoided costs, with a gas combustion turbine (CT) units assumed to be the least-cost source of peaking capacity.

Q. DO THE PARTIES GENERALLY AGREE THAT NORTH CAROLINA UTILITIES SHOULD CONTINUE USING SOME FORM OF THE PEAKER METHOD?

A. Yes. Staff states that "the peaker method is a reasonable means of quantifying avoided capacity costs for QFs in general." (Staff Witness Kirsch, p. 23, lines 14-15). NCSEA states that "it would be reasonable for the Commission to direct the utilities to continue to use the peaker method to calculate avoided costs" (NCSEA Witness Beach, p. 10, lines 5) subject to suggested modifications. SACE also states that, should other associated avoided costs be quantified, "it remains reasonable to use a peaking combustion turbine as that marginal plant" (SACE Witness Rábago, p. 15, lines 5-6). While DEC/ DEP and DNCP each propose modifications to the peaker method they each basically propose continuing to use it in their proposed modified form.

Q. THE PEAKER METHOD REQUIRES A CALCULATION OF THE INSTALLED COST OF A PEAKER UNIT. PLEASE COMMENT ON THE INPUT ASSUMPTIONS THAT SHOULD BE USED TO MAKE THAT CALCULATION.

A. I agree with Mr. Beach that the input assumptions North Carolina utilities use for these calculations should be based on data "…taken from public and transparent industry sources, such as the EIA or PJM cost of new entry studies" (NCSEA Witness Beach, p. 17, lines 8-10). The components (and costs thereof) associated with the construction of the CT should mirror the company's IRP, and at a minimum should include:

- land (even if the utility owns the land, its immediate value as an asset is foregone if used to host a generator),
- all construction and materials costs,
- obtaining a firm fuel delivery system (e.g., the costs associated with obtaining a lateral for gas delivery), and

- the costs of transmission systems upgrades associated with the installation of the generator.

The costs should also include all fixed operations and maintenance costs, taxes and weighted average cost of capital.

Q. WHAT SIZE GENERIC CT INSTALLATION SHOULD BE USED WHEN APPLYING THE PEAKER METHOD TO DETERMINE AVOIDED CAPACITY COST OF GENERATION?

A. Both DNCP and DEC/DEP have used a four unit CT installation in recent proceedings. Mr. Snider proposes that DEC/DEP use "a four unit greenfield site" (DEC/DEP Witness Snider, p. 18, lines 11-12). DNCP proposes "a two (2) unit facility at a brownfield site" (DNCP Witness Petrie, p. 9, line 5). I recommend that utilities use their next peaker project as detailed in their most recent IRPs as a guide for sizing the CT when using the peaker method. Because in the case of both DEC/DEP and DNCP the most recent IRP projects a two-unit facility, the size of the generic CT facility used in the peaker method should be a two-unit facility for both DEC/DEP and DNCP.

Q. DO YOU AGREE WITH THE PROPOSAL BY DNCP TO MODIFY ITS ESTIMATE OF AVOIDED CAPACITY COSTS UNDER THE PEAKER METHOD?

A. No. The peaker method is founded on the premise that "…the utility's long-term avoided cost is its projected system marginal cost of energy in any given hour (which could be from coal units off peak and oil units on peak) plus the fixed cost of a peaking unit." (Emphasis added.)[4] Staff states that the peaker method is based on the theory that the utility system "has an optimal resource mix" and therefore "the per-unit fixed costs (including capital costs) of a new plant net of fuel savings will be identical for all types of generating plants" (Staff Witness Kirsch, p. 21, lines 9-12).

DNCP is essentially proposing that it use the "net cost of new entry" or net CONE method that PJM uses in its forward capacity market. However, the net CONE method assumes the owner of the capacity will earn a margin on the sale of energy and ancillary services during peak hours that will equal the difference between the market price of the energy and ancillary services and the owner's cost of providing energy, and that the owner will use that margin to help recover its capital costs. However, DNCP is not proposing to pay QFs the market price of energy and ancillary services, instead it is proposing to pay QFs its avoided cost of energy. Moreover, as noted above, under the peaker method DNCP should pay its avoided fixed cost of capacity, not the QF owner's estimated net cost of capacity.

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[4] Graves, Hanser, and Basheda, "PURPA: Making the Sequel Better than the Original", Edison Electric Institute, December 2006, page 10

Q. WHAT METHOD DO YOU RECOMMEND NORTH CAROLINA UTILITIES USE FOR QUANTIFYING AVOIDED GENERATION CAPACITY COSTS?

A. Consistent with North Carolina's tradition and familiarity, I recommend that the North Carolina utilities continue to use the peaker method to quantify avoided capacity costs. I also recommend that they use a set of comprehensive, transparent and verifiable input assumptions including land, construction and materials, infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and weighted average cost of capital.

<u>**Avoided Energy Costs**</u>

Q. WHAT METHOD DO NORTH CAROLINA UTILITIES CURRENTLY USE TO CALCULATE THE COSTS OF ENERGY THEY CAN AVOID BY PURCHASING FROM QFS?

A. North Carolina utilities currently use a production costing method to calculate the avoided costs of electric energy.

Q. IS IT POSSIBLE FOR NORTH CAROLINA UTILITIES TO UNDER-ESTIMATE THEIR AVOIDED COSTS OF ELECTRIC ENERGY BY USING UNREASONABLE INPUT ASSUMPTIONS IN THEIR PRODUCTION COSTING METHOD?

A. Yes. North Carolina utilities may under-estimate their avoided cost of electric energy by using unreasonably low values for key input assumptions, such as natural gas prices and carbon dioxide emission costs. The Commission can prevent those under-estimates by requiring utilities to demonstrate that the values of their key input assumptions are reasonable.

Q. IS IT POSSIBLE FOR NORTH CAROLINA UTILITIES TO UNDER-ESTIMATE THEIR TOTAL AVOIDED COSTS BY USING A PRODUCTION COSTING METHOD IN COMBINATION WITH THE PEAKER METHOD?

A. Yes. Both DNCP and DEP/DEC are planning to add new gas combined cycle (CC) units over the next several years. Those utilities may under-estimate their avoided cost of electric energy by using a production costing method in combination with the peaker method because a gas CC unit has a higher fixed cost than a new gas CT. DNCP is proposing to add gas CC units in 2015 and 2016, while DEC/DEP is proposing to add both a CT and a CC in 2018, as indicated in Exhibit____(JRH-4).

The under-estimate may occur if these utilities estimate their avoided energy costs from production costing models that include those new gas CC additions. The total capacity and energy costs resulting from that approach would under-estimate the expected costs of generating capacity, which the utility could avoid by purchasing from QFs. The amount of the under-estimate would be the total cost of capacity of the new resource addition minus the avoided cost of capacity calculated under the peaker method. For example, consider a utility that is planning to acquire a gas CC unit at an installed cost of $1,176/kW in the absence of purchases from QFs, which would have an avoided cost of $182/kW-year, but that calculates its avoided cost of capacity under the peaker method to be $141/kW-year, based on a gas CT installed cost of $977/kW.[5] That utility could be under-estimating its total avoided costs by $ 41/kW-year (i.e., $182/kW-year minus $141/kW-year). Using a solar nameplate capacity of 42% and annual output of 1,524 kWh/kW from the Crossborder Study, a differential of $ 41/kW-year equates to solar capacity value of 1.13 cents/kWh.

Q. CAN THE COMMISSION PREVENT NORTH CAROLINA UTILITIES WHO ARE PLANNING NEW RESOURCE ADDITIONS FROM UNDER-ESTIMATING THEIR AVOIDED COSTS OF ELECTRIC ENERGY IN THIS MANNER?

A. Yes. The Commission can prevent North Carolina utilities that are planning new resource additions from under-estimating their avoided costs

[5] Newell, Samuel et al. "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM". Interconnection LLC. May 15, 2014. Derived from values for Dominion zone, Column 5 of Tables 1 and 2

of electric energy in this manner in at least two possible ways. One way would be for the Commission to require that a utility's avoided energy costs include the net fixed costs of new resources, i.e., net of avoided capacity costs per the peaker method. The other way would be to require those utilities to calculate their avoided energy costs using the proxy method. Mr. Beach mentions those options in his testimony at p. 9, lines 10-12 and p. 10, lines 7-12 respectively.

Q. DO YOU AGREE WITH THE PROPOSAL BY DEC/DEP TO CAP ITS AVOIDED ENERGY COSTS AT THE PRODUCTION COST OF AN AVOIDED CT?

A. No. DEC/DEP proposes to cap the production cost savings calculated in the system dispatch model at the production cost of the CT that DEC/DEP assumed in its peaker method calculation (DEC/DEP witness Snider, p.41, lines 4-7). The rationale Mr. Snider presents for this proposal rests on his premise that DEC/DEP should be calculating the cost of energy it would avoid in each hour by dispatching a gas CT. That premise is not correct. DEC/DEP should be calculating the cost of energy it would avoid in each hour by purchasing energy from QFs.[6] Staff states that the peaker method is based on the theory that the utility system "has an optimal resource mix" (Staff Witness Kirsch, p. 21, lines 9-10).

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[6] Graves, Hanser, and Basheda, "PURPA: Making the Sequel Better than the Original", Edison Electric Institute, December 2006, page 10

Q. SHOULD NORTH CAROLINA UTILITIES DEVELOP AVOIDED ENERGY COST RATES THAT REFLECT THE LOAD PROFILES OF SOLAR AND WIND QFS RESPECTIVELY?

A. Yes. NCSEA witness Beach presents evidence demonstrating that North Carolina utilities will under-estimate the avoided energy costs of purchases from solar QFs if the utilities have calculated those avoided energy costs assuming QF generation is essentially flat in each hour, i.e., a baseload profile (NCSEA witness Beach, pages 11-13). Based on that evidence he recommends that "avoided energy credits for solar generation be calculated with greater granularity to recognize more accurately the energy costs which solar generation enables the utility to avoid." I support that recommendation and suggest that it be applied to generation from wind QFs to the extent there is a similar, material under-estimate.

Q. IS IT REASONABLE FOR NORTH CAROLINA UTILITIES TO HAVE QF TECHNOLOGY-SPECIFIC AVOIDED COST RATES?

A. Yes. North Carolina has historically allowed utilities to have different avoided cost rates for purchases from run-of-river hydro QFs and for other renewable technology QFs. Run-of-river hydro QFs received rates based on a performance adjustment factor (PAF) of 2.0 whereas other renewable technologies had rates based on a PAF of 1.2. Additionally, Staff observes the "possibility of calculating technology-specific avoided cost rates," (Staff Witness Kirsch, p. 20, lines 2-3), envisioning a capacity market divided into five segments: technologies not included in North Carolina's REPS, renewable technologies (excluding the carve-outs), poultry waste, swine waste, and solar (Staff Witness Kirsch, p. 20, lines 8-15). Finally, distinguishing QFs by a technology type as broad and commonly understood as solar photovoltaic won't confuse small QF project developers. For example, Georgia Power offers a tariff specific to small solar power facilities.[7]

Calculating a PV QF-specific on-peak and off-peak avoided energy cost that accounts for PV QF's predictably variable output is technically feasible within current modeling and data sets, more accurately links the PV QF's energy output with the utility's avoided energy costs, and will not be burdensome or confusing to utilities or QFs.

Q. WHAT METHOD DO YOU RECOMMEND NORTH CAROLINA UTILITIES USE FOR QUANTIFYING AVOIDED ENERGY COSTS?

A. I recommend that the North Carolina utilities continue to use a production cost method to determine their avoided energy cost for each hour.

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[7] Georgia Power Solar Purchase Schedule SP-2, http://georgiapower.com/energy-efficiency/green/solar-buyback.cshtml and http://georgiapower.com/pricing/files/rates-and-schedules/11.20_SP-2.pdf, accessed May 21, 2014.

However, North Carolina utilities that are planning resource additions other than a new CT in the absence of purchases from QFs should include in their avoided energy costs the net fixed costs of the marginal new resources, i.e., the fixed cost of the marginal resource minus the avoided capacity costs per the peaker method. North Carolina utilities should develop avoided energy costs that are QF technology-specific, given the differences in generation profile by QF technology.

Avoided Environmental Costs

Q. SHOULD NORTH CAROLINA UTILITIES INCLUDE THE COSTS OF CARBON DIOXIDE EMISSIONS IN THEIR PRODUCTION COST SIMULATION MODELING TO DETERMINE AVOIDED ENERGY COSTS?

A. Yes. Both DNCP and DEC/DEP assumed a price for carbon emissions in the Reference Cases of their most recent integrated resource plans (IRPs). Those IRPs reflect the projections of those utilities over similar long-term planning horizons covered by the production cost simulation modeling they conducted for this proceeding. Therefore, DNCP and DEC/DEP should calculate their avoided energy costs using, at a minimum, the same forecast prices of carbon emissions as they used in their most recent IRP. NCSEA witness Mr. Beach makes this point in his testimony, page 13 line 9 through page 16 line 2.

Q. ARE OTHER MAJOR UTILITIES ASSUMING CARBON COSTS IN THEIR LONG-TERM PLANNING?

A. Yes. While Congress has not yet passed legislation governing greenhouse gas (“GHG”) emissions from power plants, it is prudent to forecast CO_2 prices in long term planning. For example, a 2014 report by Synapse[8] indicates that 42 utility IRPs, out of a sample of 91 utility IRPs released in 2012□2013, include a non-zero CO_2 price in their reference case. That data demonstrates that, despite the failure of Congress to pass comprehensive climate legislation, a significant number of utilities are basing their long-term plans on the assumption that they will have to comply with limits on carbon dioxide emissions. (The utilities in the sample of 91 IRPs account for 20 percent of total electricity sales in the US.)

Q. ARE THE CARBON EMISSION PRICES NORTH CAROLINA UTILITIES USED IN THEIR LATEST IRPS CONSERVATIVE?

A. Yes. The carbon emission prices that DNCP used in the Reference Case of its most recent IRP is below the low-case forecast in the Synapse 2014 report, while the carbon emission price that DEC/DEP used in the Reference Cases of their most recent IRPs is somewhat above the Synapse low-case forecast. That low Synapse forecast assumes federal regulation

[8] Luckow, Patrick et al. “CO_2 Price Report, Spring 2014”. Synapse Energy Economics, May 22, 2014.

of carbon emissions goes into effect in 2020 at an initial price of $15/short ton of CO_2 (in 2012 dollars).

It is worth noting that EPA, under Section 111(d) of the Clean Air Act, has the obligation to promulgate performance standards for existing sources of GHG such as the emissions produced at the existing coal units in North Carolina. Thus it is possible they could place such standards into effect earlier than the Federal legislation assumed in the Synapse 2014 forecast, and could require reductions that would equate to the Synapse mid- or high-case CO_2 forecasts.

Avoided energy losses

Q. SHOULD NORTH CAROLINA UTILITIES ADJUST THEIR AVOIDED CAPACITY AND ENERGY COSTS FOR SOLAR QFS TO REFLECT AVOIDED LINE LOSS COSTS?

A. Yes. The Duke Energy Photovoltaic Integration Study: Carolina Service Areas (Duke Energy PV Study) is helpful to answer this question. Mr. Beach summarizes the results of the line loss analysis in the Duke Energy PV Study, stating that the Study estimates the avoided line losses associated with solar QF output to be 3.3% on an annual basis (Beach 23:1). This implies that, by avoiding line losses due to distributed PV, DEC/DEP avoids an additional 3.3% of avoided energy cost and avoided capacity cost.

The Duke Energy PV Study makes a compelling case that line losses are real, quantifiable, and that distributed PV reduces those losses. I recommend that DEC/DEP include a 3.3% adjustment to both energy and capacity credits. I further recommend that DNCP also use a 3.3% adjustment to both energy and capacity credits until a comprehensive study within DNCP's territory can be performed. Finally, I recommend that DNCP undertake a study to understand how distributed PV reduces line losses within DNCP's North Carolina service territory, so that a future docket can refine the line loss adjustment within DNCP's territory.

Avoided Capacity Costs for Transmission and Distribution

Q. DO NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID TRANSMISSION AND DISTRIBUTION COSTS BY PURCHASING GENERATION FROM PHOTOVOLTAIC QFS?

A. Yes. North Carolina utilities have the potential to avoid, or defer, transmission and distribution costs by purchasing generation from photovoltaic QFs.

Q. PLEASE EXPLAIN HOW NORTH CAROLINA UTILITIES CAN AVOID OR DEFER CAPITAL INVESTMENTS IN TRANSMISSION BY PURCHASING FROM QFS.

A. North Carolina utilities have the potential to avoid or defer capital investments in transmission by purchasing from QFs which deliver their generation directly into the distribution system, at least during times of the system's coincident peak load. By acquiring generation delivered directly into the distribution system the utilities reduce the peak load on their transmission system. Reducing that peak load may allow the utility to defer, or ultimately avoid, capital investments to increase the capacity of its transmission systems.

Q. HAVE PARTIES PROPOSED METHODS FOR ESTIMATING THESE AVOIDED TRANSMISSION COSTS.

A. Yes. The Crossborder Study used the NERA regression method to estimate marginal load-related transmission capacity costs. For DEC, a regression slope of $438 per kilowatt and a real economic carrying charge of 7.41% yielded an estimated annualized marginal transmission cost of $37.45 per kW-year. Transformed to a volumetric rate, the Crossborder Study finds a value for DEC of $0.010 per kWh. The parallel calculation for DEP yielded $0.007/kWh.[9] DEC/DEP claims that "intermittent generation does not alleviate the need for incremental transmission investment" (DEC/DEP Witness Snider p. 20, lines 2-3). That position is not consistent with the attribution of capacity value to solar generation delivered directly into the DEC/DEP distribution system. I recommend that DEC/DEP use that avoided transmission cost in its calculation of avoided costs for distribution-level PV QFs.

A more direct method is available for DNCP, due to its membership in PJM. As the Crossborder Study explains on page 13, the network integrated transmission service (NITS) rate, after applying the 46% solar capacity value, yields an avoided transmission capacity cost of

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[9] NCSEA Witness Beach, Exhibit 2, pages 11-12.

$0.009/kWh. I recommend that this avoided transmission capacity cost be included in DNCP's calculation of avoided cost for distribution-level PV QFs.

To my knowledge, DNCP did not submitted testimony regarding avoided transmission capacity costs.

Q. PLEASE EXPLAIN HOW NORTH CAROLINA UTILITIES CAN AVOID OR DEFER DISTRIBUTION SYSTEM CAPITAL INVESTMENTS BY PURCHASING FROM QFS.

A. The potential for North Carolina utilities to avoid or defer capital investments in distribution transmission by purchasing from QFs appears to be small but likely greater than zero. Table 8 of the Crossborder Study (page 14) includes six studies, five of which were completed in the past two years. While one of those five includes the possibility that there is no avoided distribution capital cost for that utility at that time, the other four studies project an avoided distribution capital cost. The arithmetic mean of those five studies (taking the midpoint value of 0.45 cents for the PA-NJ study) is $0.0026/kWh ($0.0024/kWh if the 2009 study is also included).

Similar to avoided transmission capital costs, I am not aware of DNCP testimony regarding avoided distribution capital costs. Although Mr. Snider doesn't explicitly claim the avoided distribution capital costs associated with PV QFs is zero, my understanding of his testimony is that he believes that avoided distribution capital costs, like avoided distribution capital costs, are nonexistent (DEC/DEP Witness Snider, p. 19, line 20 – p. 20, line 4). Staff suggests that there may be avoided distribution capital costs (Staff Witness Brown, p. 36 line 20 – p. 37, line 9), but observes that this would not apply to utility-scale PV and that "distribution feeders have a small geographical footprint and PV generation may not always occur during particular periods of peak load" (Staff Witness Brown, p. 37, lines 16-17).

I recommend that distribution-connected PV systems be eligible for the avoided distribution capital cost payment and that the avoided distribution capital cost payment be $0.0025/kWh, and finally that both DNCP and DEC/DEP continue to collect documentation and data on avoided distribution capital costs, so that a future docket may refine this payment.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RELATED TO TRANSMISSION AND DISTRIBUTION AVOIDED COSTS.

A. For this avoided cost category, I distinguish between solar QFs that deliver directly into the distribution system versus larger solar QFs that deliver into the transmission system. Utilities which purchase from larger PV installations that deliver into the transmission system may have limited ability to avoid capital investment in T&D. In contrast, purchases from smaller PV systems should allow utilities to avoid some investment in transmission.

For avoided transmission capital investments, I recommend that DEC include $0.010 per kWh, that DEP include $0.007 per kWh, and that DNCP include an avoided transmission capacity cost of $0.009 per kWh. For avoided distribution capital investments, I recommend that DEC, DEP, and DNCP use a value of 0.0025/kWh. Finally, I recommend that DEC/DEP and DNCP both continue to collect and analyze data and that both utilities study these avoided cost issues so that the avoided cost paid to PURPA QFs is appropriate as both the physical system and our understanding of that system continue to evolve.

<u>Other Types of Avoided Utility Costs</u>

Q. DO NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID ENERGY MARKET COSTS BY PURCHASING FROM QFS?

A. Yes. Dominion currently participates in PJM's wholesale energy and capacity markets and it is possible that DEC/DEP may do so at some point in the future. Utilities such as Dominion that purchase capacity and energy from those wholesale markets have the potential to benefit from the suppression in prices in those wholesale prices that will result from their purchases from QFs**.** Price suppression is a generally accepted component in the modeling and operation of wholesale capacity and energy markets, as indicated by the range of parties who have developed the estimates listed in Exhibit JRH-5. Parties may disagree over the calculation of certain aspects (such as magnitude and duration), but there is general agreement that it does occur.

These avoided energy market costs can be significant. For example, in a report completed last July for the efficiency program administrators in New England, Synapse estimated the costs New England consumers would avoid through 2028 by reducing their use of electricity, natural gas, and other fuels.[10] That report estimated that Massachusetts consumers who reduce their summer peak hour electricity use would avoid 9.6 cents in energy and capacity costs for every kWh reduced (15-year levelized savings) and would benefit from price suppression valued at 3.4 cents per kWh due to mitigation of wholesale capacity and energy prices.

Q. DO NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID FUEL HEDGING COSTS BY PURCHASING FROM QFS?

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[10] Hornby, Rick et al. *Avoided Energy Supply Costs in New England: 2013 Report* (AESC 2013). Synapse Energy Economics. July 2013. Available at www.synspse-energy.com

A. Yes. North Carolina utilities that incur fuel hedging costs have the potential to avoid some of those costs by purchasing from QFs. Moreover even if utilities do not hedge any portion of their fuel supplies they and their customers still benefit from reducing their exposure to volatile fuel prices. One approach to estimating the value of avoiding the risk associated with natural gas fired generation is to calculate the difference in cost between buying a specific quantity of gas on a spot basis and buying it at a fixed price under a long-term contract.[11]

Ancillary service costs

Q. DO NORTH CAROLINA UTILITIES HAVE THE POTENTIAL TO AVOID ANCILLARY SERVICE COSTS BY PURCHASING FROM QFS?

A. Yes. North Carolina utilities have the potential to avoid some ancillary service costs by purchasing ancillary services from QFs.

[11] Keyes, Jason B., Rábago, Karl R., *Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*, Interstate Renewable Energy Council, Inc. and Rábago Energy, LLC (October 2013).

Q. PLEASE COMMENT ON THE PROPOSALS TO ALLOW NORTH CAROLINA UTILITIES TO INCLUDE SOME LEVEL OF SOLAR INTEGRATION COSTS IN THEIR CALCULATION OF THEIR AVOIDED COST RATES FOR SOLAR QFs.

A. Witnesses for several of the parties have presented testimony regarding various "solar integration costs" that North Carolina utilities may incur as a result of generation from solar QFs. The Duke Energy PV Study provides estimates of these costs under the headings of generation, transmission, and distribution.

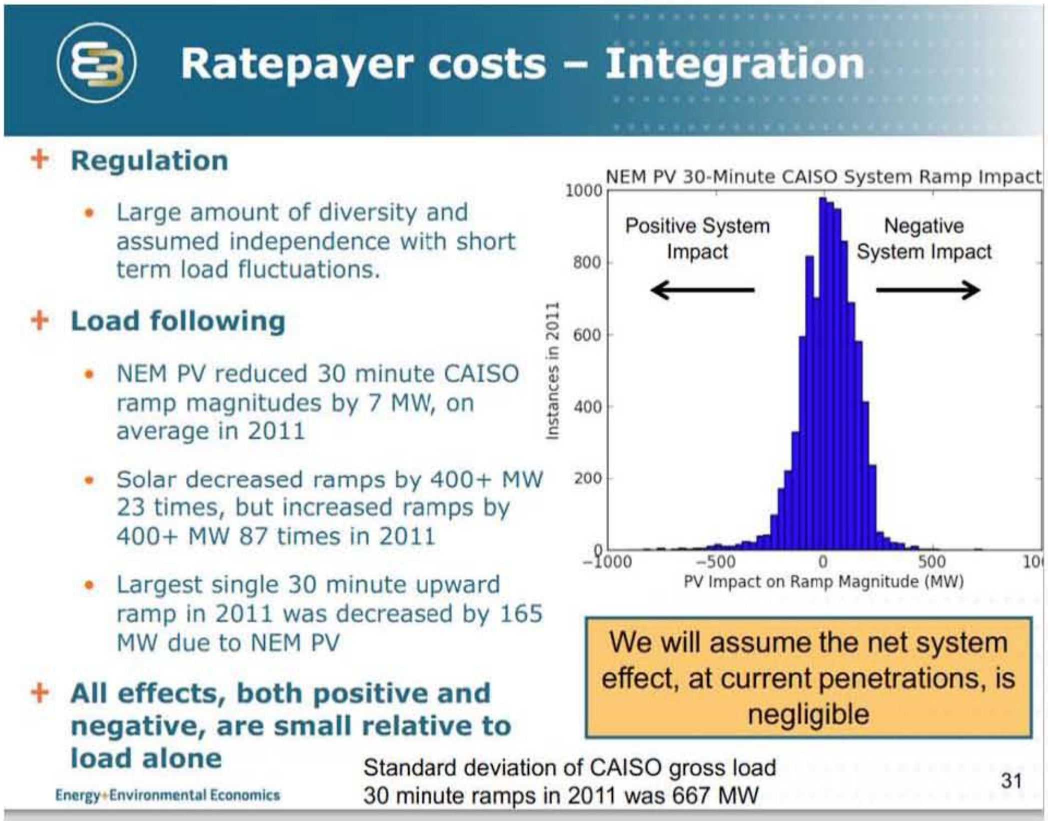
Mr. Beach states that the Duke Energy PV Study indicates that the Duke utilities may incur incremental costs for incremental reserves and cycling of $1.43 per MWh of PV energy generation at the current level of PV penetration in North Carolina (Beach, page 27, line 6). He further notes that the Duke Energy PV Study states that the costs Duke will avoid from the incremental avoided line losses associated with that PV generation will offset those integration costs.

Q. DOES THE DUKE ENERGY PV STUDY INDICATE THAT NORTH CAROLINA UTILITIES CAN MAKE A SMOOTH TRANSITION TO A HIGH-PV ENERGY MIX.

A. Yes. Section 2.5.2 of the Duke Energy PV Study states "The same set of assumptions and models which affect study results significantly also point to the directions of operation and technology improvements for a smooth transition toward the high-PV energy mix." The section discusses these operation and technology improvements under two broad headings – increase fleet flexibility and reduce uncertainty and variability.

Q. HAVE OTHER ANALYSES ALSO CONCLUDED THAT THE AVOIDED COSTS FROM SOLAR GENERATION WILL OFFSET SOLAR INTEGRATION COSTS EVEN AT HIGHER LEVELS OF SOLAR PENETRATION THAN NORTH CAROLINA?

A. Yes. For example, California now has a significant penetration of small solar PV and it has not experienced any appreciable solar integration costs. That is the conclusion of a recent analysis prepared for the California Commission. Based on an analysis of data from the California Independent System Operator, the study determined that a high penetration of distributed solar PV was unlikely to cause a net increase in system operating costs for regulation and load following because the incremental savings from net metered PV were approximately equal to the incremental costs caused by net metered PV.



Source: Presentation from Energy+Environmental Economics at a California Public Utilities Commission Stakeholder Workshop on NEM Cost-Effectiveness [slide 31] (October 22, 2012), *available at* www.cpuc.ca.gov/NR/rdonlyres/3C73CEF6-71CA-4B6C-84E4-FDA389D8F2B9/0/NEMApproachStakeholderWorkshop.pdf

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO ANY ADJUSTMENTS FOR SOLAR INTEGRATION COSTS?

A. I recommend that the Commission consider the limits of the estimates of the impact of PV generation on North Carolina utilities discussed in Section 2.5.2 of the Duke Energy PV Study as well as the Study's conclusion that North Carolina utilities can make a smooth transition to a high-PV energy mix. If, after considering those factors, the Commission determines that it is reasonable to allow an adjustment for solar integration costs, I recommend that the adjustment be no greater than the $1.43/MWh recommended by Mr. Beach.

Q. **DOES THIS CONCLUDE YOUR ADDITIONAL TESTIMONY?**

A. Yes.

DOCKET NO. E-100, SUB 140

EXHIBITS TO THE ADDITIONAL DIRECT TESTIMONY OF J. RICHARD HORNBY ON BEHALF OF THE ALLIANCE FOR SOLAR CHOICE

JRH-1
TO
JRH-5

Synapse Energy Economics, Inc.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Consultant,* 2006 – present.

Provides analysis and expert testimony regarding planning, market structure, ratemaking and supply contracting issues in the electricity and natural gas industries. Planning cases include evaluation of resource options for meeting tighter air emission standards (e.g. retrofit vs. retire coal units) in Kentucky, West Virginia and U.S. Midwest as well as development of long-term projections of avoided costs of electricity and natural gas in New England. Ratemaking cases include electric utility load retention rate in NS, various gas utility rate cases and evaluation of proposals for advanced metering infrastructure (smart grid or AMI) and dynamic pricing in MD, PA, NJ, AR, ME, NV, DC and IL.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA. *Principal,* 2004 – 2006, *Senior Consultant,* 1998 – 2004.

Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA. *Vice President and Director of Energy Group*, 1997 – 1998. *Manager of Natural Gas Program,* 1986 – 1997.

Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.

Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.

Assistant Deputy Minister of Energy, 1983–1986.

Director of Energy Resources, 1982-1983.

Assistant to the Deputy Minister, 1981-1982.

Nova Scotia Research Foundation, Dartmouth, Canada. *Consultant*, 1978–1981.

Canadian Keyes Fibre, Hantsport, Canada. *Project Engineer*, 1975–1977.

Imperial Group Limited, Bristol, England. *Management Consultant*, 1973–1975.

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
Master of Science in Energy and Technology Policy, 1979

Dalhousie University, Nova Scotia, Canada
Bachelor of Engineering, Industrial Engineering, 1973. Distinctions.

TESTIMONY

Jurisdiction	Company	Docket	Date	Issue
District of Columbia	PEPCO Energy	Formal Case No. 1114	April 2014	Dynamic pricing
Ohio	Ohio Manufacturers' Association	Substitute Senate Bill 58	November 2013	Proposed legislation regarding utility compensation for energy efficiency
West Virginia	Appalachian Power Company and Wheeling Power Company	11-1775-E-P and 12-1655E-PC	June 2013	Acquisition of generating capacity
West Virginia	Monongahela Power and Potomac Edison	12-1571-E-PC	April 2013	Acquisition of generating capacity
Pennsylvania	Metropolitan Edison Company *et al.*	M-2013-2341990 *et al.*	April 2013 and May 2014	Smart Meter Deployment Plan
Ohio	Duke Energy Ohio	12-2400-EL-UNC *et al.*	March 2013	Rate for generating capacity services
Hawaii	Hawaii Electric Light Company and Hawaiian Electric Company	2012-0185	March 2013	Biofuel supply contract
Michigan	Consumers Energy	U-17087	February 2013	Retrofit of five coal units
Hawaii	Hawaiian Electric Company	2011-0369	January 2013	Biofuel supply contract
Illinois	Ameren Illinois	12-0244	August 2012	Advanced metering infrastructure (AMI)

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Kentucky	Kentucky Power Company	2011-00401	March 2012	CPCN for Big Sandy Unit 2
Nova Scotia	Heritage Gas	NG-HG-R-11	September 2011 and May 2012	Cost allocation and rate design
Arkansas	Oklahoma Gas & Electric	10-109-U	May 2011 and June 2011	Advanced metering infrastructure (AMI)
Texas	Texas-New Mexico Power	PUC 38306	April 2011	Advanced metering infrastructure (AMI)
Arkansas	Oklahoma Gas & Electric	10-067-U	March 2011	Windspeed transmission line
Pennsylvania	PECO Energy	M-2009-2123944	December 2010 and January 2011	Dynamic Pricing
Arkansas	Oklahoma Gas & Electric	10-073-U	November 2010	Wind power purchase agreement
Indiana	Vectren Energy Delivery of Indiana	Cause No. 43839	July 2010	Sales Reconciliation Adjustment
Alaska	Enstar Natural Gas	U-09-069 and U-09-070	March 2010	Rate Design
Pennsylvania	Allegheny Power	M-2009-2123951	March 2010 and October 2009	Smart meters / advanced metering infrastructure (AMI)
Massachusetts	All Massachusetts regulated electric and gas utilities	D.P.U. 09-125 *et al.*	December 2009	Avoided Energy Supply Costs in New England
Pennsylvania	Metropolitan Edison Company	M-2009-2123950	October 2009	Smart meters / AMI
Maryland	Potomac Electric Power	No. 9207	October 2009 and July 2011	Smart meters / AMI
Maryland	Baltimore Gas and Electric	No. 9208	October 2009 and July 2010	Smart meters / AMI
New Jersey	Jersey Central	EO08050326 and	July 2009	Demand response

Jurisdiction	Company	Docket	Date	Issue
	Power & Light	EO08080542		programs
Minnesota	CenterPoint Energy	G-008/GR-08-1075	June 2009	Conservation Enabling Rider
South Carolina	Progress Energy Carolinas	2008-251-E	January 2009	Compensation for efficiency programs
North Carolina	Progress Energy Carolinas	No. E-2 sub 931	December 2008	Compensation for efficiency programs
Maine	Central Maine Power	2007 – 215	October 2008	Smart meters / AMI
North Carolina	Duke Energy Carolinas	E-7 Sub 831	June 2008	Compensation for efficiency programs (save-a-watt)
Indiana	Duke Energy Indiana	No. 43374	May 2008	Compensation for efficiency programs (save-a-watt)
Pennsylvania	PECO Energy Company	P-2008-2032333	June 2008	Residential Real Time Pricing pilot
Arkansas	Entergy Arkansas	06-152-U Phase II A	October 2007	Interim tolling agreement and proposed allocation of Ouachita Power capacity
Washington	Avista Utilities	UE-070804 and UG-070805	September 2007	Cost allocation, rate design
Arkansas	Entergy Arkansas	06-152-U	January 2007	Need for load-following capacity
Michigan	Consumers Energy Company	U-14992	December 2006	Proposed sale of Palisades nuclear plant and associated power purchase
Connecticut	Connecticut Natural Gas Corporation	06-03-04PH01	November 2006	Gas supply strategy and proposed rate recovery
Michigan	Consumers Energy Company	U-14274-R	October 2006	Purchases from Midland Cogeneration Venture Limited

Jurisdiction	Company	Docket	Date	Issue
				Partnership
Illinois	WPS Resources and Peoples Energy Corporation	Docket No. 06-0540	October and December 2006	Service quality metrics and benchmarks
Arizona	Arizona Public Service	E-01345A-05-0816	August 2006 and September 2006	Hedging strategy and base fuel recovery amount
Ontario	Transalta Energy Corporation versus Bayer Inc.	Private arbitration	January 2006	Price for steam under a 20-year contract
Nova Scotia	Nova Scotia Power vs Shell	Private arbitration	October 2005	New natural gas price under a 10-year supply contract
New York	Consolidated Edison of New York, New York State Electric and Gas	Case 00-M-0504	September and October 2002	Rates for unbundled supply, distribution, metering and billing services
New Jersey	Public Service Electric and Gas	BPU Docket GM00080564	April 2001	Proposed transfer of gas contracts to an unregulated affiliate and supply contract associated with that transfer
Nova Scotia	Sempra	NSUARB-NG-SEMPRA-SEM-00-08	February 2001	Proposed distribution service tariff rates including market-based rates
New Jersey	Generic proceeding	BPU Docket EX99009676	March 2000	Design and pricing of unbundled customer account services
United States of America	Bonneville Power Administration	BPA Docket WP-02	November 1999	Functionalization of communication plant
South Carolina	South Carolina Electric and Gas	99-006-G	October 1999	Purchased gas costs
New Jersey	Public Service Electric & Gas,	GO99030122–GO99030125	July and September 1999	Service unbundling policies and rates

Jurisdiction	Company	Docket	Date	Issue
	South Jersey Gas, New Jersey Natural Gas and Elizabethtown Gas			
Maine	Northern Utilities Inc.	Docket 97-393	September and December 1998	Rate redesign and partial unbundling
Pennsylvania	Peoples Natural Gas	R-00984281; A-12250F0008	May 1998	Purchased gas costs and proposal to transfer production assets to affiliate
New Jersey	Rockland Electric Company	BPU E09707 0465 OAL PUC-7309-97 BPU E09707 0464 OAL PUC-7310-97	January and March 1998	Rate unbundling
New Jersey	Jersey Central Power & Light d/b/a GPU Energy	BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97	November 1997	Rate unbundling
Pennsylvania	Equitable Gas Company	R-00963858	June and July 1997	Rate structure proposals
Pennsylvania	Peoples Natural Gas Company	R-00973896 and A-0012250F-0007	May 1997	Purchased gas costs, proposal to transfer producing assets to CNG Producing Company and proposed Migration Rider
South Carolina	South Carolina Pipeline Corporation	97-009-G	April 1997	Reasonableness of proposal to acquire additional pipeline capacity
FERC	Transcontinental Gas Pipeline	RP95-197-001; RP97-71-000	March 1997	Review of proposed rolled-in ratemaking for Leidy Line incremental

Jurisdiction	Company	Docket	Date	Issue
				facilities
Arkansas	Arkla	95-401-U	September 1996	Gas purchasing and transportation plan
Maine	Northern Utilities Inc. and Granite State Gas Transmission	95-480; 95-481	April 1996	Precedent Agreement for LNG Storage Service and PNGTS Transportation Service
Rhode Island	ProvGas	2025	November 1995	Settlement Agreement
Pennsylvania	T.W. Phillips Gas and Oil	R-953406	October 1995	Cost allocation, rate design
Illinois	Northern Illinois Gas	95-0219	August1995	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-953316	May 1995	Purchased gas costs
Pennsylvania	Peoples Natural Gas	R-943252	May 1995	Cost allocation, rate design
South Carolina	South Carolina Pipeline Corporation	94-007-G	April 1995	1994 purchased gas costs
Pennsylvania	National Fuel Gas Distribution Corp	R-943207	March 1995	1995 Purchased Gas Adjustment filing
Pennsylvania	UGI Utilities	R-00943063	December 1994	FERC Order 636 transition cost tariff
South Carolina	South Carolina Electric and Gas Co.	94-008-G	October 1994	1994 Purchased Gas Adjustment
Oklahoma	Public Service of Oklahoma	PUD 920 001342	September and November 1994	Gas supply strategy, transportation and agency services and rate mechanism
Pennsylvania	Pennsylvania Gas and Water	R-943078	September 1994	Market Sensitive Sales Service
Massachusetts	Generic proceeding	D.P.U. 93-141-A	September 1994	Policies on interruptible transportation and

Jurisdiction	Company	Docket	Date	Issue
				capacity release
Hawaii	HELCO	7259	August 1994	DSM programs for competitive energy end-use markets, multi-attribute analysis
Pennsylvania	Pennsylvania Gas and Water	R-00943066	July 1994	1994 Purchased Gas Adjustment
Pennsylvania	Pennsylvania Gas and Water	R-942993; R-942993 C0001-C0004	May 1994	Take-or-Pay Cost Recovery
Pennsylvania	Columbia Gas of Pennsylvania	R-943001	May 1994	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-943029	May 1994	1994 Purchased Gas Adjustment; Negotiated Sales Service
Pennsylvania	Peoples Natural Gas	R-932866; R-932915	March 1994	Cost allocation, rate design
Kansas	Generic proceeding	180; 056-U	February 1994	IRP rules for gas utilities
Arizona	Citizens Utility Company Arizona Gas Division	E-1032-93-111	December 1993	Cost allocation, rate design
Hawaii	HECO	7257	December 1993	Residential sector water heating program
Hawaii	GASCO	7261	September 1993	IRP
Pennsylvania	Pennsylvania Gas and Water	R-932655; R-932655 C001; R-932655 C002	September 1993	Balancing service
Pennsylvania	Pennsylvania Gas and Water	R-932676	July 1993	1993 Purchased Gas Adjustment filing
Rhode Island	Providence Gas Company	2025	April 1993	IRP
Pennsylvania	Equitable	I-900009; C-	March 1993	Charges for transportation

Jurisdiction	Company	Docket	Date	Issue
		913669		service and cost allocation methods in general
Arkansas	Arkla Energy Resources, Arkansas Louisiana Gas	92-178-U	August 1992	Gas cost and purchasing practices
Colorado	Generic proceeding	91R-642EG	August 1992	Gas integrated resource planning rule
Pennsylvania	Pennsylvania Gas and Water	R-00922324	July 1992	1992 Purchased Gas Adjustment filing
Pennsylvania	Peoples Natural Gas Company	R-922180	May 1992	Cost allocation, rate design
Michigan	Consumers Power Company	U-10030	April 1992	Gas Cost Recovery Plan, role of demand-side management as a resource in five-year forecast and supply plan
Pennsylvania	T.W. Phillips	R-912140	March 1992	1992 Purchased Gas Adjustment
FERC	Columbia Gas Transmission and Columbia Gulf Transmission	RP91-161-000 et al RP91-160-000 *et al.*	February 1992	Cost allocation, rate design
Arkansas	Arkla Energy Resources	91-093-U	February 1992	Base cost of gas
New Hampshire	Energy North Natural Gas	DR90-183	January 1992	Cost allocation, rate design
Arizona	Southwest Gas Corporation	U-1551-89-102 & U-1551-89-103; U-1551-91-069	September 1991	Gas Procurement Practices and Purchased Gas Costs
Maryland	Baltimore Gas and Electric	8339	July 1991	Cost allocation, rate design
Rhode Island	Bristol and Warren Gas	1727	June 1991	Gas procurement

Jurisdiction	Company	Docket	Date	Issue
New Mexico	Gas Company of New Mexico	2367	June 1991	Gas transportation policies
Pennsylvania	T.W. Phillips	R-911889	March 1991	Gas supply
Michigan	Michigan Gas Company	U-9752	March 1991	Gas Cost Recovery Plan
Arkansas	Arkla	90-036-U	August and September 1990	Gas supply contracts, including Arkla-Arkoma transactions
Arizona	Southern Union Gas	U-1240-90-051	August 1990	Cost Allocation and Rate Design
Utah	Mountain Fuel Supply	89-057-15	July1990	Cost Allocation and Rate Design
Pennsylvania	Equitable Gas Company	R-901595	June 1990	Cost Allocation and Rate Design
West Virginia	APS	90-196-E-GI ; 90-197-E-GI	May 1990	Coal supply strategy
Pennsylvania	T.W. Phillips Gas and Oil Co.	R-891572	March 1990	Purchased Gas Costs
Colorado	Generic proceeding	89R-702G	January 1990	Policies and rules for gas transportation service
Arizona	Generic proceeding	U-1551-89-102 and U-1551-89-103	October 1989	Regulatory Oversight of Purchased Gas Costs
Rhode Island	Narragansett Electric Company	1938	October 1989	Sales Forecast, Cost Allocation, rate design
Pennsylvania	Pennsylvania Gas and Water	R891293	July 1989	Purchased Gas Costs
Pennsylvania	Columbia Gas of Pennsylvania	R891236	May 1989	Take-or-Pay Cost Recovery
New Jersey	Elizabethtown Gas Company	GR 88081-019	December 1988 and February 1989	Take-or-Pay Cost Recovery

Jurisdiction	Company	Docket	Date	Issue
Montana	Montana-Dakota Utilities	87.7.33; 88.2.4; 88.5.10; 88.8.23	December1988	Gas Procurement, Transportation Service Gas Adjustment Clause
New Jersey	South Jersey Gas Company	GR 88081-019 and GR 88080-913-	November 1988 and February 1989	Take-or-Pay Cost Recovery
New Jersey	Public Service Electric and Gas	GR 88070-877	October 1988 and February 1989	Take-or-Pay Cost Recovery
District of Columbia	District of Columbia Natural Gas	Formal Case 874	September 1988	Gas Acquisition, Gas Cost Allocation, take or pay-costs; Regulatory Oversight
Illinois	Generic proceeding	88-0103	July 1988	Take-or-Pay Cost Recovery
West Virginia	Generic proceeding	240-G	June 1988	Gas Transportation Rate Design
Pennsylvania	Pennsylvania Gas & Water	R-880958	June 1988	Purchased Gas Adjustment
Utah	Mountain Fuel Supply	86-057-07	March 1988	Gas Transportation Rate Design
South Carolina	South Carolina Electric & Gas	87-227-G	September 1987	Gas Supply and Rate Design
Arizona		U-1345-87-069	September 1987	Fuel Adjustment Clause

Resume dated April 2014

Exhibit___(JRH-2)

Benefits associated with distributed solar electric generation versus costs utilities avoid by purchasing electric energy from qualifying facilities (QFs)

	Benefits associated with distributed solar electric generation	Costs utilities may avoid by purchasing electric energy from QFs	
	TASC Exhibit AS-2	**Synapse Position**	**Synapse Assessment of General Consensus of other Parties**
	A	**B**	**C**
1	Avoided energy costs (Electricity generation costs)	XXX	Include
2	Avoided capacity costs for generation	XXX	
3	Avoided and deferred capacity costs for T & D	XXX	
4	Avoided Environmental Costs	XXX	Include for emissions subject to existing regulations
5	Avoided energy losses (T&D system losses)	XXX	No explicit position by all parties
6	Energy market impacts (Supply Induced price effect)	XXX	
7	Fuel price hedge	XXX	
8	Ancillary services and grid support / security	XXX	
9	Avoided renewable costs		
10	Health benefits		
11	Security and resiliency of grid		
12	Environmental and safety benefits		
13	Effects on economic activity and employment		
14	Visibility benefits		

Exhibit___(JRH-3)

Methodologies proposed for calculating costs utilities avoid by purchasing electric energy from qualifying facilities (QFs)

Costs utilities may avoid by purchasing electric energy from QFs		Staff	DNCP	DEC/DEP
	A	**B**	**C**	**D**
1	Avoided energy costs (Electricity generation costs)	Production Cost Simulation Model	Production Cost Simulation Model + Net Peaker	Production Cost Simulation Model with caps on avoided cost + Peaker
2	Avoided capacity costs for generation	No recommendation	Net peaker	Peaker
3	Avoided and deferred capital costs for T & D	No recommendation	No discussion	No discussion
4	Avoided Environmental Costs	No recommendation	Production Cost Simulation Model	Production Cost Simulation Model
5	Avoided energy losses (T&D system losses)	No recommendation	No discussion	No discussion
6	Energy market impacts (Supply Induced price effect)	$0		
7	Fuel price hedge	Black-Scholes		
8	Ancillary services and grid support / security	$0		

Exhibit___(JRH-4)

DEC/DEP and DNCP Proposed Capacity Additions Other Than Additions to comply with RPS

Year	DEC/DEP (1)	DNCP (2)
2015		1337 MW CC
2016		1375 MW CC
2017		
2018	126 MW CT	
	680 MW CC	
	66 MW uprate nuclear	
2019	813 MW CC	1375 MW CC
2020		
2021	813 MW CC	457 MW CT
	403 MW CT	

Sources

1	*Duke Energy Carolinas Integrated Resource Plan* , October 15, 2013. Table 8-H
2	*Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan* , August 30, 2013. Figure 1.4.1(a)

Estimates of Price Suppression in Wholesale Electricity Markets

	Date	Region	Resource	Citation
Ohio PUC	2013	Ohio	Renewable energy	OH PUC, 2013.
Lawrence Berkeley National Laboratory	2013	MA	Energy Efficiency	LBNL, 2013
Baltimore Gas & Electric + Potomac Electric Power Company	2012	MD	Energy efficiency and Demand response	BGE & PEPCO, 2012
New England Independent System Operator	2012	New England	Energy Efficiency	ISO-NE, 2012
Frank A. Felder, Ph.D. Director, Center for Energy, Economic & Environmental Policy, Rutgers University	2011	various	various	Felder, 2011.
National Association of Regulatory Utility Commissioners	2011	VT	Renewable energy	NARUC, 2011
Black & Veatch	2010	PA	Energy Efficiency/ renewable energy	Black & Veatch, 2010
Charles River Associates	2010	ISO-NE	Cape Wind project	Charles River Associates, 2010
Levitan Associates Inc.	2010	RI	Wind	RIEDC, 2010
PJM	2009	PJM	Wind	PJM, 2009
Lawrence Berkeley National Laboratory	2009	various	Renewable energy	LBNL, 2009
Tudor Pickering Holt & Co	2009	ERCOT	Wind	Tudor Pickering Holt & Co., 2009
KEMA Inc	2009	NYISO	Renewable energy	NYSERDA, 2009a
Summit Blue Consulting	2009	NYISO	Energy Efficiency/ renewable energy	NYSERDA, 2009b
The Brattle Group	2007	PJM	Demand response	Brattle Group, 2007
Christensen Associates Energy Consulting	2007	various	Renewable energy	Christensen Associates, 2007

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