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Via Hand Delivery

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

Re: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2012
Docket No. E-100, Sub 136

Dear Mrs. Mount:

Enclosed please find for filing in connection with the above-referenced matter the original and thirty (30) copies of the Rebuttal Testimony and Exhibits of Glen A. Snider and Kendal C. Bowman on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc. (collectively, the "Companies").

Portions of the testimony of Glen A. Snider contain confidential information, including (a) financial information used to develop the Companies' filed avoided cost rates, (b) business or technical information filed confidentially in support of the Companies' respective 2012 Integrated Resource Plans, (c) the Companies' combustion turbine ("CT") cost projections, and (d) actual and estimated costs of the Companies' recently constructed gas-fired generating units. Such information designated by the Companies as confidential qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3). If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to ratepayers. Information clearly marked as confidential and/or highlighted in yellow shall be considered confidential filed under seal, and the Companies respectfully request that the Commission treat this information as confidential and protect it from public disclosure pursuant to N.C. Gen. Stat. § 132-1.2. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

I also enclose two copies of the public, redacted version of the Companies' testimony and exhibits for filing with the Commission. The confidential information has been redacted from the public version of the testimony, and this version is acceptable for public disclosure.

One additional copy of the confidential version of the testimony and exhibits is enclosed to be file-stamped and returned with our courier. Thank you for your assistance in this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

KCF

Enclosures

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Progress Energy Carolinas, Inc.'s Rebuttal Testimony in Docket No. E-100, Sub 136 has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 18th day of October, 2013.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012	))))	REBUTTAL TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, INC., AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy Carolinas ("DEC") as Director of Carolinas Resource Planning and Analytics.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of DEC and Duke Energy Progress ("DEP"), also referred to as the Utilities in my testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to show that, despite the assertions made by other parties in this proceeding, the installed combustion turbine ("CT") costs used by DEC and DEP in calculating their proposed avoided capacity rates are reasonable and appropriate. Specifically, my rebuttal testimony addresses the following issues: 1) the reasonableness of the installed CT costs used by the Utilities in light of current CT cost data and the installed CT estimates used by the Utilities in previous filings; 2) using the average CT cost of a four-unit site is proper for calculating avoided costs; 3) the Utilities' use of contingency in their CT cost estimates is appropriate; 4) the Utilities' use of a 35-year useful life for in their CT cost estimates is appropriate; and 5) it was appropriate for the Utilities to exclude transmission system upgrade costs from their CT cost estimates. I will also address the specific CT cost estimate recommendations made by Renewable Energy Group ("REG") witness Reading and Public Staff witness Hinton and explain why their recommendations should not be accepted by the Commission

Q. PLEASE SUMMARIZE THE CONCLUSIONS THAT YOU MAKE IN YOUR TESTIMONY IN THIS PROCEEDING.

A. The CT cost estimates used by the Utilities in calculating their avoided capacity rates are reasonable and well-supported. They were based on cost studies by Burns & McDonnell ("B&M") and Sargent & Lundy ("S&L"), performed independently of each other. They are also supported by the testimony of the Utilities' outside expert witness Ted Pintcke of Black & Veatch ("B&V") and CT estimates developed by the Brattle Group, the United States Energy Information Administration ("EIA"), and the Electric Power Research Institute ("EPRI").

REG, the Public Staff, and North Carolina Sustainable Energy Association ("NCSEA") argue that the Utilities' CT costs should be higher. These parties make a number of arguments, including that the Utilities' cost estimates should be higher because CT costs are increasing, that the Utilities should use significantly higher contingency adders in their estimates, and that the Utilities should have ignored the economies of scale that naturally occur when multiple CTs are installed. I will address each of these arguments individually, but generally speaking, every piece of third party, independent cost data presented in this case fully supports the CT cost estimates used by the Utilities in their avoided capacity rates. Public Staff Witness Hinton notes correctly that cost estimates are affected by a large number of factors, which makes it difficult to develop single-point cost estimates. For this reason, the best cost estimates result from using several independently developed cost studies. That is what the Utilities did in this case and it confirms the reasonableness of the Utilities' CT cost estimates. The fundamental point is that the Utilities have presented CT cost estimates validated by overwhelming evidence and the other parties have presented no meaningful cost data to the contrary.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am introducing Rebuttal Exhibits GAS-1 through 4 in support of my rebuttal testimony. Rebuttal Exhibit GAS-1 is the November 2012 Cost of New Entry ("CONE") Study Settlement filed with the Federal Energy Regulatory Commission on behalf of PJM and other PJM stakeholders.[1] Confidential Rebuttal Exhibit GAS-2 makes certain necessary adjustments to present the Brattle CONE Study estimate on a comparable basis to the DEC and DEP CT cost estimates. Rebuttal Exhibit GAS-3 presents a CT unit-cost comparison between the 2012 and 2013 *Gas Turbine World* publications to show that prices have, in fact, trended downward during this period. My Confidential Rebuttal Exhibit GAS-4 is DEP's response to Public Staff Data Request 3-4, which shows the actual CT costs used in the Reserve Margin Study.

I. <u>THE UTILITIES' CT COST ESTIMATES ARE REASONABLE AND APPROPRIATE</u>

Q. WHAT ARE THE CT COST ESTIMATES USED IN THE UTILITIES' AVOIDED CAPACITY COST CALCULATIONS?

A. DEP's proposed avoided capacity rates assume an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and DEC's avoided capacity rates assume installed CT cost of **[BEGIN**

[1] *PJM Interconnection, L.L.C.*, Docket Nos. ER12-513-000, -003, Settlement Agreement and Offer of Settlement; (Nov. 21, 2012).

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

Q. WHAT IS THE BASIS FOR YOUR POSITION THAT THE UTILITIES' CT COST ESTIMATES ARE REASONABLE AND APPROPRIATE?

A. The installed CT costs used by the Utilities in developing their respective avoided cost rates were developed based on two independent and separately-commissioned cost studies (one by DEP and one by DEC) from two leading engineering firms –B&M and S&L. No party has identified or even suggested that there is any flaw or error in the B&M or S&L studies. In addition, Ted Pintcke of B&V has submitted testimony that further supports the CT costs used by the Utilities and suggests that those CT costs may actually be slightly higher than the current market indicates. Similarly, the PJM CONE Study prepared by the Brattle Group[2], and relied upon by Public Staff witness Hinton, further confirms that the Utilities' CT cost estimates are reasonable and appropriate.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS HINTON'S ASSERTION THAT THE CONE STUDY SUGGESTS A HIGHER CT COST THAN THE COST USED BY THE UTILITIES?

A. For several reasons, the Brattle Group's CONE Study does not support witness Hinton's position.

First, witness Hinton does not actually rely on the CONE study. Rather, he purports to rely on the settlement agreement reached by certain parties in the FERC proceeding involving the CONE. In any negotiated settlement of a complex matter, the end result is a product of give-and-take on multiple issues and often involves trade-offs between issues. Using the CONE settlement is particularly troublesome because even the parties to that settlement described it as a "black box" settlement with "no agreement on any assumptions, estimates, or methodologies to calculate [the] specific values [agreed to]." (Rebuttal Exhibit GAS-1 at 11)

Second, witness Hinton asserts that the CONE settlement included a 3% increase in the installed CT cost used in the Brattle Group CONE study for the Dominion Zone of PJM. This is not the case. The values set forth in the black box settlement were annual costs on a $/kw-yr basis and the settlement reflected a 3% increase from the annualized ($/kw-yr) capacity cost the Brattle Group study calculated for the Dominion Zone. (*Id.* at 25, 51, 73) As witness Hinton acknowledges, annualized capacity costs involve more elements than the installed CT cost. (Hinton Direct at 9) It also includes carrying costs, O&M costs, line losses, etc. Thus, there is no way to determine from the "black box" CONE settlement how much of this 3% increase, if any, should be attributed to the installed CT cost.

Third, witness Hinton did not adjust the conservative summer-only rating of 196 MW per unit assumed by the Brattle Group. Even though the Utilities and Brattle Group all based their cost estimates on GE 7FA units, DEC and

DEP applied higher unit ratings in calculating their CT cost estimates. DEC used a summer rating of 201 MW and DEP used a winter/summer average rating of 213 MW. The difference between the ratings used by the Utilities and the Brattle Group may be due to the fact that the Brattle Group published its CONE study in mid-2011 and, therefore, may have used an older GE 7FA.03 CT model, as opposed to the GE 7FA.05 used by the Utilities for their CT cost estimates. In any case, witness Hinton's use of the lower unit rating assumed by the Brattle Group skews his $/kw CT cost higher compared to the Utilities' cost estimates.

Finally, witness Hinton made no adjustment in his calculation for the fact that the Brattle Group's CONE cost estimate assumes the construction of a two CT site, as opposed to a four-unit CT site which serves as the basis for the Utilities' avoided cost rates. As a result, witness Hinton's analysis ignores the significant cost reductions that are achieved by adding additional units to a site and results in a CT cost estimate that is not equivalent to the Utilities' CT cost estimates.

As a result of the foregoing, the $666/kw CT cost estimate that witness Hinton derives from the Brattle Group's CONE Study is overstated. In fact, when viewed on a truly comparable basis with the Utilities' CT cost estimates, it is clear that the Brattle Group's study supports the CT costs used in calculating the Utilities' avoided capacity rates.

Q. GIVEN THE FOREGOING, WHY DO YOU BELIEVE THAT THE BRATTLE GROUP'S CONE STUDY SUPPORTS THE CT COSTS USED BY THE UTILITIES IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. When the actual cost estimates set forth in the CONE Study are compared to the Utilities' cost estimates on an apples-to-apples basis, it is clear that the CONE Study is entirely consistent with the CT costs used by the Utilities.

The Brattle Group estimated that the installed CT cost (with AFUDC) for the Dominion Zone was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the CONE Study. This cost estimate was based on 2015/16 installation and assumed two GE 7 FA units at a single site and used a conservative summer-only unit rating of 196 MW. Conversely, the DEC and DEP CT cost estimates assumed 2012 installation, four GE 7 FA.05 units at a single site and the associated higher unit ratings. My Confidential Rebuttal Exhibit GAS-2 shows the adjustments to make the Brattle Group's CONE Study estimate comparable to the DEC and DEP estimates in terms of date of installation, unit ratings, and number of units per site.

Q. PLEASE EXPLAIN THE INFORMATION SHOWN ON YOUR CONFIDENTIAL REBUTTAL EXHIBIT GAS-2.

A. As Confidential Rebuttal Exhibit GAS-2 shows, when the straight-forward adjustments described above are made, the Brattle Group CT cost estimate is consistent with the Utilities' CT cost estimates. Rebuttal Exhibit GAS-2 compares the Brattle Group CT cost estimate to DEC's and DEP's estimates separately due to the difference in the unit rating assumptions used by DEC and DEP. These comparisons start with the actual installed cost estimate contained in the Brattle Group's CONE Study of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** which includes allowance for funds used during construction ("AFUDC"). The first adjustment takes that figure, which is presented in 2015 dollars, back to 2013 dollars. This produces a 2013 cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The next adjustment recognizes the difference between the Brattle Group's assumption of a rating of 196 MW per unit and the unit ratings used by DEC and DEP. This adjustment produces cost estimates of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** comparable to DEC's estimate and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** comparable to DEP's cost estimate.

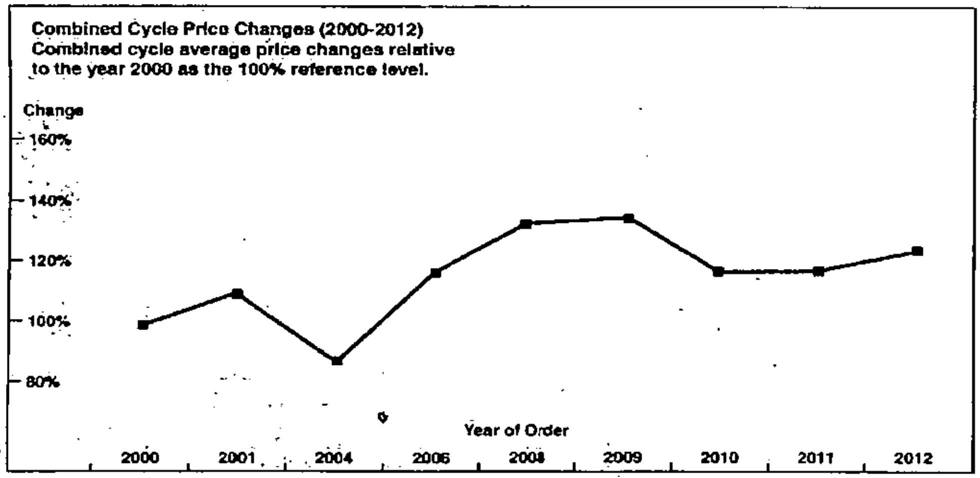
The final adjustment accounts for the difference in the economies of scale between the two unit site assumed by the Brattle Group and the four unit site assumed by the Utilities in calculating their avoided capacity costs. The B&M CT cost study shows that a cost reduction of approximately 10% can be realized between a two-unit site and a four-unit site. Confidential Rebuttal Exhibit GAS-2 shows that after making that adjustment, the results are almost identical to the Utilities' CT cost estimates.

Thus, like the B&M, S&L, and B&V analyses, the cost estimates contained in the CONE Study unequivocally demonstrate the reasonableness of the cost estimates used by the Utilities.

Q. HOW DO YOU RESPOND TO THE ASSERTIONS OF WITNESSES READING AND HINTON THAT DEC AND DEP SHOULD HAVE USED CT COSTS THAT ARE HIGHER THAN THOSE USED IN THE UTILITIES' PREVIOUS FILINGS?

A. REG witness Reading and Public Staff witness Hinton argue from a fundamentally incorrect premise that CT costs are rising. The truth is that CT costs have been gradually declining since they peaked in 2009.

Both witness Reading and witness Hinton rely upon information from the *2012 Gas Turbine World Handbook* ("*GTW 2012*") to support their assertion that CT costs are rising. Specifically, *GTW 2012* stated that an increase of 5-7% in CT equipment costs was expected in 2012. (Hinton Direct at 12; Reading Direct at 9) That assumption was reflected in the following chart showing the anticipated rebound in CT equipment costs in 2012.



Despite the prediction reflected in *GTW 2012*, the anticipated recovery in CT equipment costs has not occurred. This is demonstrated by comparing the CT prices listed in *GTW 2012* to the CT prices set forth in the *2013 Gas Turbine World Handbook* ("*GTW 2013*"), which are attached hereto as Rebuttal Exhibit GAS-3. As that information shows, CT equipment costs are declining. Compare, for example, the cost data for the GE 7FA Series 5 units that DEC and DEP assumed in calculating their avoided capacity rates. *GTW 2012* lists the cost for such equipment as $251/kw, whereas *GTW 2013* lists the cost for the same model CT equipment as $240/kw. Similar pricing declines can be seen for other GE turbines and other manufacturer's turbines. Clearly, the predicted rebound in CT equipment costs did not occur. If the actual declining cost trend had been plotted on the table above, it would show that after reaching their high water mark in 2009, CT equipment prices have gradually declined to a level that is below 2008 and 2010 levels. This is consistent with the observations of Utilities witness Pintcke that the current market for CTs is slow, which is depressing prices. (Pintcke Direct at 6)

Significantly, the actual cost data in *GTW* supports the change in the CT costs from DEP's 2010 avoided cost rate filing and its current cost rate filing. As Public Staff witness Hinton notes, DEP used an installed CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its 2010 avoided cost rates and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its 2012 avoided cost rates. (Hinton Direct at 18) That is a decrease of approximately 15%. This is exactly the type of cost decrease that one would expect when the most recent cost data in *GTW* is considered in conjunction with the table above. To further put this in perspective, witness Hinton observes that from 1996 to 2010, the average change in installed CT costs used by DEP between avoided cost cases was 22.5%. During that same period, the average change in DEC's installed CT costs used in avoided cost rates was 19.5%. Thus, the 15% change in DEP's installed CT cost between its 2010 avoided cost filing and the present filing is consistent with the magnitude of changes in CT costs historically and in line with current cost data.

Q. HOW DO YOU RESPOND TO THE ASSERTIONS OF REG WITNESS READING AND PUBLIC STAFF WITNESS HINTON THAT THE CHANGE IN MARKET COSTS FOR CTS CANNOT EXPLAIN THE MAGNITUDE OF THE DECREASE IN THE CT COSTS USED BY DEC IN THIS PROCEEDING COMPARED TO PREVIOUS PROCEEDINGS?

A. The Utilities have never claimed, as Witnesses Reading and Hinton suggest, that the total change in DEC's CT cost estimates is due solely to decreasing CT costs. Rather, the Utilities have explained that much of the change in CT costs used by DEC is a result of DEC moving away from using a "worst case" scenario approach to estimating CT costs. As a result, DEC's current CT costs reflect a much smaller contingency adder. To put this in perspective, DEP's installed CT cost decreased 15% between its 2010 and 2012 avoided cost rate filings due largely to changes in the $/kw cost of CTs. The decrease in the installed CT cost used by DEC between its 2010 and 2012 avoided cost rate filings is 27%. The percentage decrease is larger for DEC because it reflects the effect of declining CT costs ***and*** DEC's use of an "expected case" contingency factor. Thus, while it is true that the decrease in DEC's CT costs from previous filings are not wholly explained by changes in the market cost for CTs, the Utilities have made clear that a significant portion of this change is due to DEC's use of lower contingency adders, not just changes in CT costs.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS HINTON'S USE OF GENERAL INDUSTRY PRICE INDICES TO SUGGEST THAT CT COSTS ARE RISING?

A. Public Staff witness Hinton points to the Producer Price Index ("PPI") for Turbines and Turbine Generator Sets and CERA's Power Capital Cost Index ("PCCI") in arguing that the CT costs used in the Utilities' avoided cost rates should be increasing. (Hinton Direct at 12-14) However, these generalized, broad-based indices have limited probative value. The PPI is a compilation of data covering all kinds of turbines and related equipment. Consequently, one cannot draw any precise conclusions regarding cost trends regarding a specific type of turbine equipment. For example, a general cost index would not show the specific cost reductions for a particular type of turbine that is becoming larger and more efficient over time, which has been the case with F-frame CTs, such as the GE 7FA.

The PCCI has even less probative value than the PPI because it goes beyond multiple turbine types and includes costs for multiple generation types, including coal-fired, nuclear, wind, and solar generation. To illustrate, applying witness Hinton's interpretation of the PCCI, one would assume that the cost of installing solar and wind generation is increasing because the PCCI includes the cost of solar and wind facilities. Of course, as proponents of solar and wind power unfailingly argue, the capital costs for solar and wind generation has decreased over the last several years. Simply put, the PCCI reveals no more about the specific cost trends for conventional CTs than it does for solar and wind facilities.

Q. ARE THERE ANY OTHER ASPECTS OF THE COST DATA CONTAINED IN *GTW 2012* AND *GTW 2013* THAT SHOULD BE ADDRESSED?

A. Yes. Past CT costs should not be used as a means to measure the reasonableness of current CT cost estimates. Such an approach ignores technological innovations. Over time, CT manufacturers improve the output and efficiency of their turbines without an increase in price. The cost data in *GTW 2012* and *GTW 2013* is a prime example of such advances. In *GTW 2012,* the Siemens SGT6-5000F was listed with a unit rating of 208 MW and a price of $52 million. In the *GTW 2013,* however, the same unit was listed as having a unit rating of 232 MW and a price of $49 million. The net effect of those changes is that in one year the cost per kw of that unit dropped from $251/kw to $213/kw. This demonstrates the fallacy in the positions of REG, NCSEA, and Public Staff that past CT costs are an appropriate measure for current costs and that to the extent CT costs change they must increase.

II. THE CONTINGENCY ADDER USED BY THE UTILITIES' CT COST ESTIMATES IS REASONABLE AND APPROPRIATE

Q. WHAT CONTINGENCY ADDERS DID DEP USE IN ITS 2012 IRP AND ITS PROPOSED AVOIDED CAPACITY RATES?

A. For both its 2012 IRP and its proposed avoided cost rates, DEP applied a 5% contingency adder in calculating installed CT costs. A 5% contingency adder was also used for the CT cost estimates in the B&M study commissioned by DEP. S&L used a higher contingency adder (approximately 15%) in its study for DEC. The Utilities used the lower contingency adder reflected in the B&M study because it was consistent with their actual experience. As I explain in my direct testimony, since 2009, the Utilities have found that little or no contingency adder is necessary when constructing gas turbine generation. This includes combined cycle facilities, which are more complex than the simple cycle CTs that serve as the basis for the Utilities' avoided capacity rates.

Q. OTHER THAN THE UTILITIES' EXPERIENCE IN BUILDING COMBUSTION TURBINE GENERATION, DO THE UTILITIES HAVE ADDITIONAL SUPPORT FOR THEIR USE OF A 5% CONTINGENCY ADDER IN THEIR CT COST ESTIMATES?

A. Yes. As I mentioned previously, B&M, one of the leading engineering and construction firms in the utility sector, used a 5% contingency adder in their CT cost study. Also, as I noted in my direct testimony, EIA also uses a 5%

contingency in developing their estimates of current CT costs. Similarly, the Brattle Group used a 5% contingency in developing its CT cost estimates in the CONE study. (Rebuttal Exhibit GAS-1 at 15)

Q. HOW DO YOU RESPOND TO THE SUGGESTIONS OF WITNESSES READING AND HINTON THAT THE UTILITIES SHOULD HAVE USED A HIGHER CONTINGENCY ADDER IN THEIR CT COST ESTIMATES?

A. The positions taken by REG witness Reading and Public Staff witness Hinton are incorrect for two reasons: 1) the sources they cite do not actually support their position; and 2) their positions are inconsistent with the purpose of the avoided cost rate process.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THE SOURCES CITED BY WITNESSES READING AND HINTON DO NOT SUPPORT THEIR POSITION?

A. Both witness Reading at page 17 of his direct testimony and witness Hinton at page 26 of his direct testimony cite a B&V report entitled *Cost and Performance Data for Power Generation Technologies (2011)* ("*B&V Cost Report*") for the proposition that non-site specific cost estimates might include contingencies of 20-30%. However, this statement is taken out of context and is inapplicable to the Utilities' use of contingency adders in this proceeding.

The portion of the *B&V Cost Report* cited by witnesses Reading and Hinton is contained in an introductory portion of the report, which explains why the cost projections in the report should not be taken as single point estimates. (B&V Cost Report at 7-8) It is important to note that the *B&V Cost Report* is a compilation of general industry data used to produce generic cost projections for building multiple types of generation (including new and emerging technologies) in the United States through 2050. Given the nature of such projections, it is understandable why B&V would be careful to hedge its projections. Moreover, witnesses Reading and Hinton ignore that B&V observed that "[m]ature technologies have a smaller band of uncertainty around their costs…." (*Id.* at 3) Even more telling, with regard to conventional CTs specifically, the *B&V Cost Report* states that the "[c]ost uncertainty for this technology is low." (*Id.* at 11)

The statements in the *B&V Cost Report* must be considered in light of their specific intent. B&V was discussing how project estimates might be done in the absence of detailed information. In such a situation, uncertainties may exist in a number of areas, including: 1) site availability and suitability; 2) generation type and configuration; 3) timing of the project; and 4) the amount of detail that is put into the cost estimate. None of those uncertainties are significant issues for the CT cost estimates relied upon by the Utilities.

Even though the Utilities' estimates in this case are not based on a specific site, issues associated with the suitability and availability of a site are mitigated by the fact that the owners of the projected CTs are public utilities with the power of eminent domain. As to generation type, the estimates are not just based on generic assumptions regarding CTs, but rather are based on specific CT models (i.e., GE 7FA.05) and a specific four-unit configuration. Both the CT type and the four-unit configuration are common and well-understood. Moreover, the cost estimates in question are not based on an uncertain project date or a hypothetical date in the distant future. They are based on an assumption of immediate construction, which eliminates the uncertainties associated with the timing of the project. Additionally, the Utilities based their CT costs on cost studies performed by B&M and S&L. These were not generic cost estimates based on broad industry data.

Thus, the nature of the cost studies used by the Utilities simply do not justify the large contingency adders suggested by REG witness Reading or Public Staff witness Hinton. Tellingly, neither witness Reading nor witness Hinton provide a single concrete example of the use of a contingency adder of that magnitude in cost estimates of this type.

Q. DO THE OTHER PARTIES PROVIDE ANY OTHER SUPPORT FOR THEIR POSITION THAT THE UTILITIES SHOULD HAVE USED LARGER CONTINGENCY ADDERS IN THEIR CT COST ESTIMATES?

A. On page 14 of his direct testimony, REG witness Reading suggests that a larger contingency adder is warranted to account for uncertainties in macro-economic conditions, such as the domestic fiscal conditions and economic conditions in Europe and China. This argument ignores the fact that these conditions can just as easily lead to cost decreases. Further, any potential impact from global economic factors is mitigated in the context of avoided costs by the fact that avoided cost rates are reset every two years. Concerns pertaining to macro-economic volatility may have some relevance to cost estimates for projects that take years to complete (e.g., nuclear plant construction) or to projects that are decades in the future. However, such concerns simply have no bearing on current cost estimates for CTs that are updated biennially.

Q. PREVIOUSLY YOU STATED THAT THE POSITIONS OF WITNESSES READING AND HINTON ARE INCONSISTENT WITH THE PURPOSE OF AVOIDED COST RATE PROCEEDINGS. WHAT DO YOU MEAN?

A. Avoided capacity rates must be based on the costs that the utility actually expects to incur if it has to build capacity rather than purchasing power from a QF. Thus, in this case, the Utilities' avoided capacity costs must be based on the cost one would reasonably expect them to incur to build CT capacity. The positions taken by witnesses Reading and Hinton are not consistent with that principle.

REG witness Reading and Public Staff witness Hinton suggest that the Utilities should have adopted the approach used by bidders and project managers for the most preliminary of project estimates. This approach would require a contingency large enough to account for every possible risk, including risks that have not yet been identified. Such a "worst case scenario" method of determining contingency may be acceptable in developing a "not to exceed" preliminary project estimate, but not in the development of avoided cost rates.

III. <u>THE UTILITIES PROPERLY BASED THEIR CT COST ESTIMATES ON THE AVERAGE COST OF A FOUR-UNIT SITE AND THE RESULTING ECONOMIES OF SCALE</u>

Q. PLEASE EXPLAIN WHY THE UTILITIES BASED THEIR CT COST ESTIMATES ON THE AVERAGE COST OF A FOUR-UNIT SITE?

A. Historically, DEC and DEP have constructed their CTs on multiple unit sites. Of the ten sites on which DEP has built CTs, six have four or more units and one has three units and a large combined cycle combustion turbine plant. The other three sites consist of two sites with small (15 MW) oil-fired units that are not comparable to the type of CT used to calculate DEP's avoided capacity rates and a remote site in Asheville that has two CTs. Similarly, three of DEC's four CT sites have four or more units. The fourth is a two-unit site that is utilized as a back-up source of generation to a nuclear site. Because the Utilities typically construct CTs with at least four units at a site, it is reasonable to use the four-unit configuration as the basis for their avoided capacity rates. Furthermore, in using the average cost of a four-unit site, the Utilities are following the guidance recently provided by the Commission in the EPCOR arbitration *See Order on Arbitration* Docket No. E-2, Sub 966, (January 26, 2011) *("EPCOR")*. My understanding is that the Commission, in its EPCOR order, specifically rejected the same argument being made here by the intervenors and ruled that the proper way to calculate DEP's avoided capacity cost is to use the average unit cost to construct four CTs at a plant site.

In my opinion, nothing has changed in the 20 months since the *EPCOR* order was issued to warrant a change in the Commission's analysis for either DEP or DEC.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF WITNESS READING THAT THE UTILITIES' AVOIDED CAPACITY RATES SHOULD BE BASED ON THE COST OF A ONE-UNIT SITE?

A. In general, the arguments raised by REG witness Reading are the same arguments that the Commission considered and rejected in *EPCOR*. More specifically, the arguments of witness Reading are inconsistent with the Peaker Methodology upon which the Utilities' avoided cost rates are based.

The Peaker Methodology combines a utility's cost of building CT capacity with the utility's incremental cost of energy (i.e., its highest energy cost for each hour) to produce avoided cost rates. Consequently, under this methodology, the avoided capacity rates are based on CT costs regardless of the type and amount of generation that the utility plans to build. Nevertheless, witness Reading suggests that the Utilities should ignore the fact that their practice is to build four or more CTs at a single site because the Utilities may not have immediate plans to develop a four-unit CT site. (Reading Direct at 22 and 27-28)

The specific generation additions reflected in the Utilities' resource plans are not relevant to the calculation of avoided capacity rates under the Peaker Methodology. If that were the case, the calculations would work both ways and Utilities would be paying avoided capacity rates of zero during years in which they are not adding new capacity. It is doubtful witness Reading would support this model in that instance. In any event, the implication of witness Reading's position that a prudent utility would adopt a policy of only developing single-unit CT sites is implausible.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF WITNESS HINTON THAT THE UTILITIES' AVOIDED CAPACITY RATES SHOULD BE BASED ON THE COST OF A TWO-UNIT SITE?

A. Public Staff witness Hinton takes a slightly different approach than witness Reading. Witness Hinton argues that the current value of combined cycle generation suggests that the Utilities are less likely to build CTs and, therefore, may depart from their practice of building four or more units at a single site. (Hinton Direct at 23-24) The implication of this argument is that a change in DEC's and DEP's approach to developing multi-unit CT sites would also warrant a change in the siting assumption used in developing their avoided capacity rates.

First, as the individual responsible for resource planning for both DEC and DEP, I can state unequivocally that both of the Utilities will continue to pursue CT development as an option to meet their obligation to provide least cost power to their customers. That means that siting four or more CTs at a single site will continue to be the rule for DEC and DEP, not the exception. This is the most cost-effective approach to developing CTs because it optimizes the economies of scale associated with multi-unit sites. Spreading the cost of land, site preparation, roadways, gas infrastructure, electric transmission infrastructure, water infrastructure, and administrative and auxiliary buildings among several units (instead of just one or two) significantly lowers the average capital cost of the CTs. That is why the Utilities have historically sited CTs at sites with four or more units and why they will continue to do so.

Second, witness Hinton's argument is based on an apparent misunderstanding of the nature of economies of scale gained by multi-unit siting of CTs. Witness Hinton appears to assume that, if current market conditions cause the Utilities to favor combined cycle units over CTs, the resulting delay in the construction of CTs will result in more two-unit sites. This assumption ignores the fact that the economies of scale achievable by siting several CTs at a single site are not dependent on building all of the CTs at the same time. Thus, while it is conceivable that current circumstances could cause the Utilities to initially build a two-unit CT site, nothing would prevent them from subsequently adding more CTs to that site. Alternatively, the Utilities might build two CTs, but co-locate them with combined-cycle units, thereby achieving the same type of economies of scale as are achieved with a four-unit site. In any event, I expect the Utilities to continue to pursue the development of CTs in a manner that achieves economies of scale comparable to those reflected in their avoided capacity rates.

Q. HOW DO YOU RESPOND TO THE ASSERTION OF PUBLIC STAFF WITNESS HINTON THAT THE UTILITIES' CT COST ESTIMATES OVERSTATE THE EFFECT OF ECONOMIES OF SCALE ASSOCIATED WITH BUILDING FOUR UNITS AT A SINGLE SITE?

A. Importantly, DEC and DEP did not calculate a specific measure of economies of scale for their CT cost estimates. They based their CT cost estimates on the cost studies performed by B&M and S&L for the average CT cost based on a four-unit configuration. The Utilities did not direct B&M or S&L to assume a particular amount of savings due to economies of scale. B&M and S&L independently developed their cost estimates and any economies of scale assumed in their cost studies are a product of their own experience and judgment.

The effect of the economies of scale is more evident in the B&M study because B&M broke down its four-unit cost estimate between the cost of the first unit and subsequent units. B&M's first-unit cost estimate includes the full cost of elements such as land, site development, shared infrastructure and facilities. The costs for subsequent units do not include these initial costs and, therefore, are lower. S&L did not provide a breakdown of estimated CT costs by first and subsequent units. It simply provided a cost of the entire four-unit CT site. As a result, S&L's consideration of economies of scale is not as apparent. Nonetheless, S&L and B&M ultimately arrived at very similar cost estimates for the cost of a single site with four GE 7FA.05 units. It is, therefore, reasonable to conclude that their assumptions as to the effect of economies of scale on such a project were comparable.

The Utilities' actual experience also confirms that co-locating CTs at a single site can produce significant cost savings. For example, DEP completed the last of five CTs located at its Wayne County site in May 2009. As the data in *2012 GTW* shows, 2009 was the period when CT costs peaked. DEP's avoided cost rate filings confirm this fact because DEP used a CT cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in its 2008 avoided capacity rates, which represented a 64% increase from the CT costs used by DEP in its 2006 avoided capacity rates. Despite being built at the height of the CT market, the last Wayne County CT was built for only **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

A comparison of the CT cost estimates produced by EPRI further illustrates the significance of the cost savings associated with constructing multiple CTs at a single site. EPRI has estimated that the cost of building a single GE 7FA unit to be \$637/kw (in 2011 dollars). On the other hand, EPRI has estimated the cost of building three such CTs on a single site to be only \$558/kw (in 2010 dollars). While a small portion of the difference in these cost estimates may be due to the difference between 2011 and 2010 costs, the vast majority of these savings must be attributed to the economies of scale associated with building two additional units at the same site. Such cost reductions would be even greater if, as the Utilities have for purposes of their avoided capacity calculations, EPRI has assumed a four-unit site as opposed to a three-unit site. Thus, whatever doubts witness Hinton may have regarding the magnitude of savings to be derived by building four or more CTs at a single site, the Utilities' experience and the cost studies conducted by B&M, S&L, and EPRI confirm that those savings are real and they are significant.

Witness Hinton does not cite any studies, reports, or data to support his position that the economies of scale reflected in the B&M and S&L studies are over-stated. He does refer to the testimony of Utilities' witness Pintcke, who stated that such economies of scale could be "25% or more" on the balance of plant costs. (Hinton Direct at 22) Witness Pintcke further noted that balance of plant costs are only approximately 40% of the total cost of a CT. (Pintcke Direct at 4) However, witness Hinton seems to ignore that witness Pintcke stated that the economies of scale saving on balance of plant costs could be "25% ***or more.***" (Pintcke Direct at 8) Clearly, witness Pintcke was describing the minimum savings that one would expect by siting four CTs at a single site. More importantly, Public Staff witness Hinton disregards witness Pintcke's ultimate conclusion that his "experience leads me to expect that the $/kw cost of a four CT site would be in the range of 15% to 25% less than the $/kw cost of a single CT greenfield." (Pintcke Direct at 8) That range of savings from economies of scale is consistent with the savings reflected in the B&M study, the EPRI cost estimates, and the Utilities' experience.

IV. THE UTILITIES' USE OF A 35-YEAR USEFUL LIFE FOR CTS IN CALCULATING THEIR AVOIDED CAPACITY RATES IS REAONABLE AND APPROPRIATE

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S ARGUMENT THAT THE UTILITIES SHOULD NOT HAVE USED A 35-YEAR USEFUL CT LIFE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. Witness Reading's arguments regarding the Utilities' use of a 35-year useful CT life are completely unsupported and without merit. In the Utilities' Reply Comments and my direct testimony, the Utilities have shown that: 1) the actual operating lives of the Utilities' CTs are 35 years or more; and 2) the 35-year CT useful life assumption is consistent with the useful life assumption used in setting the Utilities' current retail rates. Given those facts, it is clear that 35 years is an appropriate useful life for the Utilities to use in calculating their avoided capacity rates. REG witness Reading presents no evidence to contradict those facts.

Rather than providing specific evidence regarding the useful life of the Utilities' CTs, witness Reading points to e-mail exchanges among the DEC and DEP employees to support his position. (Reading Direct at 19) These e-mails, however, do nothing to further witness Reading's arguments. As noted in my direct testimony, the Utilities engaged in collaborative process after the Duke-Progress Merger to begin developing best practices. This process included review and discussion of the Utilities' respective approaches to calculating their avoided cost rates. One of the issues that was discussed at length was the useful CT life estimate to be used in setting avoided capacity rates. Ultimately, it was determined that a 35-year useful life was appropriate given the actual operational lives of the CTs and the assumptions underlying the Utilities' retail rates. Because this assumption constituted a change for both DEC (which previously used a 30-year life) and DEP (which previously used a 25-year life), it is understandable that there was considerable discussion of it. The e-mails quoted by witness Reading merely reflect the kind of robust and open debate around this issue that is to be expected and that the Utilities in fact encourage. These exchanges in no way diminish the fact that the 35-year useful life is fully supported by and consistent with the actual operating lives of the Utilities' CT fleet and the manner in which the Utilities' retail rates are set.

Witness Reading also suggests that if the Utilities adopt a longer useful life for their CTs then they should have increased the variable O&M expense rate associated with their CTs. (Reading Direct at 26) His assumption is that a longer useful life would equate to a higher cost to operate and maintain the unit. (Reading Direct at 19-20) Witness Reading's argument, however, proceeds from a false premise. The variable O&M included in the Utilities' avoided cost rates are based on their actual variable O&M expense from a mix of CT and non-CT generation. This includes cost data from the Utilities' CTs, including those that have been in operation for 35 years or more. Thus, the variable O&M expense reflected in the Utilities already account for effects of a 35-year useful CT life.

V. IN CALCULATING THEIR AVOIDED CAPACITY COSTS, THE UTILITIES PROPERLY EXCLUDED THE COST OF TRANSMISSION NETWORK SYSTEM UPGRADES

Q. WHAT IS YOUR UNDERSTANDING OF THE ISSUES RAISED IN THIS PROCEEDING REGARDING THE UTILITIES' APPROACH TO EXCLUDING TRANSMISSION NETWORK SYSTEM UPGRADE COSTS IN THIER AVOIDED CAPACITY RATES?

A. Public Staff witness Hinton and REG witness Reading suggest that Network System Upgrade costs associated with installing a hypothetical CT should have been included in developing the Utilities' avoided capacity costs. Traditionally, DEC has included such upgrade costs in its avoided capacity rates and DEP has not. For purposes of the present case, it was determined that neither DEC nor DEP would include such costs in their avoided capacity rates. However, the Utilities have included the cost of transmission interconnection in their avoided capacity cost calculations.

Q. WHAT IS THE DIFFERENCE BETWEEN INTERCONNECTION COSTS AND NETWORK SYSTEM UPGRADES COSTS?

A. Network upgrades, unlike interconnection costs, involve improvements to the transmission system beyond merely connecting a generation resource to the transmission system. Such upgrades are needed to accommodate the anticipated increases in power flows as growing load is met from sources such as new generating facilities or new power purchases.

Sometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions require such upgrades. A number of factors, including the current state of the transmission system, the amount and type of generation being added to the system, and the location of the new generation can influence whether network upgrades are required by the addition of new generation. Moreover, network upgrades can range from minor additions such as a bank of capacitors to the enormously expensive undertakings such as the construction of a new transmission line. All other things being equal, utilities will try to plan their generation additions to avoid or minimize the need for network upgrades. As the foregoing makes clear, although all generation requires interconnection, not all generation necessitates network upgrades.

Buying power from a QF allows a utility to avoid interconnection costs because: 1) the utility "avoids" the interconnection costs associated with the CT capacity that it is avoiding; and 2) the QF is fully responsible for the interconnection costs associated with its own facility. This is not the case for network system upgrades, however, and, therefore, the cost for such upgrades has not been included in the Utilities' avoided capacity rates.

Q. WHY HAVE THE UTILITIES' EXCLUDED NETWORK SYSTEM UPGRADE COSTS FROM THEIR AVOIDED CAPACITY RATES?

A. The Utilities' did not include network system upgrade costs in their avoided capacity rates because those types of costs are not "avoided" in the sense required by PURPA. As noted above, interconnection costs for a CT are considered avoided because if a utility buys power from a QF, rather than building a CT, the utility avoids the interconnection cost ***and*** the QF, not the utility, is responsible for the interconnection costs associated with the QF. However, unlike the situation with interconnection costs, small QFs are not responsible for any network system upgrade costs associated with the addition of its facility. DEC and DEP do not require comprehensive system impact and facilities studies for small QFs to interconnect. Without such studies, any network transmission upgrades required to accommodate incremental additions of small QF generation (individually or in aggregate) are borne by the Utilities and their customers.

Q. HOW DO YOU RESPOND TO THE ASSERTIONS OF REG WITNESS READING AND PUBLIC STAFF WITNESS HINTON THAT SMALL QFS ARE UNLIKELY TO CAUSE OR CONTRIBUTE TO THE NEED FOR NETWORK SYSTEM TRANSMISSION UPGRADES?

A. Neither witness Reading nor witness Hinton provide any specific support for their supposition that the addition of numerous small QFs to the Utilities' system would impose little or no costs or impacts on the Utilities' transmission system. For example, witness Hinton merely opines that it is "unlikely" that an aggregation of 5 MW QFs distributed throughout a utility's system would have the same network system impact as a single 200 MW CT at a single location.

The implication of witness Hinton's statements is that installing QFs are "unlikely" to contribute to the need for network system upgrades and therefore the fact that the Utilities and their customers are responsible for any such upgrades is moot. This argument, however, misses the point. Regardless of how likely it is that the installation of numerous QFs will contribute to the need for network system upgrades, the fact remains that the Utilities and their customers, not the QFs, bear the full cost responsibility for them. It would be unfair and inconsistent with PURPA for the Utilities' customers to pay for "avoided" network system upgrade costs through rates paid to QFs ***and*** to pay for the cost of network system upgrades necessitated by the QFs.

Finally, it is not certain that distributed QFs will not cause or contribute to the need for network system upgrades. Unlike the Utilities, QFs are not required or incented to site their facilities in the most efficient location possible. Accordingly, QFs seek to interconnect to the Utilities' systems where it is most financially advantageous for them and issues associated with transmission impacts are not relevant to QFs when they select a site for their facilities. In fact, the predominant factors affecting QF siting decisions, such as, land costs, suitability of topography, atmospheric conditions, proximity to fuel sources, and tax credit advantages, have nothing to do with transmission issues. As a result, multiple new QFs may be located in clusters or be located at particularly disadvantageous locations from a transmission perspective. Consequently, one cannot simply assume that it is "unlikely" that no network transmission upgrades will be necessitated by adding hundreds of MWs of new QF capacity to the Utilities' system. It follows that it would be inappropriate to require the Utilities and their customers to bear the risk of paying twice for network system upgrades – once through the avoided cost rates paid to QFs and once if the QFs contribute to the need for network system upgrades.

VI. <u>RESPONSE TO THE SPECFIC RECOMMENDATIONS OF WITNESS READING</u>

Q. WHAT ARE THE CT COSTS THAT WITNESS READING RECOMMENDS THAT DEC AND DEP SHOULD BE REQUIRED TO USE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. REG witness Reading recommends that DEC be required to use CT cost of $742/kw and that DEP be required to use CT cost of $725/kw.

Q. TURNING FIRST TO DEC, HOW DO YOU RESPOND TO REG WITNESS READING'S RECOMMENDATION THAT DEC BE REQUIRED TO USE A CT COST $742/KW FOR ITS AVOIDED CAPACITY RATES?

A. I am not aware of any cost data that would support $742/kw as a cost that DEC would reasonably be expected to incur for new CT capacity. Even the study that witness Reading cites, *The B&V Cost Study,* only quotes an installed CT cost of $651/kw and that is for a single-unit site.

Q. DOES REG WITNESS READING PROVIDE ANY SUPPORT FOR HIS RECOMMENDATION?

A. He does not provide any meaningful support for his recommendation. He relies on the CT cost estimates filed by DEC in previous proceedings. (Reading Direct at 12-14) As I noted above, past CT cost estimates are a poor indicator of current CT costs. Moreover, DEC's previous filings were based on the conservative approach of using high contingency adders (i.e., worst case scenario cost estimates). Consequently, DEC's previous filings do not provide meaningful evidence of actually anticipated, current costs to construct a CT.

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S RECOMMENDATION THAT DEP BE REQUIRED TO USE A CT COST OF $725/KW FOR ITS AVOIDED CAPACITY RATES?

A. REG witness Reading's recommendation as to DEP has even less validity than his DEC recommendation. In the case of DEP he cannot even rely on specious comparisons to DEP's previous filings because his recommendation is significantly higher than any CT cost estimate used by DEP in any regulatory proceeding. Moreover, in an effort to gloss over the lack of support for his recommendation, he mischaracterizes cost data contained in DEP's previous filings.

First, he cites the $1,784/kw cost of 42 MW fast-start turbines from DEP's resource plan to show the "CT cost that DEP actually will incur…." (Reading Direct at 25) Of course, the fast-start CT bears no relationship to avoided cost calculations. It is an entirely different type of generation from the conventional CTs used to determine avoided costs under the Peaker Methodology. Fast-start units are installed for their ability to respond quickly to system conditions and emergencies, but that capability causes these units to have very high capital costs relative to other types of generation. Thus, the cost of a fast-start unit is as irrelevant to the calculation of avoided capacity rates using the Peaker Methodology as the cost of a nuclear plant. Moreover, witness Reading is well-aware of that fact because it was explained in response to a REG data request. (*Id.* at 24-25)

Second, witness Reading alleges that DEP used a CT cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in its 2012 IRP. Clearly, witness Reading is relying on the estimated cost of a single CT from DEP's 2012 IRP, which is not appropriate for the calculation of avoided capacity costs. Moreover, witness Reading has ignored the fact that the CT cost estimate used in DEP's 2012 IRP is actually ***lower*** than the CT cost estimates used to calculate DEP's avoided capacity rates. *(See, e.g.,* Utilities Reply Comments at 12-14) Further, witness Reading provides no explanation how a cost estimate for a ***single*** CT of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** provides any support for his recommendation that a CT cost of $725/kw be used for DEP's avoided cost capacity rates.

Third, witness Reading erroneously alleges that DEP used a CT cost estimate of $818.50/kw in its 2012 Generation Reserve Margin Study. (Reading Direct at 24) This figure is simply wrong. In fact, the overnight CT cost estimate reflected in that study was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the average cost of a four-unit site. While that cost estimate is higher than the CT cost estimate used by DEP in its current avoided capacity rates, the difference is due to the fact that DEP's Reserve Margin Study was based on 2011 generic unit cost estimates, which were produced when CT costs were higher than they are currently.

In any event, nothing in DEP's 2012 Generation Reserve Margin Study provides any support for the inflated CT cost quoted by witness Reading. His error is particularly confusing given that DEP made the actual CT cost estimates used in its Reserve Margin Study available to the other parties in this case, including REG. Attached to my testimony as Confidential Rebuttal Exhibit GAS-4 is DEP's response to Public Staff Data Request 3-4, which shows the actual CT costs used in the Reserve Margin Study. This data request response was served on REG as well as the Public Staff.

In sum, nothing in witness Reading's testimony provides any legitimate credence to his recommendations and they should be given no weight by the Commission.

VII. RESPONSE TO THE SPECFIC RECOMMENDATIONS OF PUBLIC STAFF WITNESS HINTON

Q. WHAT IS THE CT COST THAT PUBLIC STAFF WITNESS HINTON RECOMMENDS THAT DEC AND DEP SHOULD BE REQUIRED TO USE IN CALCULATING THEIR AVOIDED CAPACITY RATES?

A. Public Staff witness Hinton recommends that both DEC and DEP should be required to use a CT cost of $650/kw for their avoided cost rates. He states that this recommendation is based on his opinion that $625/kw to $675/kw is a reasonable range for cost building new CT capacity. Although his recommendation is not as excessive as witness Reading's recommendations, Public Staff witness Hinton's proposed CT cost is still unreasonably high.

Q. WHY DO YOU BELIEVE THAT PUBLIC STAFF WITNESS HINTON'S RECOMMENDATION OF A $650/KW CT COST IS TOO HIGH TO BE USED FOR CALCULATING THE UTILITIES' AVOIDED CPACITY RATES?

A. His recommendation is out of line with all of the independent CT cost studies presented in this case. B&M, S&L, B&V, and the Brattle Group have all produced CT cost studies that result in CT costs that are significantly lower than witness Hinton's recommendation. Similarly, the overnight cost estimates for a single CT produced by EIA ($664/kw) and EPRI ($637/kw) suggest that witness Hinton's recommended CT cost is too high.

While witness Hinton's recommendation of $650/kw is out of line with the other cost data presented in this proceeding, the cause of this discrepancy is unclear because his recommendation is unaccompanied by any back-up or explanation. Without such information, there is no way to discern what estimates and assumptions form the basis of his recommended CT cost. For example, witness Hinton provides no indication of: 1) whether he is estimating the cost of a one, two, three or four unit site; 2) the model of CT he assumes; 3) the assumed rating of the CT(s); 4) whether transmission costs are included in his cost estimate (and if so how much transmission cost is included); and 5) how much contingency is included in the CT cost estimate.

While the bases for witness Hinton's recommendation are not evident from his testimony, it is clear he could only have arrived at his recommended CT cost by assuming some combination of factors that are not appropriate for the calculation of the Utilities' avoided capacity costs. For instance, witness Hinton's recommendation may be inflated by assuming a single-unit or two-unit site as the basis of his cost estimate. Such an assumption, however, would not be an appropriate basis for calculating the Utilities' avoided capacity rates given their actual pattern of siting four or more CTs at a single site and the Commission's ruling in *EPCOR*. Similarly, witness Hinton's recommended CT cost may have been increased by the inclusion of a substantial amount of transmission system upgrade costs, which would be inconsistent with the Utilities' practice of not charging small QFs for network system upgrades. Regardless of the cause, witness Hinton's recommended CT cost is significantly higher than the Utilities' anticipated cost of CT capacity and, therefore, is too high to be used as the basis for the Utilities' avoided capacity rates.

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

A. Yes, it does.

REBUTTAL EXHIBIT GAS-1

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November 21, 2012

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20427

Re: *PJM Interconnection, L.L.C.*, Docket Nos. ER12-513-000, -003
Settlement Agreement and Offer of Settlement

Dear Ms. Bose:

Enclosed for filing pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, are a Settlement Agreement and Offer of Settlement ("Settlement Agreement") and accompanying documents, which are proposed to resolve all issues set for hearing in the above-referenced dockets. This Settlement Agreement is submitted on behalf of: American Electric Power Service Corporation, Dominion Resources Services, Inc., Edison Mission Energy, Exelon Corporation, FirstEnergy Service Company, GenOn[1], LS Power Associates, L.P., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, PJM Industrial Customer Coalition, PJM Interconnection, L.L.C. ("PJM"), and PJM Power Providers Group (collectively, "Settling Parties"). As set forth in the accompanying documents, numerous other parties have advised that they do not oppose resolution of this proceeding on the terms set forth in the Settlement Agreement.

For the reasons set forth in the accompanying documents, ***the Settling Parties request Commission acceptance of the Settlement Agreement by no later than January 20, 2013, i.e., 60 days after the date of this filing.***

In accordance with Rule 602(f), initial comments on this settlement are due December 11, 2012, and reply comments are due December 21, 2012.

The proposed settlement is composed of the following:

- The Settlement Agreement, including attached *pro forma* revisions to the PJM Open Access Transmission Tariff ("Tariff");
- A separate Explanatory Statement, as required by Rule 602(c)(1)(ii);

1 GenOn refers to GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

- An affidavit of Dr. Samuel A. Newell on behalf of PJM supporting certain aspects of the settlement; and

- A draft letter order approving the proposed settlement.

On behalf of the Settling Parties, PJM hereby requests any waiver(s) of the Commission's regulations as the Commission may deem necessary to effectuate the provisions of the Settlement Agreement.

The undersigned certifies that copies of this filing have been served, in accordance with Rule 602(d), 18 C.F.R. § 385.602(d), on all participants in the proceedings to be resolved and on all persons required to be served with the documents included in this filing. PJM also is providing a complete copy of this filing to Judge John P. Dring, the assigned settlement judge in this proceeding.

Should you have any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

/s/ Paul M. Flynn

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket Nos. ER12-513-000, -003

EXPLANATORY STATEMENT

PJM Interconnection, L.L.C. ("PJM"), on behalf of the Settling Parties in this proceeding,[1] submits this Explanatory Statement in support of the enclosed Settlement Agreement and Offer of Settlement ("Settlement Agreement"), which resolves all issues set for hearing in these proceedings. As set forth in the Settlement Agreement, the Settling Parties are American Electric Power Service Corporation ("AEP"),[2] Dominion Resources Services, Inc.,[3] Edison Mission Energy, Exelon Corporation, First Energy Service Company, GenOn,[4] LS Power Associates, L.P. ("LS Power"), North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, PJM Industrial Customer Coalition, PJM Interconnection, L.L.C., and PJM Power Providers Group

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1 PJM coordinated preparation of this Explanatory Statement with the Settling Parties, but any characterization herein of the Settlement Agreement or these proceedings is solely that of PJM and should not be attributed to any other party. In the event of any conflict between this Explanatory Statement and the Settlement Agreement, the provisions of the Settlement Agreement govern.

2 American Electric Power Service Corporation intervened in this proceeding on behalf of certain operating companies of the AEP system, i.e., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

3 Dominion Resources Services, Inc. intervened in this proceeding on behalf of its public utility affiliates Virginia Electric and Power Company and Dominion Energy Marketing, Inc.

4 GenOn refers to GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

("P3"). The Settling Parties are authorized to state that Calpine Corporation, Dayton Power and Light Company ("Dayton"), Dynegy Power Marketing, LLC, Illinois Municipal Electric Agency, Public Power Association of New Jersey, the New Jersey Board of Public Utilities, NextEra Energy Generators, NRG,[5] PHI, PPL,[6] PSEG,[7] Rockland Electric Company, and Southern Maryland Electric Cooperative do not oppose resolution of this proceeding upon the terms set forth in the Settlement Agreement. Accordingly, nearly all of the parties that have been active on the issues set for hearing in this proceeding either support or do not oppose the Settlement Agreement.

The Settling Parties request that the Commission approve the Settlement Agreement on or before January 20, 2013, so that the Cost of New Entry ("CONE") and other values in this settlement can be posted to PJM's website, along with other relevant auction parameters, by February 1, 2013 to govern the capacity auction that PJM will conduct in May 2013.

I. BACKGROUND

On December 1, 2011, as a result of a triennial review of key elements of the PJM capacity market (known as the Reliability Pricing Model or "RPM"), PJM filed in Docket

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5 NRG refers to NRG Power Marketing LLC, Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Energy Center Paxton LLC, NRG Rockford LLC, NRG Rockford II LLC, and Vienna Power LLC.

6 PPL refers to PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, and PPL Renewable Energy, LLC

7 PSEG refers to Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

No. ER12-513-000 ("December 2011 Filing") under section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, amendments to its Open Access Transmission Tariff ("Tariff") to (among other changes) revise the capacity market demand curve (known as the Variable Resource Requirement Curve or "VRR Curve") and two inputs to that curve: the Gross Cost of New Entry ("CONE") and the Net Energy and Ancillary Services ("EAS") Revenue offset that together determine the Net CONE.

Gross CONE is an estimate of the total project capital cost and annual fixed operations and maintenance expenses of a new generating plant of a type likely to provide incremental capacity to the PJM Region (which the Tariff refers to as the "Reference Resource" and defines as a combustion turbine ("CT") power plant)[8] in the forward delivery year addressed by the RPM auctions. The PJM Tariff states a Gross CONE value for the PJM Region as a whole, and for each of five subsets of the PJM Region identified in the PJM Tariff as "CONE Areas."[9] In the December 2011 Filing, PJM proposed to replace the Gross CONE values for the five CONE Areas with new values based on estimates of the costs of delivering a new plant for the 2015-2016 Delivery Year,[10] and to establish a new methodology to determine the region-wide Net CONE.

As relevant to this settlement, PJM also proposed in the December 2011 Filing to modify the Gross CONE estimates for a representative combined cycle ("CC")

[8] *See* Tariff, Attachment DD, section 2.58.

[9] *See* Tariff, Attachment DD, section 5.10(a).

[10] A Delivery Year is a twelve-month period beginning on June 1 of a calendar year and ending on May 31 of the following calendar year.

generation plant (for each of the five CONE Areas), which are used in RPM's Minimum Offer Price Rule.[11]

PJM supported its proposed CT and CC CONE values in the December 2011 Filing with detailed cost estimates prepared by independent consultants with expertise in providing such estimates and/or providing the engineering, procurement, construction, and/or operations and maintenance services that comprise such estimates, i.e., The Brattle Group, CH2M Hill, and The Wood Group, including a supporting affidavit by The Brattle Group's Dr. Samuel A. Newell ("Initial Newell Affidavit").

Numerous parties intervened and filed substantive comments on, or protests to, PJM's proposed tariff changes. As relevant to the issues addressed by this settlement, several parties filed protests claiming that PJM's filed Gross CONE values were too low.[12] Specifically, on December 22, 2011: GenOn filed its Comments and Limited Protest ("GenOn Protest"), along with a supporting Affidavit of Christopher D. Ungate of Sargent & Lundy L.L.C. ("Ungate Affidavit"); PSEG filed a Motion to Intervene, Comments, Protest, and Motion for Suspension and Evidentiary Hearing ("PSEG Protest"), along with a supporting Affidavit of Walter R. Krzastek of Cost Plus Consulting LLC ("Krzastek Affidavit"); LS Power filed a Motion to Intervene and Protest; AEP and Dayton jointly filed a Motion to Intervene and Comments; and P3 filed a Motion to Intervene, Comments and Limited Protest. Each of the above parties

11 *See* Tariff, Attachment DD, section 5.14(h).

12 By contrast, a group of state commission consumer advocate offices urged the Commission to accept PJM's filed updates to the Gross CONE. *See* the December 22, 2011 Protest and Comments of the Delaware Division of the Public Advocate, District of Columbia Office of People's Counsel, New Jersey Division of Rate Counsel, Maryland Office of People's Counsel, and Pennsylvania Office of Consumer Advocate.

identified a number of cost items or cost categories in PJM's CONE estimates that they contended were understated. In addition, GenOn and PSEG each presented their own alternative detailed estimates of CT and CC construction and operating costs, as explained and supported by the accompanying affidavits and exhibits of Mr. Ungate and Mr. Krzastek, respectively.

On January 13, 2012, PJM filed an Answer to Comments and Protests ("PJM Answer") which, as relevant here, argued that the Gross CONE values in PJM's December 2011 Filing were reasonable. PJM supported this aspect of its answer in part with an affidavit of Dr. Newell and The Brattle Group's Dr. Kathleen Spees ("Brattle Response Affidavit") responding to the claims by the above parties, including the affidavits of Mr. Ungate and Mr. Krzastek, that much higher CONE estimates are warranted. The Independent Market Monitor for PJM ("IMM") also filed an answer (on January 6, 2012) ("IMM Answer") that in part responded to GenOn's claim that the CONE values should be significantly higher than the levels in PJM's December 2011 Filing.

On January 20, 2012, GenOn filed a Motion for Leave to Answer and Answer ("GenOn Answer"), along with a further affidavit by Mr. Ungate ("Ungate Responsive Affidavit") and an affidavit of GenOn's Director, East Gas Supply, Mr. Gregory H. Thompson ("Thompson Affidavit"). On the same date, PSEG filed a Motion for Leave to Answer and Answer ("PSEG Answer"), along with a Supplemental Affidavit by Mr. Krzastek and an affidavit of PSEG's Director of Project Valuation, Mr. Steven J. Biskobing ("Biskobing Affidavit").

On January 30, 2012, the Commission issued an order accepting the December 2011 Filing in part, subject to suspension, refund and the outcome of a hearing and settlement judge procedures.[13] The January 30 Order accepted all answers submitted in the case, including the PJM Answer, GenOn Answer, PSEG Answer, and IMM Answer, and their associated affidavits and exhibits. The January 30 Order accepted most of PJM's proposed Tariff changes to be effective January 31, 2012. As to the proposed Gross CONE values, however, the January 30 Order found that the intervenors

> have raised a number of material issues of disputed fact as to the proper calculation of the Gross CONE values, [arguing], for example, that PJM has failed to include accurate electrical and gas interconnection costs, property tax estimates, location-specific adjustments, and costs for material, labor and equipment.[14]

The Commission therefore accepted and suspended PJM's proposed Gross CONE values for the five CONE Areas for five months, to become effective on June 30, 2012, subject to refund and the outcome of a hearing and settlement judge procedures. The January 30 Order also rejected PJM's proposal to establish a new method of determining the PJM Region-wide Net CONE value.

On rehearing of the January 30 Order, the Commission issued an order in Docket Nos. ER12-513-000 and -003 on April 11, 2012 setting the issue of the region-wide Gross CONE value for hearing and settlement judge procedures.[15]

As a result of the January 30 Order, the Gross CONE values that were in place before the December 2011 filing (for both combustion turbine and combined cycle plant types, for the five CONE Areas and for the PJM Region) remained in place for the Base

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13 *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062 (2012) ("January 30 Order").

14 January 30 Order at P 41.

15 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,031 (2012) ("April 11 Order").

Residual Auction[16] PJM conducted in May 2012 to secure capacity commitments for the 2015-2016 Delivery Year.[17] The new values that PJM proposed in the December 2011 Filing for use with the 2015-2016 Delivery Year were not employed in the Base Residual Auction for that Delivery Year.

Pursuant to the suspension required by the January 30 Order, the CONE Area values for the 2015-2016 Delivery Year that PJM proposed in the December 2011 Filing became effective in the Tariff on June 1, 2012 (after the May 2012 Base Residual Auction). PJM has not conducted any Incremental Auctions for the 2015-2016 Delivery Year since June 1, 2012; accordingly, the Gross CONE values from the December 2011 Filing have not yet been used in any RPM Auction.

On February 7, 2012, the Commission's Chief Judge appointed Judge John P. Dring to serve as settlement judge in the settlement phase of this proceeding. The parties convened for settlement discussions on February 15, April 18, April 19, May 22, June 20, August 2, September 4, and October 3, 2012. Those discussions yielded a settlement term sheet supported or not opposed by nearly all parties that took an active interest in the issues set for hearing in this case.

The parties supporting the settlement, with input from parties that declared they would not oppose the settlement, then prepared the enclosed Settlement Agreement.

16 The Base Residual Auction, held three years before the start of a Delivery Year, is the principal capacity auction PJM conducts for a Delivery Year. PJM also conducts three "Incremental Auctions" for each Delivery Year between the Base Residual Auction and the start of the Delivery Year. *See* Tariff Attachment DD, sections 2.5 and 2.34.

17 The stated values in the Tariff were adjusted for use in that auction to the extent required by the Tariff's prescribed index-adjustment methodology, known as the Handy-Whitman Index or "Applicable H-W Index" adjustment. *See* Tariff, Attachment DD, section 5.10(a)(iv)(B).

PJM, in coordination with the Settling Parties and with input from the unopposed parties, prepared this explanatory statement.[18] PJM further supports this settlement with the enclosed affidavit of Dr. Newell.

II. DETAILED DESCRIPTION AND EXPLANATION OF THE SETTLEMENT AGREEMENT

A. Gross CONE Values

1. Description of Settlement Provisions.

The Settlement Agreement provides at Section II.A that Sections 5.10(a) and 5.14(h) of the PJM Tariff shall be revised to state the following Gross CONE values (in $/MW-yr) for the combustion turbine Reference Resource for the 2015-16 Delivery Year for each indicated CONE Area:

CONE Area 1	140,000
CONE Area 2	130,600
CONE Area 3	127,500
CONE Area 4	134,500
CONE Area 5	114,500

Section II.B of the Settlement Agreement provides that Section 5.10(a) of the PJM Tariff shall be revised to state a value of $128,000/MW-yr for the Gross CONE value for the PJM Region for the 2015-16 Delivery Year.

Section II.C of the Settlement Agreement provides that Section 5.14(h) of the PJM Tariff shall be revised to state the following gross CONE values (in $/MW-yr) for the combined cycle asset class for the 2015-16 Delivery Year for each indicated CONE Area:

18 As noted above, while PJM coordinated preparation of this Explanatory Statement with the Settling Parties, any characterization herein of the Settlement Agreement or these proceedings is solely that of PJM and should not be attributed to any other party. In the event of any conflict between this Explanatory Statement and the Settlement Agreement, the provisions of the Settlement Agreement govern.

CONE Area 1	173,000
CONE Area 2	152,600
CONE Area 3	166,000
CONE Area 4	166,000
CONE Area 5	147,000

Section II.D of the Settlement Agreement states that the Settling Parties agreed upon the Gross CONE values specified in sections II.A through II.C of the Settlement Agreement, but that they did not attempt to reach agreement on any method for calculating the Gross CONE values.[19]

2. The Settlement Gross CONE Values Are Reasonable.

As indicated in the Settlement Agreement, the Settling Parties arrived at all of the Gross CONE values in the settlement—for both CT and CC plants, for each CONE Area, and for the PJM Region—on a "black-box" basis. They agreed simply on the values; there was no agreement on any assumptions, estimates, or methodologies to calculate those specific values.

Despite that, the Commission can find abundant support in the existing record of this case for the settlement values. The Commission has before it in this proceeding not only PJM's December 2011 Filing, along with the Initial Newell Affidavit and detailed estimates by Brattle, CH2M HILL, and the Wood Group (supplemented by the PJM Answer and the Brattle Responsive Affidavit), but also the GenOn Protest and Ungate Affidavit (supplemented by the GenOn Answer, Ungate Responsive Affidavit, and Thompson Affidavit) and the PSEG Protest and Krzastek Affidavit (supplemented by the

[19] Section II.E further provides that PJM or any other party may submit analyses, calculations, data, assumptions, estimates, information, or arguments to demonstrate that the Settlement Agreement's Gross CONE values are just and reasonable, but that no other party shall be deemed to have agreed with or accepted any such analyses, calculations, data, assumptions, estimates, information, or arguments submitted by any party.

PSEG Answer, Krzastek Supplemental Affidavit and Biskobing Affidavit), as well as the comments and protests on this issue by LS Power, AEP-Dayton, the IMM, and the Consumer Advocates.

In particular, the Commission already has in the record (from PJM, PSEG, and GenOn) three very detailed, alternative "bottom-up" estimates (showing distinct estimates for dozens of different cost components or line items) of the costs of adding new CT or CC capacity to the PJM Region, with hundreds of pages of supporting detail and explanation.

The CONE settlement values fall within the range of those detailed estimates. In fact, the settlement values are fairly close to the CONE estimates in PJM's December 2011 Filing, and both parties that presented detailed alternative estimates—GenOn and PSEG—either support or do not oppose the settlement, which includes these CONE values. This context is highly significant to the Commission's review of this settlement; it means that *one way* the Commission could arrive at the settlement values would be to credit (in whole or in part) a handful of cost adjustments from among the dozens proposed by PSEG and GenOn.

In his enclosed affidavit ("Newell Settlement Affidavit"), Dr. Newell reviews the existing record and provides more detail on how the previously filed estimates bracket the CONE values in this settlement. He then identifies (strictly as an illustrative matter) a few adjustments to line items in PJM's estimate, in the direction of the PSEG or GenOn estimates of those line items, that could produce the settlement values.[20]

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[20] To be clear, there are also other reasonable routes to calculating the settlement CONE values that would involve, for example, lower cost estimates for some line items than PJM included in the December 2011 Filing, offset by higher cost estimates for other line items. The illustrative adjustments described in this

Dr. Newell first compares the CT and CC CONE values in PJM's December 2011 Filing with the PSEG and GenOn estimates. As he notes, the CONE estimates in the PSEG Protest are 36 percent to 75 percent (depending on the CONE Area and whether for CC or CT) higher than the values in PJM's December 2011 Filing.[21] Dr. Newell explains that the GenOn Protest did not present a levelized CONE value, but its filed capital and operating cost estimates imply a CONE (assuming PJM and GenOn adopt a comparable relationship between capital costs, O&M expenses, and the levelized CONE) that exceeds the December 2011 Filing's CONE values by 46 to 89 percent.[22] By contrast, as Dr. Newell shows, the CT and CC CONE values in this settlement exceed the values in PJM's December 2011 Filing by only 2 to 6 percent.[23]

Dr. Newell then observes that PSEG, GenOn and the other protestors identified several cost categories that they claimed the December 2011 CONE Filing understated, including major equipment (or "owner-furnished equipment") costs; costs incurred by the engineering, procurement, and construction ("EPC") contractor for labor, materials, and balance-of-plant equipment; electrical interconnection costs, gas interconnection costs, project development costs; project financing costs; property taxes; and contingency costs.[24] Dr. Newell notes that GenOn and PSEG also pointed out that the costs of

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Explanatory Statement are only one fairly straightforward path to supporting the settlement values; other Settling Parties could readily identify alternative paths to the agreed values.

21 Newell Settlement Affidavit at 3.

22 *Id.* at 4, Table 1, note 3.

23 *Id.* at 3.

24 *Id.* at 4.

working capital and inventories were omitted from the estimates in the December 2011 Filing; and that PSEG claimed that costly foundational pilings could be needed.[25]

While PJM has argued that the alternative estimates presented by PSEG and GenOn do not demonstrate that the CONE values in the December 2011 Filing are unreasonable, that does not mean that every one of those parties' alternative estimates for all of the various cost categories and line items are themselves unreasonable. As Dr. Newell explains, "estimating the cost of a power plant is not an exact science. There may be reasonable differences in assumed plant configurations and cost drivers, and equally valid estimating techniques could produce a range of reasonable values."[26] Stated in terms more familiar to Commission jurisprudence, it is well-recognized that a just and reasonable rate need not be the only alternative, or even the single best alternative. Therefore, whether or not PSEG or GenOn demonstrated through their protests that PJM was *compelled* to accept their alternative estimates of the various CONE line items, a settlement rate that (implicitly) adopts a few of their alternative cost estimates on some items along with PJM's cost estimates on other items can be just and reasonable.

As a prime example of this principle, Dr. Newell explains that "one cost category where different expert analysts could reasonably differ is project contingency."[27] As he explains, "contingency costs reflect both changes in material prices and quantities that the EPC contractor might need (priced into the EPC contract), and also the expected cost of any changes to the design to accommodate particular site characteristics or permitting

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25 *Id.*

26 *Id.* at 5.

27 *Id.*

requirements."[28] Most importantly, Dr. Newell acknowledges that "[c]ontingency is typically difficult to quantify because it reflects the cost of the unknown."[29]

Specifically, Dr. Newell explains that the December 2011 Filing estimated approximately 5 percent contingency on EPC costs plus a 3 percent owner's contingency factor on all project costs, for a total of approximately 5 percent of total project capital cost. He notes that PSEG and LS Power, by contrast, both claimed that contingency costs should be approximately twice that percentage. He calculates that doubling the contingency cost estimate from the December 2011 Filing would increase CONE by 4.5 percent (for a CT plant) or 5.2 percent (for a CC plant).[30] Thus, adjusting PJM's originally filed values on this single issue of the appropriate contingency—a classic example of a cost line item on which expert estimators could reasonably disagree—could account for most of the 4 to 6 percent increase in the settlement CONE values above PJM's originally filed values.

Dr. Newell also notes that the protestors were correct that the December 2011 Filing largely omitted working capital and inventories (except for capital spares for major maintenance).[31] He calculates that adopting GenOn's filed estimate for such costs would add 1.8 to 2.0 percent to the Gross CONE values.[32]

Dr. Newell adds that another category that could reasonably increase is electrical interconnection costs. He explains that PJM based its estimate on historical experience in

28 *Id.* at 5-6.

29 *Id.* at 6.

30 *Id.*

31 *Id.* at 5.

32 *Id.*

PJM with electrical interconnection costs, but did not escalate those historic costs to 2015 dollars. He testifies that it would be appropriate to escalate those historic costs, since the CONE estimate is endeavoring to determine the cost to deliver a power plant in 2015. He calculates that escalating the costs to 2015 would add 1.5 to 1.7 percent to Gross CONE.[33]

More generally, Dr. Newell observes that there are many other cost categories (including, for example, owner-furnished equipment, owner's development costs, and foundation pilings) that contribute to GenOn and PSEG's filed CONE estimates being so much higher than the estimates in the December 2011 Filing — by 36 to 89 percent overall.[34] As he observes, were the Commission to accept even a small fraction of these claims, it would readily arrive at CONE values comparable to those in the Settlement Agreement.[35]

The Gross CONE value for the PJM Region in the Settlement Agreement also was negotiated on a "black box" basis. That Gross CONE is a stated value of $128,000/MW-yr (for the 2015-16 Delivery Year); there is no agreement on a methodology for determining the PJM Region Gross CONE.

This approach, and the agreed value, is just and reasonable. Prior to the December 2011 Filing, the PJM Region Gross CONE was a stated value in the Tariff. In the December 2011 Filing, PJM proposed to replace the stated value with a methodology

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33 *Id.*

34 *Id.* at 6-7.

35 *Id.* at 7.

for determining the PJM Region Net and Gross CONE. The January 30 Order rejected PJM's proposed approach.

While there is no agreement on a calculation method, PJM notes that if the method the Commission approved to determine the EAS Revenue Offset component of PJM Region Net CONE were applied to determine the Gross CONE component of Net CONE, it would produce roughly the same value as the settlement value.

The April 11 Order affirmed that the EAS Revenue Offset for the PJM Region is calculated as the average of the energy revenues that the Reference Resource would earn across all PJM Zone,[36] which in practice is a load-weighted average. As shown in the table below, the peak-load-weighted average of the Gross CONE values for the five CONE Areas in the Settlement Agreement is $129,285/MW-yr. The settlement region-wide Gross CONE value of $128,000/MW-yr is less than one percent below this value.[37]

CONE Area	2015/2016 Forecast Peak Load	Percentage of RTO Peak Load	Gross CONE	Contribution to Region-wide Gross CONE
1	33,282.0	0.203973818	140,000	$28,556
2	14,151.0	0.086726564	130,600	$11,326
3	81,720.0	0.500833497	127,500	$63,856
4	13,674.0	0.083803197	134,500	$11,272
5	20,341.0	0.124662924	114,500	$14,274
RTO Region	163,168.0	1		$129,285

36 April 11 Order at P 20, n. 14 and P 23.

37 For the 2015/2016 forecast peak loads, *see 2015/2015 RPM Base Residual Auction Planning Parameters*, updated May 23, 2012, available at http://wired.pjm.com/markets and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2015-2016-planning period-parameters.ashx

To be clear, the Settling Parties have *not* agreed to calculate the region-wide Gross CONE on any particular basis, including a load-weighted average basis, and PJM's discussion above is not offered to establish any precedent on this issue. To the extent the Commission seeks record support for this value, however, it could (in PJM's view) be supported as bringing consistency to the determination of the two components (i.e., Gross CONE and the EAS offset) of region-wide Net CONE.

B. Implementation and Effectiveness

The Settlement Agreement provides at Section II.E that Sections II.A through II.C of the Settlement Agreement shall be implemented through changes to the Tariff with a request for Commission approval by, and prospective effect from, January 20, 2013, including application in the May 2013 Base Residual Auction for the 2016-2017 Delivery Year. The Settlement Agreement further provides that Gross CONE values stated in the Settlement Agreement will establish the Benchmark CONE values for the 2015-2016 Delivery Year and will be subject to adjustment in accordance with the then effective Tariff provisions for use in capacity auctions for subsequent Delivery Years (including through use of the Applicable H-W Index under the current effective Tariff to establish the gross CONE values for use with the 2016-2017 and 2017-18 Delivery Years). The Settlement Agreement clarifies that PJM is not required by the settlement to reconduct the previously completed Base Residual Auction for the 2015-16 Delivery Year, but will apply the settlement Gross CONE values to any Incremental Auctions conducted for the 2015-16 Delivery Year after the settlement values become effective in the Tariff.

In short, this settlement establishes new CONE values for prospective effect only. Specifically, the 2015-16 CONE values stated in the Settlement Agreement will be applied in the three Incremental Auctions that are yet to be conducted for the 2015-16 Delivery Year, and the settlement values will be adjusted in accordance with the Tariff to determine the Gross CONE values to be used for subsequent Delivery Years, including the Base Residual Auction for the 2016-17 Delivery Year in May 2013.

Section II.E also provides that the specific Tariff changes to implement these provisions of the Settlement Agreement are shown in redline form in an attachment to the Settlement Agreement. The Settlement Agreement states that these *pro forma* Tariff changes are not being submitted through the Commission's eTariff system, but will be incorporated in the current effective Tariff through an appropriate filing by PJM following Commission approval of the Settlement Agreement. PJM therefore asks that the Commission, in its order on this settlement, direct PJM in a compliance filing to file the changes shown in the pro forma attachments as eTariff changes to PJM's Tariff, effective January 20, 2013.

C. Stakeholder Process on Triennial Review Changes

The Settlement Agreement provides at Section II.F that PJM shall conduct a stakeholder process to identify any desired changes in the CONE triennial review process in light of lessons learned from the most recent triennial review process, including an assessment of the current effective Tariff's Handy-Whitman Index adjustment method for Gross CONE, with a PJM filing of any resulting tariff changes with FERC in sufficient time to govern the 2014 triennial review, or the filing of a status report at such time if there is no stakeholder consensus on such changes.

III. REQUIRED INFORMATION

In accordance with the Chief Administrative Law Judge's October 15, 2003 Notice to the Public, the Settling Parties provide the following information:

A. Issues Underlying the Settlement and Major Implications

The issue underlying the Settlement Agreement is the determination of just and reasonable Gross CONE values for the PJM Region and CONE Areas, for both CT and CC plants. The Settling Parties agree that the Settlement Agreement resolves all issues in this proceeding..

B. Policy Implications

The issues settled in this proceeding do not require the Commission to examine or change any existing policy or procedure.

C. Other Pending Cases

The Settlement Agreement does not affect any other pending proceeding.

D. Issues of First Impression or Reversals on Issues

The Settlement Agreement does not involve issues of first impression, nor are there any previous reversals on the issues involved.

E. Applicable Standard of Review

The standard of review of the Settlement Agreement is the just and reasonable standard.

IV. CONCLUSION

For the foregoing reasons, the Settlement Agreement is just and reasonable, and the Settling Parties respectfully request that the Commission accept it.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER12-513-000

**AFFIDAVIT OF DR. SAMUEL A. NEWELL
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

My name is Dr. Samuel A. Newell, and I am a Principal of The Brattle Group ("Brattle"). I am submitting this affidavit in support of the Settlement Agreement and Offer of Settlement ("Settlement Agreement") that is being concurrently submitted today by PJM Interconnection, L.L.C. ("PJM") and numerous other parties to this proceeding ("Settling Parties"). Specifically, my affidavit supports the proposed values in the Settlement Agreement for the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM"). My affidavit is submitted on behalf of PJM, and the views I express herein should not necessarily be associated with any other Settling Party.

In my position with Brattle, I support clients throughout the United States in regulatory, litigation, and business strategy matters involving wholesale electricity market design, generation asset valuation, transmission development, demand response programs, integrated resource planning, and contract disputes. I have written expert reports for regional transmission organizations ("RTOs") and provided testimony before state regulatory commissions and this Commission. Prior to joining Brattle, I was Director of the Transmission Service at Cambridge Energy Research Associates. Before that, I was a Manager in the Utilities Practice at A.T.Kearney. I earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and an A.B. in Chemistry and Physics from Harvard University. A complete list of my qualifications, publications, reports, and prior experience is set forth in Attachment A to my affidavit.

In March of 2011, PJM retained Brattle to assist PJM in a review of RPM and certain of its components, including the type of generator to use for the estimated CONE, an appropriate configuration and technology for that generator, and its levelized capital and fixed operations and maintenance ("O&M") costs, expressed in $/MW-Year or $/MW-Day. The results of Brattle's analysis are set forth in a report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM" ("2011 CONE Study"), which was prepared under my direction and supervision.[1]

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1 Brattle prepared the 2011 CONE Study in cooperation with CH2M HILL, a major engineering, procurement, and construction company with extensive experience in

On December 1, 2011, PJM filed adjustments to the CONE parameters ("December 2011 Filing") for use beginning with the RPM auctions for the RPM "Delivery Year" (a 12-month period beginning on June 1) from June 1, 2015 to May 31, 2016. PJM's CONE adjustments were based on the results of the 2011 CONE Study. The December 2011 Filing included an affidavit from me in which I presented and affirmed the results of the 2011 CONE Study.

In December, 2011, several parties filed protests claiming that PJM's filed CONE values (from Brattle's 2011 CONE Study) were too low.[2] GenOn[3], PSEG[4], and LS Power Associates, L.P. ("LS Power") each identified a number of cost categories that they believed were understated. In addition, GenOn and PSEG each presented their own estimates and evidence supporting their estimates. In January, 2012, my colleague Dr. Kathleen Spees and I filed an additional affidavit responding to claims made by the protesters.[5] GenOn and PSEG in turn filed counter-responses and presented additional evidence supporting their estimates.[6]

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the design and construction of power plants, and Wood Group, a power plant operations and maintenance ("O&M") services provider.

2 On December 22, 2011, GenOn filed its Comments and Limited Protest ("GenOn Protest"), along with a supporting Affidavit of Christopher D. Ungate of Sargent & Lundy L.L.C. ("Ungate Affidavit"); on the same date, PSEG filed its Comments and Limited Protest ("PSEG Protest"), along with a supporting Affidavit of Walter R. Krzastek ("Krzastek Affidavit") and a supporting Affidavit of Robert H. Uniszkiewicz ("Uniszkiewicz Affidavit").

3 GenOn refers to GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

4 PSEG refers to Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

5 Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of PJM Interconnection, L.L.C., dated January 13, 2012 ("Brattle Response Affidavit").

6 On January 20, 2012, GenOn filed a Motion for Leave to Answer and Answer ("GenOn Answer"), along with a further affidavit by Mr. Ungate ("Ungate Responsive Affidavit") and an affidavit of GenOn's Director, East Gas Supply, Mr. Gregory H. Thompson ("Thompson Affidavit"). On the same date, PSEG filed a Motion for Leave to Answer and Answer ("PSEG Answer"), along with a Supplemental Affidavit by Mr. Krzastek and an affidavit of PSEG's Director of Project Valuation, Mr. Steven J. Biskobing ("Biskobing Affidavit").

On January 30, 2012, the Commission set the Gross CONE values for hearing, stating that, "intervenors have raised a number of material issues of disputed fact as to the proper calculation of the Gross CONE values... These issues, along with related cost disputes detailed above, cannot be resolved based on the submitted record and we will therefore accept and suspend the Gross CONE values for five months, subject to the outcome of a hearing."[7] The Commission also encouraged settlement discussions, which Administrative Law Judge John Dring facilitated. That settlement process resulted in the Settlement Agreement that PJM and the other Settling Parties are filing now.

The purpose of this affidavit is to present my opinion that the CONE values in the Settlement Agreement reflect a reasonable estimate of the levelized cost of new plant. As demonstrated below, the Settlement Offer is between PJM's original filed value and the protesters' filed values, but much closer to PJM's filed value. Given this, it would take relatively few adjustments to PJM's previously filed CONE values to result in values comparable to those in the Settlement Agreement. Below, I review the differences between the alternative CONE estimates previously filed in this case; identify, for illustrative purposes, several reasonable adjustments to PJM's original filed value that would result in CONE values comparable to those in the Settlement Agreement; and note that other modest changes to other cost components in the direction of the estimates propounded by PSEG or GenOn also could result in CONE values comparable to those in the Settlement Agreement.

I. Comparison of Filed CONE Values and PJM's Settlement Offer

Table 1 compares PJM's filed CONE (from the 2011 CONE Study) to the protestors' filed CONE estimates and to the Settlement Agreement values. As indicated, the protestors' estimates exceeded PJM's filed value by large margins. PSEG's filed estimate was 36 percent to 46 percent higher, depending on location and technology. GenOn's filing did not present a levelized CONE value, but its filed cost estimates imply a CONE that exceeds PJM's by 66 to 89 percent. By contrast, the Settlement Agreement CONE values exceed PJM's previously filed values by only 2 to 6 percent.

As can be seen in Table 1, the comparison includes both the combustion turbine and combined cycle plant configurations at issue in this proceeding, and all five CONE Areas defined in the PJM Tariff. On the latter point, while PSEG provided estimates only for CONE Area 1, and GenOn provided estimates only for CONE Areas 1 and 2, most of their adjustments, if accepted by the Commission, would require comparable increases in the CONE values for the other CONE Areas.[8]

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7 *See* PJM Interconnection, L.L.C., Docket No. ER12-513-000, 138 FERC ¶ 61,062 (January 30, 2012) at P 41.

8 For example, GenOn's assumed higher cost of gas turbines and other major equipment would apply to every other CONE Area.

Table 1
Settlement Proposed CONE and Filed CONE Comparison

	PJM	PSEG		GenOn		Settlement Terms	
	As Filed on Dec. 1, 2011	As Filed on Jan. 19, 2012	% Increase From PJM Original	Implied from Installed Cost and FOM	% Increase From PJM Original	Settlement Agreement	% Increase From PJM Original
	($/kW-yr)	*($/kW-yr)*	*(%)*	*($/kW-yr)*	*(%)*	*($/kW-yr)*	*(%)*
	[1]	[2]	[2]/[1]-1	[3]	[3]/[1]-1	[4]	[4]/[1]-1
CT							
EMAAC	$134.0	$196.0	46%	$252.9	89%	$140.0	4%
SWMAAC	$123.7	n.a.	n.a.	$207.3	68%	$130.6	6%
RTO	$123.5	n.a.	n.a.	n.a.	n.a.	$127.5	3%
WMAAC	$130.1	n.a.	n.a.	n.a.	n.a.	$134.5	3%
DOM	$111.0	n.a.	n.a.	n.a.	n.a.	$114.5	3%
CC							
EMAAC	$168.2	$229.0	36%	$294.6	75%	$173.0	3%
SWMAAC	$147.6	n.a.	n.a.	$244.5	66%	$152.0	3%
RTO	$162.2	n.a.	n.a.	n.a.	n.a.	$166.0	2%
WMAAC	$161.8	n.a.	n.a.	n.a.	n.a.	$166.0	3%
DOM	$143.8	n.a.	n.a.	n.a.	n.a.	$147.0	2%

Sources and Notes:

[1] Newell Affidavit filed on Dec. 1, 2011.

[2] Biskobing Affidavit filed on Jan. 19, 2012. Evidence presented only for CONE Area 1.

[3] GenOn estimated project capital costs and annual fixed operating and maintenance ("FOM") costs but did not provide a levelized CONE value. Brattle calculated the implied CONE shown in this table based on GenOn's cost estimates and the following formula: CONE = Capital Charge Rate x Installed Cost + FOM, where the Capital Charge Rate is the levelization factor implied by the CONE values in the December 2011 Filing and their underlying installed cost and FOM. GenOn's installed cost and FOM are from Ungate Affidavit filed Dec. 22, 2011.

II. Sources of Differences in Filed CONE Values

In their filings, the protestors identified several cost categories that they claimed the 2011 CONE Study understated. Cost categories that at least one of the protestors claimed were underestimated include: major equipment (or "owner-furnished equipment") costs; costs incurred by the engineering, procurement, and construction ("EPC") contractor for labor, materials, and balance-of-plant equipment; electrical interconnection costs; gas interconnection costs; project development costs; project financing costs; property taxes; and contingency costs. Protestors also noted that the costs of working capital and inventories were omitted, and PSEG claimed that costly foundational pilings would be needed at some project sites in New Jersey.

PSEG's and GenOn's protests also included their own cost estimates. GenOn presented estimates for each category of costs compared to those in the 2011 CONE Study. The response that Dr. Spees and I submitted in January 2012 similarly provided and commented on a line-by-line comparison to both GenOn's and PSEG's estimates. Our response affidavit clarified that the apparent difference in financing cost was attributable to unclear reporting in the 2011 CONE Study, and that the financing costs actually included in PJM's filed CONE were close to theirs. Otherwise, our affidavit disputed much of the protestors' evidence and reaffirmed our belief that our original estimate was in the "range of reasonableness" and that the protestors' estimates were not.[9]

However, the fact that we disputed the protestors' evidence does not mean that none of their claims have any merit. Estimating the cost of a power plant is not an exact science. There may be reasonable differences in assumed plant configurations and cost drivers, and equally valid estimating techniques could produce a range of reasonable values. Given how close the Settlement Agreement CONE values are to the December 2011 Filing values, it would take very few adjustments to arrive at the settlement values. Below, I identify, solely for illustration purposes, a few reasonable adjustments that would be sufficient to produce CONE values comparable to those in the Settlement Agreement.

III. Adjustments that Could Result in the Settlement Agreement CONE Values

First, I note that the protestors were correct that the 2011 CONE Study largely omitted the costs of working capital and inventories (except for capital spares for major maintenance). GenOn argued that including the costs of working capital and inventories would raise the cost of building a CT by \$6.7 million in EMAAC and by \$5.8 million in SWMAAC.[10] For a CC, GenOn estimated \$15 million in EMAAC and \$12 million in SWMAAC.[11] Adopting these estimates and applying the level-nominal levelization method used in the 2011 CONE Study would increase CONE by approximately \$2.4/kW-year (1.8%) for the CT, and \$3.3/kW-year (2.0%) for the CC.

Second, another cost category that could reasonably increase is electrical interconnection costs. Although our methodology, which was based on the historical interconnection costs of actual projects, was appropriate for all of the reasons stated on our January affidavit, we did not escalate historical interconnection costs to 2015 dollars. Such escalation would be appropriate since the goal of the study is to identify the cost to deliver new capacity in 2015. The 2011 CONE Study reported electric interconnection costs of \$11 million for a CT and \$15.5 million for a CC. Appropriately escalating historical interconnection costs to 2015 dollars increases capital costs by approximately \$6 million for the CT and \$10 million for the CC, raising CT CONE by \$2.3/kW-year (1.7%) and CC CONE by \$2.5/kW-year (1.5%).

Third, I note that one cost category where different expert analysts could reasonably differ is project contingency. Contingency costs reflect both changes in material prices and quantities that the EPC contractor might need (priced into the EPC contract), and also the expected cost of any changes to the design to accommodate particular site characteristics or permitting requirements. Contingency is typically

9 Brattle Response Affidavit at P 5.

10 Ungate Affidavit at P 10.

11 Ungate Affidavit, Exhibit C.

difficult to quantify because it reflects the cost of the unknown. The 2011 CONE Study estimated approximately 5 percent contingency on EPC costs (approximately $6.6 million for a CT and $18 million for a CC) plus a 3 percent owner's contingency factor on all project costs (another $9 million for the CT and $18 million for the CC), for a total of approximately 5 percent of total project capital cost. However, PSEG and LS Power both claimed that contingency costs should be approximately twice that percentage.[12] Doubling the contingency costs from the 2011 CONE Study would add $6/kW-year (4.5%) to CT CONE and $8.7/kW-year (5.2%) to CC CONE, or some fraction thereof if the protestors' claims are only partially accepted.

Thus, accepting some or all of just these three adjustments, which would properly apply to every CONE Area, and to both the CT and CC plant configurations, would be sufficient to produce CONE values comparable to those in the Settlement Agreement, which are 2 to 6 percent higher than the CONE values in the December 2011 Filing.

There are many other cost categories that contribute to GenOn and PSEG's filed CONE estimates being so much higher than the estimates in our 2011 CONE Study — by 36 to 89 percent overall, as shown in Table 1. In addition to the three items discussed above, examples of other cost categories that GenOn or PSEG claimed were understated in the 2011 CONE Study include:

- **Owner-Furnished Equipment (OFE).** Owner-Furnished Equipment includes two combustion turbines and, in the case of the CC, a steam turbine and heat recovery steam generator (HRSG). GenOn estimated OFE costs of $129 million for a CT and $213 million for a CC, compared to $115 million and $176 million, respectively, in the 2011 CONE Study.[13] Accepting GenOn's higher OFE costs would increase the CT CONE by $5.4/kW-yr (4.0%) and CC CONE by $9.0/kW-yr (5.4%).

- **Owner's Development Costs.** For owner's development costs, including market studies, interconnection studies, environmental studies, staff time for project development, permitting fees, legal fees, water and sewer interconnection, project management, and financial advisory fees, GenOn estimated $30 million for a CT and $67 million for a CC.[14] This is much higher than the $6 million and $8 million owner's development cost estimates in the 2011 CONE Study. Adopting GenOn's development cost

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12 Brattle Response Affidavit, Table 6.

13 GenOn estimated $57 million per turbine, compared to $47 million in the 2011 CONE Study. GenOn estimated $27 million for the HRSG, compared to $21 million in the 2011 CONE Study. GenOn estimated $46 million for the steam turbine, compared to $42 million in the 2011 CONE Study. See Ungate Affidavit P 19 and Exhibits B and C.

14 See Ungate Affidavit, Exhibits B and C.

estimates would increase CT CONE by $9.2/kW-yr (6.9%) and CC CONE by $14.4/kW-yr (8.5%).

- **Pilings**. PSEG suggested that construction in New Jersey would require foundational pilings at a cost of $12 million for a CT and $19 million for a CC.[15] Adding PSEG's estimated cost of pilings would increase CT CONE by another $4.4/kW-yr (3.3%) and CC CONE by $4.6/kW-yr (2.8%).

- There were also many other cost components, but they were more difficult to compare on an apples-to-apples basis to the 2011 CONE Study based on the filed evidence, so they are not quantified here.

Were the Commission to accept even a small fraction of these claims, it would readily arrive at CONE values comparable to those in the Settlement Agreement.

IV. Conclusion

Considering the comparisons and adjustments described above, I believe the CONE values in the Settlement Agreement are very much in the reasonable range of the levelized cost of new CT and CC plants in PJM.

This concludes my affidavit.

15 See PSEG Protest, page 23, and December 22 Krzastek Affidavit, Exhibit 4.

	)	Commonwealth of Massachusetts
SS:	)	
	)	County of Middlesex

AFFIDAVIT OF DR. SAMUEL A. NEWELL

Dr. Samuel A. Newell, being first duly sworn, deposes and states that he has read the foregoing "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/
Dr. Samuel A. Newell

Subscribed and sworn to before me this 21st day of November, 2012.

/s/
Debra A. Paolo, Notary Public

My Commission expires: September 30, 2016

DEBRA A. PAOLO
Notary Public
Commonwealth of
Massachusetts
Commission Expires Sep 30, 2016

NOTARY
PUBLIC

Resume of

Samuel A. Newell

SAMUEL A. NEWELL — Principal

Office: Cambridge, MA ♦ Phone: +1.617.234.5725 ♦ Email: Sam.Newell@brattle.com

Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC.

Prior to joining *The Brattle Group,* Dr. Newell was Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.Kearney.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- *Electricity Wholesale Market Design*
- *Transmission Planning and Modeling*
- *Integrated Resource Planning*
- *Evaluation of Demand Response (DR)*
- *Valuation of Generation Assets*
- *Energy Contract Litigation*
- *Analysis of Market Power*
- *RTO Participation and Configuration*
- *Tariff and Rate Design*
- *Business Strategy*

EXPERIENCE

Electricity Wholesale Market Design

- *Evaluation of Investment Incentives and Resource Adequacy in ERCOT.* For the Electric Reliability Council of Texas (ERCOT), led a team that (1) characterized the factors influencing generation investment decisions; (2) evaluated the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluated options to enhance long-term resource adequacy while maintaining market efficiency. Conducted the study by performing forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Findings and recommendations became a launching point for a PUCT Proceeding, in which I presented at several workshops.

- *Review of PJM Capacity Market.* Conducted second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry, based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters.

- *Midwest ISO Capacity Market Enhancements.* Supported the Midwest ISO in developing market design elements for its recently-filed annual locational capacity auctions.

- *Evaluation of the Midwest ISO's Resource Adequacy Construct and Market Design Elements.* For the Midwest ISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with Midwest ISO in its work with the Supply Adequacy Working Group on design improvements.

- *Evaluation of Midwest ISO's Demand Response Integration.* For the Midwest ISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of the Midwest ISO's recent "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.

- *Evaluation of Tie-Benefits.* For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.

- *ISO Evaluation of Major Initiatives.* With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in

ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.

- *Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.* With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.

- *Evaluation of Reliability Pricing Model (RPM) Results and Design Elements.* For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.

- *Evaluation of a Potential Forward Capacity Market.* For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.

- *RTO Accommodation of Demand Response (DR) for Resource Adequacy.* For the Midwest ISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the Midwest ISO footprint.

- *Integration of DR into ISO-NE's Energy Markets.* For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the current economic DR programs when they expire in 2010.

- *Integration of DR into Midwest ISO's Energy Markets.* For the Midwest ISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels. Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).

- *LMP Impacts on Contracts.* For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.

- *RTO Accommodation of Retail Access.* For the Midwest ISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access programs in the three restructured states within the Midwest ISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Transmission Planning and Modeling

- *Benefits of New 765kV Transmission Line.* Analyzed renewable integration and congestion relief benefit of proposed $1.2 billion transmission line in western PJM.
- *Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind.* Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.
- *Analysis of Transmission Congestion and Benefits.* Analyzed the impacts on transmission congestion, California benefits, and Arizona utility impacts of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in 2013 and 2020 considering the recent changes in economic and fuel market conditions, and increased renewable generation requirements throughout the Western Electricity Coordination Council region.
- *Benefit-Cost Analysis of New Transmission.* For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.
- *Benefit-Cost Analysis of New Transmission in the Midwest.* For the American Transmission Company (ATC), supported *Brattle* witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.

- *Transmission Investments and Congestion.* Worked with executives and board of an independent transmission company to develop a "metric" indicating access and congestion-related benefits provided by its transmission investments and operations.

- *Analysis of Transmission Constraints and Solutions.* For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- *Merchant Transmission Impacts.* For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.

- *Security-Constrained Unit Commitment and Dispatch Model Calibration.* For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in the Midwest ISO's first allocation of FTRs.

- *Model Evaluation.* Led an internal *Brattle* effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (*e.g.*, LMP, losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

Integrated Resource Planning (IRP)

- *IRP in Connecticut (for 2008).* For the two major utilities in Connecticut, co-led a comprehensive 10-year evaluation of alternative resource strategies. Strategies were analyzed in the context of the ISO-NE energy and capacity markets across several scenarios spanning a range of plausible futures for uncontrollable external factors such as fuel prices, climate change legislation, economic growth, and generation capital costs. All cases were analyzed using the DAYZER locational market simulation model that contains a detailed representation of the ISO-NE transmission system and mimics the ISO-NE energy market. Metrics that were examined to inform policy recommendations included total resource costs, customer costs, natural gas consumption and emissions. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *IRP in Connecticut (for 2009).* For the two major utilities in Connecticut, co-led a second annual IRP, this time focused on ten topics: resource adequacy, demand-side management, renewables, transmission, nuclear generation, combined heat and power, environmental regulation/legislation, resource development financing, emerging technologies, and energy security. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *IRP in Connecticut (for 2010).* For the two major utilities in Connecticut, co-led a third annual IRP, with a major overhaul of the energy, capacity, and renewables (REC) market modeling; an evaluation of alternative resource strategies across multiple scenarios; and an update of the ten policy/technology topics analyzed for the 2009 IRP. Solicited input from numerous stakeholders. Provided oral testimony before the Connecticut Department of Public Utility Control.

- *IRP in Connecticut (for 2012).* For the two major utilities in Connecticut and The Connecticut Department of Energy and Environmental Protection (DEEP), helped lead a fourth IRP. Focused particularly on all-cost-effective energy efficiency, resource adequacy, renewables, environmental regulations, natural gas, transmission planning, emerging technologies, and a macroeconomic/jobs evaluation of potential resource strategies.

- *Analysis of Potential Retirements to Inform Transmission Planning.* For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.

- *Resource Planning in Wisconsin.* For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- *DR Potential Study.* For an ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.

- *Evaluation of DR Compensation Options.* For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted with its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000.

- *Wholesale Market Impacts of Price Responsive Demand (PRD).* For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.

- *Energy Market Impacts of DR.* For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.

- *Present Value of DR Investments.* For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the *Brattle*-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Valuation of Generation Assets and Contracts

- *Valuation Methodology for a Coal Plant Transaction in PJM.* For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to assess the market value of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.

- *Valuation of a Coal Plant in PJM.* For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.

- *Valuation of a Coal Plant in New England.* For a utility, evaluated a coal plant's economic viability based on projected market revenues, operating costs, and capital investments likely needed to comply with future environmental mandates.

- *Valuation of Generation Assets in New England.* For several potential buyers of various assets in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to inform considerations of risk.

- *Valuation of Generation Asset Bundle in New England.* For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.

- *Valuation of Generation Asset Bundle in PJM.* For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.

- *Wind Power Development.* For a developer proposing to build a several hundred megawatt wind farm in Michigan provided a market-based revenue forecast for energy and capacity. Identified gas and CO_2 allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.

- *Wind Power Financial Modeling.* For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.

- *Contract Review for Cogeneration Plant.* For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.

- *Generation Strategy/Valuation.* For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.

- *Generation Asset Valuation.* For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Contract Litigation

- *Contract Damages.* For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- *Contract Damages.* For the same client and contract described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.

- *Contract Termination Payment.* For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Analysis of Market Power

- *Vertical Market Power.* Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.

- *Market Monitoring and Market Power Mitigation.* For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

RTO Participation and Configuration

- *Market Impacts of RTO Seams.* For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the Midwest ISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with the Midwest ISO to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.

- *Analysis of RTO Seams.* For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.

- *RTO Participation.* For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Tariff and Rate Design

- *Transmission Tariffs.* For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.

- *Retail Rate Riders.* For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.

- *Rate Filings.* For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- *Evaluation of Cogeneration Venture.* For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.

- *Strategic Sourcing.* For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.

- *M&A Advisory.* For a European utility aiming to enter the U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).

- *Marketing Strategy.* For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.

- *Distributed Generation (DG) Market Assessment.* For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.

- *Fuel Cells.* For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY AND REGULATORY FILINGS

Before the Texas Legislature Committee on State Affairs, presented oral testimony: "The Resource Adequacy Challenge in ERCOT," October 24, 2012.

Before the Texas Public Utility Commission, filed comments and presented at a workshop in Project 40480 *Commission Proceeding Regarding Policy Options on Resource Adequacy*, October 25, 2012.

Before the Texas Public Utility Commission, filed comments and presented at workshop in Project 40480 *Commission Proceeding Regarding Policy Options on Resource Adequacy*, September 6, 2012.

Before the Texas Public Utility Commission, filed comments and presented at workshop in Project 40000 *Commission Proceeding to Ensure Resource Adequacy in Texas*, July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, *SIG Energy, LLLP v. California Independent System Operator Corporation*, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at *The Brattle Group*, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of *The Brattle Group*, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22-25, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, D. Murphy, and J. Wharton, January 2, 2008. *Supplemental Report* co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

REPORTS, ARTICLES, AND PRESENTATIONS

"Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

"ERCOT Investment Incentives and Resource Adequacy," report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).

"Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with Jurgen Weiss).

"Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" *Public Utilities Fortnightly*, December 2011 (with J. Pfeifenberger).

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15," report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

"Fostering economic demand response in the Midwest ISO," *Energy* 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).

"DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" *Public Utilities Fortnightly*, November 2010.

"Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," report prepared for Midwest ISO, January 2010 (with K. Spees and A. Hajos).

"Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," report prepared for Midwest ISO, January 2010 (with A. Hajos).

"Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

"Fostering Economic Demand Response in the Midwest ISO," whitepaper written for the Midwest ISO, December 30, 2008 (with R. Earle and A. Faruqui).

"Review of PJM's Reliability Pricing Model (RPM)," report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," *Energy*, Vol. 1, 2008, *The Brattle Group* (with M. Chupka and D. Murphy).

"Enhancing Midwest ISO's Market Rules to Advance Demand Response," report written for the Midwest Independent System Operator, March 12, 2008 (with R. Earle).

Before the PJM Board of Directors and senior level representatives at PJM's General Session, Panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"The Power of Five Percent," *The Electricity Journal*, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

"Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes and others).

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, May 3, 2007 (with J. Pfeifenberger, presenter).

"Valuing Demand-Response Benefits in Eastern PJM," *Public Utilities Fortnightly*, March 2007 (with J. Pfeifenberger and F. Felder).

"Quantifying Demand Response Benefits in PJM," study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," *Energy*, Vol 2, 2006, *The Brattle Group* (with J. Pfeifenberger).

"Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Effect of Cross Sound Cable," *CERA Alert*, October 24, 2003 (with H. Stauffer and G. Mukherjee).

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

November 21, 2012

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket Nos. ER12-513-000 and -003

SETTLEMENT AGREEMENT
AND OFFER OF SETTLEMENT

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, this Settlement Agreement and Offer of Settlement ("Settlement Agreement") is submitted by the following parties in this proceeding: American Electric Power Service Corporation ("AEP")[1], Dominion Resources Services, Inc.[2], Edison Mission Energy, Exelon Corporation, FirstEnergy Service Company, GenOn[3], LS Power Associates, L.P. ("LS Power"), North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, PJM Industrial Customer Coalition, PJM Interconnection, L.L.C. ("PJM"), and PJM Power Providers ("P3") (collectively "Settling Parties"). The Settling Parties are authorized to state that Calpine Corporation, Dayton Power and Light Company ("Dayton"), Dynegy Power Marketing, LLC, Illinois Municipal Electric Agency, Public Power Association of New Jersey, the New Jersey Board of Public Utilities, NextEra

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1 American Electric Power Service Corporation intervened in this proceeding on behalf of certain operating companies of the AEP system, i.e., Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

2 Dominion Resources Services, Inc. intervened in this proceeding on behalf of its public utility affiliates Virginia Electric and Power Company and Dominion Energy Marketing, Inc.

Energy Generators, NRG,[4] PHI, PPL,[5] PSEG,[6] Rockland Electric Company, and Southern Maryland Electric Cooperative do not oppose resolution of this proceeding upon the terms set forth in this Settlement Agreement.

This Settlement Agreement, if approved by the Commission, will resolve all issues set for hearing in Docket Nos. ER12-513-000 and -003.

I. BACKGROUND

On December 1, 2011, as a result of a triennial review of key elements of the PJM capacity market (known as the Reliability Pricing Model or "RPM"), PJM filed in Docket No. ER12-513-000 ("December 2011 Filing") under section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, amendments to its Open Access Transmission Tariff ("Tariff") to (among other changes) revise the capacity market demand curve (known as the Variable Resource Requirement Curve or "VRR Curve") and two inputs to that curve: the Gross Cost of New Entry ("CONE") and the Net Energy and Ancillary Services ("EAS") Revenue offset, which together determine the Net CONE used in the VRR Curve.

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3 GenOn refers to GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

4 NRG refers to NRG Power Marketing LLC, Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Energy Center Paxton LLC, NRG Rockford LLC, NRG Rockford II LLC, and Vienna Power LLC.

5 PPL refers to PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Brunner Island, LLC, PPL Holtwood, LLC, PPL Martins Creek, LLC, PPL Montour, LLC, PPL Susquehanna, LLC, Lower Mount Bethel Energy, LLC, PPL New Jersey Solar, LLC, PPL New Jersey Biogas, LLC, and PPL Renewable Energy, LLC

6 PSEG refers to Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

Gross CONE is an estimate of the total project capital cost and annual fixed operations and maintenance expenses of a new generating plant of a type likely to provide incremental capacity to the PJM Region (which the Tariff refers to as the "Reference Resource" and defines as a combustion turbine power plant[7]) in the forward delivery year addressed by the RPM auctions. The PJM Tariff states a Gross CONE value for the PJM Region as a whole, and for each of five subsets of the PJM Region identified in the PJM Tariff as "CONE Areas."[8] In the December 2011 Filing, PJM proposed to replace the Gross CONE values for the five CONE Areas with new values based on estimates of the costs of delivering a new plant for the 2015-2016 Delivery Year,[9] and to establish a new methodology to determine the region-wide Net CONE.

As relevant to this settlement, PJM also proposed in the December 2011 Filing to modify the Gross CONE estimates for a representative combined cycle generation plant (for each of the five CONE Areas), which are used in RPM's Minimum Offer Price Rule.[10]

On January 30, 2012, the Commission issued an order accepting the December 2011 Filing in part, subject to suspension, refund and the outcome of a hearing and settlement judge procedures.[11] The Commission accepted most of PJM's proposed changes to be effective January 31, 2012. The January 30 Order found, however, that

7 *See* Tariff, Attachment DD, section 2.58.

8 *See* Tariff, Attachment DD, section 5.10(a).

9 A Delivery Year is a twelve-month period beginning on June 1 of a calendar year and ending on May 31 of the following calendar year.

10 *See* Tariff, Attachment DD, section 5.14(h).

11 *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062 (2012) ("January 30 Order").

PJM's proposed Gross CONE updates raised material issues of disputed fact as to the proper calculation of those values and that such issues could not be resolved on the submitted record. The Commission therefore accepted and suspended PJM's proposed Gross CONE values for the five CONE Areas for five months, to become effective on June 30, 2012, subject to refund and the outcome of a hearing and settlement judge procedures. The January 30 Order also rejected PJM's proposal to establish a new method of determining the PJM Region-wide Net CONE value.

On rehearing of the January 30 Order, the Commission issued an order in Docket Nos. ER12-513-000 and -003 on April 11, 2012 setting the issue of the region-wide Gross CONE value for hearing and settlement judge procedures.[12]

As a result of the January 30 Order, the CONE values that were in place before the December 2011 filing (for both combustion turbine and combined cycle plant types, for the five CONE Areas and for the PJM Region) remained in place for the Base Residual Auction[13] PJM conducted in May 2012 to secure capacity commitments for the 2015-2016 Delivery Year.[14] The new values that PJM proposed in the December 2011

12 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,031 (2012) ("April 11 Order").

13 A Base Residual Auction is an auction that PJM conducts three years before a Delivery Year to secure capacity commitments for that Delivery Year. PJM subsequently conducts three scheduled Incremental Auctions for each Delivery Year to allow for increases in, decreases to, or adjustments to, the capacity commitments secured in earlier auctions. *See* Tariff Attachment DD, sections 2.5 and 2.34.

14 The stated values in the Tariff were adjusted for use in that auction to the extent required by the Tariff's prescribed index-adjustment methodology, known as the Handy-Whitman Index or "Applicable H-W Index" adjustment. *See* Tariff, Attachment DD, section 5.10(a)(iv)(B).

Filing for use with the 2015-2016 Delivery Year were not employed in the Base Residual Auction for that Delivery Year.

Pursuant to the suspension required by the January 30 Order, the CONE Area values for the 2015-2016 Delivery Year that PJM proposed in the December 2011 Filing became effective in the Tariff on June 1, 2012. Since that time, PJM has not conducted any further capacity auctions for the 2015-2016 Delivery Year; accordingly, those values have not yet been used in any RPM Auction.

On February 7, 2012, the Commission's Chief Judge appointed Judge John P. Dring to serve as settlement judge in the settlement phase of this proceeding. The parties convened for settlement discussions on February 15, April 18, April 19, May 22, June 20, August 2, September 4, and October 3, 2012. Those discussions yielded a settlement term sheet supported or not opposed by nearly all the parties that took an active interest in the issues set for hearing in this case.

II. SETTLEMENT AGREEMENT

A. Combustion Turbine Gross CONE Values

Sections 5.10(a) and 5.14(h) of the PJM Tariff shall be revised to state the following Gross CONE values (in $/MW-yr) for the combustion turbine Reference Resource for the 2015-16 Delivery Year:

CONE Area 1	140,000
CONE Area 2	130,600
CONE Area 3	127,500
CONE Area 4	134,500
CONE Area 5	114,500

B. Region-Wide Gross CONE Value

Section 5.10(a) of the PJM Tariff shall be revised to state a value of $128,000/MW-yr for the region-wide Gross CONE value for the 2015-16 Delivery Year.

C. Combined Cycle Gross CONE Values

Section 5.14(h) of the PJM Tariff shall be revised to state the following Gross CONE values (in $/MW-yr) for the combined cycle asset class for the 2015-16 Delivery Year:

CONE Area 1	173,000
CONE Area 2	152,600
CONE Area 3	166,000
CONE Area 4	166,000
CONE Area 5	147,000

D. No Agreement on Calculation Methodology

The Settling Parties have agreed upon the Gross CONE values specified in sections II.A through II.C, but have not attempted to reach agreement on any method for calculating the Gross CONE values. The Settling Parties acknowledge that PJM or any other party may submit analyses, calculations, data, assumptions, estimates, information, or arguments in connection with this Settlement Agreement to demonstrate that the foregoing Gross CONE values are just and reasonable. No other party shall be deemed to have agreed with or accepted any such analyses, calculations, data, assumptions, estimates, information, or arguments submitted by any party.

E. Implementation and Effectiveness

Sections II.A through II.C above shall be implemented through changes to the Tariff with a request for Commission approval by, and prospective effect from, January 20, 2013, including application in the May 2013 Base Residual Auction for the 2016-2017 Delivery Year. The above-stated Gross CONE values will establish the Benchmark CONE values for the 2015-2016 Delivery Year and will be subject to adjustment in accordance with the then effective Tariff provisions for use in capacity auctions for subsequent Delivery Years (including through use of the Applicable H-W Index under the current effective Tariff to establish the Gross CONE values for use with the 2016-2017 and 2017-18 Delivery Years). This settlement shall not require PJM to reconduct the previously completed Base Residual Auction for the 2015-16 Delivery Year; however, the settlement Gross CONE values shall be used in Incremental Auctions for the 2015-16 Delivery Year conducted after the effective date of the Tariff revisions to incorporate the settlement Gross CONE values.

The specific Tariff changes to implement these provisions of the Settlement Agreement are shown in redline form in Attachment A to this Settlement Agreement. These *pro forma* Tariff changes are not being submitted through the Commission's eTariff system, but will be incorporated in the current effective Tariff through an appropriate compliance filing by PJM following Commission approval of the Settlement Agreement.

F. Stakeholder Process on Triennial Review Changes

PJM shall conduct a stakeholder process to identify any desired changes in the CONE triennial review process in light of lessons learned from the most recent triennial review process, including (but not limited to) an assessment of the current effective Tariff's Handy-Whitman Index adjustment method for Gross CONE, with a PJM filing of any resulting tariff changes with FERC in sufficient time to govern the 2014 triennial review, or the filing of a status report at such time if there is no stakeholder consensus on such changes.

III. FILING RIGHTS

Nothing contained in this Settlement Agreement shall be construed as affecting in any way PJM's right unilaterally to make application to the FERC for a change in rates, terms and conditions under section 205 of the Federal Power Act and pursuant to the

Commission's Rules and Regulations promulgated thereunder. Nothing contained in the Settlement Agreement shall be construed as restricting any rights of the other parties under the Federal Power Act, including rights under section 206, 16 U.S.C. § 824e.

IV. MISCELLANEOUS PROVISIONS

Amendments to the PJM Tariff. The Tariff amendments submitted with this Settlement Agreement implement the terms and conditions of this Settlement Agreement and are incorporated as part of this Settlement Agreement.

Capitalized Terms. Capitalized terms used in this Settlement Agreement that are not otherwise defined in this Settlement Agreement shall have the meanings provided for such terms in the Tariff.

Just and Reasonable Standard. The Commission's review of any proposed modifications to this Settlement Agreement shall be based on the just and reasonable standard and not the public interest standard.

No Admissions or Precedent. This entire Settlement Agreement, and the Settling Parties' performance of their obligations hereunder, are the result of the settlement and compromise of all the claims and actions expressly addressed in this Settlement Agreement, and neither the Settlement Agreement nor the Settling Parties' performance hereunder shall be deemed to be an admission of any fact or of any liability. This Settlement Agreement shall be binding on the Settling Parties only with respect to the subject matter of this Settlement Agreement, and shall not bind the Settling Parties to apply the principles or provisions of this Settlement Agreement to any other agreement, arrangement, or proceeding. The Settlement Agreement establishes no principles and no precedent with respect to any issue in this proceeding. The acceptance of this Settlement

Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegation or contention made in this proceeding.

Entire Agreement. This Settlement Agreement, including any attachments, constitutes the entire agreement between and among the Settling Parties, and no other agreement with regard to the matters addressed in this Settlement Agreement shall be binding on the Settling Parties except by written amendment to this Settlement Agreement. Except for the terms and conditions enumerated in this Settlement Agreement and any attachment hereto, the Settling Parties acknowledge and agree that the Settling Parties have not made any other promises, warranties, or representations to each other or any other Settling Party regarding any aspect of the settlement of the matters addressed in this Settlement Agreement. Each Settling Party acknowledges that it has read this Settlement Agreement and executed it without relying upon any other promise, warranty, or representation, written or otherwise, of any other Settling Party. Each Settling Party acknowledges that no other Settling Party has made any promise, warranty, or representation, express or implied, to induce the Settling Parties to execute this Settlement Agreement.

Settlement Discussions. The discussions between the Settling Parties that have produced this Settlement Agreement have been conducted on the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all settlement communications and discussions shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant making such communications or participating in any such discussions, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

Further Assurances. Following execution of this Settlement Agreement, the Settling Parties shall prepare and execute any further pleadings, documents, or amendments to existing or future PJM agreements reasonably necessary to effectuate the Settling Parties' intent under this Settlement Agreement.

Successors and Assigns. This Settlement Agreement is binding upon and for the benefit of the Settling Parties and their successors and assigns.

Authorizations. Each person executing this Settlement Agreement represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to sign for, the Settling Party for whom he or she has signed.

Counterparts. This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement Agreement to be duly executed.

Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003

/s/ Amanda Riggs Conner
Amanda Riggs Conner
Senior Counsel

On behalf of
American Electric Power Service Corporation

**Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003**

/s/ Michael C. Regulinski
Michael C. Regulinski
Assistant General Counsel

On behalf of
Dominion Resources Services, Inc.

**Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003**

/s/ Reem J. Fahey
Reem J. Fahey
Vice President, Market Policy & Market Operations

On behalf of
Edison Mission Energy

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Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003

/s/ Divesh Gupta
Divesh Gupta
Assistant General Counsel

On behalf of
Exelon Corporation,

**Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003**

<u>/s/ Tyler Brown</u>
Tyler Brown
Latham & Watkins

On behalf of
FirstEnergy Service Company,

Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003

<u>/s/ Robert J. Gaudette</u>
Robert J. Gaudette
Senior Vice President and Chief Commercial Officer
GenOn Energy, Inc.

On behalf of
GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

**Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003**

/s/ Robert Colozza
Robert Colozza
Senior Vice President, Development

On behalf of
LS Power Associates, L.P.,

Signature Page for Settlement Agreement and Offer of Settlement
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in Docket Nos. ER12-513-000 and ER12-513-003

<u>/s/ Michael W. Burnette</u>
Michael W. Burnette
Senior Vice President, Power Supply and
Chief Operating Officer, NCEMC

On behalf of
North Carolina Electric Membership Corporation

Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003

<u>/s/ Glen L Ortman</u>
Glen L. Ortman
Adrienne E. Clair
Stinson Morrison Hecker LLP

On behalf of
Old Dominion Electric Cooperative

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<u>/s/ Robert A. Weishaar, Jr</u>
Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC
Counsel to the PJM Industrial Customer Coalition

On behalf of
PJM Industrial Customer Coalition

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<u>/s/ Paul M. Flynn</u>
Paul M. Flynn
Wright & Talisman, P.C.

On behalf of
PJM Interconnection, L.L.C.

**Signature Page for Settlement Agreement and Offer of Settlement
Filed November 21, 2012
in Docket Nos. ER12-513-000 and ER12-513-003**

<u>/s/ Laura Chappelle</u>
Laura Chappelle
Chappelle Consulting, LLC

On behalf of
PJM Power Providers Group

Attachment A

Pro Forma Revisions to the PJM Open Access Transmission Tariff
Attachment DD Sections 5.10 & 5.14

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus

3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the

Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, ~~2012~~2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000~~112,868~~ per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	140,000 ~~134,000~~
BGE, PEPCO ("CONE Area 2")	130,600~~123,700~~
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK ("CONE Area 3")	127,500~~123,500~~
PPL, MetEd, Penelec ("CONE Area 4")	134,500~~130,100~~
Dominion ("CONE Area 5")	114,500~~111,000~~

B) Beginning with the ~~2013~~2016 ~~2014~~ 2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however, that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-16 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June

1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the sum of the following: (1) the marginal value of system capacity for the PJM Region, without considering locational constraints, (2) the Locational Price Adder, if any in such LDA, (3) the Annual Resource Price Adder, if any, and (4) the Extended Summer Resource Price Adder, if any, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd); and

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section

5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such

Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall, through May 31, 2012, calculate and post the Final Zonal Capacity Price after all ILR resources are certified for the Delivery Years and, thereafter, shall calculate and post such price after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction. For such purpose, for the three consecutive Delivery Years ending May 31, 2012 only, the Forecast ILR allocated to loads located

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

in the AEP transmission zone that are served under the Reliability Pricing Model shall be in proportion for each such year to the load ratio share of such RPM loads compared to the total peak loads of such zone for such year; and any remaining ILR Forecast that otherwise would be allocated to such loads shall be allocated to all Zones in the PJM Region pro rata based on their Preliminary Zonal Peak Load Forecasts.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Planned Generation Capacity Resources

(1) For purposes of this section, the Net Asset Class Costs of New Entry shall be asset-class estimates of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. The gross Cost of New Entry component of Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, ~~2014~~2015, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT") and a combined cycle generator ("CC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	140,000~~134,000~~	130,600~~123,700~~	127,500~~123,500~~	134,500~~130,100~~	114,500~~111,000~~
CC $/MW-yr	173,000~~168,200~~	152,600~~147,600~~	166,000~~162,200~~	166,000~~161,800~~	147,000~~143,800~~

(2) Beginning with the Delivery Year that begins on June 1, ~~2015~~2016, the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue

estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on

(i) a Generation Capacity Resource located in the PJM Region that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year; or

(ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.

(5) A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection *or the Commission,* prior to the

RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets . The following process and requirements shall apply to requests for such determinations:

(i) The Capacity Market Seller may request such a determination *by* no later than *one hundred twenty (120)* days prior to the *commencement of the offer period for the RPM A*uction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a *written* request with *all of the required* documentation as described below and in the PJM Manuals. *For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of* the minimum offer level *expected to be established under* subsection (4). *I*f the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

(ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the *public.* Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. *Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.*

(iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.

(iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection *by* no later than *ninety (90)* days *prior to the commencement of the offer period for such auction.* The Office of the Interconnection *shall also* review *all exception requests and documentation and shall provide in writing to the Capacity Market Seller and the Market Monitoring Unit its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction.*

i) Capacity Export Charges and Credits

Pro Forma Revisions to the PJM Open Access Transmission Tariff Attachment DD

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This Transition Provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this Transition Provision. A Demand Resource cleared for a Transition Delivery Year is not viable for purposes of this Transition Provision to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

$$DRTC = (IAP - BRP) * DRMW$$

Where:

DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

IAP = the Capacity Resource Clearing Price paid by the Qualified DR

Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this Transition Provision, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

c. an aggregate amount that exceeds:

(i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

(ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

(iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this Transition Provision shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this Transition Provision, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

PROPOSED ORDER

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

_________, 2013

Attention: Paul M. Flynn
Wright & Talisman, P.C.

Re: PJM Interconnection, L.L.C.,
Docket Nos. ER12-513-000, -003
Settlement Agreement and Offer of Settlement filed November 21, 2012

Sir:

On November 21, 2012, PJM Interconnection, L.L.C. ("PJM") filed with the Commission, on behalf of itself and American Electric Power Service Corporation, Dominion Resources Services, Inc., Edison Mission Energy, Exelon Corporation, FirstEnergy Service Company, GenOn[1], LS Power Associates, L.P., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, PJM Industrial Customer Coalition, and PJM Power Providers Group a Settlement Agreement and Offer of Settlement ("Settlement Agreement") which resolves all issues that were set for hearing in Docket Nos. ER12-513-000 and ER12-513-003. The Commission finds that the Settlement Agreement is fair and reasonable and serves the public interest. Accordingly, the Settlement Agreement is accepted and approved as to all of its terms without modification or condition.

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1 GenOn refers to GenOn Energy Management, LLC, GenOn Mid-Atlantic, LLC, GenOn Chalk Point, LLC, GenOn Power Midwest, LP, and GenOn REMA, LLC.

Although the Settlement Agreement is controlling, its principal feature is that the PJM Open Access Transmission Tariff ("Tariff") shall be revised to reflect certain values for the Gross Cost of New Entry ("CONE") (as that term is defined in the Tariff) that were negotiated and accepted by the Settling Parties. The Settling Parties ask that the Commission approve the identified Tariff changes with an effective date of January 20, 2013. Accordingly, PJM is hereby directed to submit through the Commission's eTariff system revisions to its Tariff, with an effective date of January 20, 2013, conforming to the pro forma Tariff revisions shown in Attachment A to the Settlement Agreement.

The Settlement Agreement also requires PJM to conduct a stakeholder process to identify any desired changes in the CONE triennial review process in light of lessons learned from the most recent triennial review process, with a PJM filing of any resulting tariff changes with the Commission in sufficient time to govern the 2014 triennial review, or the filing of a status report at such time if there is no stakeholder consensus on such changes

The Commission's approval of the Settlement Agreement does not constitute approval of or precedent regarding any principle or issue in this proceeding.

The Secretary is hereby directed to cause this letter order to be published in the FERC Reports.

By Direction of the Commission.

Secretary

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 21st day of November, 2012.

/s/ Paul M. Flynn
Paul M. Flynn

Attorney for
PJM Interconnection, L.L.C.

REBUTTAL EXHIBIT GAS-2

REBUTTAL EXHIBIT GAS-2

Comparison of Brattle Group CONE
CT Cost Estimate to DEC CT Cost Estimate

Adjustments	Brattle Estimate	DEC Estimate
Base w/AFUDC	$xxx/kw	$xxx/kw
Adjust from $2015 to $2013	$xxx/kw	n/a
Adjust Unit Rating from 196 MW to 201 MW	$xxx/kw	n/a
Adjust for Economies of Scale from 2-Unit to 4-Unit Site (10% savings per B&M Study)	$xxx/kw	$xxx/kw

Comparison of Brattle Group CONE
CT Cost Estimate to DEP CT Cost Estimate

Adjustments	Brattle Estimate	DEP Estimate
Base w/AFUDC	$xxx/kw	$xxx/kw
Adjust from $2015 to $2013	$xxx/kw	n/a
Adjust Unit Rating from 196 MW to 213 MW	$xxx/kw	n/a
Adjust for Economies of Scale from 2-Unit to 4-Unit Site (10% savings per B&M Study)	$xxx/kw	$xxx/kw

REBUTTAL EXHIBIT GAS-3

SC Prices

Model	ISO Base Load	Heat Rate Btu/kWh	Efficiency	Budget Plant Price	$ per kW
LM6000PG	51,204 kW	8142 Btu	41.9%	$18,219,800	$356
Trent 60 DLE	51,685 kW	8138 Btu	41.9%	$18,296,500	$354
LM6000PG	53,500 kW	8582 Btu	39.8%	$17,961,700	$336
Trent 60 DLE ISI	58,000 kW	8001 Btu	42.6%	$19,546,000	$337
Trent 60 WLE	61,210 kW	8328 Btu	41.0%	$19,832,000	$324
Trent 60 WLE ISI	64,000 kW	8209 Btu	41.6%	$21,056,000	$329
AE64.3A	75,000 kW	9505 Btu	35.9%	$22,671,400	$302
6FA	77,577 kW	9574 Btu	35.6%	$23,196,500	$299
7EA	88,718 kW	10,192 Btu	33.5%	$25,151,800	$284
LMS100PB	99,400 kW	7695 Btu	44.3%	$36,436,100	$367
LMS100PA	103,500 kW	7815 Btu	43.7%	$36,016,600	$348
SGT6-2000E	112,000 kW	10,066 Btu	33.9%	$33,222,300	$297
M501DA	113,950 kW	9780 Btu	34.9%	$33,943,900	$298
GT11N2	115,400 kW	10,065 Btu	33.9%	$33,636,000	$291
9E	128,183 kW	9980 Btu	34.2%	$36,559,200	$285
M701DA	144,090 kW	9810 Btu	34.8%	$40,271,100	$279
V94.2	157,000 kW	9920 Btu	34.4%	$42,945,200	$274
SGT5-2000E	166,000 kW	9834 Btu	34.7%	$44,892,000	$270
AE94.2K	170,000 kW	9348 Btu	36.5%	$46,412,100	$273
GT13E2	184,500 kW	9027 Btu	37.8%	$49,960,600	$271
7FA	184,906 kW	8953 Btu	38.1%	$47,755,800	$258
M501F3	185,400 kW	9230 Btu	37.0%	$47,334,800	$255
SGT6-5000F	208,000 kW	8953 Btu	38.1%	$52,267,300	$251
7FA	215,769 kW	8830 Btu	38.6%	$54,098,000	$251
GT24	230,700 kW	8531 Btu	40.0%	$57,572,000	$250
9FA	261,284 kW	9146 Btu	37.3%	$61,999,000	$237
M501GAC	272,000 kW	8600 Btu	39.7%	$65,273,000	$240
SGT6-8000H	274,000 kW	8530 Btu	40.0%	$67,728,500	$247
SGT5-4000F	289,000 kW	8652 Btu	39.4%	$70,449,700	$244
GT26 (2006)	296,400 kW	8617 Btu	39.6%	$71,853,100	$242
9FB	298,174 kW	8855 Btu	38.5%	$71,611,200	$240
GT26 (2011)	320,000 kW	8530 Btu	40.0%	$76,616,000	$239
M501J	327,000 kW	8325 Btu	41.0%	$78,471,400	$240
M701G2	334,000 kW	8630 Btu	39.5%	$78,880,400	$236
9FB	339,366 kW	8526 Btu	40.0%	$82,498,000	$243
M701F5	359,000 kW	8530 Btu	40.0%	$83,268,000	$232
SGT5-8000H	375,000 kW	8530 Btu	40.0%	$89,300,600	$238
M701J	470,000 kW	8325 Btu	41.0%	$103,669,000	$221

Gas Turbine Model	ISO Base Load	Heat Rate Btu/kWh	Efficiency	Budget Plant Price	$ per kW
M501DA	113,950 kW	9780 Btu	34.9%	$32,530,000	$286
GT11N2	115,400 kW	10,065 Btu	33.9%	$32,200,000	$279
9E 3-series	128,183 kW	9980 Btu	34.2%	$35,050,000	$273
M701DA	144,090 kW	9810 Btu	34.8%	$38,590,000	$268
V94.2	157,000 kW	9920 Btu	34.4%	$41,170,000	$262
SGT5-2000E	166,000 kW	9834 Btu	34.7%	$43,070,000	$259
AE94.2K	170,000 kW	9348 Btu	36.5%	$44,430,000	$261
7F 3-series	184,906 kW	8953 Btu	38.1%	$45,740,000	$247
M501F3	185,400 kW	9230 Btu	37.0%	$45,350,000	$245
GT13E2	202,700 kW	8980 Btu	38.0%	$52,590,000	$259
SGT6-5000F	232,000 kW	8953 Btu	38.1%	$44,930,000	$216
7F 5-series	215,769 kW	8830 Btu	38.6%	$51,770,000	$240
GT24	230,700 kW	8531 Btu	40.0%	$55,140,000	$239
SGT6-5000F	232,000 kW	8794 Btu	38.8%	$49,420,000	$213
9F 3-series	261,284 kW	9146 Btu	37.3%	$59,290,000	$227
SGT6-8000H	274,000 kW	8530 Btu	40.0%	$64,980,000	$237
M501GAC	276,000 kW	8574 Btu	39.8%	$63,400,000	$230
SGT5-4000F	292,000 kW	8567 Btu	39.8%	$68,160,000	$233
9F 5-series	298,174 kW	8855 Btu	38.5%	$68,490,000	$230
GT26	326,000 kW	8467 Btu	40.3%	$74,890,000	$230
M501J	327,000 kW	8325 Btu	41.0%	$75,120,000	$230
M701G2	334,000 kW	8630 Btu	39.5%	$75,480,000	$226
9F 7-series	339,386 kW	8526 Btu	40.0%	$78,900,000	$233
M701F5	359,000 kW	8530 Btu	40.0%	$79,790,000	$222
SGT5-8000H	375,000 kW	8530 Btu	40.0%	$85,440,000	$228
M701J	470,000 kW	8325 Btu	41.0%	$99,220,000	$211

CONF. REBUTTAL EXHIBIT GAS-4

CONFIDENTIAL

NCUC Public Staff
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DUKE ENERGY PROGRESS

Request:

4. Please provide detailed support for the capital cost per kW in 2011 dollars for the generic CT shown in Appendix D in the Company's 2012 Generation Reserve Margin Study. This response should include the following cost components on a cost per kW basis:

(a) Plant equipment and installation,
(b) Engineering and project management,
(c) Administrative and general expenses,
(d) Spare parts,
(e) Taxes,
(f) AFUDC,
(g) Property acquisition,
(h) Gas pipeline and interconnection,
(i) Electric transmission connection,
(j) Contingency factor,
(k) Transmission upgrades, and
(l) Total project cost.

Response:

Below is the cost data and format that is available for the 1st unit and Next unit CT data used in the Reserve Margin study. This data is based on an earlier B&M study with costs updated by internal project estimators.

(2011$)	1st Unit	Next Unit
Construction ($/kW)		
Construction		
Start-up and Testing		
Land		
Total Overnight Cost ($/kW)		

In addition, a [redacted] transmission upgrade cost was included in the Reserve Margin Study that reflects the average expected transmission upgrade cost for a 4 unit site.

Strategist calculates AFUDC and taxes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 136

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012	))))	REBUTTAL TESTIMONY OF KENDAL C. BOWMAN ON BEHALF OF DUKE ENERGY CAROLINAS, INC., AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kendal Crowder Bowman. My address is 410 South Wilmington Street, Raleigh, NC 27601

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President Regulatory Affairs and Policy North Carolina for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively the "Utilities") which are wholly owned subsidiaries of Duke Energy Corporation

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Utilities.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to address issues raised by other parties pertaining to the avoided cost rates for solar and wind Qualifying Facilities ("QFs") and the Utilities' standard QF contracts. Specifically, I will address the recommendation of Public Staff witness Kennie D. Ellis that DEP adopt an avoided rate schedule that is more similar to DEC's Option B avoided rate schedule (Schedule PP). I will also address arguments made by North Carolina Sustainable Energy Association ("NCSEA") witness Karl R. Rabago and Renewable Energy Group ("REG") witness Don C. Reading that the Performance Adjustment Factor ("PAF") for the avoided capacity rates paid to wind and solar QFs should be increased from 1.2 to 2.0. Finally, I will address the positions asserted by REG witness John E.P. Morrison pertaining to: 1) the purpose of the public Utility Regulatory Policy Act of 1978 ("PURPA") and related state policies, and 2) certain terms in DEC's and DEP's standard QF contracts.

Q. PLEASE SUMMARIZE THE CONCLUSIONS THAT YOU MAKE IN YOUR TESTIMONY IN THIS PROCEEDING.

A. With regard to Public Staff witness Ellis' recommendation, DEP's avoided cost rate schedule is already consistent with DEC's Option B and it does not need to be made more similar. Specifically, DEP's avoided cost rate schedule and its non-residential time of use ("TOU") rate schedules use the same definition of on-peak hours as DEP's current time-of-use rate schedules, just as DEC's Option B and its non-residential TOU rate schedule share a common definition of on-peak hours.

As to the various arguments presented to increase the PAF for solar and wind QFs, the Utilities continue to believe that such an increase in the PAF violates the underlying principles of PURPA and would unfairly provide a windfall for solar and wind QFs at the expense of the Utilities' customers. Furthermore, with regard to NCSEA witness Rabogo's discussion of "value of solar" ("VOS") studies, the Utilities maintain that 1) such studies are not an appropriate means of establishing avoided costs, 2) that witness Rabago's generic discussion of VOS studies is not probative of any relevant issue in this proceeding, and 3) witness Rabago's general statements regarding VOS studies do not justify his recommendation that avoided capacity rates for solar QFs be increase by 67%.

As to REG witnesses Morrison's testimony, the Utilities believe he misinterprets PURPA by understating the importance of ensuring that utility customers are not disadvantaged by paying more than the utility's avoided costs. With regard to witness Morrison's comments regarding the Reduction-in-Energy Charge in DEP's standard terms and conditions, this provision is a fair and reasonable mechanism for protecting DEP and its customers from overpaying QFs under a levelized rate power purchase agreement ("PPA"). As to Section 2 of DEC's standard terms and conditions, DEC has already committed to revise that section to address the issue raised by witness Morrison.

Q. ARE YOU INTRODUCTING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Not at this time.

I. RESPONSE TO PUBLIC STAFF WITNESS ELLIS' RECOMMENDATION THAT DEP REVISE ITS AVOIDED COST RATE SCHEDULE TO MAKE IT MORE SIMILAR TO DEC'S OPTION B

Q. PLEASE DESCRIBE DEC'S AVOIDED COST RATE OPTION B.

A. DEC currently has two different avoided cost rate schedules, commonly referred to as Option A and Option B. DEC's Option A and Option B have different rate structures but are based on the same avoided cost calculations. The primary difference between Option A and Option B is their respective definitions of on-peak hours. Option A applies a broader definition of on-peak hours that includes 4,160 hours. Option B applies a narrower definition of on-peak hours, which encompasses only 1,860 hours. As a result of this difference, the avoided capacity rates under Option B are higher than the avoided capacity rates under Option A because DEC's avoided capacity costs are being recovered over fewer hours under the Option B rate. Thus, a QF electing DEC's Option B has to run fewer hours to maximize the amount of avoided capacity payments its receives. Conversely, failing to run during a peak hour has a greater adverse impact on a QF under Option B than it does under Option A.

Q. HOW DOES DEP'S AVOIDED COST RATE (SCHEDULE CSP) COMPARE TO DEC'S OPTION B?

A. Unlike DEC, DEP only has a single avoided cost rate structure. Conceptually, DEP's current avoided cost rate schedule is equivalent to DEC's Option B. Like DEC's Option B, DEP's avoided cost rates uses a definition of on-peak hours that is based on the on-peak hours reflected in DEP's non-residential TOU rate schedules (Schedules LGS-TOU and SGS-TOU). Thus, DEP's avoided cost rates and DEC's Option B both use a TOU-based definition of on-peak hours to focus avoided capacity rate payments on the times when the need for capacity is highest. This is the best measure of when power purchased from a QF provides meaningful capacity value.

Although DEP's avoided cost rates and DEC's Option B share a common conceptual basis, they are not identical. The definition of on-peak hours applied in DEP's non-residential TOU rate schedule and its avoided cost rate schedule is more expansive than the on-peak hours definition reflected in DEC's non-residential TOU rates and in DEC's Option B. Accordingly, DEP's avoided rate schedule (and its non-residential TOU rates) uses a definition of on-peak hours that encompasses 3,132 hours, as opposed to the 1,860 on-peak hours reflected in DEC's Option B (and DEC's non-residential TOU rate schedules).

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS ELLIS' RECOMMENDATION THAT DEP ADOPT DEC'S OPTION B?

A. Given that DEP's avoided cost rates are conceptually comparable to DEC's Option B, it is unnecessary for DEP to amend its avoided cost rate schedule as proposed by Public Staff witness Ellis. Although DEP's avoided cost rate schedule uses a broader definition of on-peak hours than DEC's Option B, both of these rate schedules apply on-peak hour definitions based on each respective Utility's TOU rates.

DEP is also currently assessing the design of its TOU rates. In its most recent rate case, DEP committed to review its TOU rates and propose new TOU schedules within two years.[1] After this assessment is complete, DEP intends to continue its practice of using a consistent definition on-peak hours for its TOU rates and its avoided cost rates. It is possible, although not certain, that such assessment will result in DEP proposing changes to its TOU rates, including a redefinition of on-peak hours that is more similar to the definition reflected in DEC's Option B. In any event, these assessments should be completed before any premature changes are made.

As a practical matter, DEP would find it difficult to immediately adopt a significant change in the definition of on-peak hours before the assessment of DEP's TOU rates is completed. This is due to the need for a change in the

[1] See Section 5.B.3 of the *Agreement and Stipulation of Settlement*, as filed on February 28, 2013, in Docket No. E-2, Sub 1023, DEP's 2013 general rate case proceeding. DEP agreed in this provision of the Stipulation to complete a study of its TOU hours for all customer classes within two years from the date of the Commission's General Rate Case Order or by the date that DEP files its next general rate case, whichever comes first.

metering for small QFs to accommodate such a change. Consequently, it would be problematic for DEP to implement Public Staff witness Ellis' recommendation before it is made moot by DEP's reassessment of its TOU rates.

II. <u>THE PAF FOR SOLAR AND WIND QFS SHOULD NOT BE INCREASED FROM 1.2 TO 2.0</u>

Q. WHAT IS YOUR UNDERSTANDING OF THE PAF AND HOW IT WORKS?

A. The PAF is simply a multiplier applied to avoided cost capacity rates to increase the rates paid to QFs. For example, if the PAF is 1.2, then the avoided capacity rates would be the rate approved by the Commission based on the utility's actual avoided cost of capacity multiplied by 1.2. Thus, a PAF of 1.2 increases avoided capacity rates by 20%. Currently, the PAF is 2.0 for the avoided capacity rates paid small hydroelectric QFs and 1.2 for all other QFs.

Initially, the Commission established a PAF of 1.2 for all QFs because QFs, like all types of generation are not capable of running 100% of the time. A PAF of 1.2 allowed a QF to receive a full amount of capacity payments even if it only operates during 83% of on-peak hours. In other words, a 2 MW QF would receive capacity payments equivalent to 2 MW of avoided capacity costs even if it fails to run during 17% of the utility's peak period. In 1997, the Commission increased the PAF solely for small run-of-the-river hydroelectric QFs to 2.0. In so doing, the Commission noted that there was a specific State policy in favor of encouraging the continued operation of such facilities. Given the significant increase in applications for QF licenses, there is no policy justification for artificially high payments, which increase the costs to consumers and are inconsistent with PURPA guidelines.

Q. WHAT IS YOUR UNDERSTANDING OF RECOMMENDATIONS THAT ARE BEING MADE IN THIS PROCEEDING RELATED TO THE PAF?

A. REG witness Reading recommends that the PAF for solar and wind QFs should be increased to 2.0. NCSEA witness Rabago also recommends a PAF of 2.0 for solar QFs, but does not address the PAF for wind QFs.

Q. DO THE UTILITIES SUPPORT INCREASING THE PAF FOR SOLAR AND WIND QFS TO 2.0?

A. No. The Commission should reject the proposed increase in the PAF for solar and wind QFs, which would effectively increase avoided capacity rates paid to such QFs by 67%. As previously explained by the Utilities in this proceeding, there are many reasons for this position:

1. Increasing the capacity rates to certain QFs to compensate for their inability to operate reliably and consistently during peak periods is illogical and violates the avoided cost principles of PURPA;

2. Providing such an enormous additional subsidy to solar and wind QFs under the guise of "avoided costs" is inconsistent with Senate Bill 3, in

which the General Assembly established a specific framework for encouraging the development of such solar and wind generation, including limits on the costs that consumers must pay to achieve that goal;

3. This additional subsidy is not needed to encourage the development of solar and wind QFs given the tremendous influx of proposed solar and wind projects that has occurred over the past year; and

4 Increasing the PAF for solar and wind QFs would impose an unnecessary and unjustified economic burden of millions of dollars on the Utilities' customers.

Q. HOW DO YOU RESPOND TO REG WITNESS READING'S ARGUMENTS THAT THE PAF FOR SOLAR AND WIND QFS SHOULD BE INCREASED TO 2.0?

A. REG witness Reading's arguments are merely a summary repetition of the arguments made by REG and NCSEA in their comments filed previously in this proceeding. Those arguments are fully addressed and rebutted in the Utilities' Joint Reply Comments and direct testimony that the Utilities have submitted in this docket.[2]

[2] *See* Utilities Joint Reply Comments at pp. 33-40; Bowman Direct Testimony at pp. 16-21; and Snider Direct Testimony at pp. 44-55.

Q. HOW DO YOU RESPOND TO NCSEA WITNESS RABAGO'S ARGUMENTS THAT THE PAF FOR SOLAR QFS SHOULD BE INCREASED TO 2.0?

A. NCSEA witness Rabago bases his recommendation on the theory that a VOS study would show that solar generation provides more "value" than is reflected in traditional avoided cost calculations. Witness Rabago suggests that the Commission should require the Utilities to pay solar QFs more than their avoided costs and that a convenient way to do that is to increase the avoided capacity payments to solar QFs by 67% by increasing the PAF for solar QFs to 2.0. There are numerous flaws in witness Rabago's arguments and conclusions. First and foremost, the VOS studies that he describes are inappropriate for setting avoided cost rates and are irrelevant to the present proceeding.

As described by witness Rabago, a VOS study attempts to measure the value of solar generation by quantifying a wide range of alleged, indirect benefits of such generation. These benefits go far beyond the cost of energy and capacity that solar generation displaces. Witness Rabago states that a VOS study would capture and quantify such alleged benefits as: 1) broad environmental benefits for society; 2) job creation; 3) reduced health risks; and even 4) reputational benefits for customers who install solar generation. (Rabago Direct at 8-9) Clearly, such factors are not appropriate in the context of an avoided cost proceeding.

Although QF rates under PURPA are often described with the short hand label of "avoided cost rates," PURPA makes clear that it really means costs and that no rate paid to a QF shall "exceed the cost to the [purchasing utility] of alternative electric energy."[3] Thus, factors such as customer's reputations or job creation are outside the scope of what is permitted under PURPA. Thus, the Commission has held that such factors "cannot properly be included in calculating avoided cost rates."[4]

Witness Rabago has effectively conceded that a VOS goes beyond what is appropriate for consideration in the context of avoided costs. He concedes that PURPA is not "designed ... to fully address all of the issues" encompassed by a VOS study. (Rabago Direct at 15-16) By making such a concession, witness Rabago also concedes that the considerations encompassed by a VOS study are beyond the scope of the Commission's authority to set avoided cost rates. Ordinarily, the Commission cannot set rates for wholesale power transactions because that authority is reserved exclusively to the federal government under the Federal Power Act. However, PURPA delegates to the states limited authority to set rates for a particular type of wholesale power transaction (i.e., rates for purchases of power by utilities from QFs). Because the Commission derives this specific ratemaking authority from PURPA, its decisions are subject to the limits

[3] *See* 16 USCS § 824a-3(d).
[4] *In the Matter of Biennial Determination of Avoided Cost rates for Electric Utility Purchases from Qualifying Facilities*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 106 at 8, 23-24 (Dec. 19, 2007) (ruling that externalities such as general environmental costs are not appropriate for avoided costs).

established by PURPA. Thus, when witness Rabago correctly concedes that his approach to setting "avoided costs" for solar facilities goes beyond the boundaries of PURPA, he is admitting that it also extends beyond the Commission's authority to set avoided cost rates and, thus, beyond the scope of this docket.

Q. ARE THERE OTHER FLAWS IN NCSEA WITNESS RABAGO'S ARGUMENTS AND CONCLUSIONS?

A. Yes, there are several. First, even if VOS studies for the Utilities' systems were appropriate bases for establishing avoided cost rates – which they are not – witness Rabago has not provided any such study for the Commission to consider. To the contrary, he admits that he does not rely upon any such study and does not know if any such study even exists. (Rabago Direct at 11-12) His conjecture regarding alleged benefits of solar generation is not a sound basis for setting avoided cost rates.

Second, again putting aside the inapplicability of VOS studies for avoided cost rate purposes, there is no basis to assume that such a study would produce any quantifiable results. Alleged benefits, such as improvement in customer reputation and reduction in occupational health costs, are difficult to quantify and even more difficult to quantify accurately. For other alleged benefits, it is questionable whether they can even be shown to exist. For example, the assertion that intermittent low capacity factor resources such as solar can improve overall system reliability is at best debatable. Moreover, witness Rabago's approach to assessing solar generation appears heavily skewed toward identifying its benefits and insufficiently concerned with considering its costs. Issues such as the potential impact on spinning reserve and operating reserve requirements of adding a substantial amount of intermittent generation to a utility system are not discussed at all by witness Rabago. Thus, whatever value a VOS study might have, unless it is actually conducted in an even-handed manner, assumptions regarding the results of such a study are unsupported suppositions.

Third, witness Rabago's hypothetical discussion of VOS studies does not support his recommendation to increase the PAF for solar QFs to 2.0. In fact, he fails to establish a quantitative or even conceptual nexus between his discussion and his recommendation. There is simply no way to reach the conclusion that the avoided capacity rates for solar QFs should be increased by 67% from witness Rabago's general discussion of VOS studies.

III. <u>RESPONSE TO THE TESTIMONY AND RECOMMENDATIONS OF REG WITNESS MORRISON</u>

Q. DO YOU AGREE WITH REG WITNESS MORRISON'S STATEMENTS REGARDING THE PURPOSE OF PURPA?

A. Not entirely. Witness Morrison suggests that a goal of PURPA is to ensure that QFs are paid as much as possible to spur their development. That is a one-sided and incomplete description of PURPA. Witness Morrison is correct that PURPA was enacted to encourage the development of small non-utility generation that would help reduce the country's dependence on fossil fuels.

However, PURPA also is clear that pursuit of this policy objective shall not result in higher rates to electric customers.

While it is true that PURPA was not designed to deliver cost savings, it is equally true that PURPA requires that avoided cost rates paid to QFs must be "just and reasonable to customers of the [purchasing utility]."[5] To that end, PURPA strictly prohibits avoided cost rates for QFs that exceed a utility's cost of obtaining electric energy from another source.[6] Thus, although witness Morrison accurately quotes the United States Supreme Court's decision in *American Paper Institute*[7], the Supreme Court's approval of using the "maximum rate authorized by Congress" to provide the "maximum incentive" for QF development must be understood in light of how Congress established that maximum rate. In the case of PURPA, Congress defined the maximum rate with the clear intent of ensuring that the effort to encourage QF development did not impose higher cost for electricity on utility ratepayers.

Q. HOW DO YOU RESPOND TO REG WITNESS MORRISON'S SUGGESTION THAT THE UTILITIES PROPOSED AVOIDED COST RATES MUST BE INCREASED TO ENSURE THE CONTINUED DEVELOPMENT OF QFS IN NORTH CAROLINA?

A. Generally, REG witness Morrison's arguments appear to be influenced by his particular perspective of PURPA. The purpose of the present proceeding is to

[5] 18 C.F.R. 292.304(a)(1)(i) (requiring avoided cost rates paid to QFs to be "just and reasonable to the electric consumer of the electric utility and in the public interest").
[6] *State ex rel. Util's Comm'n v. North Carolina Power*, 338 N.C. 412, 418 (N.C. 1994) (recognizing that "states cannot impose purchase rates in excess of avoided costs").
[7] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (U.S. 1983).

establish rates to be paid for power produced by QFs based on the individual utility's cost of alternative power (i.e., the utility's avoided costs). The goal is not to establish rates that ensure the profitability of QFs. Over time, a utility's avoided costs fluctuate based on a number of variables. Accordingly, there will be periods during which full avoided cost rates are highly favorable to QFs and periods when they are not. However, Congress made it abundantly clear that, under PURPA, no rate may be paid to a QF that exceeds the purchasing utility's avoided costs, even if the rate is not financially attractive to all types of QFs and QF developers.

Q. HOW DO YOU RESPOND TO THE ARGUMENTS OF REG WITNESS MORRISON THAT ADOPTING THE UTILITIES' PROPOSED AVOIDED COST RATES WILL CAUSE MANY QF DEVELOPERS TO CEASE DOING BUSINESS IN NORTH CAROLINA?

A. In the final analysis, that issue is simply not relevant to this proceeding. The objective is to set rates at avoided costs – not to set rates at levels needed to attract QFs. Furthermore, it is not clear that Mr. Morrison's concerns are well-founded.

Witness Morrison suggests that a decrease of 20% in avoided cost rates will cause QFs to become financially infeasible. (Morrison Direct at 10) However, since the Utilities filed revised avoided cost rates on November 1, 2012, it has been publicly known that a sharp decrease in natural gas prices since 2010 would cause a substantial decrease in the Utilities' avoided energy rates (the larger component of avoided cost payments to QFs). Specifically, DEC and DEP propose decreases in their respective avoided energy rates of up to 29% and 14%, while Dominion North Carolina Power proposes a decrease of up to 19%. Those decreases are essentially unchallenged in this proceeding.

Despite this imminent decline in avoided cost rates, solar development (and investor interest) in North Carolina has trended sharply upwards in the past year. Certificate applications with the Commission have increased exponentially in 2013. A recent September 2013 analysis of North American Solar PV Markets forecasted installed solar PV in North Carolina to increase by 80% in Fiscal Year 2013 (second only to California). By contrast, solar PV across the United States would increase only by 17% year over year.[8] Thus, QF development in the State does not appear to have been slowed by the anticipated decrease in the Utilities' avoided cost rates. Further, in a recent March 23, 2013, News & Observer article, Mr. Morrison commented on the current state of the North Carolina solar PV market suggesting that solar PV was six times more expensive in 2007 when Senate Bill 3 was passed than today.[9] As QFs are not obligated to make their financial information public, it is difficult to assess the accuracy of witness Morrison's description of the economics of QF projects. However, his dire predictions regarding the impact of a 20% decrease in avoided cost rates seem at least questionable in light of such a precipitous drop in solar PV install costs.

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[8] See http://www.solarbuzz.com/news/recent-findings/california-sets-quarterly-record-solar-pv-q213-us-adds-976-mw-according-npd-so

[9] http://www.newsobserver.com/2013/03/23/2772040/possible-tax-credit-repeal-could.html (Published March 23, 2013).

Q. WHAT IS YOUR UNDERSTANDING OF WITNESS MORRISON'S ARGUMENTS REGARDING THE TERMS AND CONDITIONS IN DEC'S AND DEP'S STANDARD QF CONTRACTS?

A. REG witness Morrison has raised concerns relating to one provision in DEC's standard QF contract and one provision in DEP's standard QF contract. The provision in question form the DEC is Section 2 and the provision of the DEP standard QF contract is Section 6.

Q. WHAT IS YOUR RESPONSE TO REG WITNESS MORRISON'S ARGUMENTS REGARDING SECTION 2 OF DEC'S STANDARD QF CONTRACTS?

A. REG witness Morrison notes that certain language that had been included in previous versions of Section 2 of DEC's standard QF contract has been omitted in the version filed in this proceeding. The language in question pertains to the effect of changes made by the Commission to DEC's rate schedules and service regulations. Section 2 of DEC's Terms and Conditions provides that those rate schedules and service regulations are subject to change by the Commission and any such changes "shall immediately be made a part [of the QF contract], and shall nullify any prior provision in conflict therewith." Previously, DEC's Terms and Conditions also included language that limited the reference to changes in rate schedules to "variable rates only."

REG witness Morrison questions the omission of the foregoing language because it suggests that DEC intends for long-term fixed rates to be subject to change by subsequent Commission action. That was not DEC's intent and

DEC agrees that once a QF signs a long-term fixed rate contract, the QF is entitled to those rates for the life of the contract. However, the previous language in Section 2 was over-broad and appeared to suggest that even non-rate terms and provisions in long-term fixed rate contracts were immune from Commission-authorized changes. In light of the comments filed by the Public Staff and REG, DEC proposed in the Utilities' Joint Reply Comments to amend Section 2 of its Terms and Conditions to include the following language:

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

DEC believes that the foregoing language addresses the concerns raised by REG witness Morrison.

Q. WHAT IS YOUR RESPONSE TO REG WITNESS MORRISON'S ARGUMENTS REGARDING SECTION 6 OF DEP'S STANDARD QF CONTRACTS?

A. Witness Morrison is arguing that DEP should be required eliminate the provision of Section 6 of DEP's standard QF contract referred to as the Reduction-in-Contract-Energy-Charge. This provision provides for a modification of the amounts paid to a QF in the event that the QF fails to provide the amount of energy called for in the contract. Specifically, the Reduction-in-Contract-Energy-Charge provides, in pertinent part:

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

The Reduction-in-Contract-Energy-Charge is calculated as the total amount the QF has been paid for Energy Credits less: 1) the amount it would have received for Energy Credits if the contract had reflected the newly determined Contract Energy level; and 2) the amount that the QF would have received under the applicable Variable Rate for energy provided during any period that exceeded the new Contract energy level. The charge, therefore, only captures whatever economic excess a QF that fails to provide the contracted-for energy obtains from operating under a levelized rate.

Q. WHAT IS THE PURPOSE OF THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE?

A. The purpose of the Reduction-in-Contract-Energy-Charge is to ensure the economic balance of levelized QF contracts is maintained throughout the life of the contract. DEP includes the Reduction-in-Contract-Energy-Charge in levelized rate contracts because long-term levelized rates tend to overpay the QF in the early years.and underpay QFs in later years.

Generally, energy costs, like other types of costs, increase over time and avoided energy costs are no exception. Consequently, when avoided energy rates are levelized over the life of a contract, the utility pays a QF more than the utility's avoided cost in the early years of the contract, which is offset by the fact that the levelized rate is expected to be less than the utility's avoided cost in the later years of the contract. Similarly, from a QF's perspective, the early years of a long-term levelized contract are more profitable than the later years. A QF's cost to operate (e.g., fuel and maintenance costs) will likely increase over time, but it receives the same payment for each kwh of energy it produces in the first year of a levelized rate contract as it does in the fifteenth year. The QF's profit margins, therefore, are greatest at the beginning of a levelized rate contract and are expected to decline throughout the term of the contract. As a result, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes, and could even disappear, over the life of a long-term levelized rate contract.

Given the economics of long-term QF contracts, it would be unfair to DEP and its customers for a QF to underperform during the latter part of its contract having already reaped the excess benefits provided by levelized rates in the earlier years of the agreement. The Reduction-in-Contract-Energy-Charge prevents that situation by providing a mechanism to adjust the contract to restore the expected balance of the economic benefits to both parties in the event the QF's performance falls materially short of its contractual obligation.

Q. HOW DO YOU RESPOND TO REG WITNESS MORRISON'S ASSERTION THAT THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE IS PUNITIVE OR IS UNFAIR TO QFS?

A. The Reduction-in-Contract-Energy-Charge is neither punitive nor unfair. It merely restores the intended economic balance of the agreement in the event that a QF fails to deliver energy commensurate with the Contract Energy level. Moreover, DEP has never applied the Reduction-in-Contract-Energy-Charge in a punitive manner. The Reduction-in-Contract-Energy-Charge provision has been a part of DEP's Terms and Conditions since 1987 and this is the first time any party has objected to it. In fact, DEP has never had to resort to Reduction-in-Contract-Energy-Charge to resolve a performance issue with a QF. Thus, there is no basis for the assertion that the Reduction-in-Contract-Energy-Charge is in any way punitive to or an undue burden on QFs.

Q. HOW DO YOU RESPOND TO REG WITNESS MORRISON'S ARGUMENTS THAT THE REDUCTION-IN-CONTRACT-ENERGY-CHARGE IS UNFAIR TO INTERMITTENT RESOURCES SUCH AS SOLAR AND WIND QFS THAT ARE NOT IN CONTROL OF WHEN THEY OPERATE?

A. Such suggestions are unfounded. They greatly overstate the effect of the Reduction-in-Contract-Energy-Charge and ignore the responsibility of QFs to provide a reasonable, good faith estimate of their facilities generating capabilities.

The Reduction-in-Contract-Energy-Charge does not require QFs to predict their output perfectly. It is not triggered by a QF's failure to meet hourly, daily, monthly, or even seasonal production goals. The Reduction-in-Contract-Energy-Charge can only be invoked if the QF fails to meet its contracted-for energy targets over a 12-month period. Moreover, that calculation is based on a 12-month average of the QF's output, which gives the QF the benefit of any periods in which it produced energy in excess of the contracted-for amounts. Thus, a QF does not have to predict precisely its hourly or daily energy production to avoid the Reduction-in-Contract-Energy-Charge.

Moreover a QF's performance does not even need to perform up to its contractual representations. The Reduction-in-Contract-Energy-Charge only comes into play if the QF's output for a 12-month period falls below 80% of its contract energy level. This gives QFs a fairly wide margin of error before the application of the Reduction-in-Contract-Energy-Charge even becomes a possibility. It should also be noted that the Reduction-in-Contract-Energy-Charge only comes into play after the QF has operated for two years, which allows the QF time to work out any initial start-up issues. It also gives the QF two years to assess the actual operating capability of its facility and determine whether it can meet its contractual obligations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.