BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	))))))	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	))))	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM

DIRECT TESTIMONY OF

ROBERT B. STODDARD

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

TABLE OF CONTENTS

I. INTRODUCTION, PURPOSE AND SUMMARY OF CONCLUSIONS

Q. WHAT IS YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Robert B. Stoddard. I am a vice president of Charles River Associates ("CRA"), where I lead the firm's Energy & Environment practice. My business address is 200 Clarendon Street, T-33, Boston, Massachusetts 02116-5092.

Q. WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I have over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. My recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and the PJM Interconnection ("PJM"). I have submitted testimony to the Federal Energy Regulatory Commission ("FERC") as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and have testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts.

I was the lead economist for capacity suppliers in developing the capacity markets both in PJM and New England. I represented Mirant (now d/b/a GenOn) and other generation owners throughout the settlement discussions of the PJM Reliability Pricing Model ("RPM")—including the Fixed Resource Requirement ("FRR") Alternative—and developed many of the particular features of the market design. Following the settlement discussions, I was a member of a small team chosen by the settlement judge to draft revisions to the Tariff and RAA language consistent with the discussions. Furthermore, PJM filed affidavits from me and two other economists to provide the record on which FERC could accept the RPM settlement. Subsequent to the adoption of RPM, I participated actively in PJM's Capacity Market Evolution Committee and served as a capacity market advisor to several utilities, generation owners, and financial market participants. I have also testified on capacity market issues in the New York, Midwest, and California markets. In related areas, I served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction. I hold degrees in economics from Amherst College and Yale University. A summary of my experience is attached as Exhibit RBS-1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions" or "FES").

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

A. The purpose of my testimony is to address areas related to, first, the capacity price in the Market Rate Offer ("MRO") to which AEP Ohio compares its modified Electric Security Plan ("ESP") and, second, the proposed pricing of capacity to shopping customers. I also address portions of the testimony of AEP Ohio witnesses Frank Graves, Selwyn Dias, William Allen, Philip Nelson and Laura Thomas.

Q. PLEASE BRIEFLY SUMMARIZE YOUR OVERALL CONCLUSIONS.

A. AEP Ohio's conclusion that its modified ESP is superior to the MRO depends critically on the assumptions AEP Ohio made about the price of capacity in the MRO. The capacity rates that AEP Ohio used are unlinked from any relevant measure of the market value of capacity and, therefore, are not appropriate benchmarks for the MRO. Consequently, AEP Ohio incorrectly concludes that the modified ESP is financially superior to the MRO. As FES witness Schnitzer shows, when the MRO test is modified to use *market* prices for capacity, rather than cost-based prices, the modified ESP is markedly more costly for Ohio ratepayers than the MRO.

In one formulation of the comparison between the ESP and the MRO, AEP Ohio has used its fully loaded capacity cost as the "market price" for capacity. This cost basis is far above the actual market price of capacity in PJM[1] during the next three Delivery Years,[2] as evidenced not only by the clearing prices in the RPM auctions for those years, but also by the auctions conducted for the FirstEnergy Ohio utilities.

In its second formulation of the ESP versus MRO test, AEP Ohio also markedly overstates the true market value of capacity, instead evaluating costs based on above-market prices for capacity. In this second formulation, AEP Ohio proposes to charge some portion of shopping load a Tier 1 rate based on a stale rate, the Delivery Year 2011/12 RPM RTO capacity price, carrying this rate forward through 2015. In light of the fact that the Base Residual Auctions for each of the three relevant Delivery Years[3]

[1] Throughout my testimony, I use the term "PJM" either to mean the Office of Interconnection of PJM Interconnection, L.L.C., or the geographic area for which PJM is the RTO.

[2] A Delivery Year runs from June 1 to May 31 of the subsequent calendar year. It is the same concept as the PJM Planning Period or Planning Year.

[3] I.e., Delivery Years 2012/13, 2013/14, and 2014/15.

has already occurred (as well as several of the relevant Incremental Auctions), there is no basis for using a stale capacity price instead of using the particular information for each Delivery Year. The remaining shopping load would be charged a Tier 2 rate that appears to be completely arbitrary, unlinked from any market rate at all. Additionally in this second formulation, AEP Ohio proposes a non-bypassable Retail Stability Rider that is designed to collect above-market capacity revenues from both shopping and non-shopping customers, which further increases the cost to Ohio consumers by an expected $281.4 million.

Neither formulation is reasonable. A "market rate offer" should use prices marked against market, not against AEP Ohio's claimed embedded costs. As Mr. Schnitzer shows, correcting even this one metric demonstrates that there is a substantially higher financial cost for AEP Ohio consumers under the modified ESP than under the MRO.

Furthermore, the purported $989 million "discount" in capacity that AEP Ohio claims as a quantifiable benefit of the ESP is entirely illusory. AEP Ohio's capacity should, for the purposes of comparing the ESP to the MRO, be marked to a market price. Instead, AEP Ohio marks the value of its capacity to an internal cost-based figure that is far above the market value of capacity.[4] Although the two-tier capacity prices of the ESP are lower than AEP Ohio's cost-based figure, they are both well above the market price. AEP Ohio cannot credibly take credit for selling capacity at an above-market price. Eliminating this spurious credit from AEP Ohio's calculations, and using market prices in the MRO, shows that the "quantified benefit" from the modified ESP is actually a

[4] And, as FES witness Lesser establishes, is also above its embedded costs.

substantial cost, not a benefit, compared to the MRO. This single adjustment is not the full extent of the adjustments that would be needed to properly compare the proposed ESP to market; Mr. Schnitzer provides a comprehensive assessment.

Q. WHAT CAPACITY PRICE SHOULD AEP OHIO HAVE USED IN PRICING THE MRO?

A. The appropriate capacity price is the RPM RTO auction price. This is the rate at which the vast majority of capacity supply resources in PJM will be paid, and it is the reference price in general use for bilateral capacity trades. The RPM RTO price is the result of a market mechanism that has been found to be just and reasonable by the FERC, and the operation of this mechanism is carefully monitored to ensure that the resulting price has not been distorted by market power or other non-competitive influences. In short, the RPM RTO price is the best measure of the financial value of capacity in the PJM market.

Moreover, the RPM RTO price is economically sound. In the short run, the RPM auction price is the "right price" in terms of economic efficiency and is the closest approximation to the market value of the reliability value of capacity. In the long run, RPM is designed to provide the appropriate incentives for the entry of new, cost-efficient resources and the exit of inefficient resources over a suitably long investment horizon. Because the RPM RTO auction price is efficient in both the long- and short-term, it follows that incorporating any capacity price in the MRO other than the RPM RTO price implies a state compensation mechanism that would lead to uneconomic impacts and distortion of the competitive landscape.

Further, the RPM rate is the standard that the Public Utilities Commission of Ohio (the "Commission") should adopt in this case because:

- The RPM rate more than covers AEP Ohio’s cost of providing capacity;
- The RPM rate neither subsidizes nor discriminates against CRES providers; and
- The RPM rate is the rate charged prior to 2012 and will be the rate charged after May 2015.

AEP Ohio seeks to benchmark its modified ESP using a MRO capacity rate that is far in excess of the market price for capacity that CRES providers would have paid, but for AEP Ohio’s election of the FRR Alternative. AEP Ohio instead holds out as “market” a rate for capacity that is based on an estimate of the full embedded costs of the capacity resources. This rate includes not only the operating costs of those resources but also substantial allowances for AEP Ohio’s sunk costs, such as debt charges and depreciation. This rate is inconsistent with capacity prices set in a competitive wholesale market. In offering into a capacity *market*, competitive suppliers would base their offer prices on the costs that they could avoid by mothballing or retiring a resource. In addition, any earnings expected from the capacity resources from the sale of energy and other services should reduce the capacity price. This is the approach specified in the PJM Tariff and the standard that AEP Ohio will need to abide by as of June, 2015. Thus, capacity price in the MRO should not be based on AEP Ohio’s embedded costs, but rather on the outcome of this market process: the RPM RTO capacity price.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section II provides background information about the economic foundation, organization and operation of PJM’s capacity markets and the FRR Alternative, showing why the relevant cost metric for capacity in a competitive market is net avoidable costs, rather than embedded costs.

Section III discusses why the RPM rate is the only appropriate rate at which to price capacity in the MRO. I conclude that the use of embedded capacity costs in the MRO is inappropriate, and that the use of Delivery Year 2011/12 capacity prices in an alternative formulation of the MRO is equally inappropriate.

II. BACKGROUND OF CAPACITY ISSUES RELATED TO CRES PROVIDERS AND RETAIL ACCESS

A. BACKGROUND INFORMATION REGARDING CAPACITY PRICING

Q. WHAT ENTITY IS RESPONSIBLE FOR THE BULK POWER SYSTEM IN OHIO?

A. PJM, in its role as the Regional Transmission Organization, is responsible for operation of the bulk power system of a large area of the eastern U.S., from New Jersey southward to a portion of North Carolina and westward to Ohio and the Chicago area. With the recent additions of the FirstEnergy Ohio utilities and Duke Energy Ohio, all of Ohio is now within the PJM footprint. PJM also operates financial markets for the purchase and sale of energy, capacity, ancillary services, and transmission rights.

Q. WHERE ARE THE RULES THAT GOVERN HOW PJM OPERATES THE BULK POWER SYSTEM, AND HOW PJM MARKETS FUNCTION, SET FORTH?

A. PJM's rules are set forth primarily in two documents: its Tariff and the Reliability Assurance Agreement ("RAA"). FERC regulates PJM and approves its Tariff and the RAA.

Q. WHAT ENTITY SETS THE TARGET FOR THE AMOUNT OF CAPACITY RESOURCES NEEDED TO SERVE THE RELIABILITY NEEDS OF OHIO CUSTOMERS?

A. PJM does, in its role as the Regional Transmission Organization for the state's utilities.

Q. HOW DOES PJM ENSURE THAT SUFFICIENT CAPACITY RESOURCES WILL BE AVAILABLE?

A. PJM implemented the Reliability Pricing Model ("RPM"), which is designed to provide appropriate economic signals to capacity suppliers to make available sufficient resources to meet the forecast reliability requirements. The rules that govern RPM are set forth principally in Attachment DD to the PJM Tariff and in Section 8 of the PJM RAA.

Q. PLEASE DESCRIBE GENERALLY HOW RPM OPERATES.

A. RPM ensures that there are sufficient qualified resources available under PJM's dispatch control during each Delivery Year, defined as a twelve-month period running from June 1 to May 31 of the subsequent year, through a market mechanism.[5] Approximately three-and-a-half years prior to the start of a Delivery Year, PJM qualifies existing and planned resources as potential capacity suppliers, and (when appropriate) PJM's Market Monitor determines what caps or floors should apply to each resource's offer prices. Because the IMM has determined that the offers into the Base Residual Auction ("BRA") are structurally concentrated (meaning that small coalitions of suppliers theoretically have sufficient market power to affect price), all supply offers from existing resources are subject to offer caps in the BRA. PJM also determines what quantity of capacity resources will be needed regionally and in import-constrained locations. PJM

[5] Except for those load-serving entities that elect to use the Fixed Resource Requirement option, discussed below.

then uses an auction process to select the least-cost set of capacity resources, which also determines the capacity prices that will be paid to capacity resources. During the course of the Delivery Year, PJM pays capacity suppliers by collecting a capacity rate from each Load-Serving Entity ("LSE").

Q. HOW ARE CAPACITY RATES USUALLY SET IN PJM UNDER THE RPM?

A. Capacity rates in PJM normally are set via the auction process that constitutes PJM's capacity market.[6] For each Delivery Year, PJM conducts a BRA approximately three years prior to the start of the Delivery Year. The BRA auction process is designed to secure commitments for the necessary capacity requirements forecasted for the LSEs participating in the BRA. Eligible resources can be generation, demand response, energy efficiency or qualified transmission enhancements. LSEs can also offer their own eligible self-supply into the auction. Following the BRA, PJM conducts three Incremental Auctions for that Delivery Year, which allows capacity suppliers to offer to shed, or bid to acquire, a capacity delivery obligation. In the Delivery Year, LSEs are assigned a cost responsibility for their share of the procured capacity in the BRA and the three Incremental Auctions conducted for that Delivery Year. LSEs may financially hedge their cost exposure in the auctions by obtaining or arranging for capacity under bilateral agreements.

[6] In detail, LSE charges for capacity are made up of a weighted average of capacity clearing prices in the BRA, and three incremental auctions. These are clearing auctions, and each sets a corresponding capacity price for the locational delivery areas ("LDAs") within PJM. Load prices would further be modified by adjustments between forecast quantities and actual load allocation shares and peak load responsibility. Generators are paid the price they clear at in any specific auction in which they are sold. For the sake of simplicity and clarity, the RTO price discussed in this testimony reflects BRA prices and not the final charge to load for any specific Delivery Year.

Q. ARE ALL LOAD-SERVING ENTITIES REQUIRED TO PARTICIPATE IN THE RPM AUCTION PROCESS?

A. No. Qualifying LSEs may instead elect to meet their resource requirement through the Fixed Resource Requirement ("FRR") Alternative.

Q. HOW DOES THE FRR ALTERNATIVE WORK?

A. The FRR Alternative allows eligible LSEs (such as AEP Ohio) the option to submit a FRR Capacity Plan and meet a fixed capacity requirement as an alternative to participating in the RPM capacity auction. See PJM Reliability Assurance Agreement, Schedule 8.1, Sec. D ("FRR Capacity Plans"). Such an LSE is referred to as an FRR Entity. When an FRR Entity first elects the FRR Alternative, it must submit a conforming FRR Capacity Plan for a period of five Delivery Years. If the FRR Entity chooses to continue with the FRR Alternative beyond those five years, it must submit an amended FRR Capacity Plan covering subsequent Delivery Years two months prior to the BRA for that Delivery Year.

Q. DID AEP CHOOSE TO BECOME AN FRR ENTITY?

A. Yes. AEP Ohio, along with the other affiliated operating companies that comprise AEP East, has voluntarily made the FRR election since the inception of RPM and has continued this election through the 2014/15 Delivery Year. The BRA in which capacity is obtained by PJM and LSEs for the portion of AEP Ohio's ESP for which AEP Ohio will remain under FRR has already occurred; therefore its decision to remain an FRR Entity through the 2014/15 Delivery Year is not revocable. By making the FRR election, AEP Ohio avoids paying auction rates for capacity but remains responsible for assuring that sufficient qualified capacity resources are available to meet the reliability requirements established by PJM.

Q. WHAT LOAD MUST BE COVERED BY AEP OHIO'S FRR CAPACITY PLAN?

A. Under the terms of the PJM RAA, AEP East's FRR Capacity Plan must meet the resource needs of all load served through its distribution system.[7] This requirement has been in place since the establishment of the RPM. Consequently, when AEP Ohio elected to become an FRR Entity, it did so with full knowledge that it would have the responsibility of including all retail load in its distribution areas in its FRR Capacity Plan, regardless of whether that load was a retail customer of AEP Ohio or of a CRES provider.

Q. IS THERE A REQUIREMENT THAT THE RESOURCES DESIGNATED IN THE FRR CAPACITY PLAN MEET A LEAST-COST TEST?

A. No. As an FRR Entity, AEP East could designate any qualified capacity resources as part of its FRR Capacity Plan, provided that in aggregate the resources meet the reliability requirement determined by PJM and that the designated resources were not committed beforehand to PJM through the RPM auction process. PJM does not use a least-cost test in evaluating the FRR Capacity Plan, in contrast to the RPM auctions, where only the most economic available resources are designated as capacity supply.

[7] There is a limited exception if an LSE within AEP Ohio's distribution areas also qualified to be an FRR Entity and so elected, *e.g.* a transmission-dependent municipal utility or cooperative. This limited exception does not, however, extend to CRES providers.

Q. DOES A CRES PROVIDER HAVE THE OPTION TO ESTABLISH ITS OWN FRR CAPACITY PLAN, RATHER THAN RELYING ON THE FRR ENTITY'S PLAN?

A. Yes, but only if the FRR Entity has not already filed its FRR Capacity Plan for the Delivery Year. The RAA allows any eligible LSE within an FRR designated area that has retail access to establish its own FRR plan.[8] However, such an election can only occur after the existing FRR plan for the region (e.g. AEP Ohio's FRR plan) ends. This means that once AEP Ohio has submitted an FRR Capacity Plan, which must include all load within its zone, independent FRR plans cannot be implemented by CRES providers to meet the requirements of load they may obtain until the expiration of the existing FRR plan. AEP East has already submitted its FRR Capacity Plan for all Delivery Years of its FRR term.[9] Therefore, LSEs such as FES and other suppliers are locked in through the 2014/15 Delivery Year—the portion of the ESP term during which AEP Ohio's FRR is in place—unless AEP East would allow a CRES provider to substitute its own capacity resources in the place of an AEP resource. Such a substitution, however, would be at AEP East's sole discretion and seems unlikely to occur if AEP Ohio is able to charge an above-market price for its capacity.

Q. DOES THE FRR ALTERNATIVE SPECIFY HOW AN FRR ENTITY WILL BE COMPENSATED BY A CRES PROVIDER THAT DID NOT SUBMIT ITS OWN FRR PLAN?

A. Yes. The PJM RAA has provisions for FRR Entities to charge retail suppliers for capacity included in the FRR Capacity Plan. Specifically, under Schedule 8.1, Section D.8, the RAA provides:

---

[8] See RAA Schedule 8.D.9.

[9] AEP Ohio is participating in the RPM auctions for the 2015/2016 Delivery Year beginning June 1, 2015.

> "In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at [the unconstrained or "RTO" clearing prices], provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's costs or such other basis shown to be just and reasonable."

Thus the RAA establishes a clear sequence to determine the capacity rate that the FRR Entity may charge a CRES provider, with the "state compensation mechanism," if one exists, taking precedence. Absent such a mechanism, the capacity rate is set at the capacity clearing price in the RPM RTO. FERC has ruled that only when there is no state compensation mechanism does an FRR Entity have the option to make a filing with FERC to change to cost-based recovery.[10]

Q. AEP WITNESS THOMAS ASSERTS THAT, AS AN FRR ENTITY, AEP OHIO'S CAPACITY WILL HAVE TO BE USED "FOR CUSTOMERS TAKING SERVICE THROUGH A CRES PROVIDER AS WELL AS SSO CUSTOMERS REGARDLESS OF WHETHER AEP OHIO IS THE SUPPLIER OR IF WINNING BIDDERS THROUGH A COMPETITIVE BIDDING PROCESS ARE THE SUPPLIERS TO AEP OHIO FOR THE SSO LOAD." (THOMAS DIR. P.15, LINE 8-11.) SHE THEN USES THE SAME CAPACITY PRICE FOR ALL CUSTOMERS IN HER ESP V. MRO TEST CALCULATIONS. DOES THE RELIABILITY ASSURANCE AGREEMENT REQUIRE AEP OHIO, AS PART OF A FRR ENTITY, TO CHARGE WINNING WHOLESALE AUCTION BIDDERS IN AN ENERGY-ONLY AUCTION TO SERVE NONSHOPPING LOAD A CAPACITY PRICE EQUAL TO THE STATE COMPENSATION MECHANISM CAPACITY PRICE?

A: Although it is my view that the capacity price in the MRO and the capacity price charged to CRES providers should be the same, namely the RPM RTO capacity price, this view is based on economic and market design considerations, not because the rates

[10] *See* American Electric Power Serv. Corp., 134 FERC ¶ 61,039 (2011).

are linked by the PJM RAA. The RAA is silent on the capacity price that AEP Ohio may charge its non-shopping customers. In particular, the state compensation mechanism is not applicable. The RAA defines the role of the state compensation mechanism in Schedule 8.1, Section D.8 of the RAA, which discusses "the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE." The energy-only wholesale auction that AEP Ohio has proposed does not, however, transform the winning bidders into "alternative retail LSEs." Section 1.44 of the RAA defines an LSE as:

> any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region.

Winners of the energy-only wholesale auction, however, neither serve end-users nor sell electric energy to end-users. They will sell power at wholesale to AEP Ohio, which in turn sells that power at retail to its non-shopping customers. Consequently, bidders do not become LSEs by virtue of winning the auction.

<u>B. PRICING UNDER THE BRA</u>

Q. PLEASE SUMMARIZE HOW THE RPM RTO PRICE IS SET.

A. The RTO price is set by the supply of capacity resources offering into the BRA and the demand for resources determined by PJM. PJM buys capacity as determined by the Variable Resource Requirement, specified in Section 5 of Attachment DD of the PJM Tariff. The supply is determined by offers to sell capacity from owners of planned or existing capacity resources that qualified to participate in the BRA. Owners of existing capacity resources are subject to a must-offer obligation in the RPM markets. Because the independent market monitor ("IMM") has determined that the offers into the BRA are structurally concentrated (meaning that small coalitions of suppliers theoretically have sufficient market power to affect price), all supply offers from existing resources are subject to offer caps in the BRA.

Q. WOULD THIS OFFER MITIGATION APPLY IN THE AEP OHIO ZONE IF AEP PARTICIPATED IN THE BRA?

A. Yes. In the AEP Ohio zone, AEP Ohio is a "pivotal supplier," i.e., the reliability requirement for the zone could not be met if all of AEP Ohio's resources were taken out of the market. Thus, AEP Ohio is considered to have structural market power, pursuant to the Market Structure Test used by the IMM.[11] Therefore, its offers and the offers from all other capacity resources in the AEP Ohio zone would be subject to mitigation by the IMM.[12]

Q. HOW ARE THE OFFER CAPS FOR SUPPLIER OFFERS SET?

A. Offers from existing resources must be based on the costs that a resource's owner could avoid by retiring or mothballing the resource. Specifically, suppliers' caps are established, as specified in section 6.8 of Attachment DD of the PJM Tariff, at the Avoidable Cost Rate (the "ACR") net of Energy & Ancillary Services Offset, times 110%.

Q. ARE ALL CAPACITY SUPPLY OFFERS SUBJECT TO THESE PRICE CAPS?

A. No. Capacity offers from planned resources, including planned demand-response customers, are not subject to mitigation, nor are offers from capacity imports from

[11] PJM Tariff, Attachment DD, Section 6.3.

[12] If the AEP Ohio zone were not modeled separately as a constrained zone (as it is not during the DY 2015/16 BRA), then it would still be subject to offer mitigation. The IMM has determined in each BRA conducted to date that the RTO zone fails the No-Three-Pivotal-Supplier test in the BRA.

outside of PJM. Such unmitigated resources have played an important part in setting RPM prices in every Base Residual Auction to date.

Q. WHAT IS THE LOGIC UNDERLYING THE ESTABLISHMENT OF OFFER CAPS AT THE ACR VALUES, NET OF EARNINGS IN THE ENERGY AND ANCILLARY SERVICES MARKETS?

A. The intent of offer caps in general is to replicate the bidding behavior that would be expected in a competitive environment. In the absence of market power, individual suppliers would be expected to offer capacity resources at their short-term "to go" costs, i.e., the costs that could be avoided by either retiring or "mothballing" an existing unit for a year. The ACR values used in the PJM auction process reflect an attempt to administratively set the determination of net "to go" costs, allowing only for typical out-of-pocket costs incurred by keeping a resource in service, net of market earnings from the sale of energy and ancillary services. This net "to go" cost figure is the amount that a capacity supplier needs to keep a facility in operation and make it available to provide capacity to PJM.

Q. HOW DO "TO GO" COSTS COMPARE TO "EMBEDDED" COSTS?

A. "To go" costs are a subset of embedded costs. The embedded cost of an asset starts with the "to go" costs, such as: avoidable operations and maintenance labor; avoidable administrative expenses, such as operator training and communications; avoidable maintenance expenses, such as rented equipment; avoidable variable expenses, such as station utilities; avoidable taxes, fees and insurance; avoidable carrying charges related to levels of fuel and spare parts; and avoidable corporate level expenses, such as legal service and environmental reporting.[13] Embedded costs include, on top of "to go" costs, all non-avoidable costs. These may include items such as depreciation, amortization, taxes, and interest; allocated corporate costs, such as risk management and legal; and allocations of facility-level staffing and other costs that would continue even if one unit at the facility were closed.

Q. WHY IS IT THAT COMPETITIVE OFFERS ONLY CONSIDER "TO GO" COSTS, RATHER THAN EMBEDDED COSTS?

A. This is a standard result in economics, usually summarized by the maxim, "sunk costs are sunk." As long as a business can sell a product for more than it costs to make it—the "to go" cost—then it is earning some margin to cover fixed costs of operations, such as debt service and property taxes, and possibly enough margin to generate a return on equity. If instead the business prices its product with these fixed costs priced in, it will likely miss sales opportunities that would have added to the bottom line.

An example may help illustrate the point. Suppose an existing power plant has "to go" costs of $50 million per year. This cost covers items such as staffing, station power, and others that could be eliminated by closing the plant. The plant also has $40 million of additional costs associated with it, such as debt service and property taxes. These costs, however, cannot be reduced by closing the plant—for example, debt repayment doesn't end just because you close the asset for which you borrowed funds. Other costs, such as fuel, are covered by the energy payments the plant earns when it operates. Suppose finally that the capacity price set by PJM would provide the owner $60 million in capacity revenues. Would our hypothetical plant owner want to accept

[13] PJM multiplies the sum of these items by 1.1 to provide a margin of error for understatement of costs.

that money and pledge to be operating for another year, or rather to mothball the plant? The answer is easy: $60 million more than covers the $50 million of the plant's "to go" costs, and further it provides $10 million of contribution margin to help cover sunk costs, leaving the owner with only $30 million of additional monies it will need to earn from energy sales to break even. If, on the other hand, the owner declined the capacity payment, it would lose the full $40 million. The plant owner would, therefore, rationally accept the capacity payment of $60 million, even though this payment is below the full $90 million of costs associated with the plant's total embedded costs.

Q. IS THERE ANY EXCEPTION TO THE GENERAL RULE THAT RPM OFFER CAPS DO NOT ALLOW THE RECOVERY OF FINANCING COSTS OR OTHER FIXED CHARGES?

A. There is one such exception. The PJM Tariff allows (but does not require) capacity offers to include amortized capital costs for major incremental investment that would be expected with maintaining large, capital intensive projects, such as repowering or installation of major environmental controls. The Market Monitor computes the Avoidable Project Investment Recovery ("APIR") Rate for such incremental investments in existing generation using the formulas set forth in the Tariff. Even though the APIR Rate allows for recovery on and of capital, it is still a forward-looking concept, unlike embedded costs. The APIR only allows recovery on *avoidable* project investments, i.e. investments that have yet to be made at the time the APIR Rate is established.

Q. HOW IS THE OFFER CAP FOR ANY PARTICULAR CAPACITY RESOURCE DETERMINED?

A. The IMM sets a Maximum ACR for each existing capacity resource based on IMM's estimated benchmark costs, which it establishes for major technology types.

These maximums are laid out in Attachment DD of the PJM Tariff (pp. 2346-2447). From this Maximum ACR, the IMM subtracts its estimate of the net earnings from the sale of energy and ancillary services, valued at PJM spot market prices, over the prior three calendar years (the "E&AS Offset"), and multiplies the resulting (positive) difference by 110%, to allow some margin for uncertainty in the IMM's calculation. The capacity supplier may contest this bid cap by presenting data to the IMM showing its actual "to go" costs. In my experience working with other PJM utilities, however, the requirement for detailed, unit-specific information is challenging to meet and the default ACR calculation is fairly generous. Consequently, nearly all resource owners price their offers at (or below) the IMM-allowed benchmark offer cap.

Q WHY DOES PJM USE A THREE-YEAR HISTORICAL E&AS OFFSET?

A. The rationale of the offset calculation methodology is that the benefits of having actual data on which to base the E&AS Offset more than outweighed the potential benefits of using a forward-looking forecast of energy earnings. Using three years' data provides some degree of smoothing of fluctuations in the energy market due to, for example, weather or volatile fuel prices. FERC, presented with arguments for and against a historical offset, decided that the historical E&AS Offset is a just and reasonable proxy for the competitive offer price from existing generation.

An important element of support for the use of a historical offset is that cyclical fluctuations average out for long-lived assets, such as AEP Ohio's generation fleet. Above-normal energy earnings in one year, say 2007, work their way into higher E&AS Offsets (and, therefore lower capacity prices) in DY 2011/12, DY 2012/13, and DY 2013/14. The capacity market, therefore, works to "claw back" above-normal energy earnings through subsequent adjustments to the capacity price. Conversely, the below-normal energy earnings in 2011 will result in lower E&AS Offsets (and, therefore, higher capacity prices) in DY 2015/16 through DY 2017/18—exactly when AEP Ohio will be shifting its capacity pricing to RPM pricing. The upside to AEP Ohio for earning this premium in the capacity market, which is the logical consequence of using the three-year historical E&AS Offset, greatly exceeds AEP Ohio's current loss of energy revenues in off-system sales.

Q. HAVE YOU COMPUTED WHAT THE MAXIMUM ALLOWABLE OFFER PRICE WOULD BE FOR AEP OHIO?

A. Yes. For the three Delivery Years in question, the average net capacity cost—i.e., the Avoidable Cost Rate less the E&AS Offset—is ($46.78)/MW-day.

Q. HOW IS IT POSSIBLE FOR THE NET CAPACITY COST TO BE NEGATIVE?

A. This is an entirely normal outcome and implies that the unit would earn a contribution margin even if it received no capacity payment at all. The net capacity cost will be negative when a resource has positive cash flows—i.e., its operating revenues exceed its operating costs. AEP Ohio more than covers its "to go" costs with net cash flow from the sale of energy and ancillary services (marked to PJM market prices). Thus, any positive capacity price granted in this case will result in a contribution margin towards non-avoidable costs of these resources.

Q. BASED ON YOUR FINDINGS, WOULD YOU CONCLUDE THAT A NEGATIVE CAPACITY RATE FOR AEP OHIO WOULD BE APPROPRIATE?

A. No. It is also appropriate to consider AEP Ohio's opportunity cost—that is, the price it could receive were it to sell its capacity in the market. AEP Ohio could sell capacity outside of PJM, and if it has enough surplus capacity, it can offer that capacity into PJM Incremental Auctions. That is why, even though the AEP Ohio resources have net negative capacity costs, the appropriate price AEP Ohio should receive is the market price: the PJM RTO rate.

C. RPM DOES NOT GUARANTEE RECOVERY OF EMBEDDED COSTS

Q. HOW DO THE RPM RTO PRICES COMPARE TO AEP OHIO'S CALCULATIONS OF ITS EMBEDDED COSTS?

A. AEP Ohio's claimed embedded costs are far above the clearing prices in the RPM auctions. For the three Delivery Years 2012/13, 2013/14, and 2014/15, the RPM RTO clearing prices from the BRA were $16.46, $27.73, and $125.99 (all in $/MW-day) respectively. FES witness Dr. Lesser has converted these supplier prices into rates billed to loads of $19.89, $33.87, and $153.99 (all in $/MW-day) respectively, for an average of the three years of $69.02/MW-day. These rates are far lower than the $355.72/MW-day rate that AEP Ohio uses in the first of its MRO comparisons.

Q. DOES THE PJM TARIFF OR RAA PROVIDE FOR A CAPACITY SUPPLIER, SUCH AS AEP OHIO, TO RECOVER ITS FULL EMBEDDED COSTS OF CAPACITY?

A. No. "Embedded cost" is a concept nowhere to be found in the RPM Tariff or the RAA. In the BRA, existing resources may not include costs in their offers such as return on and of capital, interest, property taxes, or depreciation. Only the costs explicitly enumerated in the ACR definition may be included.[14] Under the FRR Alternative, nothing in the RAA provides for AEP Ohio or any other FRR Entity to recover its full embedded costs.

[14] As noted earlier, there is a provision to raise offer caps to reflect financing costs of certain major capital upgrades.

Q. IN DEVELOPING THE RAA, DID THE PARTIES ENVISION RECOVERY OF EMBEDDED COSTS IN THE STATE COMPENSATION MECHANISM?

A. No. Allowing an FRR Entity to recoup its embedded costs from other LSEs in its zone would deviate from the theory and practice underlying the entire RPM design. As a review of the relevant language in the RAA demonstrates, any state compensation mechanism would be part of a larger regulatory framework in a state to implement competitive retail access. The state compensation mechanism should, therefore, operate so as not to discriminate against competitive retail suppliers or to discourage competition. But if competitive retail suppliers had to pay embedded costs for capacity to the FRR Entity, while also having to pay market prices for *energy*, these suppliers would have been at a sharp and discriminatory cost disadvantage to the utility. Consequently, the default rate for capacity set in the RAA is such a price: the RPM RTO price.

Q. ARE YOU AWARE THAT AEP OHIO HAS CALCULATED THAT THE VALUE OF THE ENERGY CREDIT IS ONLY $3/MWH?

A. Yes, that is the testimony of AEP Ohio witness Allen, who states, "As part of a larger compromise on the capacity pricing issue, AEP Ohio will recognize a $3/MWh credit for shopped load related to possible energy margins that could be realized by AEP Ohio for reductions in SSO load."[15]

Q. DOESN'T THAT INDICATE THAT THE SUPPOSED VALUE OF BUYING POWER AT COST IS RELATIVELY SMALL?

A. No, because the calculation, as performed, fails to address that question correctly. AEP Ohio's calculation of $3/MWh reflects only a small portion of the economic value of the output of AEP Ohio's fleet because, as I understand it, AEP Ohio is filtering these

[15] Direct Testimony of AEP Ohio witness William A. Allen, filed March 30, 2012, Case No. 11-346 ("Allen Direct"), p. 13.

earnings through the AEP Pool agreement. That calculation is irrelevant, inasmuch as any subsidiary could seek to shield energy earnings through affiliate transactions; such self-dealings, however, do not change the fact of the asset's earnings. The relevant point is the earnings from selling energy generated by *one additional MW* of AEP Ohio's fleet at PJM spot market prices; these earnings should not be diluted by subsequent affiliate transfers in evaluating a market price.

III. THE ONLY APPROPRIATE CAPACITY TRANSFER PRICE IS THE RPM PRICE.

A. CAPACITY PRICING IN AEP OHIO'S FIRST MRO BENCHMARK

Q. WHAT CAPACITY PRICE DOES AEP OHIO USE IN ITS MRO?

A. In Case No. 10-2929, AEP Ohio witness Pearce computes what AEP Ohio witness Allen characterizes as a "full capacity cost" of "$355.72/MW-day after capacity losses."[16] AEP Ohio witness Thomas applies this capacity rate in her calculations of the "Competitive Benchmark" price for the MRO.[17]

Q. IS THE APPROACH THAT MS. THOMAS APPLIES TO COMPUTE THE CAPACITY PRICE IN THE MRO CONSISTENT WITH HER METHODOLOGY IN COMPUTING AN ENERGY PRICE?

A. No, the two methods differ sharply. For the energy portion of the MRO test, Ms. Thomas begins with a "Simple Swap" for wholesale energy that is "traded through the broker market and on electronic exchanges…."[18] She then builds up a final energy price by customer class using various adjustments to this market price for energy. By contrast,

[16] Allen Direct, 15:16–21.

[17] Direct Testimony of AEP Ohio witness Laura J. Thomas, filed March 30, 2012, Case No. 11-346 ("Thomas Direct"), Exhibit LJT-1, page 2 of 3, line 7.

[18] Thomas Direct, 12:21–23.

Ms. Thomas does *not* begin her assessment of capacity costs by finding the equivalent of a "Simple Swap" for capacity that is traded on the broker market or electronic exchanges. Instead, Ms. Thomas uses the capacity price from AEP Ohio's litigation position in Case No. 10-2929. As I have already noted, this rate, $355.72/MW-day, is wholly unrelated to any market price.

Q. WHAT CAPACITY PRICE SHOULD BE USED IN THE MARKET RATE OFFER?

A. The appropriate capacity price is the RPM RTO auction price, regardless of whether this is viewed in the long or short run. This is the only price that is commercially actionable, economically justified, and consistent with prices actually paid in Ohio by CRES providers outside of the AEP Ohio service territory.

Q. IS THE BASE RESIDUAL AUCTION THE ONLY AUCTION IN WHICH CAPACITY IS PRICED BY PJM?

A. No. As I discussed earlier, PJM conducts three Incremental Auctions for each Delivery Year, which provides owners of resources cleared in a prior auction to buy out of their capacity supply obligation. So, unlike the Base Residual Auction, demand in the Incremental Auction is primarily a set of willing buyers. Also, the IMM has not imposed offer caps in all of the Incremental Auctions. The resulting prices, therefore, are arm's-length prices between willing buyers and sellers.

Q. HOW HAVE THE CLEARING PRICES IN THE INCREMENTAL AUCTIONS COMPARED TO THE CLEARING PRICES IN THE BASE RESIDUAL AUCTIONS?

A. Clearing prices in Incremental Auctions have generally been at or below clearing prices in the Base Residual Auction for the same Delivery Year, which confirms that the Base Residual Auction prices are fair market values for PJM capacity.

Q. DOES THE $355.72/MW-DAY RATE USED BY AEP OHIO IN ITS MRO TEST BEAR ANY RELATION TO THE PRICES TRANSACTED IN THE MARKET?

A. No, none whatsoever. Had AEP Ohio offered its capacity into the market, either bilaterally or in any auction conducted by PJM, at its "full cost" of $355.72/MW-day, these offers would not have cleared. The $355.72/MW-day price therefore fails the most fundamental test of being a "market rate."

Q. SHOULD THE FACT THAT AEP OHIO'S CAPACITY IS SUPPLIED AS PART OF AN FRR CAPACITY PLAN CHANGE THE MARKET VALUATION?

A. No. First, I reject Mr. Graves' argument that AEP Ohio's generation fleet is providing capacity that is somehow different and worthy of a different, higher valuation. Any such argument misses a central point about capacity: it is a fungible commodity, with properties clearly defined in the PJM Tariff and RAA. The capacity rate pays for those properties, neither more nor less, because customers are under no obligation from PJM to buy resources with properties other than those defined. The capacity product from AEP Ohio's generation fleet is not a better or different product the capacity from any other qualified supply resource, so no premium or different price is justified.

Second, the obligations placed on AEP Ohio are nearly identical as between their position as an FRR Entity and the position of other capacity suppliers and LSEs that meet their RPM requirements through PJM's auctions. On the load side, LSEs have no capacity responsibilities under RPM other than to pay their bills; CRES providers in AEP Ohio's service area likewise have no capacity responsibilities. On the supply side, performance risks are borne by capacity suppliers and are specified in Attachment DD, Sections 7 through 12, to the PJM Tariff; the performance requirements are identical for resources supplied by an FRR Entity as on any other capacity supplier. Therefore, the RPM capacity price already includes the cost of carrying these enumerated risks. The only incremental risk that AEP Ohio bears (by its option) as an FRR Entity is that it may be required to provide additional resources should PJM increase the reliability requirement. (Any such change is known at least two years in advance and is likely to be small.) This risk is symmetric, however, and AEP Ohio may have capacity freed up if PJM decreases its reliability requirement.

Because all capacity is fungible, and because the AEP Ohio bears no risk that differs materially from the risks undertaken by other PJM capacity suppliers, there is no reason to believe that AEP Ohio's capacity is not fairly valued at the PJM RTO price paid to all other capacity resources in the unconstrained RTO region.

Q. IF AEP OHIO HAD PARTICIPATED IN THE RPM AUCTIONS, DO YOU HAVE A VIEW AS TO WHETHER THE CLEARING PRICES WOULD HAVE BEEN HIGHER OR LOWER?

A. Had AEP Ohio participated in the RPM auctions, rather than using the FRR Alternative to meet its RPM obligations, the clearing prices in the market would have been very similar to the prices that actually occurred. AEP Ohio was slightly long capacity throughout this period, as was PJM overall. Therefore, if AEP Ohio had participated in the Base Residual Auctions, the overall supply/demand balance (and, therefore, the clearing prices) would have been largely unchanged.

Q. DOES THE $355.72/MW-DAY RATE USED BY AEP OHIO IN ITS MRO TEST MATCH THE CAPACITY RATE CHARGED TO ANY OHIO CRES PROVIDER?

A. No. The price of capacity paid by shopping customers elsewhere in Ohio are equal or similar to the PJM RTO rate.

Q. IS AEP OHIO THE ONLY FRR ENTITY IN OHIO?

A. No, Duke Energy Ohio also opted to enter PJM using the FRR Alternative.

Q. WHAT CAPACITY RATE DOES DUKE ENERGY OHIO CHARGE CRES PROVIDERS?

A. Duke Energy Ohio proposed, and the Commission agreed, to a capacity rate equal to the RPM clearing price for the applicable Delivery Year.

Q. WHAT CAPACITY RATE DO THE FIRSTENERGY OHIO UTILITIES CHARGE CRES PROVIDERS?

A. FirstEnergy's Ohio utilities transitioned from the Midwest ISO to PJM after the BRA had been conducted for some of the future Delivery Years. For these "stub" years (Delivery Years 2011/2012 and 2012/2013), PJM administered on behalf of the FirstEnergy Ohio utilities, transition integration auctions to secure the additional capacity required, and these utilities charge CRES providers that auction price. The results of these auctions were similar to the BRA results, $108.89 for Delivery Year 11/12, and $20.46 for 12/13, compared to the RPM BRA prices of $110.04 for 11/12 and $16.46 in 12/13.

Q. WHAT CAPACITY RATE DOES DAYTON POWER & LIGHT CHARGE CRES PROVIDERS?

A. To date, Dayton Power & Light has participated in the RPM auction process since the inception of RPM. Consequently, it does not charge CRES providers any capacity rate—instead, PJM charges CRES providers the PJM zonal rate determined primarily by the BRA auction clearing price.

Q. FROM 2007 TO 2011, WHAT CAPACITY RATE HAS AEP OHIO CHARGED ITS CRES PROVIDERS?

A. Prior to this year, CRES providers have compensated AEP Ohio for capacity at RPM market-based prices. Thus, from June 1, 2011 through December 31, 2011, AEP Ohio charged CRES providers $145.79/MW-day, which is the RPM RTO clearing price for the 2011/2012 Delivery Year adjusted for scaling factors. [19]

Q. GIVEN THAT AEP OHIO HAS ASSERTED THAT $355.72/MW-DAY IS ITS FULL COST OF CAPACITY, WOULDN'T AEP OHIO BE LOSING MONEY ON CAPACITY SALES AT ANY PRICE BELOW THIS LEVEL?

A. No, to the contrary, pricing the capacity at a price that would actually clear in the market would increase AEP Ohio's net revenue. Given that AEP Ohio's revenues from the sales of energy and ancillary services more than offset the company's "to go" costs, AEP Ohio resources have a net *negative* capacity cost of ($46.78)/MW-day. This implies that all of the $355.72/MW-day rate arises from sunk costs that are economically stranded at the market price of capacity over the next three years. Any revenues that AEP Ohio can realize from the sale of capacity contribute to covering these sunk costs. Even if AEP Ohio were to charge *nothing at all* for its capacity, it would not be economically rational for it to retire any units other than those identified already by the Company.

Moreover, we know that AEP Ohio has actually sold capacity in the market at rates far below $355.72/MW-day. AEP Ohio has cleared surplus capacity in some BRAs,

[19] Direct Testimony of AEP Ohio witness Kelly D. Pearce, filed March 30, 2012, Case No. 11-346 ("Pearce Direct"), p. 22. The PJM RTO clearing price is subsequently adjusted and is then multiplied by a scaling factor and pool requirement and loss factor to determine the total price paid by CRES providers. *See id*. at 23:5-10.

when it had sufficient capacity to exceed the Threshold Quantity of the FRR.[20] These volumes must have been priced well below $355.72/MW-day to clear in the BRA.

Q. DO ANY ECONOMIC PRINCIPLES SUPPORT THE USE OF THE $355.72/MW-DAY RATE IN THE MRO?

A. No, there is no sound reason based in economic principles to diverge from the RPM RTO price as the market rate for capacity. As a matter of regulation, capacity pricing is under the jurisdiction of FERC, and the RPM RTO price is the result of a market mechanism that has been found to be just and reasonable by the FERC. The operation of this mechanism is carefully monitored to ensure that the resulting price has not been distorted by market power or other non-competitive influences. In short, the RPM RTO price is the measure established explicitly to place a financial value of capacity in the PJM market.

Moreover, in terms of fundamental economic principles, the RPM price is the correct measure of value, both in the short- and long-run. In the short run, the RPM auction price is the "right price" in terms of economic efficiency. It is the closest approximation to the market value of the reliability value of capacity, recognizing that the administrative nature of the capacity product and the lack of sufficient structural competition in the market requires a degree of regulatory oversight. We maximize efficiency by pricing or transferring commodities at their market price, so that there is a rational trade-off between the value captured by utilizing a good versus selling it in the market. In the long run, the RPM is designed to provide the appropriate incentives for the entry of new, cost-efficient resources and the exit of inefficient resources over a

[20] If an FRR Entity has surplus Capacity Resources, above what are required in its FRR Capacity Plan greater than its "Threshold Quantity," it may sell that surplus in any RPM auction. The Threshold Quantity is the lesser of 450 MW or 3% of the FRR Entity's resource requirement. See RAA Section 1.82. and Schedule 8.1, Section D.2.

suitably long investment horizon; the success of this market design has been well documented, particularly in two reports by Mr. Graves' consultancy, The Brattle Group.

Because the RPM RTO auction price is efficient in both the long- and short-term, it follows that using any other price as the "market rate" in the MRO is unfounded. Using a capacity rate that is higher than market price would overstate the alternative cost at which CRES providers could have purchased capacity, but for the monopoly position the AEP Ohio has secured for itself by electing the FRR Alternative. Conversely, using a capacity rate that is lower than the market price—for example, $0/MW-day, which would be consistent with the net capacity cost requirement of AEP Ohio's generation fleet—would understate the price at which AEP Ohio could have sold this capacity to LSEs other than the CRES providers in its region, but for its election of the FRR Alternative.

In short, the only credible capacity price to use in valuing the MRO is the RPM RTO price established by PJM.

Q. MR. GRAVES RAISES CONCERNS THAT RPM DOES NOT ADDRESS ALL THE "IMPORTANT QUESTIONS" RELATED TO CAPACITY DEVELOPMENT. DO YOU AGREE?

A. No, I believe that Mr. Graves's testimony on this point is either unclear or misleading. He states:

> RPM is not trying to address the question of what new resources could be economically or socially attractive over a very long period of time. Thus, it does not address environmental considerations, long term energy benefits or risks from alternative fuel mixes, new technology development, or local jobs and infrastructure goals. Those may be important questions, but they are beyond the scope of RPM.[21]

[21] Direct Testimony of AEP Ohio witness Frank Graves, filed March 30, 2012, Case No. 11-346 ("Graves Direct"), 6:16–21.

It is simply wrong to suggest that RPM fails to procure the most efficient set of long-term resources to serve the full range of services needed in PJM. To the contrary, RPM—*in combination with other markets* for energy, ancillary services, fuels, renewable energy credits, emissions credits, etc.—has provided and should continue to provide exactly the right set of signals to spur investors to make the most profitable *long-run* decisions. This is how markets work: investors consider all costs, all revenue streams, and relevant risks, then select the projects with the highest risk-adjusted expected return.

Mr. Graves appears to be suggesting that RPM will only spur development of least-cost capacity resources, such as demand response and single-cycle gas turbines. Such a view would give too little credit to investors, who are fully able to recognize that the *total* return from other investments may be higher, even if the cost-per-kW is also higher. For example, since the implementation of RPM developers in PJM have added a diverse mix of capacity resources, including some gas turbines and demand response, as well as incremental investments in generator uprates and environmental retrofits.

It is instructive to note that the trends in new capacity brought forth by RPM mirror decisions made by AEP itself, and by planning entities across the country. During its time as an FRR Entity, AEP has not chosen to commission any new coal-fired generation, but instead has invested in gas-fired assets and has now proposed a solar generation facility. Even in Colorado, the heart of coal country, state regulators have opted to repower coal facilities using natural gas, not only to reduce pollution and associated costs, but also to integrate wind energy more effectively.[22] In my view, these common choices affirm the ability of the RPM design to lead investors to make similar

[22] See Colorado Public Utilities Commission, Final Order Addressing Emissions Reduction Plan, Decision C10-1328 (December 15, 2010).

decisions to those that integrated planning would produce, but without the risk of creating stranded costs.

The question ultimately is whether the *market* will make decisions about new resource development—and bear the risks of poor investment decisions—or whether *regulators* will make those investment decisions through integrated resource planning and shift the risks of decisions that turn out badly to ratepayers. This question is a policy question, and one that Ohio lawmakers settled, as a general matter, in favor of the operation of competitive wholesale markets, while assigning a "backstop" role to the PUCO.

B. CAPACITY PRICING IN AEP OHIO'S ALTERNATIVE MRO BENCHMARK

Q. HAS AEP OHIO PRESENTED AN "ALTERNATIVE MRO" CALCULATION?

A. Yes. Mr. Allen and Ms. Thomas discuss an "alternative MRO" that, instead of using a $355.72/MW-day capacity price, uses the two-tiered capacity pricing that AEP Ohio has offered as part of its modified ESP. In particular, AEP Ohio proposes to set the capacity rate at $145.79/MW-day for "Tier 1" or $255.00/MW-day for "Tier 2." The lower Tier 1 rate would be available to a small but increasing fraction of shopping customer loads over the course of the three-year ESP period.[23]

Q. WHAT IS THE BASIS THAT AEP OHIO PROVIDES FOR THE $145.79/MW-DAY TIER 1 RATE?

A. AEP Ohio witness Allen explains that "The rate for the Tier 1 priced capacity was established based on the Final Zonal Capacity Price adjusted for the RPM Scaling Factor, the Forecast Pool Requirement and losses for PJM Delivery Year 2011/2012

[23] Allen Direct, 6:8–17.

($145.79/MW-day) and will remain fixed at that level throughout the modified ESP period."[24]

Q. IS THIS APPROACH A SOUND BASIS FOR PRICING CAPACITY DURING THE MODIFIED ESP PERIOD?

A. No, it is not. Although AEP Ohio does use an RPM rate for pricing capacity—as it ought—it is using a stale price. Just as AEP Ohio witness Thomas took care to use current energy futures prices in establishing the Simple Swap values,[25] so too should AEP Ohio have taken similar care to use current capacity pricing. The market price for capacity varies from year to year, reflecting changes in supply, demand, transmission capability, and other factors. AEP Ohio has "cherry-picked" a relatively high market value for capacity in DY 2011/12 and applied that value to the three subsequent years. In DY 2012/13 and DY 2013/14, however, the market value of capacity dropped sharply, to $19.89/MW-day and $33.87/MW-day, respectively.[26] Although the DY 2014/15 capacity rate is slightly higher than the proposed Tier 1 rate, this small under-market valuation falls far short of compensating for the substantial over-valuation of capacity in DY 2012/13 and DY 2013/14.

Q. IS THE $255/MW-DAY TIER 2 RATE A MARKET-BASED VALUE?

A. No. AEP Ohio offers no economic rationale for the $255/MW-day rate. It appears to be an artifact of the rejected stipulation agreement; it certainly has no foundation in any market price nor even any identified cost to AEP Ohio.

---

[24] Allen Direct, 7:6–10.

[25] Thomas Direct, 14:13–18.

[26] These values are on a cost-to-load basis, consistent with the $145.79/MW-day Tier 1 rate.

Q. AT PAGES 6 AND 7 OF HIS TESTIMONY, AEP OHIO WITNESS NELSON DISCUSSES THE PRICING ARRANGEMENT THAT AEP OHIO FORESEES, WHEREBY AEP GENCO WILL SUPPLY CAPACITY FOR AEP OHIO SSO LOADS AT $255/MW-DAY. DO YOU HAVE ANY VIEWS ON THIS ARRANGEMENT?

A. Yes. Mr. Nelson states that "From January 1, 2015 through May 31, 2015 the AEP Genco will provide capacity at $255/MW-Day, but will no longer supply the energy for SSO customers under the SSO contract."[27] This is truly a remarkable arrangement from the standpoint of an economist. The $255/MW-day rate cannot be considered the product of an arm's-length negotiation. The RPM RTO rate in this period is only $153.89/MW-day for *annual* capacity. Even this price likely overstates the market value of January-to-May capacity, because (a) the supply of capacity for this winter- and spring period should be even higher, because incremental resources from NYISO and non-market areas outside of PJM not needed for the summer peak will be available, and (b) the demand for resources will be lower than full-year resources; PJM resources that failed to clear the BRA and any Incremental Auction, but have remained operational nonetheless, will likely accept almost any payment.

Q. WHY DOES IT MATTER WHETHER THE $255/MW-DAY IS AN ARM'S-LENGTH PRICE?

A. Being at least $100/MW-day above the market price, AEP GenCo's $255/MW-day rate gives the appearance of self-dealing. FERC, and regulators generally, generally look askance at contracts between affiliates that diverge significantly from market-tested prices, on the sound grounds that such contracts discourage competition and therefore ultimately raise prices to consumers.

[27] Direct Testimony of AEP Ohio witness Philip J. Nelson, filed March 30, 2012, Case No. 11-346, p 6:20-22.

C. THE PURPORTED VALUE OF "DISCOUNTED" CAPACITY

Q. IN COMPUTING THE QUANTIFIABLE BENEFITS OF THE MODIFIED ESP, WHAT IS THE LARGEST SINGLE BENEFIT THAT AEP OHIO ASSERTS?

A. As shown on AEP Ohio witness Thomas's Exhibit LJT-1, Page 1, more than all of the asserted quantifiable benefits arise from a single item: the claimed value of "discounted" capacity. This one item is calculated to be worth \$988.7 million, more than the total quantifiable benefits of \$960.6 million.

Q. DO YOU AGREE WITH THE WAY AEP OHIO HAS COMPUTED THIS LINE ITEM?

A. No, I do not. Leaving aside any quibble with the particulars of the calculation, such as the dubious levels of switching that AEP Ohio witness Allen assumes, this item should be zero on first principles. AEP Ohio witness Dias states that "AEP Ohio is proposing to provide generation capacity to CRES providers at a significant discount from what it would otherwise be willing to charge."[28] This is the voice of the monopolist speaking; in competitive markets, sellers of a commodity do not have the luxury of dictating what prices they are "willing to charge" their customers. Of course, a competitive supplier will rationally choose not sell at a price below its incremental cost to produce the item—the "to go" concept discussed earlier—but AEP Ohio is not using its net "to go" cost as the benchmark here, but rather it is using its calculation of embedded costs.

AEP Ohio's net "to go" costs are *negative* (\$46.78)/MW-day (after taking account of market energy earnings)—well below the RPM RTO prices in every year throughout the modified ESP period. The truth of this calculation is borne out by the fact that AEP

[28] Direct Testimony of AEP Ohio witness Selwyn Dias, filed March 30, 2012, Case No. 11-346, p. 10:10–11.

Ohio has sold surplus capacity into the BRA—clearly refuting Mr. Dias's assertion that the RPM RTO price is not a price that AEP Ohio would be "willing to charge."

Selling a commodity at the prevailing market price is not discounting. Consequently, AEP Ohio can take no credit for selling capacity to shopping customers at the RPM RTO price.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

Robert B. Stoddard

Vice President and
Practice Leader, Energy & Environment

MA and MPhil Economics
Yale University

BA Economics and Music
summa cum laude
Amherst College

Vice President Robert Stoddard heads CRA's Energy & Environment Practice. He has over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction; devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

Clients

Mr. Stoddard has been a consultant on electric market issues to a wide range of energy market stakeholders including ArcLight Capital Management, AES, American Wind Energy Association, Astoria Generating, Bangor Hydro Electric, California Independent System Operator, Citibank, City of New York, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada, Dominion, Duke Energy, Edison Mission Energy, EdF, Electricity Supply Board of Ireland, Emera, Energia dos Portugal, Energy Capital Partners, Energy East, Entergy Nuclear, FirstEnergy, FirstLight, GenOn, Hydro Québec, Independent Energy Producers Association, International Power, J. Aron & Company, Maine Energy Recovery Co., Maine Public Service, Midlands Cogeneration Venture, Morgan Stanley Capital Group, Morris Energy Group, New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, North American Energy Alliance, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, PJM Power Providers, Portland General Electric, Powerex Corporation, Rhode Island Speaker and the House of Representatives, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, and Williams Power.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products' net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.
- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.

- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.

- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Articles

With Edward L. Kim, Richard D. Tabors and Todd E. Allmendinger, “Carbitrage: Utility Integration of Electric Vehicles and the Smart Grid,” *Electricity Journal*, Vol. 25 No. 2, March 2012, pp.16–23.

Testimony and reports

"Update to the Analysis of the Impact of Cape Wind on Lowering New England Energy Prices," CRA report authored by Robert B. Stoddard, on behalf of Cape Wind Associates, LLC, filed in *Petition of NSTAR Electric Company for Approval of a Proposed Long-Term Contract for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83,* March 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-50-000. Affidavit in support of complaint seeking to require allocation of partial-year Auction Revenue Rights, March 2012.

California Independent System Operator, Inc., FERC Docket No. ER12-897-000. Affidavit in support of protest by NRG Energy, Inc. of proposed waiver of provisions of the Capacity Procurement Mechanism, February 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-19-000. Affidavit in support of complaint seeking to fund Financial Transmission Rights solely from Day-Ahead Market settlement surplus, December 2011.

"Resource Adequacy in Ohio's Restructured Market," CRA report authored by Robert B. Stoddard, on behalf of Duke Energy Ohio, December 2011.

Bangor Hydro Electric Company and Maine Public Service Company Request for Exemptions and Reorganization Approvals, Maine Public Utilities Commission Docket No. 2011-170. Rebuttal testimony on behalf of Emera regarding potential horizontal and vertical market power issues of proposed acquisitions, September 2011; live testimony, December 2011, March 2012.

PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., FERC Docket No. ER12-91-000. Affidavit on behalf of Duke providing cost-benefit analysis of its proposed transition from MISO to PJM in support of inclusion of transition costs in transmission rates, October 2011; rebuttal affidavit, November 2011.

In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125), Oregon Public Utilities Commission Docket No. UE-228. Rebuttal testimony on behalf of Portland General Electric assessing reasonableness of its mid-term hedging strategy for gas and electricity procurement, August 2011.

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83, Massachusetts D.P.U. Docket No. 10-54. Direct testimony on behalf of Cape Wind Associates, LLC, June 2010.

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al., FERC Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports, June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

"Contracting and Investment: A Cross-Industry Assessment" report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

Mirant Energy Trading, LLC, et al. v PJM Interconnection, LLC, FERC Docket No. EL08-8-000. Affidavit on the flaws in the market power mitigation rules for the Third Incremental Auction of the PJM Reliability Pricing Model capacity market., November 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group, July 2007.

PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September and October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant regarding bidding rules in capacity deficiency auction, February 2005.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June 2002 regarding transmission facilities contracts. Remand testimony, January to March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc. regarding implementation of market power mitigation in installed capacity markets, March 2002.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.

1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Education

1990	M.Phil., Economics, Yale University
1986	M.A., Economics, Yale University
1983	B.A. *summa cum laude*, Amherst College; Phi Beta Kappa
1979	Diploma, Westerville (OH) South High School

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Direct Testimony of Robert B. Stoddard on Behalf of FirstEnergy Solutions Corp.* was served this 4th day of May, 2012, via e-mail upon the parties below.

s/ Laura C. McBride
One of the Attorneys for FirstEnergy Solutions Corp.

Steven T. Nourse
Matthew J. Satterwhite
Anne M. Vogel
American Electric Power Corp.
1 Riverside Plaza, 29th Floor
Columbus, OH 43215
stnourse@aep.com
mjsatterwhite@aep.com
amvogel@aep.com

Jeanne Kingery
Dorothy K. Corbett
Duke Energy Retail Sales
139 East Fourth St.
1303-Main
Cincinnati, OH 45202
jeanne.kingery@duke-energy.com
dorothy.corbett@duke-energy.com

Daniel R. Conway
Christen M. Moore
Porter Wright Morris & Arthur
41 South High St.
Columbus, OH 43215
dconway@porterwright.com
cmoore@porterwright.com

David F. Boehm
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh St.. Suite 1510
Cincinnati, OH 45202
dboehm@bkllawfirm.com
mkurtz@bkllawfirm.com

Cynthia Fonner Brady
David I. Fein
550 W. Washington St., Suite 300
Chicago, IL 60661
cynthia.a.fonner@constellation.com
david.fein@constellation.com

Terry L. Etter
Office of the Ohio Consumers' Counsel
10 West Broad St., Suite 1800
Columbus, OH 43215
etter@occ.state.oh.us

Richard L. Sites
Ohio Hospital Association
155 East Broad St., 15th Floor
Columbus, OH 43215
ricks@ohanet.org

Thomas J. O'Brien
Bricker & Eckler
100 South Third St.
Columbus, OH 43215
tobrien@bricker.com

Shannon Fisk
2 North Riverside Plaza, Suite 2250
Chicago, IL 60606
sfisk@nrdc.org

Jay E. Jadwin
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, OH 43215
jejadwin@aep.com

Mark S. Yurick
Zachary D. Kravitz
Taft Stettinius & Hollister LLP
65 East State St., Suite 1000
Columbus, OH 43215
myurick@taftlaw.com
zkravitz@taftlaw.com

Michael R. Smalz
Joseph V. Maskovyak
Ohio Poverty Law Center
555 Buttles Ave.
Columbus, OH 43215
msmalz@ohiopovertylaw.org
jmaskovyak@ohiopovertylaw.org

Terrence O'Donnell
Christopher Montgomery
Bricker & Eckler LLP
100 South Third St.
Columbus, OH 43215
todonnell@bricker.com
cmontgomcry@bricker.com

Lisa G. McAlister
Matthew W. Warnock
Bricker & Eckler LLP
100 South Third St.
Columbus, OH 43215-4291
lmcalister@bricker.com
mwarnock@bricker.com

Gregory J. Poulos
EnerNOC, Inc.
101 Federal Street, Suite 1100
Boston, MA 02110
gpoulos@enernoc.com

William L. Massey
Covington & Burling, LLP
1201 Pennsylvania Ave., NW
Washington, DC 20004
wmassey@cov.com

Glen Thomas
1060 First Avenue, Ste. 400
King of Prussia, PA 19406
gthomas@gtpowergroup.com

Laura Chappelle
4218 Jacob Meadows
Okemos, MI 48864
laurac@chappelleconsulting.net

Henry W. Eckhart
2100 Chambers Road, Suite 106
Columbus, OH 43212
henryeckhart@aol.com

Pamela A. Fox
Law Director
The City of Hilliard, Ohio
pfox@hilliardohio.gov

C. Todd Jones
Christopher L. Miller
Gregory J. Dunn
Asim Z. Haque
Ice Miller LLP
250 West St.
Columbus, OH 43215
christopher.miller@icemiller.com
asim.haque@icemiller.com
gregory.dunn@icemiller.com

M. Howard Petricoff
Stephen M. Howard
Michael J. Settineri
Lija Kaleps-Clark
Benita Kahn
Vorys, Sater, Seymour and Pease LLP
52 E. Gay St.
Columbus, OH 43215
mhpetricoff@vorys.com
smhoward@vorys.com
mjsettineri@vorys.com
lkalepsclark@vorys.com
bakahn@vorys.com

Sandy Grace
Exelon Business Services Company
101 Constitution Ave. N.W.
Suite 400 East
Washington, DC 20001
sandy.grace@exeloncorp.com

Gary A. Jeffries
Dominion Resources Services, Inc.
501 Martindale St., Suite 400
Pittsburgh, PA 15212
gary.a.jeffries@dom.com

Kenneth P. Kreider
David A. Meyer
Keating Muething & Klekamp PLL
One East Fourth St., Suite 1400
Cincinnati, OH 45202
kpkreider@kmklaw.com
dmeyer@kmklaw.com

Steve W. Chriss
Wal-Mart Stores, Inc.
2001 SE 10th St.
Bentonville, AR 72716
stephen.chriss@wal-mart.com

Holly Rachel Smith
Holly Rachel Smith, PLLC
Hitt Business Center
3803 Rectortown Rd.
Marshall, VA 20115
holly@raysmithlaw.com

Barth E. Royer
Bell & Royer Co., LPA
33 South Grant Ave.
Columbus, OH 43215-3927
barthroyer@aol.com

David M. Stahl
Arin C. Aragona
Scott C. Solberg
Eimer Stahl Klevorn & Solberg LLP
224 South Michigan Ave., Suite 1100
Chicago, IL 60604
dstahl@eimerstahl.com
aaragona@eimerstahl.com
ssolberg@eimerstahl.com

Werner L. Margard III
John H. Jones
William Wright
Thomas Lindgren
Assistant Attorneys General
Public Utilities Section
180 East Broad St., 6th Floor
Columbus, OH 43215
werner.margard@puc.state.oh.us
john.jones@puc.state.oh.us
william.wright@puc.state.oh.us
thomas.lindgren@puc.state.oh.us

Stephanie M. Chmiel
Terrance A. Mebane
Carolyn S. Flahive
Thompson Hine LLP
41 S. High St., Suite 1700
Columbus, OH 43215
Stephanie.chmiel@thompsonhine.com
carolyn.flahive@thompsonhine.com
terrance.mebane@thompsonhine.com

Emma F. Hand
Douglas G. Bonner
Clinton A. Vince
SNR Denton US LLP
1301 K St., NW, Suite 600, East Tower
Washington, DC 20005
emma.hand@snrdenton.com
doug.bonner@snrdenton.com
Clinton.vince@snrdenton.com

Samuel C. Randazzo
Joseph E. Oliker
Frank P. Darr
McNees Wallace & Nurick
21 East State St., 17th Floor
Columbus, OH 43215
sam@mwncmh.com
joliker@mwncmh.com
fdarr@mwncmh.com

Colleen L. Mooney
David C. Rinebolt
Ohio Partners for Affordable Energy
231 West Lima St.
Findlay, OH 45840
cmooney2@columbus.rr.com
drinebolt@ohiopartners.org

Diem N. Kaelber
Robert J. Walter
Buckley King LPA
10 West Broad St., Suite 1300
Columbus, OH 43215
kaelber@buckleyking.com
walter@buckleyking.com

Trent A. Dougherty
Cathryn Loucas
Ohio Environmental Council
1207 Grandview Ave., Suite 201
Columbus, OH 43212
trent@theoec.org
cathy@theoec.org

Tara C. Santarelli
Environmental Law & Policy Center
1207 Grandview Ave., Suite 201
Columbus, OH 43212
tsantarelli@elpc.org

Joel Malina
Executive Director
COMPLETE Coalition
1317 F St., NW
Suite 600
Washington, DC 20004
malina@wexlerwalker.com

Jay L. Kooper
Katherine Guerry
Hess Corporation
One Hess Plaza
Woodbridge, NJ 07095
jkooper@hess.com
kguerry@hess.com

Allen Freifeld
Samuel A. Wolfe
Viridity Energy, Inc.
100 West Elm St., Suite 410
Conshohocken, PA 19428
afreifeld@viridityenergy.com
swolfe@viridityenergy.com

Robert Korandovich
KOREnergy
P. O. Box 148
Sunbury, OH 43074
korenergy@insight.rr.com

Dane Stinson
Bailey Cavalieri LLC
10 W. Broad Street, Ste. 2100
Columbus, OH 43215-3422
dane.stinson@baileycavalieri.com

Mark A. Whitt
Melissa L. Thompson
Whitt Sturtevant LLP
PNC Plaza, Suite 2020
155 East Broad St.
Columbus, OH 43215
whitt@whitt-sturtevant.com
thompson@whitt-sturtevant.com

Vincent Parisi
Matthew White
Interstate Gas Supply, Inc.
6100 Emerald Pkwy.
Dublin, OH 43016
vparisi@igsenergy.com
mswhite@igsenergy.com

Chad A. Endsley
Ohio Farm Bureau Federation
280 North High St.
P.O. Box 182383
Columbus, OH 43218
cendsley@ofbf.org

Brian P. Barger
4052 Holland-Sylvania Rd.
Toledo, OH 43623
bpbarger@bcslawyers.com

Joseph M. Clark
6641 North High Street, Suite 200
Worthington, OH 43085
jmclark@vectren.com

Sarah Reich Bruce
Ohio Automobile Dealers Association
655 Metro Place South, Suite 270
Dublin, OH 43017
sbruce@oada.com

Judi L. Sobecki
Randall V. Griffin
The Dayton Power & Light Company
1065 Woodman Dr.
Dayton, OH 45432
judi.sobecki@dplinc.com
randall.griffin@dplinc.com

Matthew R. Cox
Matthew Cox Law Ltd.
4145 St. Theresa Blvd.
Avon, OH 44011
matt@matthewcoxlaw.com

Roger P. Sugarman
Kegler, Brown, Hill & Ritter
65 E. State St., Suite 1800
Columbus, OH 43215
rsugarman@keglerbrown.com

Randy J. Hart
Rob Remington
David J. Michalski
Hahn Loeser & Parks LLP
200 Public Square, Suite 2800
Cleveland, OH 44114
rjhart@hahnlaw.com
rrremington@hahnlaw.com
djmichalski@hahnlaw.com

Sue A. Salamido
Kristin Watson
Cloppert, Latanick, Sauter & Washburn
225 E. Broad St., 4th Floor
Columbus, OH 43215
ssalamido@cloppertlaw.com
kwatson@cloppertlaw.com

Todd M. Williams
Williams Allwein and Moser LLC
Two Maritime Plaza, 3rd Floor
Toledo, OH 43604
toddm@wamenergylaw.com

Robert Burke
Braith Kelly
Competitive Power Ventures, Inc.
8403 Colesville Rd., Suite 915
Silver Spring, MD 20910
rburke@cpv.com
bkelly@cpv.com

Larry F. Eisenstat
Richard Lehfeldt
Robert L. Kinder, Jr.
Dickstein Shapiro LLP
1825 Eye St. NW
Washington, DC 20006
eisenstatl@dicksteinshapiro.com
lehfeldtr@dicksteinshapiro.com
kinderr@dicksteinshapiro.com

Jack D'Aurora
The Behal Law Group LLC
501 S. High Street
Columbus, OH 43215
jdaurora@behallaw.com