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The Supreme Court of Ohio

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SUPREME COURT OF OHIO

To wit: August 31, 2012

Case No. 2012-1494

SUMMONS

The following have been named as respondent in the enclosed action:

The Public Utilities Commission of Ohio

Todd A. Snitchler, Chairman

Cheryl Roberto, Commissioner

Steven D. Lesser, Commissioner

Andre T. Porter, Commissioner

Lynn Slaby, Commissioner
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215

You are hereby notified that a complaint for writ of mandamus and prohibition has been filed against you in the SUPREME COURT OF OHIO, 65 South Front Street, Columbus, Ohio 43215-3431, by Industrial Energy Users-Ohio, by and through their attorney, Samuel C. Randazzo, 21 East State Street, 17th Floor, Columbus, Ohio, 43215-4228.

Furthermore, you are hereby served with a copy of the complaint (enclosed) and are required to file an answer to the complaint or a motion to dismiss on or before the 21st day after service of this summons. See S.Ct.Prac.R. 10.5.

If you fail to respond timely to the complaint, this action will proceed before the Court.

IN WITNESS WHEREOF, I have hereunto subscribed my name and affixed the seal of the Supreme Court, this 31st day of August, 2012.

KRISTINA D. FROST CLERK

Justin Kudela DEPUTY

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IN THE SUPREME COURT OF OHIO

State of Ohio, ex. Rel. Industrial Energy Users-Ohio Relator, v. The Public Utilities Commission of Ohio Todd A. Snitchler, Chairman Cheryl Roberto, Commissioner, Steven D. Lesser, Commissioner, Andre T. Porter, Commissioner, and Lynn Slaby, Commissioner, Respondents.	:	Original Action in Prohibition and Mandamus 12-1494 Case No. ____________

COMPLAINT FOR WRITS OF PROHIBITION AND MANDAMUS

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Cheryl Roberto, Commissioner
Steven D. Lesser, Commissioner
Andre T. Porter, Commissioner, and
Lynn Slaby, Commissioner
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180 East Broad Street
Columbus, OH 43215

RESPONDENTS

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SUPREME COURT OF OHIO

{C38089:18 }

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On Behalf of Industrial Energy Users-Ohio

ATTORNEYS FOR RELATOR

IN THE SUPREME COURT OF OHIO

State of Ohio, ex. Rel. Industrial Energy Users-Ohio	:	
Relators,	:	Original Action in Prohibition and Mandamus
v.	:	
The Public Utilities Commission of Ohio Todd A. Snitchler, Chairman Cheryl Roberto, Commissioner, Steven D. Lesser, Commissioner, Andre T. Porter, Commissioner, and Lynn Slaby, Commissioner,	:	
Respondents.	:	Case No. ____________

COMPLAINT FOR WRITS OF PROHIBITION AND MANDAMUS

Now comes Industrial Energy Users-Ohio ("Relator" or "IEU-Ohio") and for its Complaint states:

JURISDICTION

1. This Court has jurisdiction over original actions in prohibition and mandamus brought to prevent the unlawful assertion of jurisdiction by the Public Utilities Commission of Ohio ("Commission") under Section 2(B)(1) of Article IV of the Ohio Constitution.

2. This Complaint for a Writ of Prohibition and Writ of Mandamus ("Complaint") seeks orders of the Court preventing the Commission from asserting jurisdiction to authorize increases in prices for competitive retail electric services using a Cost-Based ratemaking

methodology and from authorizing AEP-Ohio[1] to defer and collect, with interest, that portion of the increase that exceeds the otherwise applicable market-based prices payable by Competitive Retail Electric Service ("CRES") providers. The Complaint also seeks such other orders as are necessary to correct the above actions already unlawfully undertaken by the Commission.

PARTIES

3. IEU-Ohio is a membership association that addresses issues that affect the price and availability of energy, including electricity, on behalf of its members having plants and facilities located within Ohio. Many of IEU-Ohio's members have plants and facilities that purchase Standard Service Offer ("SSO") service supplied by AEP-Ohio. These members are non-shopping customers of AEP-Ohio. Other members purchase competitive retail electric service through a CRES provider. These members are shopping customers. All members in the AEP-Ohio service territory receive unbundled distribution service from AEP-Ohio.

4. The Commission is an administrative agency created by Ohio law and holding varying degrees of authority to regulate electric light companies, electric distribution utilities, electric utilities, and electric suppliers as defined by Section 4928.01(A), Revised Code. Respondents Todd A. Snitchler, Cheryl Roberto, Steven D. Lesser, Andre T. Porter, and Lynn Slaby are Commissioners. Respondent Todd A. Snitchler is the Chairman of the Commission.

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[1] In December 2011, Ohio Power Company ("OP") merged with Columbus Southern Power Company ("CSP"). Unless otherwise designated, AEP-Ohio is used throughout this Complaint and supporting memorandum to mean the merged entity.

CAPACITY RESOURCES

5. Because of structural and other reforms mandated by the Federal Energy Regulatory Commission ("FERC"), the ownership and control over critical electric facilities of and functions performed by incumbent vertically-integrated utilities have been separated. This mandated separation is part of a larger federal and Ohio effort to address the anticompetitive structure of the electric utility industry and to subject competitive services to the discipline of market forces. This separation has been largely accomplished in Ohio by depositing control over electric transmission facilities and reliability of the electric grid with regional transmission organizations ("RTO"), such as PJM Interconnection, LLC ("PJM"),[2] which are subject to FERC's regulatory jurisdiction. The separation of ownership and control and the reliance on RTOs such as PJM to achieve this separation are also mandated by Section 4928.12, Revised Code.

6. The separation of ownership and control and reliance on RTOs such as PJM are part of a comprehensive revision of the regulation and pricing of generation services that the General Assembly adopted in Amended Substitute Senate Bill 3 ("SB 3") and Amended Substitute Senate Bill 221 ("SB 221"). Under Ohio law, incumbent vertically-integrated electric utilities must separate competitive lines of business from non-competitive lines of

[2] PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability for more than 60 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system wide basis.

business through a corporate separation plan approved by the Commission.[3] That corporate separation plan must, at a minimum, preclude the electric distribution utility (AEP-Ohio in this case) from providing competitive retail electric service. Competitive retail electric service is only available through a fully separated affiliate of the electric distribution utility.[4]

7. Under Ohio law, customers have the right to obtain electric generation supply from a CRES provider.[5] The generation supply function of an electric distribution utility such as AEP-Ohio is confined by operation of law to meeting the needs of customers that are not receiving generation supply from a CRES provider. If a CRES provider fails to provide generation supply service, the CRES provider's customers default to the electric distribution utility's standard service offer or SSO until the customers obtain supply from a CRES provider. This obligation to stand ready to accept returning customers makes the electric distribution utility the provider of last resort, or POLR.[6] As the Court has previously explained, "POLR costs are those costs incurred by [the utility] for risks associated with its legal obligation as the default provider, or electricity provider, of last resort, for customers who shop and then return to [the utility] for generation service."[7]

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[3] Section 4928.17, Revised Code. This requirement became effective on January 1, 2001, the start date of competitive retail electric service.

[4] Section 4928.17(A)(1), Revised Code.

[5] Section 4928.03, Revised Code.

[6] *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 517 (2011).

[7] *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, 104 Ohio St.3d 530 n.5 (2004). The Court has admonished the Commission to "carefully consider what costs it is attributing" to "POLR obligations." *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St.3d 340, 2007-Ohio-4276, 872 N.E.2d 269, ¶ 26.

The POLR obligation of an electric distribution utility was created by SB 3 and has remained essentially the same since that time.[8] The Commission has previously held that the POLR risk of an electric distribution utility such as AEP-Ohio does not include any claim for migration risk or the related lost generation-related revenues that may occur because customers exercise their right to obtain generation supply from a CRES provider.[9]

8. As part of its reliability mission and in keeping with FERC's and Ohio's actions that replace traditional economic regulation with the discipline of competitive markets for services that are declared to be competitive, PJM has established various types of wholesale electric markets for unbundled generation-related electric services and products. These markets are organized by PJM, in part, to permit PJM to accomplish its region-wide reliability mission. Within these markets, compensation for these generation-related resources is established through periodic competitive bidding procedures or auctions in which suppliers of such resources offer to supply such resources at offered prices. The offers of suppliers seeking to provide the required amount of resources at the lowest price are accepted or "cleared" through this auction process and all offers that "clear" in the auction are compensated based on the results of the auction.

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[8] SB 3 created an obligation to provide default service in the amended Section 4928.14, Revised Code.

[9] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Security Plan; and the Sale or Transfer of Certain Generating Assets*, Case Nos. 08-917-EL-SSO, *et al.*, Order on Remand at 32 (Oct. 3, 2011) ("*ESP I*").

9. Within the PJM market structure, Capacity Resources are one of these generation-related resources. PJM mandates that all Load Serving Entities[10] ("LSE") make available to PJM an amount of Capacity Resources that PJM determines is required to permit PJM to maintain reliability within the PJM Region. PJM defines Capacity Resources to include generation plant and non-generation resources such as energy efficiency and demand response resources.[11]

10. The Capacity Resource obligation of LSEs within the PJM region allows PJM to call upon a pool of such Resources as needed to maintain the necessary balance between supply and demand within the electric grid.[12] PJM's FERC-approved Reliability Assurance Agreement ("RAA") documents this pooled approach to reliability. American Electric Power Service Corporation ("AEPSC"), the agent jointly for AEP-Ohio and other operating electric companies of American Electric Power ("AEP"), is a member of PJM and a signatory of the RAA.

11. The RAA generally requires that the compensation for Capacity Resources be established in accordance with PJM's FERC-approved Reliability Pricing Model ("RPM"). RPM is the primary and default means within PJM's electricity market for valuing Capacity

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[10] As defined by PJM, a "Load Serving Entity" or LSE shall means 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. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services. Reliability Assurance Agreement, Section 1.44 ("RAA") (Appx. at 14).

[11] *Id.*, Section 1.8 (Appx. at 7).

[12] Generally, PJM does not directly maintain reliability in the lower voltage and mostly distribution segment of the electric grid. However, reliability of the distribution segment requires maintenance of that reliability at the higher voltage levels.

Resources and establishing the compensation as between buyers and sellers of Capacity Resources. To value and price Capacity Resources, RPM relies upon periodic centralized capacity auctions in which eligible Capacity Resources are "cleared" or matched to forecasted load based upon prices offered by sellers of such Resources three years prior to the June to May "delivery year." This method of valuing Capacity Resources and establishing market-based compensation is referred to as the RPM-Based Pricing method that yields the RPM-Based Price.

12. During the periods relevant to this Complaint, the RPM Base Residual Auction Price for Capacity Resources in the unconstrained portions of the PJM Region, which includes the AEP-Ohio service territory, is $110.00 per megawatt-day ("MW-day") in planning year 2011/2012, $16.46/MW-day in planning year 2012/2013, $27.73/MW-day in planning year 2013/2014, and $125.99/MW-day in planning year 2014/2015. The final RPM-Based Prices for this same period and specific to the AEP-Ohio zone within the unconstrained portions of the PJM Region are $145.79/MW-day in planning year 2011/2012, $20.01/MW-day in planning year 2012/2013, $33.71/MW-Day in planning year 2013/2014, and $153.89/MW-Day in planning year 2014/2015.[13] The PJM planning year is a twelve-month period commencing on June 1.

13. In lieu of participating in RPM, an LSE such as an electric utility may elect to satisfy its capacity obligation through the Fixed Resource Requirement Alternative ("FRR Alternative"). Once an LSE selects the FRR Alternative, it is then responsible for satisfying the PJM-determined Capacity Resource obligation for all demand (retail,

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[13] The initial auction results are subject to certain published adjustments by PJM that, once made, yield the final RPM-Based Price for the AEP-Ohio zone within the unconstrained region of PJM.

wholesale, shopping and non-shopping customers) for the entire geographical footprint of the LSE's service area ("FRR Service Area"), provided that a CRES[14] provider may elect to satisfy its portion of this Capacity Resource in future years not covered by the then-current FRR Capacity Plan. An LSE that elects the FRR Alternative is defined as an FRR Entity for purposes of the RAA. An FRR Entity must provide a Capacity Resource Plan to PJM for PJM's review and approval. This Plan must identify the specific Capacity Resources that the FRR Entity shall permit PJM to control and dispatch for purposes of maintaining reliability within the PJM region. AEPSC, on behalf of the group of AEP electric distribution companies, including AEP-Ohio, has elected to participate through the FRR Alternative through May 31, 2015.

14. Since the FRR Entity assumes the Capacity Resource obligation for its entire footprint, the RAA provides the means by which CRES providers are to compensate the FRR

[14] Pursuant to Section 4928.01(B), Revised Code, "a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service." Section 4928.03, Revised Code, declares certain generation services to be competitive:

> Beginning on the starting date of competitive retail electric service, retail electric generation, aggregation, power marketing, and power brokerage services supplied to consumers within the certified territory of an electric utility are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers. In accordance with a filing under division (F) of section 4933.81 of the Revised Code, retail electric generation, aggregation, power marketing, or power brokerage services supplied to consumers within the certified territory of an electric cooperative that has made the filing are competitive retail electric services that the consumers may obtain subject to this chapter from any supplier or suppliers. Beginning on the starting date of competitive retail electric service and notwithstanding any other provision of law, each consumer in this state and the suppliers to a consumer shall have comparable and nondiscriminatory access to noncompetitive retail electric services of an electric utility in this state within its certified territory for the purpose of satisfying the consumer's electricity requirements in keeping with the policy specified in section 4928.02 of the Revised Code.

Entity for any Capacity Resources associated with the retail customers they serve within the FRR Service Area. Accordingly and during the 2012/2013 to 2014/2015 planning years, CRES providers supplying competitive retail electric generation service to retail customers in the AEP-Ohio service territory must compensate the FRR Entity for the portion of the total footprint Capacity Resource obligation associated with the demands of their customers. Under the RAA, these CRES providers are referred to as Alternative Retail LSEs.

15. To establish capacity-related compensation paid to an LSE operating under the FRR Alternative by a CRES provider serving retail customers located in the FRR Service Area, the RAA states in Section D.8 of Schedule 8.1:

> In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. 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 capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, 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 cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

16. Beginning in 2007, when the RAA became effective, the compensation for capacity available to CRES providers serving customers in the AEP-Ohio distribution service territory was set at the RPM-Based Price. As discussed herein, this changed early in 2012 because of actions by the Commission which are the subject of this Complaint.

17. Beginning in 2006 and through 2011, AEP-Ohio's SSO generation supply prices increased significantly. During this period and while AEP-Ohio's SSO electricity prices were on the rise, conditions in the wholesale electric market began to produce a decline in market-based wholesale generation supply prices. In November 2010 and as AEP-Ohio's retail customers began to favor generation supply available from CRES providers offering lower and more predictable prices, AEPSC, on behalf of AEP-Ohio, filed an application with FERC seeking to substantially and uniquely increase the compensation for Capacity Resources payable by CRES providers serving retail customers in AEP-Ohio's distribution service territory. More specifically, the November 2010 application asked FERC to authorize AEP-Ohio to discontinue RPM-Based Pricing and approve AEP-Ohio's use of an "embedded" or book cost method of ratemaking generally referred to herein as the "Cost-Based ratemaking methodology." In the November 2010 application, AEPSC sought FERC permission to displace the RPM-Based Pricing method with its Cost-Based methodology and, thereby, secure a significant increase in the compensation payable by CRES providers. The practical goal of the November 2010 application requesting a change from a market-based pricing methodology to a Cost-Based ratemaking methodology was to insulate AEP-Ohio's generation business from business risk created by the declines in generation supply prices in the wholesale electric market and the related competition from CRES providers.

18. In response to AEPSC's November 2010 FERC application, the Commission opened an investigation in *In the Matter of the Commission Review of The Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC ("*Capacity Case*") on December 8, 2010. In the December 8, 2010 Entry, the

Commission stated that it had previously approved an electric security plan for AEP-Ohio based on the continuation of RPM-Based Prices for capacity and, in case there was any doubt on the subject, the Commission adopted RPM-Based Pricing as the State Compensation Mechanism in Ohio under Section D.8 of Schedule 8.1 of the RAA.

19. In Comments filed with FERC in response to the AEPSC's November 2010 application, the Commission further explained its position: "Although the state compensation mechanism has implicitly been in place since the inception of AEP-Ohio's current Standard Service Offer, the Ohio Commission expressly adopted as its state compensation mechanism the AEP Ohio Companies' charges established by the reliability pricing model's three-year capacity auction conducted by PJM."[15] Further, the Commission requested that FERC dismiss AEPSC's application since Ohio's State Compensation Mechanism prevailed under the applicable provision of the FERC-approved RAA.[16] On January 20, 2011, FERC dismissed AEPSC's application. Subsequently AEPSC requested FERC to grant rehearing. The FERC granted rehearing for further consideration on March 24, 2011.

20. In response to the Commission's December 8, 2010 Entry in the *Capacity Case,* AEP-Ohio filed on January 7, 2011 an application for rehearing with the Commission and asserted that the Commission lacked jurisdiction to set the wholesale price for capacity available to CRES providers under federal and state law. AEP-Ohio was also advancing this claim in the FERC proceeding. The Commission granted the application for

[15] *American Electric Power Service Corporation*, FERC Docket No. ER11-2183-000, Comments Submitted on Behalf of the Public Utilities Commission of Ohio at 3 (Dec. 10, 2010) (Appx. at 426).

[16] *Id.* at 4 (Appx. at 429).

rehearing to allow itself additional time to consider the application on February 2, 2011. The Commission has not issued a final decision on AEP-Ohio's application for rehearing which the Commission granted on February 2, 2011.

21. With its Section 205 Application dismissed and the Commission directing AEP-Ohio to maintain the RPM-Based Pricing method, AEPSC (on behalf of OP and CSP) filed a complaint under Section 206 of the Federal Power Act ("FPA") ("Section 206 Complaint"). In the Section 206 Complaint, AEPSC unilaterally sought to amend Section 8.1 of the RAA to displace and subordinate the role of any state compensation mechanism and RPM-Based Pricing. It alleged, among other things, that the state compensation mechanism contained in Section 8.1 of the RAA was not just and reasonable because it would allow the Commission to establish a wholesale rate for capacity and circumvent AEPSC's ability to secure the specific type of cost-based compensation for such capacity that AEPSC favored. FERC has not addressed AEPSC's Section 206 Complaint.

22. The Commission set a procedural schedule in the *Capacity Case* calling for a hearing to commence in October 2011. Prior to the commencement of this hearing, AEP-Ohio entered into a Stipulation and Recommendation as part of the settlement of the *Capacity Case*, its pending electric security plan ("ESP") case, and several other cases. AEP-Ohio filed the Stipulation and Recommendation with the Commission on September 7, 2011. The Stipulation and Recommendation proposed a two-tiered capacity pricing scheme ("Pricing Scheme") as part of the resolution of the *Capacity Case*. The first tier of the Pricing Scheme was tied to RPM-Based Pricing and applicable to a percentage of CRES provider sales made to retail customers in AEP-Ohio's service area. For CRES provider

sales above this stated percentage (the second tier), the capacity price was arbitrarily set at $255/MW-day. On the same day that the Stipulation and Recommendation was filed with the Commission, AEP-Ohio hosted a conference call with members of the investment community in which AEP-Ohio made it clear that the Pricing Scheme was designed to protect AEP-Ohio's generation business and block retail customer choice for any sales outside the first tier. The Commission initially approved, with modifications, the Pricing Scheme on December 14, 2011. Over objections and a request to make the collection of above-market capacity prices subject to refund, the Commission permitted the Pricing Scheme to become effective on a "bills rendered" basis on January 1, 2012. After a public uproar about the rate-shock produced by the Commission-approved Stipulation and Recommendation, the Commission, however, rejected the Stipulation and Recommendation on February 23, 2012, finding that the Stipulation and Recommendation was not in the public interest. The Commission accompanied the rejection of the Stipulation and Recommendation with a directive that AEP-Ohio return to establishing capacity prices based on the RPM-Based Pricing method previously adopted by the Commission (as documented in the *Capacity Case*) and further directed that the *Capacity Case* be set for hearing.

23. AEP-Ohio refused to comply with the Commission's directive to restore the RPM-Based Pricing method of establishing the compensation due from CRES providers and sought relief from the Commission's order rejecting the Stipulation and Recommendation. The Commission granted AEP-Ohio's motion on March 7, 2012 and permitted the two-tier Pricing Scheme to continue until May 30, 2012, at which time the price of all capacity available to CRES providers was to be based on the RPM-Based Price as established for

the 2012/2013 PJM delivery year beginning June 1, 2012. The RPM-Based Price of capacity in the AEP-Ohio zone became $20.01/MW-day on June 1, 2012.

24. The Commission began an evidentiary hearing in the *Capacity Case* on April 17, 2012. The hearing concluded on May 16, 2012. In the hearing, AEP-Ohio continued to maintain that the Commission lacked subject matter jurisdiction to set the capacity price for generation related capacity service provided to CRES providers while it also sought authorization to establish prices for generation capacity service based on a Cost-Based ratemaking methodology that, according to AEP-Ohio, yielded a price of $355/MW-day. Stating that the Commission was not likely to issue a decision concerning its request to displace the Commission-approved RPM-Based Pricing method with AEP-Ohio's Cost-Based ratemaking methodology by June 1, 2012, AEP-Ohio sought additional relief so as to maintain the price of $145.79/MW-day[17] for first tier capacity, and the arbitrary second tier price of $255/MW-day. Over the opposition of IEU-Ohio and others, the Commission retreated from its prior directive that AEP-Ohio restore RPM-Based Pricing and granted the relief requested by AEP-Ohio on May 30, 2012.

25. IEU-Ohio filed applications for rehearing of the March 7, 2012 Entry and the May 30, 2012 Entry granting AEP-Ohio relief from the Commission's prior order authorizing AEP-Ohio to bill CRES providers at RPM-Based Prices. In each application for rehearing, IEU-Ohio demonstrated that the Commission did not have jurisdiction to authorize a capacity price billable to CRES providers other than the RPM-based price. The Commission granted both applications for rehearing to give itself additional

[17] As a result of the May 30, 2012 Entry, AEP-Ohio charged a price over seven times higher than the RPM-Based Price which the Commission had previously approved and which it had previously directed AEP-Ohio to restore.

consideration time.[18] Beyond granting these applications for rehearing, the Commission has not addressed the issues raised therein.

26. During the *Capacity Case*, AEP-Ohio's claim that it was proper for the Commission to authorize AEP-Ohio to increase its compensation for generation capacity service by shifting to a Cost-Based ratemaking methodology was contested. As already explained, AEP-Ohio contested the Commission's jurisdiction to address pricing for wholesale electricity transactions. Beyond AEP-Ohio, IEU-Ohio and other parties again demonstrated that the Commission lacked the jurisdiction to set prices for generation capacity service using a Cost-Based ratemaking methodology. In addition, IEU-Ohio and other parties demonstrated that to the extent that the Commission did have jurisdiction to set prices for generation capacity service using a Cost-Based ratemaking methodology the Commission had totally failed to follow the ratemaking process or formula that Ohio law mandates for unbundled electric non-competitive services that are subject to Ohio's cost-based form of ratemaking.

27. On July 2, 2012, the Commission issued its Opinion and Order in the *Capacity Case*. In the Opinion and Order, the Commission found that it had jurisdiction to authorize AEP-Ohio to significantly increase its compensation for generating capacity service based on Sections 4905.04, 4905.05, and 4905.06, Revised Code and Chapter 4909, Revised

[18] *Capacity Case*, Entry on Rehearing (Apr. 11, 2012); *Capacity Case*, Entry on Rehearing (July 11, 2012) (Appx. at 419-23).

Code.[19] The Commission further stated that its exercise of jurisdiction was consistent with the governing section of the RAA, Section D.8 of Schedule 8.1.[20]

28. The Commission found that it was unnecessary to determine if it was authorized to permit AEP-Ohio to significantly increase its compensation for generation capacity service under the terms of Chapter 4928, Revised Code.[21] As stated above, the Commission previously held (on December 8, 2010) that it had adopted the RPM-Based Pricing method as part of AEP-Ohio's ESP approved in *In the Matter of the Application of the Columbus Southern Power Company and Ohio Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets,* Case Nos. 08-917-EL-SSO, *et al.* ("*ESP I Case*").

29. In reaching its decision in the *Capacity Case*, the Commission invented and applied a Cost-Based ratemaking methodology to find that AEP-Ohio's unique cost of generation capacity service available to CRES providers is $188.88/MW-day.[22] However, it also determined that for the balance of the planning years 2012/13 and planning years 2013/2014 and 2014/15, AEP-Ohio would be authorized to bill CRES providers the much lower RPM-Based Price for generation capacity service.[23] It then found that AEP-Ohio could defer the portion of the $188.88/MW-day price not collected from CRES providers serving retail customers in AEP-Ohio's service area. It also permitted AEP-Ohio to add a

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[19] *Capacity Case*, Opinion and Order at 12 & 22(Appx. at 212 & 222).

[20] *Id.* at 13 (Appx. at 213).

[21] *Id.*

[22] *Id.* at 14-36 (Appx. at 214-236).

[23] *Id.* at 23 (Appx. at 223).

carrying charge (compounding interest) to the portion of the \$188.88/MW-day price not collected from CRES providers at the weighted average cost of capital ("WACC") until a recovery mechanism is authorized.[24] The Commission further provided that it would establish a recovery mechanism for the deferred portion of the \$188.88/MW-day price in another pending case, *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 Section 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO, *et al.* ("*ESP II Case*"), even though the record in the *ESP II Case* had already closed. Additionally, the Commission permitted AEP-Ohio to move the temporary capacity price further away from RPM-Based Pricing by continuing the two-tier Pricing Scheme, as modified by its May 30, 2012 decision, until August 8, 2012 or such earlier time as the Commission issued a decision in the *ESP II Case*.[25]

30. On August 8, 2012 in the *ESP II Case*, the Commission issued an Opinion and Order in which it authorized AEP-Ohio to raise electric bills by \$3.50/MWh through a non-bypassable rider to begin collection of the deferred portion of the \$188.88/MW-day price the Commission authorized in the *Capacity Case*. Of the total \$3.50/MWh increase, the Commission held that \$1/MWh would be applied to the deferred portion of the \$188.88/MW-day price that AEP-Ohio did not collect from CRES providers. As a result of the combined effects of the Commission's decisions in the *Capacity Case* and the *ESP II Case*, shopping and non-shopping customers will, beginning with electric bills

[24] *Id.* The Commission authorized AEP-Ohio to accrue interest at the WACC as the deferral was accumulated. Once amortization of the deferred balance commenced, the Commission determined that the balance should accrue interest at the long-term debt rate. *Id.* at 23-24 (Appx. at 223-24).

[25] *Id.* at 38 (Appx. at 238).

rendered with the September 2011 billing cycle, incur approximately $144 million in immediate rate increases associated with the move from the RPM-Based Pricing method to the Cost-Based ratemaking methodology. The Commission further authorized AEP-Ohio to defer the balance of a portion of the $188.88/MW-day price not collected through receipts for capacity provided to CRES providers and the $1/MWh immediate rate increase and stated that this residual deferred amount will be recovered by AEP-Ohio through future non-bypassable rate increases over a three-year period commencing after the conclusion of the ESP approved in the *ESP II Case*. The Commission's orders in the *Capacity Case* and the *ESP II Case* substantially increase AEP-Ohio's generation-related compensation through the introduction of immediate and future non-bypassable charges that transfer the risk of AEP-Ohio's above-market generation supply prices to AEP-Ohio's shopping and non-shopping customers during a period of time when the previously-approved RPM-Based Pricing method provides the greatest opportunity for such customers to reduce their electric bills. In other words, the Commission's orders subject customers to electric bill increases which are based on RPM-Based Pricing or Cost-Based Pricing, whichever is higher, and thereby wall off customers' full opportunity to reduce their electric bills through the exercise of the "customer choice" rights guaranteed by Ohio law.

THE COMMISSION LACKS JURISDICTION TO AUTHORIZE A PRICE FOR GENERATION CAPACITY SERVICE BASED ON A COST-BASED RATEMAKING METHODOLOGY

31. In authorizing AEP-Ohio to bill and defer its "cost" of capacity, the Commission, in the *Capacity Case* and the *ESP II Case,* is exercising or will exercise judicial or quasi-judicial power.

32. The Commission has jurisdiction over matters conferred upon it by the General Assembly. Commission jurisdiction extends to the regulation of an electric utility that includes an electric light company that is engaged on a for-profit basis in the business of supplying a non-competitive retail electric service or in the businesses of supplying both a non-competitive and competitive retail electric service in Ohio. An electric utility includes an electric light company which is a company engaged in the business of supplying electricity for light, heat, or power purposes to consumers within Ohio. An electric utility that supplies at least retail electric distribution service is an electric distribution utility ("EDU").

33. With regard to an electric utility, the Commission's jurisdiction to authorize retail rates for electric utilities is set out in Chapter 4909 and Chapter 4928, Revised Code. Chapter 4909, Revised Code, sets out the procedures and requirements for the authorization of rates and charges for non-competitive retail electric service. Chapter 4928, Revised Code, sets out the jurisdiction, procedures, and requirements that determine which services have been determined to be competitive and non-competitive and the scope and manner of regulation of competitive retail electric services.

34. The General Assembly has identified "retail electric generation" as a "competitive retail electric service." Since January 1, 2001, competitive retail electric service has not been subject to supervision and regulation by the Commission under Chapters 4901 to 4909, 4925, 4933, and 4963, Revised Code, (with exceptions not relevant to this matter), except Section 4905.06, Revised Code, as that Section relates to service reliability and public safety. Under Chapter 4928, Revised Code, the scope of the Commission's price

regulation as it relates to retail electric generation service of an EDU is limited to setting rates and other terms of the SSO under Sections 4928.141 to 4928.143, Revised Code.

35. Despite a lack of jurisdiction, the Commission, in the *Capacity Case*, asserted jurisdiction to entertain, act upon and approve an application to uniquely increase electric prices for generation capacity service available to CRES providers based upon a Cost-Based ratemaking methodology, citing Sections 4905.04, 4905.05, and 4905.06, and Chapter 4909, Revised Code, and finding that its exercise of authority under the cited Sections and Chapter was consistent with the terms of the RAA.

36. The Commission is without jurisdiction to entertain, act upon, or approve an application to uniquely increase electric prices for generation capacity service available to CRES providers based upon a Cost-Based ratemaking methodology or to defer any portion of any increase adopted from the use of such Cost-Based ratemaking methodology.

    a. Sections 4905.04, 4905.05, and 4905.06, Revised Code, do not provide jurisdiction to the Commission to increase electric prices for generation capacity service available to a CRES provider or for any competitive retail electric service based on a Cost-Based ratemaking methodology.[26]

    b. The Commission's ratemaking authority provided in Chapter 4909, Revised Code, applies exclusively to non-competitive services. Capacity service is a generation-related service declared competitive under Section 4928.03, Revised Code. The Commission has no jurisdiction to apply a Cost-Based ratemaking

[26] Chapter 4905 does not provide the Commission with the authority to set utility rates for any service provided by an electric utility company. *Indus. Energy Users-Ohio v. Pub. Util. Comm.*, 117 Ohio St.3d 486, 2008-Ohio-990 at ¶ 28 ("R.C. Chapter 4905 governs the commission's general power to regulate utilities, while R.C. Chapter 4909 governs the commission's power to set utility rates and charges.").

methodology to increase electric prices for competitive services under Chapter 4909, Revised Code.

c. The RAA is an agreement approved by the FERC. It cannot and does not delegate any type of ratemaking authority to the Commission including ratemaking authority to increase electric prices for generation capacity service through the use of a Cost-Based ratemaking methodology. The Commission's ratemaking and rate increasing authority is limited to such authority as the Commission has received from the General Assembly.

d. If the Commission is authorized by Chapters 4909 and 4928, Revised Code, to uniquely and substantially increase AEP-Ohio's compensation for generation capacity service by means of a Cost-Based ratemaking methodology, AEP-Ohio and the Commission have failed to comply with the detailed regulatory requirements associated with Ohio's form of Cost-Based ratemaking.

e. The Commission is without authority to authorize AEP-Ohio to bill and collect, through a non-bypassable rider applicable to retail electric consumers, all or any portion of the \$188.88/MW-day price for generation capacity service provided to CRES providers that is not billed and collected from such CRES providers.

f. The Commission is without authority to establish a phase-in of an electric distribution utility rate or price unless it is established under Sections 4928.141 to 4928.143, Revised Code. The Commission did not assert authority to establish a Cost-Based generation-related capacity price under Sections 4928.141 to 4928.143, Revised Code, and expressly determined that it did not exercise authority to establish such a price or charge under Chapter 4928, Revised Code.

The Commission is without authority to permit AEP-Ohio to increase electricity rates so as to recover the deferred balance in the *ESP II Case* through non-bypassable charges collected immediately or after the conclusion of the ESP approved in the *ESP II Case*, the terms of which are scheduled to be effective with bills rendered as of the first billing cycle of September 2012.

THE COMMISSION LACKS AUTHORITY TO AUTHORIZE GENERATION-RELATED TRANSITION REVENUE

37. By authorizing an increase in the price for generation capacity service for all or part of planning years 2012/2013 to 2014/2015 by means of a Cost-Based ratemaking methodology yielding a price far in excess of the price established by the market-based RPM-Based Pricing method previously approved by the Commission and adopted by the RAA, the Commission is authorizing electric rate increases to permit AEP-Ohio to collect additional generation-related transition revenue.

38. The Commission has no authority to increase electric prices to permit AEP-Ohio to bill and collect generation-related transition revenue or any equivalent revenue except as specifically authorized in Sections 4928.31 to 4928.40, Revised Code.

39. The period for recovery of generation-related transition revenue as authorized in Section 4928.31 to 4928.40, Revised Code, ended in 2005. Section 4928.38, Revised Code, states that after the period for collection of generation-related transition revenue ends, AEP-Ohio's generation business is required to be fully on its own in the competitive market. Additionally, Section 4928.141, Revised Code, compels the Commission to remove transition revenue from electric rates.

40. As part of a Commission-approved settlement agreement, AEP-Ohio agreed in 2000 that it would not seek generation-related transition revenue and that it would not impose lost generation-related revenue charges on shopping customers.

41. By operation of law including AEP-Ohio's binding commitment to not seek generation-related transition revenue in the future or impose lost generation-related revenue charges on shopping customers, the Commission has no authority to increase electric prices to permit AEP-Ohio to recover transition revenue.

RELATOR HAS NO ADEQUATE REMEDY AT LAW

42. The Commission's unlawful actions will cause injury to the Relator for which there is no adequate remedy at law.

43. This Complaint is supported by an Affidavit of Kevin Murray.

WHEREFORE, IEU-Ohio, Relator, respectfully prays for this Court to issue alternative Writs of Prohibition and Mandamus immediately that: (1) prohibit the Commission from inventing and applying a Cost-Based ratemaking methodology to increase significantly and uniquely AEP-Ohio's compensation for generation capacity service available to CRES providers serving retail customers located in AEP-Ohio's service area; (2) prohibit the Commission from authorizing AEP-Ohio to collect the above-market portion of such increased compensation on shopping and non-shopping customers through non-bypassable charges now and later; (3) to the extent that the Commission has authority to resort to a Cost-Based ratemaking methodology to uniquely and substantially increase AEP-Ohio's compensation for generation capacity service, prohibit the Commission from doing so without compliance with the procedural and substantive requirements set out in Ohio law in circumstances where Ohio's Cost-Based ratemaking methodology does apply; (4) prohibit the Commission from authorizing AEP-Ohio to phase-in such unique and substantial increases in AEP-Ohio's compensation for generation capacity service since the resulting $188.88/MW-day price does not stem from a proceeding under Sections 4928.141 to 4928.143, Revised Code; (5) require the Commission to restore the RPM-Based Pricing method previously adopted by the Commission as required by Section 4928.143(C), Revised Code; (6) prohibit the Commission from authorizing AEP-Ohio to obtain above-market compensation for generation capacity service increases since such above-market compensation amounts to additional transition revenue, or its equivalent, which is barred by Ohio law or otherwise conflicts with the General Assembly's mandate that an EDU's electric generation business shall be fully on its own in the competitive market; (7) require the Commission to enforce AEP-Ohio's Commission-approved obligation to not impose lost generation-related revenue charges on shopping customers; and (8) issue orders for such other relief as the Court deems appropriate based on the facts and circumstances.

Relator IEU-Ohio also prays for this Court to issue permanent Writs of Prohibition and Mandamus of the same effect following hearing and argument.

Respectfully Submitted,

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ATTORNEYS FOR RELATOR,
INDUSTRIAL ENERGY USERS-OHIO

IN THE SUPREME COURT OF OHIO

State of Ohio, ex. Rel. Industrial Energy Users-Ohio	:	
	:	Original Action in Prohibition
Relators,	:	
v.	:	
The Public Utilities Commission of Ohio Todd A. Snitchler, Chairman Cheryl Roberto, Commissioner, Steven D. Lesser, Commissioner, Andre T. Porter, Commissioner, and Lynn Slaby, Commissioner,	:	
Respondents.	:	Case No. ________________

MEMORANDUM IN SUPPORT

INTRODUCTION

IEU-Ohio seeks Writs of Prohibition and Mandamus to prevent the Commission from asserting jurisdiction to authorize AEP-Ohio to uniquely and substantially increase prices for generation capacity service available to CRES providers by means of a Cost-Based ratemaking methodology, and to bill and collect an amount in excess of the market-based price for capacity established by PJM's RPM-Based Pricing method. The Commission's decisions inventing and applying a Cost-Based ratemaking methodology to increase the price for generation capacity service and permitting AEP-Ohio to bill and collect that price rest on the premise that the Commission's authority to do so is provided by its general supervisory authority and its traditional ratemaking authority in Chapter 4909, Revised Code. The Commission has also asserted authority to authorize a phase-in of the Cost-Based capacity price increase under authority that applies only when the Commission is considering an SSO.

The Commission, however, has no jurisdiction to authorize an increase in the price for generation capacity service available to CRES providers serving customers in AEP-Ohio's service area by inventing and substituting a Cost-Based ratemaking methodology for the market-based ratemaking method previously approved by the Commission. And even if the Commission had authority to resort to a Cost-Based ratemaking methodology to authorize an increase in the price for generation capacity service, such authority cannot be exercised without compliance with mandatory statutory requirements. Similarly, the Commission has no authority to increase electricity prices through a non-bypassable charge that collects, with interest, the deferred difference between the price established by the previously approved RPM-Based Pricing method and $188.88/MW-day, the so-called "cost" of capacity. Due to the Commission's unlawful assertion of jurisdiction, retail customers including members of IEU-Ohio will be forced to pay AEP-Ohio hundreds of millions of dollars in above-market compensation for generation capacity service provided to CRES providers.

The Commission's acquiescence in AEP-Ohio's efforts to extract revenue from customers in excess of market-based prices when those prices are low will frustrate customer choice. At a time when customers such as IEU-Ohio's members have an opportunity to benefit from shopping because wholesale capacity and energy prices are relatively favorable to customers, the Commission should be encouraging shopping as required by the State Energy Policy, and the Commission's obligation to effectuate that policy.[27] If the Commission's unlawful orders are permitted to stand, however, AEP-Ohio's rates will be increased by hundreds

[27] Sections 4928.02 & 4928.06, Revised Code.

of millions of dollars that will be unavoidable in the near term. With the expectation that electric prices will increase after 2015, the Commission's unlawful orders also have the effect of piling on additional costs for customers in the longer term. Thus, the Commission's unlawful assertion of jurisdiction to authorize electric price increases for generation capacity service through the use of a Cost-Based ratemaking methodology also deprives consumers of the customer-choice dividend promised by SB 3, a promise that was somewhat deferred by AEP-Ohio's collection of hundreds of millions of dollars in generation-related stranded costs.

SUMMARY OF ARGUMENT

Despite express limitations on its jurisdiction, the Commission held, in the Commission proceedings at issue here, that it may resort to a Cost-Based ratemaking methodology to uniquely and significantly increase AEP-Ohio's compensation for generation capacity service based on its general supervisory powers under Sections 4905.04, 4905.05, and 4905.06, and Chapter 4909, Revised Code. It also stated that its exercise of jurisdiction was consistent with the FERC-approved RAA. Based on the assertion of jurisdiction to authorize rate increases for competitive generation capacity service by means of a Cost-Based ratemaking methodology, the Commission authorized AEP-Ohio to obtain compensation of $188.88/MW-day (about nine times higher than the current market-based price of capacity). Despite its holding that the price for generation capacity service should be $188.88/MW-day, the Commission directed AEP-Ohio to bill to and collect from CRES providers receiving the generation capacity service the much lower RPM-Based Price. As to the difference between $188.88/MW-day and the RPM-Based Price, the Commission authorized AEP-Ohio to recover that difference from shopping and non-shopping customers through non-bypassable rate increases. Based on the Commission's action, part of the difference is payable by shopping and non-shopping customers through a non-bypassable rate increase that the Commission authorized through May 31, 2015. The Commission also authorized future rate increases by permitting AEP-Ohio to collect any remaining amount of the $188.88/MW-day tab over three years following May 31, 2015 through another non-bypassable rider again applicable to shopping and non-shopping retail customers. Each part of the Commission's decisions authorizing AEP-Ohio to increase electric prices and to effectively deprive consumers of beneficial opportunities in the electricity market manifests itself in rates and charges for competitive retail electric service that are substantially in excess of the applicable market-based prices and are unlawful.

First, the Commission lacks jurisdiction to invent or use a Cost-Based ratemaking methodology as the means by which it may authorize an increase in the price of generation capacity service uniquely applicable to CRES providers serving retail consumers in AEP-Ohio's service area. The General Assembly has declared retail generation service to be competitive. Retail electric generation service is defined to include *any* service involved in supplying or arranging for the supply of electricity to ultimate customers in this State, from the point of generation to the point of consumption.[28] There is no dispute that the provision of capacity to CRES providers is a generation service. Having defined retail electric service to cover the provision of generation service from end to end, the General Assembly in Section 4928.05(A)(1), Revised Code, precluded any Commission regulation under the general supervisory or rate making provisions of Title 49 with two exceptions. The first exception, under Section 4905.06, Revised Code, authorizes the Commission to address service reliability and public safety of retail electric service. The other exception permits the Commission to set the SSO prices under Sections 4928.141 to 4928.143, Revised Code. Nether exception is relevant here.

[28] Section 4928(A)(27), Revised Code.

The Commission instead relied on Sections 4905.04, 4905.05, and 4905.06 and Chapter 4909, Revised Code, to claim that it had authority to authorize a substantial increase in AEP-Ohio's compensation for generation service capacity prices. Sections 4905.04, 4905.05, and 4905.06, Revised Code, however, do not provide the Commission authority to invent or apply a Cost-Based ratemaking methodology as a means to authorize increases in generation service capacity compensation.[29] Because capacity service is a competitive electric service, the Commission also lacks authority to invent or apply a Cost-Based ratemaking methodology under Chapter 4909, Revised Code, and neither AEP-Ohio nor the Commission followed the detailed requirements associated with applications to increase rates under Chapter 4909, Revised Code, even if the provisions of that Chapter did provide a basis for Commission jurisdiction. Finally, the Commission cannot derive any authority to invent or apply a Cost-Based ratemaking methodology to authorize an increase in capacity service prices based on the RAA, a FERC-approved agreement. The RAA does not and cannot delegate authority to a state regulatory commission.

Second, the Commission's assertion of jurisdiction to delete the previously-approved RPM-Based Pricing method of establishing capacity prices and insert a Cost-Based ratemaking methodology as a means to authorize rate increases and above-market prices for generation-related service violates the statute of limitations that bars actions to obtain generation-related transition revenue as well as the collection of such revenue. When the General Assembly declared that generation service was competitive in SB 3, it offered electric utilities a transition period, the Market Development Period ("MDP"). During that period, the electric utility was

[29] *Indus. Energy Users-Ohio*, 2008-Ohio-990 at ¶ 28 ("R.C. Chapter 4905 governs the commission's general power to regulate utilities, while R.C. Chapter 4909 governs the commission's power to set utility rates and charges.").

permitted, with Commission approval, to seek and obtain generation–related transition revenue that was not otherwise recoverable in the competitive market. The period for the collection of generation-related transition revenue, however, ended in 2005. Once the MDP was over, the General Assembly mandated that an incumbent utility's generation business, the competitive business, was to be fully on its own in the competitive market and barred the Commission from authorizing "the receipt of transition revenues or any equivalent revenues by an electric utility."[30] Section 4928.141, Revised Code, which became effective in 2008, also specifically directs the Commission to preclude any collection of transition revenue beyond the previously approved term for such collection. Further, AEP-Ohio agreed in 2000, in a Commission-approved settlement, that it would not seek to recover generation-related transition revenue or collect lost generation revenue charges from shopping customers. By deleting the previously-approved RPM-Based Pricing method of establishing capacity prices and inserting a Cost-Based ratemaking methodology as a means to authorize rate increases and above-market prices for generation-related service, the Commission has violated and will continue to violate the statutory and contractual bars against the recovery of transition revenue or any equivalent revenue.

Third, the Commission has no authority to approve the collection of the balance of the \$188.88/MW-day price not collected from CRES providers through a non-bypassable rate increase imposed on shopping and non-shopping customers under Section 4928.143, Revised Code, or through a phase-in (also through a non-bypassable rate increase on shopping and non-shopping customers) under Section 4928.144, Revised Code. Section 4928.143, Revised Code provides no authority to the Commission to approve a non-bypassable rider to collect some or all of the difference between the RPM-Based Price and \$188.88/MW-day. Likewise, the

[30] Section 4928.38, Revised Code.

Commission cannot phase-in the balance of the capacity price not recovered from CRES providers with compounding interest under Section 4928.144, Revised Code. That Section provides the Commission authority to approve a phase-in only if the rate or price is approved in proceedings under Section 4928.141 to 4928.143, Revised Code. In approving the $188.88/MW-day generation service capacity price, the Commission held it was unnecessary to determine whether capacity service is governed by Chapter 4928, Revised Code, and instead relied on the general supervisory provisions of Chapter 4905 and Chapter 4909, Revised Code. The Commission's assertion of jurisdiction to authorize collection through non-bypassable rate increases of the difference between the RPM-Based Price and the $188.88/MW-day price, therefore, is unlawful.

Because the Commission is without jurisdiction to authorize an increase in the price for generation capacity service through the use of a Cost-Based ratemaking methodology or to authorize subsequent collection of the amount of such price not collected from CRES providers, the Court should issue an alternative writ prohibiting the Commission's unlawful assertion of jurisdiction and such additional orders as are necessary to correct the Commission's unlawful assertion of jurisdiction. Further, the Court should issue permanent writs of prohibition and mandamus prohibiting the Commission from asserting jurisdiction to authorize AEP-Ohio to unlawfully increase capacity prices in excess of RPM-Based Prices.

STATEMENT OF THE FACTS

1. Capacity Reliability and the PJM Structure

Capacity is a fundamental building block in the provision of electric generation supply.[31] In planning energy supply, the grid's designers seek to ensure that there is sufficient capacity in the form of generation facilities, transmission to bring energy from nearby resources, demand reduction, and energy efficiency so that the electric needs of customers are met and the electric grid is stable.[32]

To assure the stability and reliability of the electric grid, FERC and the states have mandated the development of regional transmission organizations ("RTO"). The RTO in which the Ohio EDUs participate is PJM, which includes members from thirteen states and the District of Columbia. As part of FERC's effort to remedy the anticompetitive electric industry structure which was dominated by vertically-integrated investor-owned electric utilities, FERC required vertically-integrated electric utilities to move to service unbundling, open access, comparable and non-discriminatory transmission service, and encouraged vertically-integrated electric utilities that owned generating plants to transfer operational control of their high voltage transmission facilities to independent RTOs such as PJM.

Over time, the role of RTOs, subject to FERC's supervision and regulation, has expanded beyond the operation and control of transmission assets to remedy the anticompetitive industry structure. RTOs have become responsible for maintaining real time reliability of the electric grid and do so in coordination with regional wholesale electricity markets. Under FERC's supervision, RTOs have done much to maintain reliability in ways that better check the abuses that occurred in the anticompetitive vertically-integrated industry structure. The RTOs are

[31] Jonathan A. Lesser and Leonardo R. Giacchino, *Fundamentals of Energy Regulation,* 278 (2007) ("Capacity is the ability to instantaneously supply energy.").

[32] *Id.* at 278-79.

managing the operation of regional electricity markets to secure economies of scale and scope with independent market-monitoring oversight to determine if, and when, RTO or FERC intervention is needed to address anticompetitive behavior or circumstances in which competition is not adequate to produce just and reasonable rates. These regional electricity markets typically include a number of products associated with the generation of electricity.

PJM began operating a regional electricity market in 1997. Within PJM, the current FERC-approved and supervised market structure includes separate products for capacity and energy as well as various ancillary services which include, for example, regulation and synchronized reserves. "The capacity market is designed to assure that capacity resources cover their fixed and variable costs from a combination of energy and ancillary market net revenues and capacity market revenues."[33]

Securing Capacity Resources to serve the PJM footprint is governed by comprehensive FERC-approved documents including PJM's RAA and provisions of the FERC-approved Open Access Transmission Tariff ("OATT"). Under the RAA, PJM's capacity market is intended to ensure the availability of necessary resources that can be called upon to maintain the necessary supply and demand balance for the entire footprint of PJM, not just the distribution service area of AEP-Ohio.[34] Each LSE within PJM is responsible for contributing owned or controlled Capacity Resources to the common pool of resources that are available to PJM to satisfy PJM's

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[33] Monitoring Analytics, Capacity in the PJM Market at 4 (Aug. 20, 2012) (available at http://pjm.com/documents/~/media/documents/reports/20120820-imm-and-pjm-capacity-whitepapers.ashx).

[34] RAA, Art. 2 (Appx. at 24).

reliability mission. These Capacity Resources include electric generating plants, eligible energy efficiency resources, and demand response resources.[35]

When the General Assembly enacted SB 3 in 1999, it included a requirement that owners of transmission facilities transfer control of such facilities to an RTO.[36] The separation of ownership and control and reliance on RTOs such as PJM is part of a comprehensive revision of the regulation and pricing of generation services that the General Assembly adopted in SB 3 and SB 221. *Under Ohio law, incumbent vertically-integrated electric utilities must separate* competitive lines of business from non-competitive lines of business through a corporate separation plan approved by the Commission.[37] That corporate separation plan must, at a minimum, preclude the electric distribution utility (AEP-Ohio in this case) from providing competitive retail electric service. Competitive retail electric service is only available through a fully separated affiliate of the electric distribution utility.[38]

In Ohio, customers have the right to obtain electric generation supply from a CRES provider.[39] The generation supply function of an electric distribution utility such as AEP-Ohio is confined by operation of law to meeting the needs of customers that are not receiving generation supply from a CRES provider. If a CRES provider fails to provide generation supply service, the customers of a CRES provider default to the electric distribution utility's standard service offer

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[35] *Id.*, Section 1.8 (Appx. at 7).

[36] Section 4928.12, Revised Code.

[37] Section 4928.17, Revised Code. This requirement became effective on January 1, 2001, the start date of competitive retail electric service.

[38] Section 4928.17(A)(1), Revised Code.

[39] Section 4928.03, Revised Code.

or SSO until the customers obtain supply from a CRES provider. This obligation to stand ready to accept returning customers makes the electric distribution utility the provider of last resort, or POLR.[40] As the Court has previously explained, "POLR costs are those costs incurred by [the utility] for risks associated with its legal obligation as the default provider, or electricity provider, of last resort, for customers who shop and then return to [the utility] for generation service."[41] The POLR obligation of an electric distribution utility was created by SB 3 and has remained essentially the same since that time.[42] The Commission has previously held that the POLR risk of an electric distribution utility such AEP-Ohio does not include any claim for migration risk or the related lost generation-related revenues that may occur because customers exercise their right to obtain generation supply from a CRES provider.[43]

2. *Capacity Pricing under the RAA*

Under the RAA, there are two means of securing sufficient Capacity Resources to maintain region-wide reliability. The first and default means of securing capacity is through the market-based RPM. The goal of RPM is to align capacity pricing with system, region-wide, reliability requirements and to provide transparent information to all market participants far

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[40] *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 517 (2011).

[41] *Constellation NewEnergy, Inc. v. Pub. Util. Comm.*, 104 Ohio St.3d 530 n.5 (2004). The Court has admonished the commission to "carefully consider what costs it is attributing" to "POLR obligations." *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St.3d 340, 2007-Ohio-4276, 872 N.E.2d 269, ¶ 26.

[42] SB 3 created an obligation to provide default service in the amended Section 4928.14, Revised Code.

[43] *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Security Plan; and the Sale or Transfer of Certain Generating Assets*, Case Nos. 08-917-EL-SSO, *et al.*, Order on Remand at 32 (Oct. 3, 2011) ("*ESP I*").

enough in advance of transactions so as to allow time for potential buyers and sellers to respond to the information. RPM relies upon a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through a base residual auction ("BRA"), incremental auctions ("IAs") and bilateral market transactions. BRAs are held each May three years in advance of each delivery year, which runs from June 1 through the following May 31. Subsequent to the BRA, up to three IAs are held to procure additional resources, if necessary, and to adjust commitments to reflect known changes in market requirements prior to the delivery year.

So that the auctions procure sufficient Capacity Resources to meet the anticipated peak load and a reserve to assure reliability, PJM determines a peak load forecast for each delivery year. PJM then calculates an installed reserve margin for the entire PJM region. Prior to conducting BRAs, PJM assesses the need to create locational deliverability areas ("LDAs"). LDAs are load pockets within the PJM footprint in which the ability to bring additional capacity into the area is constrained, therefore requiring the use of internal Capacity Resources within the LDAs to satisfy the region-wide reliability objective. The areas within PJM that are not LDAs are referred to as the "balance of the RTO zone." Depending on supply and demand conditions, differences in prices may occur for LDAs (the capacity price will likely be higher) from the balance of the RTO zone when the BRA is conducted. AEP-Ohio's distribution service area is located in the balance of the RTO zone.

The BRA is structured to obtain sufficient Capacity Resources to satisfy the projected pool requirement scaled to reflect normal weather. To establish the auction clearing price for Capacity Resources, PJM establishes a downward sloping demand curve called the variable resource requirement curve. The price of capacity is set at the point that the supply offer price and the variable resource requirement curves intersect. The use of the variable resource requirement curve may result in the procurement of Capacity Resources in excess of the reliability objective if the total cost of resource procurement for the LDAs or balance of the RTO zone is lower at the higher level of reliability than it would be at the target reliability objective. After the BRA and prior to the delivery year, PJM conducts three IAs. The IAs are conducted to allow for replacement resource procurement and increases and decreases in the reliability objective resulting from, for example, a change in load forecast. The results from all of the auctions are mathematically weighted to determine a final market-based zonal capacity price.

For settlement purposes, each PJM electric distribution company ("EDC") is responsible for allocating its normalized previous summer's peak (measured based on five coincident peaks) to each customer in the zone (both wholesale and retail). To assist in performing these allocations, PJM publishes information, known as the five coincident peaks or 5CP, for each summer, typically by mid-October. The 5CP reflects the five highest non-holiday weekday RTO unrestricted daily peaks from the summer. An individual customer's usage during those five hours is known as the peak load contribution or PLC.

During the periods relevant to this Complaint, the RPM Base Residual Auction Price for Capacity Resources in the unconstrained portions of the PJM Region, which includes the AEP-Ohio service territory, is $110.00/MW-day in planning year 2011/2012, $16.46/MW-day in planning year 2012/2013, $27.73/MW-day in planning year 2013/2014, and $125.99/MW-day in planning year 2014/2015. The final RPM-Based Prices for this same period and specific to the AEP-Ohio zone within the unconstrained portions of the PJM Region are $145.79/MW-day in planning year 2011/2012, $20.01/MW-day in planning year 2012/2013, $33.71/MW-Day in planning year 2013/2014, and \$153.89/MW-Day in planning year 2014/2015.[44] The PJM planning year is a twelve-month period commencing on June 1.

3. FRR Alternative

As an alternative to the requirement to participate in the periodic RPM competitive bidding process or auctions, PJM's FERC-approved documents regarding the PJM capacity market also allows LSEs[45] to use an alternative method to satisfy their capacity resource obligation to the PJM pool. This alternative method is known as the FRR Alternative.[46] The FRR Alternative permits an LSE to submit an FRR Capacity Plan (to be reviewed and approved by PJM) to satisfy the shared responsibility of all LSEs to commit Capacity Resources.[47] An LSE electing the FRR Alternative is an FRR Entity. AEPSC, acting on behalf of the group of affiliated AEP East operating companies including AEP-Ohio, made a FRR election in 2007.

When an eligible LSE elects the FRR Alternative, other LSEs, including CRES providers, have a limited opportunity to satisfy their portion of the PJM Capacity Resource obligation through the RPM method. In advance of the FRR Entity's submission of its Capacity Plan to PJM, these CRES providers may provide to the FRR Entity sufficient Capacity Resources to meet the capacity obligation of the switched load.[48] Effectively, this section of the

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44 The initial auction results are subject to certain published adjustments by PJM that, once made, yield the final RPM-Based Price for the AEP-Ohio zone within the unconstrained region of PJM.

45 RAA, Section 1.44 (Appx. at 14).

46 *Id.*, Schedule 8.1 (Appx. at 117-30). Definitions of "Capacity Resources," "FRR Alternative," "FRR Entity," and "FRR Capacity Plan" are available in the Definitions Section of the RAA. RAA, Article 1 (Appx. at 6-23).

47 *Id.*, Schedule 8.1.D (Appx. at 121-24).

48 *Id.*, Schedule 8.1, Section D.9 (Appx. at 123).

RAA requires the CRES provider to make a commitment to provide Capacity Resources three years in advance of the Planning Year. If CRES providers do not act within this timeframe, they provide Capacity Resource compensation to the FRR Entity in accordance with the RAA.

CRES provider compensation payable to an FRR Entity is governed by Schedule 8.1, Section D.8 of the RAA. The default method of establishing such compensation ties such compensation to the prices established by the RPM-Based Pricing method unless a state regulatory authority in a State regulatory jurisdiction that has adopted retail choice has adopted a "state compensation mechanism" as part of a plan of retail access. If a state regulatory authority has the power to establish a state compensation mechanism, the state compensation mechanism governs the Capacity Resource compensation payable by an alternative retail LSE (a CRES provider in Ohio). If the state regulatory authority cannot or has not established a state compensation mechanism, then the compensation payable by a CRES provider to the FRR Entity is tied to the otherwise applicable RPM-Based Price. Since the Commission previously adopted the RPM-Based Pricing method as the state compensation mechanism, CRES providers had been, until January 1, 2012, paying the RPM-Based Price for capacity available to CRES providers serving retail customers located in AEP-Ohio's distribution service area. In addition to RPM-Based Pricing (the default) and if there is no lawful state compensation mechanism, the RAA allows an FRR Entity to seek FERC approval to change the methodology of compensation from the RPM-Based Pricing method to another basis that is "just and reasonable" by filing an application pursuant to Section 205 of the FPA. A retail LSE also may seek to exercise its rights under Section 206 of the FPA to seek revisions to the RAA or OATT.[49]

[49] Schedule 8.1, Section D.8 of the RAA provides:

> In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load

RPM and FRR Alternative are byproducts of a FERC-approved settlement negotiated by many parties in a case in which PJM proposed changes to its market rules. That settlement, which AEPSC signed on behalf of all the AEP operating companies in PJM, was accepted by FERC on December 22, 2006.[50]

4. The Proceedings Regarding Capacity Prices

The capacity available to CRES providers serving retail customers located in AEP-Ohio's service area was priced based on the RPM-Based Pricing method from 2007 when the RAA become effective until January 2012. Additionally, the RPM-Based Pricing method was used by AEP-Ohio to support the year-over-year escalating SSO rates that became effective in 2009 as a result of the Commission's approval in the *ESP I* proceeding.[51]

> growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. 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 capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, 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 cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA. (Appx. at 123).

[50] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

[51] *Capacity Case*, Entry at 1-2 (Dec. 8, 2010) (Appx. at 352-53). In another proceeding, AEP-Ohio used the RPM-Based Prices to advocate the use of capacity at RPM-Based Prices to drive state-wide SSO auctions. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism and Phase In, and Tariffs for Generation Service,* Case No. 07-796-EL-ATA, Reply Comments of Columbus Southern Power Company and Ohio Power Company at 4-5 (Oct. 12, 2007).

As the market-based RPM-Based Price paid by CRES providers began to decline in combination with a general decline in wholesale electricity prices due to fundamental forces (declining natural gas prices and sharp downturn in the economy) and the default generation supply price in AEP-Ohio's SSO continued to rise, CRES providers offering lower generation supply prices began to enter AEP-Ohio's service area. About this same time, AEP-Ohio began maneuvering to obtain regulatory approvals to insulate its generation business from the discipline of competition. Since November 2010, AEP-Ohio has attempted to uniquely delete the default and previously-approved RPM-Based Pricing method and insert a so-called Cost-Based ratemaking methodology to substantially increase the compensation available from CRES providers making retail sales of generation supply in AEP-Ohio's distribution service territory.

AEP-Ohio's shopping blocking and new-found affection for a Cost-Based ratemaking methodology began with an application at FERC. On November 1, 2010, AEPSC, on behalf of OP and CSP, submitted an application in FERC Docket No. ER11-1995-000 and subsequently re-submitted an application in FERC Docket No. ER11-2183-000 ("Section 205 Application") seeking to displace the RPM-Based Pricing method with its Cost-Based ratemaking methodology and, thereby, secure a significant increase in the compensation payable by CRES providers.

Recognizing the danger that the Section 205 Application presented to customer choice, the Commission, on December 8, 2010, opened an investigation in the *Capacity Case*. After noting that it had approved AEP-Ohio's SSO rates in the *ESP I Case* based on the continuation of capacity pricing driven by the market-based RPM-Based Pricing method, the Commission explicitly "adopt[ed] as the state compensation mechanism for [AEP-Ohio] the current capacity charges established by the three-year capacity auction conducted by PJM, Inc. during the pendency of this review."[52]

In Comments filed with the FERC in response to the AEPSC's November 2010 Section 205 Application, the Commission further explained its position: "[a]lthough the state compensation mechanism has implicitly been in place since the inception of AEP-Ohio's current Standard Service Offer, the Ohio Commission expressly adopted as its state compensation mechanism the AEP Ohio Companies' charges established by the reliability pricing model's three-year capacity auction conducted by PJM."[53] Further, the Commission requested that AEPSC's application be dismissed because there was no need for FERC to advance its proceeding since the state compensation mechanism prevailed under the applicable provision of the RAA.[54] On January 20, 2011, FERC dismissed AEPSC's application. Subsequently, AEPSC requested rehearing of FERC's decision to dismiss the Section 205 Application, advancing the claim that the Commission lacked jurisdiction to authorize a Cost-Based capacity price. The FERC granted rehearing for further consideration on March 24, 2011.

In response to the Commission's December 8, 2010 Entry in which the Commission adopted the RPM-Based Pricing method as the state compensation mechanism, AEP-Ohio filed an application for rehearing. In its application for rehearing, AEP-Ohio argued that "the Commission's Entry establishing an interim wholesale capacity rate [was] unreasonable and unlawful because the Commission is a creature of statute and *lacks jurisdiction under both*

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[52] *Capacity Case,* Entry at 2 (Dec. 8, 2010) (Appx. at 353).

[53] *American Electric Power Service Corporation*, FERC Docket No. 11-2183-000, Comments Submitted on Behalf of the Public Utilities Commission of Ohio at 3 (Dec. 10, 2010) (Appx. at 428).

[54] *Id.* at 4 (Appx. at 429).

Federal and Ohio law to issue an order affecting wholesale rates regulated by the Federal Energy Regulatory Commission."[55] In its supporting memorandum, AEP-Ohio advanced the same argument concerning the Commission's lack of jurisdiction that it was advancing at FERC, *i.e.*, that the Commission was either preempted from addressing the wholesale price of capacity[56] or lacked the authority under Ohio law to establish a wholesale price for AEP-Ohio's provision to CRES providers of capacity to serve the CRES providers retail electric generation service customers.[57] The Commission granted rehearing to give itself additional time to consider the application for rehearing.[58] Since granting this application for rehearing based on AEP-Ohio's claim that the Commission lacked jurisdiction to approve a cost-based wholesale capacity price, the Commission has not addressed AEP-Ohio's rehearing application. As explained below, the Commission's actions in the *Capacity Case* reflect a pattern of granting rehearing and then failing to address the merits of the rehearing application.

With its Section 205 Application dismissed and a Commission order directing AEP-Ohio to charge RPM-Based Prices, AEPSC on behalf of OP and CSP filed a complaint with FERC under Section 206 of the FPA.[59] In the Section 206 Complaint, AEPSC sought to amend Section 8.1 of the RAA to displace and subordinate the role of any state compensation mechanism and

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[55] *Capacity Case*, Ohio Power Company's and Columbus Southern Power Company's Application for Rehearing at 3 (Jan. 7, 2011) (Appx. at 357) (emphasis added).

[56] *Id.* at 18-19 (Appx. at 372-73).

[57] *Id.* at 19-21 (Appx. at 373-75).

[58] *Capacity Case*, Entry on Rehearing (Feb. 2, 2011) (Appx. at 385).

[59] *American Electric Power Service Corporation v. PJM Interconnection, L.L.C.*, FERC Docket No. EL11-32-000, Complaint (Apr. 4, 2011).

RPM-Based Pricing.[60] It alleged, among other things, that the state compensation mechanism contained in Section 8.1 of the RAA was not just and reasonable because it would allow the Commission to establish a wholesale rate for capacity and circumvent AEPSC's ability to secure the specific type of cost-based compensation for such capacity that AEPSC favored.[61] FERC has not addressed AEPSC's Section 206 Complaint.

The Commission subsequently established a *Capacity Case* procedural schedule with an evidentiary hearing commencing on October 4, 2011. The hearing, however, did not take place as scheduled because AEP-Ohio submitted a strongly contested Stipulation and Recommendation ("Stipulation") to the Commission on September 7, 2011 that, in addition to addressing AEP-Ohio's pending ESP case, addressed wholesale capacity prices uniquely applicable to CRES providers. Despite AEP-Ohio's position that the Commission lacked jurisdiction to authorize such prices, the Stipulation provided for a two-tiered compensation structure applicable to CRES providers serving retail customers located in AEP-Ohio's distribution service area. For a limited percentage of CRES provider retail sales, the first-tier CRES provider compensation payable for wholesale generation capacity service was pegged to the RPM-Based Price. Remaining retail sales by CRES providers (the second tier) triggered compensation at an arbitrary amount of $255/MW-day. The Commission adopted the Stipulation with modifications to the proposed ESP and capacity pricing on December 14, 2011. AEP-Ohio implemented the Pricing Scheme on January 1, 2012. In response to applications for rehearing, however, the Commission granted rehearing and eventually rejected the Stipulation on

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[60] Section 16.4 of the RAA states that only the PJM Board may amend the RAA (Appx. at 74). Thus, the RAA bars AEPSC's effort to amend the RAA through its Section 206 Filing.

[61] *The Section 206 Filing* at 2-4.

February 23, 2012, finding that it was not consistent with the public interest.[62] Upon rejecting the Stipulation and in accordance with the requirements of Section 4928.143(C)(2), Revised Code, the Commission ordered AEP-Ohio to restore the prices, terms and conditions of the ESP approved in the *ESP I Case*.[63] The Commission accompanied the rejection of the Stipulation and Recommendation with a directive that AEP-Ohio return to establishing capacity prices based on the RPM-Based Pricing method previously adopted by the Commission (as documented in the *Capacity Case*) and further directed that the *Capacity Case* be set for hearing.

Despite the Commission's order to restore RPM-Based Prices, AEP-Ohio refused and continued to bill and collect for capacity under the Stipulation's two-tier Pricing Scheme. On February 27, 2012, it sought permission to maintain the Pricing Scheme from the Commission.[64] Over the protests of IEU-Ohio and other parties pointing out that the Commission lacked jurisdiction to authorize a non-RPM-Based Price, evade the ESP restoration requirements of Section 4928.143(C), Revised Code, and act on AEP-Ohio's claims without a hearing or evidence, the Commission granted AEP-Ohio's motion to maintain the Stipulation's two-tiered capacity pricing through May 31, 2012, and directed that thereafter such compensation would be based on RPM-Based Pricing.[65] As May 31, 2012 approached, AEP-Ohio filed a second motion seeking to extend *the rates* resulting from the first extension until the Commission resolved the pending *Capacity Case*.[66] Again over IEU-Ohio's and other parties' objections, the Commission

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[62] *Capacity Case*, Entry on Rehearing (Feb. 23, 2012) (Appx. at 388).

[63] *Id.* at 12 (Appx. at 399).

[64] *Capacity Case*, Motion for Relief and Memorandum in Support (Feb. 27, 2012).

[65] *Capacity Case*, Entry (Mar. 7, 2012) (Appx. at 401).

[66] *Capacity Case*, Motion for Extension (Apr. 30, 2012).

extended the deviation away from the previously approved RPM-Based Pricing method.[67] As a result of a May 30, 2012 Entry, AEP-Ohio was authorized to continue charging the higher tier-two price ($255/MW-day) and to charge a first-tier price of $145.79/MW-day instead of the newly effective RPM-Based Price, which on June 1, 2012 became $20.01/MW-day. In each instance in which the Commission authorized the continuation of the Pricing Scheme, the Commission also ignored requests by IEU-Ohio to order that the above market and illegal charges be collected subject to reconciliation.

After rejecting the Stipulation, the Commission also set a new procedural schedule for the *Capacity Case*. Throughout the hearing, AEP-Ohio continued to assert that the Commission lacked jurisdiction to address pricing applicable to CRES providers and, nonetheless, sought authorization to establish prices for generation capacity service based on a Cost-Based ratemaking methodology that, according to AEP-Ohio, yielded a price of $355/MW-day. Following the month-long hearing, the Commission found that it had jurisdiction to use a Cost-Based ratemaking methodology to set a capacity price for CRES providers serving customers in the AEP-Ohio service territory based on Sections 4905.04, 4905.05, and 4905.06, and Chapter 4909, Revised Code, and that its exercise of jurisdiction was "consistent with the governing section of the RAA," Section D.8 of Schedule 8.1.[68] Using the Cost-Based ratemaking methodology, the Commission found that the cost-based price of capacity billed and collected from CRES providers serving retail customers in AEP-Ohio's distribution service area is

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[67] *Capacity Case*, Entry (May 30, 2012) (Appx. at 446).

[68] *Capacity Case,* Opinion and Order at 12-13 (July 2, 2012) (Appx. at 201).

$188/MW-day.[69] The Commission, however, also held that it would not permit AEP-Ohio to bill CRES providers for the full amount of $188/MW-day price. Instead, it ordered AEP-Ohio to bill CRES providers the RPM-Based Price and stated it would authorize accounting changes to allow AEP-Ohio to defer the difference between what it collected and $188.88/MW-day and establish a mechanism for the collection of the deferred amount in the *ESP II Case*.[70] The Commission issued the *Capacity Case* Opinion and Order after the hearing in the *ESP II Case* had closed.

5. ESP II Case

Meanwhile, the *ESP II Case* in which the Commission indicated it would identify the recovery mechanism for the portion of the $188.88/MW-day capacity price not payable by CRES providers was also proceeding to a decision.

In January 2011, AEP-Ohio filed its Application to establish its second ESP. As described above, AEP-Ohio sought to resolve that Application through a contested Stipulation that the Commission approved in December 2011 and then rejected in February 2012. In its February 23, 2012 Entry on Rehearing rejecting the Stipulation, the Commission directed AEP-Ohio to provide notice of whether it would proceed on its initial application, amend the application, or withdraw the application.

AEP-Ohio responded to the Commission's Entry on Remand by providing notice that it would file a revised ESP application. On March 30, 2012, AEP-Ohio an application proposing a "Modified ESP" that in addition to addressing the terms and conditions of the SSO also proposed to implement a new CRES provider capacity Pricing Scheme with a first-tier price of $146/MW-day for a percentage of sales to each retail generation customer class and $255/MW-day for any

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[69] *Id.* at 23 & 36 (Appx. at 223 & 236).

[70] *Id.* at 23-24 (Appx. at 223-24).

sales above the first-tier sales. AEP-Ohio also proposed a "lost revenue" charge on all customers to assure that generation service related revenue was not lost because of customers electing to obtain generation supply from CRES providers. Opposed by every customer group and CRES provider that intervened in the *ESP II Case*, the Modified ESP went to hearing and the Commission issued an Opinion and Order ("*ESP II Order*") modifying and approving the Modified ESP on August 8, 2012.

In the *ESP II Order*, the Commission rejected AEP-Ohio's new two-tier capacity pricing scheme. Claiming authority under Section 4928.143, Revised Code, however, the Commission approved a non-bypassable rider called the Retail Stability Rider ("RSR") that compensates AEP-Ohio for generation-related revenue that would otherwise be lost by AEP-Ohio as a result of customers switching to CRES providers. As approved by the Commission, the RSR will provide AEP-Ohio with above-market generation-related revenue of $508 million over the term of the ESP.[71] To collect the $508 million, the Commission initially authorized the RSR to be set at $3.50/MWh ($.0035/kWh), on average. The Commission further directed AEP-Ohio to credit $1/MWh collected through the non-bypassable RSR to cover a portion of the $188.88/MW-day capacity price adopted by the Commission in the *Capacity Case*, the portion not paid by CRES Providers.[72] As a result of the RSR, shopping and non-shopping customers will be charged $144 million for capacity provided to CRES providers.[73] The Commission further authorized AEP-Ohio to create a regulatory asset for the balance of capacity compensation ($188.88/MW-day) not paid by CRES and not shifted to shopping and non-shopping customers through the RSR,

[71] *ESP II Case*, Opinion and Order at 35 (Appx. at 303).

[72] *Id.* at 36 (Appx. at 304).

[73] *Id.* at 75 n.32 (Appx. at 343).

with a carrying charge to be applied to the regulatory asset set at the weighted average cost of capital, compounded annually.[74] Claiming authority under Section 4928.144, Revised Code, to phase-in the balance of the wholesale capacity compensation ($188.88 MW-day) not paid by CRES providers and not shifted to shopping and non-shopping customers through the non-bypassable RSR, the Commission held that such remaining balance of the capacity compensation will be recovered over three years through a non-bypassable charge to be authorized after the conclusion of the ESP ordered in the *ESP II Case*.[75]

The Commission's orders in the *Capacity Case* and the *ESP II Case* substantially increase AEP-Ohio's generation-related compensation through the introduction of immediate and future non-bypassable charges that transfer the risk of AEP-Ohio's above-market generation supply prices to AEP-Ohio's shopping and non-shopping customers during a period of time when the previously-approved RPM-Based Pricing method provides the greatest opportunity for such customers to reduce their electric bills. In other words, the Commission's orders subject customers to electric bill increases that are based on RPM-Based Pricing or Cost-Based ratemaking methodology, whichever is higher, and thereby wall off customers' ability to exercise customer choice rights guaranteed by Ohio law.

LAW AND ARGUMENT

Proceedings on a petition for writ of prohibition "test the subject-matter jurisdiction of the lower court."[76] The Court may grant a writ of prohibition if it is demonstrated that (1) the

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[74] After a recovery mechanism is established, AEP-Ohio may accrue carrying charges on the deferred balance at its cost of long-term debt. *Capacity Case*, Opinion and Order at 23-24 (Appx. at 223-24).

[75] *ESP II Case,* Opinion and Order at 52 (Appx. at 320).

[76] *State, ex rel. Corn v. Russo*, 90 Ohio St.3d 551, 554, 740 N.E.2d 265, 268 (2001).

Commission is about to exercise quasi-judicial power; (2) the exercise of that power is unauthorized by law; and (3) denial of the writ will cause injury for which no other adequate remedy in the ordinary course of law exists.[77] "If a lower court patently and unambiguously lacks jurisdiction to proceed in a cause, prohibition * * * will issue to prevent any future unauthorized exercise of jurisdiction and to correct the results of prior jurisdictionally unauthorized actions."[78] "In cases of a patent and unambiguous lack of jurisdiction, the requirement of a lack of an adequate remedy of law need not be proven because the availability of alternate remedies like appeal would be immaterial."[79] Additionally, the Court may grant a writ of mandamus to correct the results of jurisdictionally unauthorized actions.[80] A writ of mandamus will lie "where it is apparent from the record that the inferior court had no jurisdiction ... even though the party aggrieved may also be entitled to appeal."[81] As discussed below, the Commission's actions authorizing the use of a Cost-Based ratemaking methodology to establish unique compensation for generation capacity service available to CRES providers serving retail customers in AEP-Ohio's distribution service area and its authorization of AEP-Ohio to bill and collect from shopping and non-shopping consumers the portion of such compensation in excess of the compensation established by RPM-Based Pricing method through non-bypassable charges

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[77] *State ex rel. Columbus S. Power Company v. Fais,* 117 Ohio St.3d 340, 342-42 (2008) *(citing State ex rel. Westlake v. Corrigan*, 112 Ohio St.3d 463 (2007)).

[78] *Id.* (*citing State ex rel. Mayer v. Henson*, 97 Ohio St.3d 276 (2002)).

[79] *Id.* at 343 (*citing State ex rel. State v. Lewis*, 99 Ohio St.3d 97 (2003)).

[80] *State, ex rel. State Fire Marshall, v. Curl*, 87 Ohio St.3d 568, 569 (2000).

[81] *State, ex rel. Bullard, v. O'Donnell*, 50 Ohio St.3d 182, 184 (1990).

require the Court's intervention in the form of the extraordinary writs of prohibition and mandamus.

1. The Commission Is Exercising Quasi-Judicial Power

When the Commission authorizes a utility to collect or increase a rate for service, it exercises quasi-judicial functions.[82] In the *Capacity* and *ESP II Cases*, the Commission is exercising quasi-judicial authority to invent and apply a Cost-Based ratemaking methodology to substantially increase the generation-related compensation available to AEP-Ohio relative to the level of compensation called for by the previously approved and market-based RPM-Based Pricing method. It made findings of fact regarding the inputs and outputs associated with the Cost-Based ratemaking methodology and affected the rights of the parties by authorizing AEP-Ohio to substantially increase, on a non-bypassable basis, its compensation for generation capacity service. Under the Commission's rulings, the substantial increase in such generation-related compensation lands directly on all ultimate consumers of electricity. Additionally, the Commission's rulings make clear that the Commission will continue to exercise quasi-judicial power with respect to the *Capacity* and *ESP II Cases*.

2. The Commission's Exercise of Judicial or Quasi-Judicial Power to Invent and Apply a Cost-Based Ratemaking Methodology to Substantially Increase, Through Non-Bypassable Charges, AEP-Ohio's Compensation for Generation Capacity Service is Unauthorized by Law

The Commission's exercise of quasi-judicial authority in the *Capacity Case* and *ESP II Case* results in the application of a Cost-Based ratemaking methodology so as to authorize AEP-Ohio, an electric distribution utility, to obtain compensation for generation capacity service, a

[82] *Helle v. Pub. Util. Comm'n of Ohio,* 118 Ohio St. 434, syll. para. 1 (1928); *Ohio Pub. Interest Action Group v. Pub. Util. Comm'n of Ohio*, 43 Ohio St.2d 175, 183 (1975). *See also, Ohio Bell Tel. Co. v. Pub. Util. Comm'n of Ohio*, 301 U.S. 292, 304 (1937) (characterizing Commission ratemaking as quasi-judicial).

competitive electric service, far in excess of the amount permitted by Ohio law. Such exercise of this quasi-judicial authority includes shifting responsibility for the cost-based generation capacity service tab from CRES providers to shopping and non-shopping customers through non-bypassable charges. The Commission's exercise of quasi-judicial authority in the *Capacity Case* and *ESP II Case* is without any legal support.

a. The Commission has no authority to invent or apply a Cost-Based ratemaking methodology to significantly increase compensation for generation capacity service under its general supervisory authority, Chapter 4909, Revised Code, or the RAA

Although the Commission acknowledged that it must operate within the legislative structure provided by the General Assembly,[83] it nonetheless held that it may utilize a Cost-Based ratemaking methodology to significantly increase the compensation available to AEP-Ohio for the provision of generation capacity service based on its general supervisory powers and Chapter 4909, Revised Code.[84] The definitions in Section 4928.01, Revised Code,[85] in combination with the declarations and limitations in Sections 4928.03 and 4928.05, Revised Code, however, make clear that the Commission may not lawfully supervise or regulate any

[83] *Capacity Case,* Opinion and Order at 12 (Appx. at 212).

[84] *Id.* at 12-13 & 22 (Appx. at 212-13 & 222). The Commission has failed to address one additional problem with its position: the general supervisory authority contained in Chapter 4905, Revised Code, cannot be used to expand the Commission's rate setting authority. *Columbus S. Power Co. v. Pub. Util. Comm'n of Ohio,* 67 Ohio St.3d 535 (1993).

[85] "'Retail electric service' means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following service components: generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service." Section 4928.01(A)(27), Revised Code.

"'Competitive retail electric service' means a component of retail electric service that is competitive as provided under division (B) of this section." Section 4928.01(A)(4), Revised Code.

service involved in supplying or arranging for the supply of electricity to ultimate consumers in Ohio, from the point of generation to the point of consumption, once that service is declared competitive, except under very narrowly defined circumstances. From these definitions and limitations, this conclusion holds irrespective of the force of federal preemption regarding sales for resale transactions[86] and regardless of whether the service is called wholesale or retail.

The definition of "retail electric service" includes *any service, i.e.*, generation, transmission, and distribution service, from the point of generation to the point of consumption.[87] Since January 1, 2001 the effective date of competitive retail electric service, generation service has been deemed a competitive service. Section 4928.03, Revised Code, provides:

> Beginning on the starting date of competitive retail electric service, retail electric generation, aggregation, power marketing, and power brokerage services supplied to consumers within the certified territory of an electric utility are competitive retail electric services[88] that the consumers may obtain subject to this chapter from any supplier or suppliers.

Because the General Assembly declared retail generation service competitive many years ago, that service (which by definition includes any generation service from the point of generation to the point of consumption) is not subject to the Commission's supervision or

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[86] Of course, the Commission can exercise no authority except that authority that has been delegated to it by the General Assembly. To have any jurisdiction over wholesale services, the Commission would thus have to find some specific grant of authority by the General Assembly and this fundamental principle is true irrespective of the powers reserved to the federal government. But the General Assembly could not lawfully delegate authority to the Commission to regulate or supervise wholesale electric transactions because the authority to regulate commerce among the states is reserved to the federal government. U.S. Const., Art. I, § 8, cl. 3.

[87] Section 4928.01(A)(27), Revised Code.

[88] The definition of "retail electric service" (in combination with the balance of Chapter 4928) also makes it clear that a service component or function is either competitive or non-competitive. Because non-competitive service components are defined to be everything except competitive service components or functions, a service component must be either competitive or non-competitive.

regulation except as may be specifically permitted by Sections 4928.141 to 4928.143, Revised Code (which relate exclusively to the establishment of an SSO for *retail* electric customers) and Section 4905.06, Revised Code, as it provides for public safety and reliability.[89] Additionally, Section 4928.05(A), Revised Code, precludes the Commission from regulating such a competitive service under Chapter 4909, Revised Code. Thus, the Commission is barred from using its supervisory powers or the regulatory authority in Chapters 4905, 4909, and 4928, Revised Code, except as specifically noted, to address pricing for any generation service from the point of generation to the point of consumption.

The Commission has recognized the limits on its authority to regulate an EDU in its default supplier role. In its decision regarding the closure of AEP-Ohio's Sporn 5 generating facility in which AEP-Ohio sought recovery of the stranded costs resulting from the early closure of a coal fired generation plant, the Commission held:

> *[p]ursuant to Sections 4928.03 and 4928.05(A)(1), Revised Code, retail electric generation service is a competitive retail electric service and, therefore, not subject to Commission regulation, except as otherwise provided in Chapter 4928, Revised Code.* Just as the construction and maintenance of an electric generating facility are fundamental to the generation component of electric service, we find that so too is the closure of an electric generating facility. Additionally, although there are exceptions in Section 4928.05(A)(1), Revised Code, that permit Commission regulation of competitive services in some circumstances, the enumerated statutory exceptions do not include Sections 4905.20 and 4905.21, Revised Code, which otherwise govern applications to abandon or close certain facilities.
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> ...
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> [AEP-Ohio] also requests approval of a rider to collect the costs associated with the closure of Sporn Unit 5. *As discussed above, Section 4928.05(A)(1), Revised Code, generally prohibits Commission regulation of retail electric generation service.*[90]

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[89] Section 4928.05(A), Revised Code.

[90] *In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider,* Case No. 10-1454-EL-RDR, Finding and Order at 16-17 (Jan. 11, 2012) (emphasis added) (Appx. at 261-62).

Thus, the legislative declaration that the generation function is competitive precludes the Commission from exercising jurisdiction to regulate that service from the point of production to the point of consumption.

Because of the legislative prohibition contained in Section 4928.05(A), Revised Code, the Commission has no authority to invent or apply a Cost-Based ratemaking methodology to significantly increase AEP-Ohio's compensation for generation capacity service under Section 4905.04, 4905.05, and 4905.06, Revised Code. As noted previously, Section 4928.05, Revised Code, generally precludes the Commission from exercising any regulatory authority under Chapter 4905, Revised Code, in regard to the pricing of competitive services. The only exception found is for the continued regulation of safety and reliability under Section 4905.06, Revised Code. In the proceedings below, however, the Commission is not addressing the reliability or public safety of generation-related capacity service; it only authorized a substantial increase in generation capacity service compensation.

Moreover, the Commission's general supervisory powers do not grant the Commission the authority to set or increase the compensation for any utility rates or prices; the Commission's authority to set prices is contained in other statutes,[91] and the Commission cannot expand its pricing authority by relying on the statutes granting the Commission general supervisory

[91] Chapter 4909, Revised Code, grants the Commission authority to set rates for non-competitive services. Chapter 4928, Revised Code, grants the Commission authority to set rates for competitive generation services available to retail customers from an electric distribution company in its role as the provider of last resort or default supplier.

powers.[92] If the Commission had the authority to set or increase prices under its general supervisory authority for any matter, including the generation capacity service compensation available to AEP-Ohio, it would completely usurp the requirements and restrictions on the Commission's rate and price setting authority contained elsewhere in the Ohio Revised Code. As the Court has held, the General Assembly could not have intended to grant the Commission unbounded authority under its general supervisory powers and at the same time enacted specific ratemaking statutes.[93]

The Commission's reliance on Chapter 4909, Revised Code, also is unauthorized by law. The General Assembly has declared the generation function to be competitive.[94] Once declared competitive, the generation function is beyond the scope of the provisions contained in Chapter 4909, Revised Code.[95]

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[92] *Columbus S. Power Co. v. Pub. Util. Comm.*, 67 Ohio St.3d 535, 620 N.E.2d 835 (1993). In this case, the Ohio Supreme Court had to address whether the Commission could use its seemingly broad grant of authority contained in Section 4901.02, Revised Code to issue an order that conflicted with other ratemaking statutes. The Court held:

> The comprehensive ratemaking formula provided by the General Assembly is meant to protect and balance the interests of the public utilities and their ratepayers alike. *Dayton Power & Light Co. v. Pub. Util. Comm., supra,* 4 Ohio St.3d 91, 4 OBR 341, 447 N.E.2d 733. We cannot conclude that it was the General Assembly's intent under the above enabling statute, R.C. 4901.02(A), to permit the PUCO to disregard *that very formula* in instances in which it simply did not agree with the result Cf. *Consumers' Counsel, supra,* 67 Ohio St.2d at 165, 21 O.O.3d at 104, 423 N.E.2d at 828 ("the General Assembly undoubtedly did not intend to build into its recently revised [1976] ratemaking formula a means by which the PUCO may effortlessly abrogate that very formula").

Id. at 840.

[93] *Id.*

[94] Section 4928.03, Revised Code.

[95] Section 4928.05(A), Revised Code. Section 4933.81, Revised Code, dealing with the certified non-competitive service area of an electric distribution company, also makes it clear that

Even if the provision of capacity to a CRES provider was deemed a non-competitive electric service (something the Commission has not claimed), any action by the Commission to consider or approve a substantial increase in the compensation available for the provision of such non-competitive service would be unauthorized by law unless or until the Commission first satisfied significant procedural and substantive requirements associated with ratemaking for non-competitive services. The Commission's authority to set rates or increase compensation for non-competitive retail electric service is defined by Chapters 4901, 4909, 4933, 4935, and 4963, Revised Code.[96] In particular, Chapter 4909, Revised Code, sets out detailed requirements governing the approval of an increase in rates.

The first mandatory step in securing an increase in rates under Chapter 4909, Revised Code, is to file a notice of intent to file an application to increase rates.[97] The notice of intent must be sent to the mayor and legislative authority of each municipality served by the EDU.[98] No earlier than thirty days later, the public utility may then file its application to increase rates.[99]

"electric service" *excludes* electric power or energy furnished at wholesale or for resale and, effective on January 1, 2001, *excludes* competitive retail electric service.

[96] Under Chapter 4909, Revised Code, a utility can make a "first filing" for a new service to establish a rate and the Commission may approve the application without a hearing. Section 4909.18, Revised Code. If the Commission determines that the application is an application to increase rates, the Commission must follow the rate base rate of return method to evaluate the utility's revenue requirement (in total) and determine if additional compensation is warranted. Traditional ratemaking does not allow the Commission to adopt transition-to-market or glide path pricing.

[97] Section 4909.43, Revised Code; Rule 4901-7-1, Ohio Administrative Code ("O.A.C.").

[98] Section 4909.43, Revised Code.

[99] *Id.*

The president or vice-president and the secretary or treasurer of the public utility must verify the accuracy of the application.[100] The application itself must also contain extensive details.

An application to increase rates of a non-competitive service must include a description of its property used and useful in rendering service to the public as laid out in Section 4909.05, Revised Code. An application to increase rates must also include a list of current and proposed rate schedules the public utility seeks to establish.[101] Further, the application must contain a "complete operating statement of its last fiscal year, showing in detail all its receipts, revenues, and incomes from all sources, all of its operating costs and other expenditures, and any analysis such public utility deems applicable to the matter referred to in said application;" "a statement of the income and expense anticipated under the application filed;" and "a statement of financial condition summarizing assets, liabilities, and net worth."[102]

Once the EDU has filed a proper application with all the appropriate information with the Commission, the Staff at the Commission ("Staff") is required by statute to investigate the facts contained in the rate increase application.[103]

Once the Staff has completed its review, the Staff Report of Investigation must be docketed with the Commission and served on the mayors of all municipalities within the public utility's service territory.[104]

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[100] Section 4909.18, Revised Code.

[101] *Id.*

[102] *Id.*

[103] Section 4909.19(C), Revised Code.

[104] *Id.*

Parties that have intervened in the proceeding are then afforded a statutory right to object to the Staff Report of Investigation.[105]

AEP-Ohio did not attempt to satisfy any of the ratemaking requirements contained in Chapter 4909, Revised Code. AEP-Ohio did not file a notice of intent to file an application for a rate increase. AEP-Ohio did not present any evidence that it served a notice on the mayor and legislative authority of each municipality served by the EDU. AEP-Ohio did not present any evidence as to what property was used and useful in rendering capacity service to the public. Nor did AEP-Ohio have any of the information it presented in the *Capacity Case* verified by the proper personnel.

The Commission likewise failed to comply with the requirements of Chapter 4909, Revised Code. It made no findings regarding the test year, the value of AEP-Ohio's used and useful property, the inadequacy of AEP-Ohio's current compensation, or the other elements of the Cost-Based ratemaking methodology that apply to non-competitive electric services.

Therefore, even if Chapter 4909, Revised Code, could somehow be made relevant to the *Capacity Case*, the Commission and AEP-Ohio complied with none of the mandatory steps to seek, obtain, and authorize a rate increase.

The Commission's decision in the *Capacity Case* suggests that the Commission's may believe that its jurisdiction to authorize a significant increase in compensation available to AEP-Ohio for generation capacity service stems from the RAA, a FERC-approved agreement. Such a view is completely inconsistent with our system of government that reserves powers not conveyed to our federal government to the states. But and in any event, the Commission can

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[105] *Id.*

receive no ratemaking authority from a FERC-approved agreement; the Commission's authority is delegated by the General Assembly.

Although the Commission noted that its assertion of jurisdiction was "consistent with the governing section of the RAA" which the Commission stated "acknowledges the authority of a state regulatory jurisdiction, such as the Commission, to establish a state compensation mechanism,"[106] the RAA does not specify a Cost-Based ratemaking methodology. It only calls for a state compensation mechanism to prevail "where the state regulatory jurisdiction requires the switching customer or the LSE to compensate the FRR Entity for its FRR capacity obligations."[107] Indeed, the Commission's prior adoption of the RPM-Based Pricing method as the state compensation mechanism is also consistent with the RAA since the RAA specifically makes the RPM-Based Pricing method the default means of determining the compensation available to AEP-Ohio for generation service capacity available to CRES providers.

Additionally, the RAA language cited by the Commission does not purport to authorize the Commission to invent or apply a Cost-Based ratemaking methodology to significantly and uniquely increase the compensation available to AEP-Ohio for generation capacity service available to CRES providers. The RAA language only recognizes that such compensation shall control if a state regulator has adopted a state compensation mechanism in accordance with its lawful authority.

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[106] *Capacity Case*, Opinion and Order at 13 (Appx. at 213).

[107] RAA, Schedule 8.1, § D.8 (Appx. at 121).

The Commission's subject matter jurisdiction is set by the General Assembly.[108] As demonstrated previously, the General Assembly has not delegated authority to the Commission to invent or apply a Cost-Based ratemaking methodology to substantially and uniquely increase the compensation available to AEP-Ohio for generation capacity service available to CRES providers operating in AEP-Ohio's service area.[109] Because there is no basis in Ohio law for the Commission to assert jurisdiction, through the RAA, to invent or apply a Cost-Based ratemaking methodology to substantially and uniquely increase compensation available to AEP-Ohio for generation capacity service available to CRES providers, the RAA standing alone cannot extend the jurisdiction of the Commission to permit it to authorize a cost-based capacity charge.[110]

Therefore, none of the reasons the Commission advanced to justify its assertion of jurisdiction to establish a Cost-Based ratemaking methodology to substantially and uniquely increase the capacity-related compensation available to AEP-Ohio is lawful. Its general supervisory powers are limited to the regulation of safety and reliability and are not available to invent or apply a ratemaking methodology that significantly increases compensation for competitive or non-competitive electric services whether such services are retail or wholesale services. It has no rate increasing or price setting authority for competitive electric service

[108] *City of Washington v. Pub. Util. Comm'n of Ohio*, 99 Ohio St. 70, 72 (1918). *See also, Federal Deposit Insurance Corp. v. Board of Finance and Revenue*, 84 A.2d 495, 499 (Pa. Sup. Ct. 1951) (an agency cannot confer jurisdiction on itself).

[109] The General Assembly on occasion has indicated that the Commission must apply federal law as part of its regulatory decision-making. Section 4928.12, Revised Code (requiring transfer of control of transmission facilities to FERC-approved RTO). *See, also,* Section 4927.15, Revised Code (9-1-1 Service governed by rules adopted by Commission and Federal Communications Commission).

[110] *Fox v. Eaton Corp.*, 48 Ohio St.2d 236, 238 (1976); *In re Kerry Ford, Inc.*, 106 Ohio App.3d 643, 651 (10th Dist. Ct. App. 1995).

available from an EDU except that which is provided for setting the SSO pursuant to Sections 4928.141 through 4928.143, Revised Code. It has no authority to increase utility compensation for non-competitive electric services under Ohio's form of Cost-Based ratemaking in Chapter 4909, Revised Code, without satisfaction of the specific procedural and substantive requirements associated with such ratemaking. Further, the RAA does not and cannot delegate ratemaking authority to the Commission. Thus, the Commission acted without jurisdiction.

> ***b. Increasing AEP-Ohio's compensation for generation capacity service based on the application of a Cost-Based ratemaking methodology to a level in excess of the market-based compensation established by the previously approved RPM-Based Pricing method violates the statute of limitations on transition revenue claims and is otherwise unauthorized by law.***

The Commission's assertion of jurisdiction to invent and apply a Cost-Based ratemaking methodology for the purpose of substantially and uniquely increasing the compensation available to AEP-Ohio for generation capacity service above the compensation established by the RPM-Based Pricing method also violates the statutory and contractual bars on claims for above-market generation-related revenue (sometimes referred to as "stranded costs" or "stranded revenue") and actions by the Commission to authorize the collection of such revenue. It is undisputed that the "Cost-Based" ratemaking methodology invented and applied by the Commission to substantially and uniquely increase the generation capacity service compensation available to AEP-Ohio produces, in substance, an untimely and precluded opportunity for AEP-Ohio to collect, on a non-bypassable basis, generation plant-related transition revenue for many years in the future.[111] Pursuant to SB 3, however, AEP-Ohio's opportunity to seek and obtain recovery of above-

[111] In the *Capacity Case*, the Commission does not address the issue of transition revenue recovery. In the *ESP II Case*, the Commission rejects the argument that transition revenue recovery is "inappropriate," but does not reject the conclusion that AEP-Ohio will recover transition revenue as a result of the Commission's decision. *ESP II Case*, Opinion and Order at 32 (Appx. at 300).

market generation-related transition charges terminated, as a matter of statutory law, with the end of its MDP in 2005.[112] This new generation-related transition revenue claim comes well after the expiration of the time period specified by SB 3 for bringing a transition revenue claim.[113] It fundamentally conflicts with the General Assembly's mandate, in Section 4928.38, Revised Code, that AEP-Ohio's generation business shall be fully on its own in the competitive market. It also offends the General Assembly's directive in Section 4928.141, Revised Code, requiring the Commission to remove any transition charges from future rate plans. Thus, the Commission's invention and application of a Cost-Based ratemaking methodology to authorize AEP-Ohio to collect above-market charges for generation capacity service is unauthorized by Ohio law.

Beyond the statutory limits on the Commission's ability to invent and apply a Cost-Based ratemaking methodology to, in substance, provide AEP-Ohio with another opportunity to collect above-market generation-related revenue, the Commission's decision in the *Capacity Case* is precluded by the binding settlement agreement approved by the Commission in the Electric Transition Plan ("ETP") cases of OP and CSP. In that settlement agreement, AEP-Ohio agreed that it would forego recovery of any generation-related transition revenues and that it would not impose any lost generation-related revenue charges on shopping customers.[114] This settlement agreement was subsequently incorporated in the rate plan approved by the Commission that

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[112] Section 4928.38, Revised Code.

[113] Section 4928.32, Revised Code (an ETP, including requests for transition revenues, had to be filed within 90 days of October 5, 1999).

[114] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of an Electric Transition Plan and Application for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP, *et al.* Opinion and Order at 18 (Sept. 28, 2000) (Appx. at 169).

preceded the plan adopted in the *ESP I Case*. The Commission is without jurisdiction to abridge the rights of consumers under the terms of a previously approved settlement agreement by inventing and applying a Cost-Based ratemaking methodology to substantially and uniquely authorize AEP-Ohio to collect above-market compensation for generation capacity service through non-bypassable charges that apply to shopping and non-shopping customers.[115]

c. ***The Commission does not have authority to permit AEP-Ohio to collect, for generation capacity service available to CRES providers, the revenue difference between the RPM-Based Pricing method and the Commission's invented and applied Cost-Based ratemaking methodology***

Building on the foundation it laid down in the *Capacity Case,* the Commission in the *ESP II Case* authorized AEP-Ohio to begin collecting above-market generation-related revenue. Increasing AEP-Ohio's total SSO revenue by $508 million, the Commission authorized AEP-Ohio to impose the non-bypassable RSR on shopping and non-shopping customers.[116] The Commission's decision in the *ESP II Case* calls for a portion of the RSR revenue collected from shopping and non-shopping customers ($1/MWh) to go towards payment of the $188.88/MW-

[115] In the context of AEPSC's Section 205 Application and its Section 206 Complaint, the Commission has advised FERC that AEPSC and AEP-Ohio are bound by the RAA. As the Commission stated in a filing with FERC, "AEP made a deal. Now it must, under [FERC] precedent, live with that deal." *American Electric Power Service Corp.*, FERC Docket No. EL11-32-000, Response Submitted on Behalf of the Public Utilities Commission of Ohio at 9 (July 30, 2012). The Commission's position is based on the application of the *Mobile-Sierra* Doctrine. United Gas Co. v. Mobile Gas Corp., 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348 (1956). Since the source of RPM-Based Pricing is a contract binding on AEP-Ohio and approved by FERC, demonstrating that RPM-Based Pricing yields unjust and unreasonable compensation requires AEP-Ohio to satisfy a *Mobile-Sierra* review standard that the pricing under the RAA is not in the public interest. AEP-Ohio made no effort to demonstrate that continuation of RPM-Based Pricing is contrary to the public interest and the *Capacity Case Order* does not find that continuation of RPM-Based Pricing is contrary to the public interest. The Commission, however, has now veered from that position in the *Capacity* and *ESP II Cases* by refusing to enforce the terms of the ETP settlement absent a showing that compliance with the ETP settlement is not in the public interest.

[116] *ESP II Case*, Opinion and Order at 31 (Appx. at 299).

day capacity price which the Commission held (in the *Capacity Case*) would not be collected from CRES providers.

Based on current total sales of generation supply to all AEP-Ohio distribution service customers and the $1/MWh portion of the RSR which the Commission earmarked to help fund AEP-Ohio's above-market compensation for generation capacity service available to CRES providers, the electric bills of AEP-Ohio's shopping and non-shopping customers will increase by $144 million through the RSR to pick up a part of the Cost-Based ratemaking tab.[117]

Since the $1/MWh rate increase through the RSR is not sufficient to cover the total increase in compensation for generation capacity service authorized by the Commission, the Commission's decision in the *ESP II Case* sets the stage for another future non-bypassable charge to pick up the slack. More specifically, the Commission's decision in the *ESP II Case* commits consumers to pay a future non-bypassable charge after the conclusion of the rate plan approved in the *ESP II Case* to recover any balance of the total increase in compensation for generation capacity service the Commission authorized in the *Capacity Case*. This slack-eliminating commitment will likely shift payment responsibility for several hundred million dollars in compensation for generation capacity service to shopping and non-shopping customers. The Commission casts this commitment as though it is a phase-in authorized by Section 4928.144, Revised Code. The Commission, however, does not have authority to permit AEP-Ohio to increase electric prices applicable to shopping and non-shopping customers, on a non-bypassable basis, so as to permit AEP-Ohio to receive above-market compensation for generation capacity service available to CRES providers through either the RSR or the future non-bypassable rider.

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[117] *Id.* at 75 n.32 (Appx. at 343).

Because AEP-Ohio's generation business has been declared competitive, generation-related revenue may not be recovered in an ESP through a non-bypassable charge unless the rate is authorized under one of two narrowly defined provisions. These two narrowly defined provisions allow for the recovery of construction work in progress ("CWIP") and generating facilities that are newly used and useful after January 1, 2009, provided other detailed conditions are satisfied.[118] Also, charges lawfully adopted under these narrow provisions may, nonetheless, be bypassable under Sections 4928.20 (I) and (J), Revised Code. In any event, neither the $1/MWh portion of the RSR nor the future slack-eliminating non-bypassable charges for which the Commission set the stage in the *ESP II Case* arise from the two narrowly defined provisions in the ESP statute permitting the Commission to lawfully approve non-bypassable generation-related charges.

Perhaps in recognition of its very limited authority to embed non-bypassable generation-related charges in an ESP, the Commission's decision in the *ESP II Case* appears to hold that the RSR is lawful under Section 4928.143(B)(2)(d), Revised Code. That provision provides that an ESP may include "terms, conditions, or charges relating to limitations on customer shopping … as would have the effect of stabilizing or providing certainty regarding retail electric service." Section 4928.143(B)(2), Revised Code, however, must be read in light of the prohibition on the recovery of transition revenue. Sections 4928.141 and 4928.38, Revised Code, specifically preclude the recovery of transition revenue, and there is no exception in Section 4928.143(B)(2),

[118] The exceptions are provided by Sections 4928.143(B)(2)(b) & (c), Revised Code. Deferred rate increases, again with significant conditions, may also be recovered through a non-bypassable charge. Section 4928:144, Revised Code. *See In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider*, Case No. 10-1454-EL-RDR, Finding and Order at 19 (Jan. 11, 2012) (Appx. at 264). See discussion below.

Revised Code, that would permit AEP-Ohio to recover generation-related transition revenue that is precluded by Sections 4928.141 and 4928.38, Revised Code.

Furthermore, the collection of a part of the deferred portion of the capacity price through the RSR violates the statutory prohibition on recovering generation-related costs through transmission or distribution rates. Section 4928.02(H), Revised Code, states that it is the policy of the State to ensure effective competition in the provision of retail electric service "by prohibiting the recovery of any generation-related costs through distribution or transmission rates." The Commission previously concluded that a non-bypassable generation-related charge, *i.e.*, a charge collected from all distribution service customers, is prohibited by Section 4928.02(H), Revised Code.[119] In the *ESP II Case*, however, the Commission ignores Section 4928.02(H), Revised Code, and its prior decision and authorizes the recovery of the deferred capacity price. It did so without legal authority.

The Commission also lacks the authority to phase-in the remaining balance of the difference between the RPM-Based Price and $188.88/MW-day price based on provisions applicable to the phase-in of ESP prices. In the *ESP II Case*, the Commission claimed authority to phase-in the remaining deferred balance under Section 4928.144, Revised Code, through a non-bypassable rider.[120] Section 4928.144, Revised Code, however, provides that the Commission may authorize a phase-in only of a "rate or price established under sections

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[119] *Id.*

[120] *ESP II Case*, Opinion and Order at 52 (Appx. at 320). Section 4928.144, Revised Code, provides that the deferred asset created by the Commission's order to phase-in a rate shall also authorize a non-bypassable rider for collection of the deferral.

4928.141 to 4928.143 of the Revised Code."[121] As the Commission made clear in the *Capacity Case*, the \$188.88/MW-day price is not a product of any authority delegated to the Commission in Chapter 4928, Revised Code.[122] In the *Capacity Case*, the Commission held (incorrectly) that its authority to authorize AEP-Ohio to significantly increase AEP-Ohio's compensation for generation capacity service stems from Sections 4905.04, 4905.05 and 4905.09, and Chapter 4909, Revised Code, not Sections 4928.141 to 4928.143, Revised Code. Plainly, then, the Commission's resort to its phase-in authority in Section 4928.144, Revised Code, is unauthorized by law.

3. Legal Remedies are Inadequate

The practical goal of AEPSC's November 2010 FERC filing and the request to change from a market-based pricing methodology to a Cost-Based ratemaking methodology is to insulate AEP-Ohio's generation business from the competition provided by CRES providers. Through the Commission's exercise of jurisdiction in the *Capacity* and *ESP II Cases*, it has allowed AEP-Ohio to further that goal. The Commission, however, is patently and unambiguously without jurisdiction to invent and apply a Cost-Based ratemaking methodology to increase substantially AEP-Ohio's compensation for generation capacity service and to

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[121] The Commission's use of the phase-in authority provided by Section 4928.144, Revised Code, also requires the Commission to authorize the deferral of "incurred costs" as part of the accounting used to implement the phase-in. While the Commission's use of Section 4928.144, Revised Code, is precluded for the reasons explained herein, the Commission's application of Section 4928.144, Revised Code, would also be unauthorized by law because the Commission has failed to identify the "incurred costs" that are to be deferred in an amount equal to the amount not collected as a result of the phase-in. In this circumstance, it would not be possible for the Commission to identify the "incurred costs" that are to be deferred in an amount equal to the amount not collected as a result of the phase-in since the Commission is deferring the difference between two revenue streams (the RPM-Based Pricing revenue stream and the revenue stream associated with the \$188.88/MW-day price).

[122] *Capacity Case*, Opinion and Order at 13 (Appx. at 213).

authorize the recovery of the above-market portion of such compensation from ultimate customers through non-bypassable riders. Under circumstances such as this in which a lower court has acted without jurisdiction, the Court has stated:

> If an inferior court is without jurisdiction whatsoever to act, the availability or adequacy of a remedy of appeal to prevent the resulting injustice is immaterial to the exercise of supervisory jurisdiction by a superior court to prevent usurpation of jurisdiction by the inferior court.[123]

This principle applies to the current proceeding. Because the Commission actions were patently without authority, any consideration of the significance of a potential remedy that might be available through the traditional appellate process is immaterial. Further, the Court may order a lower court, or in this case the Commission, by writ of mandamus to correct the results of any jurisdictionally unauthorized actions.[124]

The need for a writ preventing the Commission from illegally authorizing a Cost-Based capacity price is further heightened by the inability to order refunds of the amounts illegally collected from customers during the pendency of an appeal.[125] Even under the normal appellate process, customers will be injured and will be without a remedy until the Court determines that the Commission has acted without authority to invent and apply a Cost-Based ratemaking methodology to significantly and uniquely increase AEP-Ohio's compensation for generation capacity service. During the ESP II term, alone, delay can translate into a $144 million illegal payment from shopping and non-shopping customers to AEP-Ohio for above-market capacity

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[123] *State ex rel. Adams v. Gusweiler*, 30 Ohio St.2d 326, 329 (1972); *State ex rel. Osborn v. Jackson*, 46 Ohio St.2d 41, 51-52 (1976).

[124] *State, ex rel. State Fire Marshall, v. Curl*, 87 Ohio St.3d 568, 569 (2000).

[125] *In re Columbus Southern Power Co.*, 128 Ohio St.3d 512 (2011).

prices through the RSR. The injury to consumers is made more certain by the Commission's ability to delay the appellate process. Because the Commission has repeatedly granted rehearing without providing a final appealable order in the *Capacity Case* and can continue to do so in both the *Capacity Case* and the *ESP II Case*, it can thwart appellate review that would afford customers an opportunity to avoid some of the effects of the Commission's unlawful actions. Thus, Court intervention is both legally warranted and necessary to prevent significant and irreparable injury to the customers of AEP-Ohio.

RELIEF REQUESTED

Because of the extraordinary circumstances herein involving an important issue that is ripe for court review, IEU-Ohio, Relator, respectfully prays for this Court to issue alternative Writs of Prohibition and Mandamus immediately that: (1) prohibit the Commission from inventing and applying a Cost-Based ratemaking methodology to increase significantly and uniquely AEP-Ohio's compensation for generation capacity service available to CRES providers serving retail customers located in AEP-Ohio's service area; (2) prohibit the Commission from authorizing AEP-Ohio to collect the above-market portion of such increased compensation on shopping and non-shopping customers through non-bypassable charges now and later; (3) to the extent that the Commission has authority to resort to a Cost-Based ratemaking methodology to uniquely and substantially increase AEP-Ohio's compensation for generation capacity service, prohibit the Commission from doing so without compliance with the procedural and substantive requirements set out in Ohio law in circumstances where Ohio's Cost-Based ratemaking methodology does apply; (4) prohibit the Commission from authorizing AEP-Ohio to phase-in such unique and substantial increases in AEP-Ohio's compensation for generation capacity service since the resulting $188.88/MW-day price does not stem from a proceeding under

Sections 4928.141 to 4928.143, Revised Code; (5) require the Commission to restore the RPM-Based Pricing method previously adopted by the Commission as required by Section 4928.143(C), Revised Code; (6) prohibit the Commission from authorizing AEP-Ohio to obtain above-market compensation for generation capacity service increases since such above-market compensation amounts to additional transition revenue, or its equivalent, which is barred by Ohio law or otherwise conflicts with the General Assembly's mandate that an EDU's electric generation business shall be fully on its own in the competitive market; (7) require the Commission to enforce AEP-Ohio's Commission-approved obligation to not impose lost generation-related revenue charges on shopping customers; and (8) issue orders for such other relief as the Court deems appropriate based on the facts and circumstances.

Relator IEU-Ohio also prays for this Court to issue permanent Writs of Prohibition and Mandamus of the same effect following hearing and argument.

Respectfully Submitted,

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**ATTORNEYS FOR RELATOR,
INDUSTRIAL ENERGY USERS-OHIO**

STATE OF OHIO)

)

COUNTY OF FRANKLIN)

AFFIDAVIT

Kevin M. Murray, being first duly sworn, says that he is Executive Director of Industrial Energy Users-Ohio, Relator herein, that he has read the foregoing Complaint for Writ of Prohibition and Mandamus, that he is acquainted with the facts set forth in the Complaint, and that the facts stated therein are true to the best of his knowledge.

Kevin M. Murray
Executive Director of
Industrial Energy Users-Ohio

Sworn to before me and subscribed in my presence this 30th day of August 2012.

Debbie Ryan
Notary Public

DEBBIE SUE RYAN
NOTARY PUBLIC • STATE OF OHIO
Recorded in Knox County
My commission expires Nov. 14, 2015

IN THE SUPREME COURT OF OHIO RECEIVED-DOCKETING DIV

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PUCO

State of Ohio, ex. Rel. Industrial Energy Users-Ohio	:	
Relator,	:	Original Action in Prohibition and Mandamus
v.	:	
The Public Utilities Commission of Ohio *Todd A. Snitchler, Chairman* Cheryl Roberto, Commissioner, Steven D. Lesser, Commissioner, Andre T. Porter, Commissioner, and Lynn Slaby, Commissioner,	:	12-1494
Respondents.	:	Case No. ________

APPENDIX OF COMPLAINT FOR WRITS OF PROHIBITION AND MANDAMUS

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FILED
AUG 31 2012
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SUPREME COURT OF OHIO

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On Behalf of Industrial Energy Users-Ohio

ATTORNEYS FOR RELATOR

APPENDIX **APP. PAGE**

PJM Interconnection, L.L.C.
Rate Schedule FERC No. 44

Reliability Assurance Agreement

Among

LOAD SERVING ENTITIES

in the

PJM REGION

Effective Date: 7/25/2012

PJM Reliability Assurance Agreement

Table of Contents

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

RELIABILITY ASSURANCE AGREEMENT

RELIABILITY ASSURANCE AGREEMENT, dated as of this 1st day of June, 2007 by and among the entities set forth in Schedule 17 hereto, hereinafter referred to collectively as the "Parties" and individually as a "Party."

WITNESSETH:

WHEREAS, each Party to this Agreement is a Load Serving Entity within the PJM Region;

WHEREAS, each Party is committing to share its Capacity Resources with the other Parties to reduce the overall reserve requirements for the Parties while maintaining reliable service; and

WHEREAS, each Party is committing to provide mutual assistance to the other Parties during Emergencies;

WHEREAS, each Party is committing to coordinate its planning of Capacity Resources to satisfy the Reliability Principles and Standards; and

NOW THEREFORE, for and in consideration of the covenants and mutual agreements set forth herein and intending to be legally bound hereby, the Parties agree as follows:

Effective Date: 7/18/2012 - Docket #: ER12-1784-000

ARTICLE 1 – DEFINITIONS

ARTICLE 1 – DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement

Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.1A Annual Demand Resource

Annual Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.2 Applicable Regional Entity

Applicable Regional Entity shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction

Base Residual Auction shall have the same meaning as in Attachment DD to the PJM Tariff.

1.4 Behind The Meter Generation

Behind The Meter Generation shall mean a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection; provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Capacity Resource or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

1.5 Black Start Capability

Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Emergency Transfer Objective ("CETO")

Capacity Emergency Transfer Objective ("CETO") shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Paragraph C of Schedule 5.

1.7 Capacity Emergency Transmission Limit ("CETL")

Capacity Emergency Transmission Limit ("CETL") shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

1.8 Capacity Resources

Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources, Energy Efficiency Resources, or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.9 Capacity Transfer Right

Capacity Transfer Right shall have the meaning specified in Attachment DD to the PJM Tariff.

1.10 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and each Applicable Regional Entity;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.11 Daily Unforced Capacity Obligation

Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8 or, as to an FRR Entity, in Schedule 8.1.

1.12 Delivery Year

Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment DD to the Tariff or pursuant to an FRR Capacity Plan.

1.13 Demand Resource

Demand Resource or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan. As set forth in Schedule 6, a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.14 Demand Resource Provider

Demand Resource Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.15 DR Factor

DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.16 [Reserved for Future Use]

1.17 Electric Cooperative

Electric Cooperative shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

1.18 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.19 Emergency

Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

1.20 End-Use Customer

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.20A Energy Efficiency Resource

Energy Efficiency Resource shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

1.20B Existing Generation Capacity Resource

Existing Generation Capacity Resource shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation

Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

1.20C Extended Summer Demand Resource

Extended Summer Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.21 Facilities Study Agreement

Facilities Study Agreement shall have the same meaning as in the PJM Tariff

1.22 FERC

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.23 Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.24 Firm Transmission Service

Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.25 Fixed Resource Requirement Alternative or FRR Alternative

Fixed Resource Requirement Alternative or FRR Alternative shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in Schedule 8.1 to this Agreement.

1.26 Forecast Pool Requirement

Forecast Pool Requirement or FPR shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.27 Forecast RTO ILR Obligation

Forecast RTO ILR Obligation shall have the same meaning as in the PJM Tariff.

1.28 Forecast Zonal ILR Obligation

Forecast Zonal ILR Obligation shall have the same meaning as in the PJM Tariff.

1.29 FRR Capacity Plan

FRR Capacity Plan shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

1.30 FRR Entity

FRR Entity shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

1.31 FRR Service Area

FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection;

and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

1.32 Full Requirements Service

Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.33 Generation Capacity Resource

Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

1.34 Generation Owner

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.35 Generator Forced Outage

Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.36 Generator Maintenance Outage

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.37 Generator Planned Outage

Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.38 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.39 ILR Provider

ILR Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.40 Incremental Auction

Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, the Third Incremental Auction, or the Conditional Incremental Auction, each as defined in Attachment DD to the PJM Tariff.

1.41 Interconnection Agreement

Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.42 Interruptible Load for Reliability, or ILR

Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year. At a minimum, ILR shall be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the ILR shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time in the corresponding Delivery Year.

1.43 IOU

IOU shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

1.43A Limited Demand Resource

Limited Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.44 Load Serving Entity or LSE

Load Serving Entity or LSE shall mean 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. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.45 Locational Reliability Charge

Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.46 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.46A Maximum Emergency Service Level

Maximum Emergency Service Level or MESL of Price Responsive Demand shall mean the level, determined at a PRD Substation level, to which Price Responsive Demand shall be reduced during the Delivery Year when a Maximum Generation Emergency is declared and the Locational Marginal Price exceeds the price associated with such Price Responsive Demand identified by the PRD Provider in its PRD Plan.

1.47 Member

Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.48 Members Committee

Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.49 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.50 Network Resources

Network Resources shall have the meaning set forth in the PJM Tariff.

1.51 Network Transmission Service

Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner (as that term is defined in the PJM Tariff).

1.51A Nominal PRD Value

Nominal PRD Value shall mean, as to any PRD Provider, an adjustment, determined in accordance with Schedule 6.1 of this Agreement, to the peak-load forecast used to determine the quantity of capacity sought through an RPM Auction, reflecting the aggregate effect of Price Responsive Demand on peak load resulting from the Price Responsive Demand to be provided by such PRD Provider.

1.52 Nominated Demand Resource Value

Nominated Demand Resource Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.53 Nominated ILR Value

Nominated ILR Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.54 Non-Retail Behind the Meter Generation

Non-Retail Behind the Meter Generation shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

1.55 Obligation Peak Load

Obligation Peak Load shall have the meaning specified in Schedule 8 of this Agreement.

1.56 Office of the Interconnection

Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.57 Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement

Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.58 Operating Reserve

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.59 Other Supplier

Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.60 Partial Requirements Service

Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.61 Percentage Internal Resources Required

Percentage Internal Resources Required shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

1.62 Party

Party shall mean an entity bound by the terms of this Agreement.

1.63 PJM

PJM shall mean the PJM Board and the Office of the Interconnection.

1.64 PJM Board

PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.65 PJM Manuals

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.66 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.67 PJM Region

PJM Region shall have the same meaning as provided in the Operating Agreement.

1.68 PJM Region Installed Reserve Margin

PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.69 Planned Demand Resource

Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.69A Planned External Generation Capacity Resource

Planned External Generation Capacity Resource shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery

Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Reliability Pricing Model Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement under the PJM Tariff for Base Residual Auction and an Interconnection Service Agreement under the PJM Tariff for Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and if applicable the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. An External Generation Capacity Resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

1.70 Planned Generation Capacity Resource

Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under Part IV, Subpart A of the PJM Tariff, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Plan; (ii) a System Impact Study Agreement has been executed prior to the Base Residual Auction for such Delivery Year; (iii) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

1.71 Planning Period

Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.71A PRD Curve

PRD Curve shall mean a price-consumption curve at a PRD Substation level, if available, and otherwise at a Zonal (or sub-Zonal LDA, if applicable) level, that details the base consumption level of Price Responsive Demand and the decreasing consumption levels at increasing prices.

1.71B PRD Provider

PRD Provider shall mean (i) a Load Serving Entity that provides PRD; or (ii) an entity without direct load serving responsibilities that has entered contractual arrangements with end-use customers served by a Load Serving Entity that satisfy the eligibility criteria for Price Responsive Demand.

1.71C PRD Provider's Zonal Expected Peak Load Value of PRD

PRD Provider's Zonal Expected Peak Load Value of PRD shall mean the expected contribution to Delivery Year peak load of a PRD Provider's Price Responsive Demand, were such demand not to be reduced in response to price, based on the contribution of the end-use customers comprising such Price Responsive Demand to the most recent prior Delivery Year's peak demand, escalated to the Delivery Year in question, as determined in a manner consistent with the Office of the Interconnection's load forecasts used for purposes of the RPM Auctions.

1.71D PRD Reservation Price

PRD Reservation Price shall mean an RPM Auction clearing price identified in a PRD Plan for Price Responsive Demand load below which the PRD Provider desires not to commit the identified load as Price Responsive Demand.

1.71E PRD Substation

PRD Substation shall mean an electrical substation that is located in the same Zone or in the same sub-Zonal LDA as the end-use customers identified in a PRD Plan or PRD registration and that, in terms of the electrical topography of the Transmission Facilities comprising the PJM Region, is as close as practicable to such loads.

1.71F Price Responsive Demand

Price Responsive Demand or PRD shall mean end-use customer load registered by a PRD Provider pursuant to Schedule 6.1 of the PJM Reliability Assurance Agreement that have, as set forth in more detail in the PJM Manuals, the metering capability to record electricity consumption at an interval of one hour or less, Supervisory Control capable of curtailing such load (consistent with applicable RERRA requirements) at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection, and a retail rate structure, or equivalent contractual arrangement, capable of changing retail rates as frequently as an hourly basis, that is linked to or based upon changes in real-time Locational Marginal Prices at a PRD Substation level and that results in a predictable automated response to varying wholesale electricity prices.

1.71G Price Responsive Demand Credit

Price Responsive Demand Credit shall mean a credit, based on committed Price Responsive Demand, as determined under Schedule 6.1 of this Agreement.

1.71H Price Responsive Demand Plan or PRD Plan

Price Responsive Demand Plan or PRD Plan shall mean a plan, submitted by a PRD Provider and received by the Office of the Interconnection in accordance with Schedule 6.1 of this Agreement and procedures specified in the PJM Manuals, claiming a peak demand limitation due to Price Responsive Demand to support the determination of such PRD Provider's Nominal PRD Value.

1.72 Public Power Entity

Public Power Entity shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

1.73 Qualifying Transmission Upgrades

Qualifying Transmission Upgrades shall have the meaning specified in Attachment DD to the PJM Tariff.

1.74 [Reserved for Future Use]

1.74A Relevant Electric Retail Regulatory Authority

Relevant Electric Retail Regulatory Authority or RERRA shall have the meaning specified in the PJM Operating Agreement.

1.75 Reliability Principles and Standards

Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Entity to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.76 Required Approvals

Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.77 Self-Supply

Self Supply shall have the meaning provided in Attachment DD to the PJM Tariff.

1.78 [Reserved for Future Use]

1.79 [Reserved for Future Use]

1.80 State Consumer Advocate

State Consumer Advocate shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.81 State Regulatory Structural Change

State Regulatory Structural Change shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

1.81A Supervisory Control

Supervisory Control shall mean the capability to curtail, in accordance with applicable RERRA requirements, load registered as Price Responsive Demand at each PRD Substation identified in the relevant PRD Plan or PRD registration in response to a Maximum Generation Emergency declared by the Office of the Interconnection. Except to the extent automation is not required by the provisions of this Agreement, the curtailment shall be automated, meaning that load shall be reduced automatically in response to control signals sent by the PRD Provider or its designated agent directly to the control equipment where the load is located without the requirement for any action by the end-use customer.

1.82 Threshold Quantity

Threshold Quantity shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Schedule 8.1).

1.83 Transmission Facilities

Transmission Facilities shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

1.84 Transmission Owner

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.85 Transmission Owners Agreement

Transmission Owners Agreement shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

1.86 Unforced Capacity

Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.87 [Reserved for Future Use]

1.88 Zonal Capacity Price

Zonal Capacity Price shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

1.89 Zone or Zonal

Zone or Zonal shall refer to an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

Effective Date: 7/18/2012 - Docket #: ER11-4628-003

ARTICLE 2 – PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, Energy Efficiency Resources, and ILR will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in Section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

ARTICLE 3 -- TERM AND TERMINATION OF THE AGREEMENT

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

3.1 Term.

This Agreement shall become effective as of June 1, 2007 and shall govern Unforced Capacity Obligations for the Planning Period beginning as of that date ("Initial Delivery Year"), and for each Planning Period thereafter, unless and until terminated in accordance with the terms hereof.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

3.2 [Reserved for Future Use]

Effective Date: 7/18/2012 - Docket #: ER12-1784-000

3.3 Termination.

3.3.1 Rights to Terminate.

This Agreement may be terminated by a vote in the Members Committee to terminate the Agreement by an affirmative Sector Vote as specified in the Operating Agreement and upon the receipt of all Required Approvals related to the termination of this Agreement. Any such termination must be approved by the PJM Board and filed with the FERC and shall become effective only upon the FERC's approval.

3.3.2 Obligations upon Termination.

Any provision of this Agreement that expressly or by implication comes into or remains in force following the termination of this Agreement shall survive such termination. The surviving provisions shall include, but shall not be limited to: (a) final settlement of the obligations of each Party under Articles 8 and 12 of this Agreement, including the accounting for the period ending with the last day of the month for which the Agreement is effective, (b) the provisions of this Agreement necessary to conduct final billings, collections and accounting with respect to all matters arising hereunder and (c) the indemnification provisions as applicable to periods prior to such termination.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 4 -- ADDITION OF NEW PARTIES

Each Party agrees that any entity that (i) is or will become a Load Serving Entity, (ii) complies with the process and data requirements set forth in Schedule 1, and (iii) meets the standards for interconnection set forth in Schedule 2 shall become a Party to this Agreement and shall be listed on Schedule 16 of this Agreement upon becoming a party to the Operating Agreement, and execution of a counterpart of this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 5 -- WITHDRAWAL OR REMOVAL OF A PARTY

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

5.1 Withdrawal of a Party.

5.1.1 Notice.

Upon written notice to the Office of the Interconnection, any Party may withdraw from this Agreement, effective upon the completion of its obligations hereunder and the documentation by such Party, to the satisfaction of the Office of the Interconnection, that such Party is no longer a Load Serving Entity.

5.1.2 Determination of Obligations.

A Party's obligations hereunder shall be completed as of the end of the last month for which such Party's obligations have been set at the time said notice is received, except as provided in Article 13, or unless the Members Committee determines that the remaining Parties will be able to adjust their obligations and commitments related to the performance of this Agreement consistent with such earlier withdrawal date as may be requested by the withdrawing Party, without undue hardship or cost, while maintaining the reliability of the PJM Region.

5.1.3 Survival of Obligations upon Withdrawal.

(a) The obligations of a Party upon its withdrawal from this Agreement and any obligations of that Party under this Agreement at the time of its withdrawal shall survive the withdrawal of the Party from this Agreement. Upon the withdrawal of a Party from this Agreement, final settlement of the obligations of such Party under Articles 7 and 11 of this Agreement shall include the accounting through the date established pursuant to Sections 5.1.1 and 5.1.2.

(b) Any Party that withdraws from this Agreement shall pay all costs and expenses associated with additions, deletions and modifications to communication, computer, and other affected facilities and procedures, including any filing fees, to effect the withdrawal of the Party from the Agreement.

(c) Prior to withdrawal, a withdrawing Party desiring to remain interconnected with the PJM Region shall enter into a control area to control area interconnection agreement with the Office of the Interconnection and the transmission owner or Electric Distributor within the PJM Region with which its facilities are interconnected.

5.1.4 Regulatory Review.

Any withdrawal from this Agreement shall be filed with FERC and shall become effective only upon FERC's approval.

5.2 Breach by a Party.

The provisions of Section 15.1 of the Operating Agreement shall apply to a Party's (a) failure to pay any amount due under this Agreement when due or (b) breach of any material obligation under this Agreement. In addition to the remedies available to the Office of the Interconnection set forth in Section 15.1 of the Operating Agreement, if the Party fails to cure such non-payment or breach, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (a) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (b) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).

Effective Date: 2/18/2012 - Docket #: ER12-636-000

ARTICLE 6 -- MANAGEMENT ADMINISTRATION

Except as otherwise provided herein, this Agreement shall be managed and administered by the Parties, Members, and State Consumer Advocates through the Members Committee and the Markets and Reliability Committee as a Standing Committee thereof, except as delegated to the Office of the Interconnection and except that only the PJM Board shall have the authority to approve and authorize the filing of amendments to this Agreement with the FERC.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 7 -- RESERVE REQUIREMENTS AND OBLIGATIONS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.1 Forecast Pool Requirement and Unforced Capacity Obligations.

(a) The Forecast Pool Requirement shall be established to ensure a sufficient amount of capacity to meet the forecast load plus reserves adequate to provide for the unavailability of Generation Capacity Resources, load forecasting uncertainty, and planned and maintenance outages. Schedule 4 sets forth guidelines with respect to the Forecast Pool Requirement.

(b) Unless the Party and its customer that is also a Load Serving Entity agree that such customer is to bear direct responsibility for the obligations set forth in this Agreement, (i) any Party that supplies Full Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for all of that Load Serving Entity's capacity obligations under this Agreement for the period of such Full Requirements Service and (ii) any Party that supplies Partial Requirements Service to a Load Serving Entity within the PJM Region shall be responsible for such portion of the capacity obligations of that Load Serving Entity as agreed by the Party and the Load Serving Entity so long as the Load Serving Entity's full capacity obligation under this Agreement is allocated between or among Parties to this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.2 Responsibility to Pay Locational Reliability Charge.

Except to the extent its capacity obligations are satisfied through the FRR Alternative, each Party shall pay, as to the loads it serves in each Zone during a Delivery Year, a Locational Reliability Charge for each such Zone during such Delivery Year. The Locational Reliability Charge shall equal such Party's Daily Unforced Capacity Obligation in a Zone, as determined pursuant to Schedule 8 of this Agreement, times the Final Zonal Capacity Price for such Zone, as determined pursuant to Attachment DD of the PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.3 LSE Option to Provide Capacity Resources.

A Party obligated to pay a Locational Reliability Charge for a Delivery Year may partially or wholly offset amounts it must pay for such charge by offering Capacity Resources for sale in the Base Residual Auction or an Incremental Auction applicable to such Delivery Year; provided such resources clear such auctions. Resources offered for sale in any such auction must satisfy the requirements specified in this Agreement and the PJM Manuals. Such a Party may choose to nominate a resource in the Base Residual Auction as Self-Supply, may choose to designate a price offer for such resource into any such auction, or may indicate in its offer that it wishes to commit such resource regardless of the clearing price, in which case the Party shall receive the marginal value of system capacity and the price adders for any applicable binding locational constraint in accordance with Attachment DD of the PJM Tariff. Each such Party acknowledges that the clearing price it receives for a resource offered for sale and cleared, or Self-Supplied, in an auction may differ from the Final Zonal Capacity Price determined for the applicable Zone for the applicable Delivery Year, and that the Party shall remain responsible for the Locational Reliability Charge notwithstanding any such difference between the Capacity Resource Clearing Price and the Final Zonal Capacity Price. In addition, such Parties recognize that they may receive an allocation of Capacity Transfer Rights which may offset a portion of the Locational Reliability Charge, and that they may offset a portion of the Locational Reliability Charge by nominating ILR, or by offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.4 Fixed Resource Requirement Alternative.

A Party that is eligible for the Fixed Resource Requirement Alternative may satisfy its obligations hereunder to provide Unforced Capacity by submitting and adhering to an FRR Capacity Plan and meeting all other terms and conditions of such alternative, as set forth in this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.5 Capacity Plans and Deliverability.

Each Party electing to provide Capacity Resources to meet its obligations hereunder shall submit to the Office of the Interconnection its plans (or revisions to previously submitted plans), as prescribed by Schedule 7, or, in the case of a Party electing the FRR Alternative, as prescribed by Schedule 8.1, to install or contract for Capacity Resources. As set forth in Schedule 10, each Party must designate its Capacity Resources as Network Resources or Points of Receipt under the PJM Tariff to allow firm delivery of the output of its Capacity Resources to the Party's load within the PJM Region and each Party must obtain any necessary Firm Transmission Service in an amount sufficient to deliver Capacity Resources from outside the PJM Region to the border of the PJM Region to reliably serve the Party's load within the PJM Region.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.6 Nature of Resources.

Each Party electing to Self-Supply resources, or electing the FRR Alternative, shall provide or arrange for specific, firm Capacity Resources that are capable of supplying the energy requirements of its own load on a firm basis without interruption for economic conditions and with such other characteristics that are necessary to support the reliable operation of the PJM Region, as set forth in more detail in Schedules 6, 9 and 10.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

7.7 Compliance Audit of Parties.

(a) For the 36 months following the end of each Planning Period, each Party shall make available the records and supporting information related to the performance of this Agreement from such Planning Period for audit.

(b) The Office of the Interconnection shall evaluate and determine the need for an audit of a Party and shall, upon a decision of the Members Committee to require such an audit, provide the Party or Parties to be audited with notice at least 90 days in advance of the audit.

(c) Any audit of a Party conducted pursuant to this Agreement shall be performed by an independent consultant to be selected by the Office of the Interconnection. Such audit shall include a review of the Party's compliance with the procedures and standards adopted pursuant to this Agreement.

(d) Prior to the completion of its audit, the independent consultant shall review its preliminary findings with the Party being audited and, upon the completion of its audit, the independent consultant shall issue a final audit report detailing the results of the audit, which final report shall be issued to the Party being audited, the Office of the Interconnection and the Markets and Reliability Committee; provided, however, no confidential data of any Party shall be disclosed through such audit reports.

(e) If, based on a final audit report, an adjustment is required to any amounts due to or from the Parties pursuant to Schedules 8, 12, or 13, such adjustment shall be accounted for in determining the amounts due to or from the Parties pursuant to Schedules 8, 12, or 13 for the month in which the adjustment is identified.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 8 -- DEFICIENCY, DATA SUBMISSION, AND EMERGENCY CHARGES

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

8.1 Nature of Charges.

Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

8.2 Determination of Charge Amounts.

No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period , which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

8.3 Distribution of Charge Receipts.

All of the monies received as a result of any charges imposed pursuant to this Agreement shall be disbursed as provided in this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 9 -- COORDINATED PLANNING AND OPERATION

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a) cooperate with the members and associate members of such Party's Applicable Regional Entity to ensure the reliability of the region;

(b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

Effective Date: 7/18/2012 - Docket #: ER12-1784-000

9.2 Generator Planned Outage Scheduling.

Each Party shall develop, or cause to be developed, its schedules of planned outages of its Capacity Resources. Such schedules of planned outages shall be submitted to the Office of the Interconnection for coordination with the schedules of planned outages of other Parties and anticipated transmission planned outages.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, in Schedule 11 hereof.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Attachment DD to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.

(b) A data submission charge, as set forth in Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in Schedule 11.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

9.5 Metering.

Each Party shall comply with the metering standards for the PJM Region, as set forth in the PJM Manuals, as well as any further metering requirements applicable to Price Responsive Demand, where such is relied upon for an adjustment to peak load pursuant to Schedule 6.1 of this Agreement.

Effective Date: 5/15/2012 - Docket #: ER11-4628-000

ARTICLE 10 -- SHARED COSTS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

10.1 Recording and Audit of Costs.

(a) Any costs related to the performance of this Agreement, including the costs of the Office of the Interconnection and such other costs that the Members Committee determines are to be shared by the Parties, shall be documented and recorded in a manner acceptable to the Parties.

(b) The Members Committee may require an audit of such costs; provided, however, the cost records shall be available for audit by any Member or State Consumer Advocate, at the sole expense of such Member or State Consumer Advocate, for 36 months following the end of the Planning Period in which the costs were incurred.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

10.2 Cost Responsibility.

The costs determined under Section 10.1(a) shall be allocated to and recovered from the Parties to this Agreement and other entities pursuant to Schedule 9-5 of the PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 11 – BILLING AND PAYMENT

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.1 Periodic Billing.

Each Party shall receive a statement periodically setting forth (i) any amounts due from or to that Party as a result of any charges imposed pursuant to this Agreement and (ii) that Party's share of any costs allocated to that Party pursuant to Article 10. To the extent practical, such statements are to be coordinated with any billings or statements required pursuant to the Operating Agreement or PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.2 Payment.

The payment terms and conditions shall be as set forth in the billing statement and shall, to the extent practicable, be the same as those then in effect under the PJM Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

11.3 Failure to Pay.

If any Party fails to pay its share of the costs allocated pursuant to Article 10, those unpaid costs shall be allocated to and paid by the other Parties hereto in proportion to the sum of the Daily Unforced Capacity Obligations of each such Party for the billing month. The Office of the Interconnection shall enforce collection of a Party's share of the costs.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 12 – INDEMNIFICATION AND LIMITATION OF LIABILITIES

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.1 Indemnification.

(a) Each Party agrees to indemnify and hold harmless each of the other Parties, its officers, directors, employees or agents (other than PJM Interconnection, L.L.C., its board or the Office of the Interconnection) for all actions, claims, demands, costs, damages and liabilities asserted by third parties against the Party seeking indemnification and arising out of or relating to acts or omissions in connection with this Agreement of the Party from which indemnification is sought, except (i) to the extent that such liabilities result from the willful misconduct of the Party seeking indemnification and (ii) that each Party shall be responsible for all claims of its own employees, agents and servants growing out of any workmen's compensation law. Nothing herein shall limit a Party's indemnity obligations under Article 16 of the Operating Agreement.

(b) The amount of any indemnity payment under this Section 12.1 shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the Party seeking indemnification in respect of the indemnified actions, claims, demands, costs, damages or liabilities. If any Party shall have received an indemnity payment in respect of an indemnified action, claim, demand, cost, damage, or liability and shall subsequently actually receive insurance proceeds or other amounts in respect of such action, claim, demand, cost, damage, or liability, then such Party shall pay to the Party that made such indemnity payment the lesser of the amount of such insurance proceeds or other amounts actually received and retained or the net amount of the indemnity payments actually received previously.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.2 Limitations on Liability.

No Party will be liable to another Party for any claim for indirect, incidental, special or consequential damage or loss of the other Party including, but not limited to, loss of profits or revenues, cost of capital or financing, loss of goodwill and cost of replacement power arising from such Party's carrying out, or failure to carry out, any obligations contemplated by this Agreement; provided, however, nothing herein shall be deemed to reduce or limit the obligation of any Party with respect to the claims of persons or entities not a party to this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

12.3 Insurance.

Each Party shall obtain and maintain in force such insurance as is required of Load Serving Entities by the states in which it is doing business within the PJM Region.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 13 -- SUCCESSORS AND ASSIGNS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

13.1 Binding Rights and Obligations.

The rights and obligations created by this Agreement and all Schedules and supplements thereto shall inure to and bind the successors and assigns of the Parties; provided, however, no Party may assign its rights or obligations under this Agreement without the written consent of the Members Committee unless the assignee concurrently becomes the Load Serving Entity with regard to the end-users previously served by the assignor.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

13.2 Consequences of Assignment.

Upon the assignment of all of its rights and obligations hereunder to a successor consistent with the provisions of Section 13.1, the assignor shall be deemed to have withdrawn from this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 14 -- NOTICE

Except as otherwise expressly provided herein, any notice required hereunder shall be in writing and shall be sent: overnight courier, hand delivery, telecopy or other reliable electronic means to the representative on the Members Committee of such Party at the address for such Party previously provided by such Party to the other Parties. Any notice shall be deemed to have been given (i) upon delivery if given by overnight courier, hand delivery or certified mail or (ii) upon confirmation if given by facsimile or other reliable electronic means.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

15.1 Initial Representations and Warranties.

Each Party represents and warrants to the other Parties that, as of the date it becomes a Party:

(a) the Party is duly organized, validly existing and in good standing under the laws of the jurisdiction where organized;

(b) the execution and delivery by the Party of this Agreement and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the Party and do not conflict with any applicable law or with any other agreement binding upon the Party. The Agreement has been duly executed and delivered by the Party, and this Agreement constitutes the legal, valid and binding obligation of the Party enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting the enforcement of creditor's rights generally and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity; and

(c) there are no actions at law, suits in equity, proceedings or claims pending or, to the knowledge of the Party, threatened against the Party before or by any federal, state, foreign or local court, tribunal or governmental agency or authority that might materially delay, prevent or hinder the performance by the Party of its obligations hereunder.

15.2 Continuing Representations and Warranties.

Each Party represents and warrants to the other Parties that throughout the term of this Agreement:

(a) the Party is a Load Serving Entity;

(b) the Party satisfies the requirements of Schedule 2;

(c) the Party is in compliance with the Reliability Principles and Standards;

(d) the Party is a signatory, or its principals are signatories, to the agreements set forth in Schedule 3;

(e) the Party is in good standing in the jurisdiction where incorporated; and

(f) the Party will endeavor in good faith to obtain any corporate or regulatory authority necessary to allow the Party to fulfill its obligations hereunder.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

ARTICLE 16 -- OTHER MATTERS

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.1 Relationship of the Parties.

This Agreement shall not be interpreted or construed to create any association, joint venture, or partnership between or among the Parties or to impose any partnership obligation or partnership liability upon any Party.

16.2 Governing Law.

This Agreement shall be interpreted, construed and governed by the laws of the State of Delaware.

16.3 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.4 Amendment.

This Agreement may be amended only by action of the PJM Board. Notwithstanding the foregoing, an Applicant eligible to become a Party in accordance with the procedures set forth in Article 4 shall become a Party by executing a counterpart of this Agreement without the need for execution of such counterpart by any other Party. The PJM Office of the Interconnection shall file with FERC any amendment to this Agreement approved by the PJM Board.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.5 Headings.

The article and section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

16.6 Confidentiality.

(a) No Party shall have a right hereunder to receive or review any documents, data or other information of another Party, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection or to the extent that they have been designated as confidential by another Party; provided, however, a Party may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite document does not disclose any individual Party's confidential data or information.

(b) Notwithstanding anything in this Section to the contrary, if a Party is required by applicable laws, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section, that Party may make disclosure of such information; provided, however, that as soon as the Party learns of the disclosure requirement and prior to making disclosure, that Party shall notify the affected Party or Parties of the requirement and the terms thereof and the affected Party or Parties may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement and the Party shall cooperate with such affected Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. Each Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(c) Any contract with a contractor retained to provide technical support or to otherwise assist with the administration of this Agreement shall impose on that contractor a contractual duty of confidentiality that is consistent with this Section.

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16.7 Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon all parties hereto, notwithstanding that all of such parties may not have executed the same counterpart.

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16.8 No Implied Waivers.

The failure of a Party to insist upon or enforce strict performance of any of the provisions of this Agreement shall not be construed as a waiver or relinquishment to any extent of such Party's right to assert or rely upon any such provisions, rights and remedies in that or any other instance; rather, the same shall be and remain in full force and effect.

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16.9 No Third Party Beneficiaries.

This Agreement is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party not a signatory hereto.

16.10 Dispute Resolution.

Except as otherwise specifically provided in the Operating Agreement, disputes arising under this Agreement shall be subject to the dispute resolution provisions of the Operating Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

[Signatures]

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 1

PROCEDURES TO BECOME A PARTY

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

A. Notice

Any entity that is or will become a Load Serving Entity within the PJM Region and thus a Party to the Reliability Assurance Agreement shall submit a notice to the Office of the Interconnection together with (i) its representation that it has satisfied or will (prior to the date the Reliability Assurance Agreement is to become effective as to that entity) satisfy the requirements to become a Party, (ii) all data required to coordinate planning and operations within the PJM Region as applicable, in a format defined in the PJM Manuals, and (iii) a deposit in an amount to be specified that will be applied toward the costs of the required analysis.

The required notice, representations, data and deposit must be submitted in sufficient time to conduct an analysis of the data submitted and to adjust the obligations of the Parties for the month in which the entity desires to become a Party:

- If the then existing boundaries of the PJM Region would be expanded by an entity becoming a Party, that entity shall submit the required notice, representation, data and deposit no later than when the entity applies for transmission service under the PJM Tariff.

- If an entity will serve load within the then existing boundaries of the PJM Region, that entity shall submit the required notice, representations, data and deposit as soon as possible prior to the month (i) in which it is to begin serving loads within the PJM Region or (ii) in which any agency relationship through which the entity's obligations under this Agreement had been satisfied is terminated; provided, however, that such submission shall not be required sooner than any request for transmission service or any change in the designation of Network Resources or points of receipt and loads under the PJM Tariff associated with providing service to those loads.

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B. Analysis of Data

The notice, representations and data submitted to the Office of the Interconnection are to be analyzed in accordance with procedures consistent with this Agreement and the encouragement of reliable operation of the PJM Region.

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C. Response

Upon completion of the analysis, the Office of the Interconnection will inform the entity of (a) the estimated costs and expenses associated with modifications to communication, computer and other facilities and procedures, including any filing fees, needed to include the entity as a Party, (b) the entity's share of any costs pursuant to Article 10, and (c) the earliest date upon which the entity could become a Party. In addition, a counterpart of the Agreement shall be forwarded for execution.

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D. Agreement by New Party

After receipt of the response from the Office of the Interconnection, the entity shall identify its representative to the Members Committee and Markets and Reliability Committee and execute the counterpart of the Agreement, indicating the desired effective date; provided, however, such effective date shall be the first day of a month, may be no earlier than the date indicated in the response from the Office of the Interconnection and shall be no later than (i) the date on which the entity begins serving loads within the PJM Region or (ii) the termination date of any agency relationship through which its obligations under this Agreement had been satisfied. The executed counterpart of the Agreement, together with payment of its share of any costs then due, shall be returned as directed by the Office of the Interconnection.

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SCHEDULE 2

STANDARDS FOR INTEGRATING AN ENTITY INTO THE PJM REGION

A. The following standards will be applied by the Office of the Interconnection to determine the eligibility of an entity to become a part of the PJM Region. For an entity to be integrated into the PJM Region it must possess generation and transmission attributes that would enable the entity to share its reserves with other entities in the PJM Region. Appropriate transmission and reliability studies are to be performed to determine the adequate transmission capability necessary to integrate the entity into the PJM Region consistent with Good Utility Practice.

B. In addition, the entity shall meet the following requirements to be included in the PJM Region:

1. All load, generation and transmission operating as part of the PJM Region's interconnected system must be included within the metered boundaries of the PJM Region.

2. The entity will accept and comply with the PJM Region's standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the PJM Manuals so that sufficient electrical equipment, control capability, information and communication are available to the Office of the Interconnection for planning and operation of the PJM Region.

3. The load, generation and transmission facilities of each entity shall be included in the telemetry to the Office of the Interconnection from a 24-hour control center. Each system operator in these control centers must be trained and delegated sufficient authority to take any action necessary to assure that the system for which the operator is responsible is operated in a stable and reliable manner.

4. Each entity must have compatible operational communication mechanisms, maintained at its expense, to interact with the Office of the Interconnection and for internal requirements.

5. Each entity must assure the continued compatibility of its local system energy management system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the Office of the Interconnection as it directs the operation of the PJM Region.

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SCHEDULE 3

OTHER AGREEMENTS TO BE EXECUTED BY THE PARTIES

- Any agreement for Network Transmission Service or Firm Point-To-Point Service that is required under the PJM Tariff for service consistent with the requirements of Section 9.1(d); and

- The Operating Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

SCHEDULE 4

GUIDELINES FOR DETERMINING THE FORECAST POOL REQUIREMENT

Effective Date: 9/17/2010 - Docket #: ER10-2710-006

A. Objective Of The Forecast Pool Requirement

The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.

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B. Forecast Pool Requirement and PJM Region Installed Reserve Margin To Be Determined Annually

No later than three months in advance of each Base Residual Auction for a Delivery Year, based on the projections described in section C of this Schedule, and after consideration of the recommendation of the Members Committee, the PJM Board shall establish the Forecast Pool Requirement, including the PJM Region Installed Reserve Margin for all Parties, including FRR Entities, for such Delivery Year. Unless otherwise agreed by the PJM Board, the Forecast Pool Requirement and PJM Region Installed Reserve Margin for such Planning Period shall be considered firm and not subject to re-determination thereafter.

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C. Methodology

Each year, the Forecast Pool Requirement for at least each of the next five Planning Periods shall be projected by applying suitable probability methods to the data and forecasts provided by the Parties and obtained from Electric Distributors, as described in Schedule 11, the Operating Agreement and in the PJM Manuals. The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary:

1. Seasonal peak load forecasts for each Planning Period as calculated by PJM in accordance with the PJM Manuals reflecting (a) load forecasts with a 50 percent probability of being too high or too low and (b) summer peak diversities determined by the Office of the Interconnection from recent experience.

2. Forecasts of aggregate seasonal load shape of the Parties which are consistent with forecast averages of 52 weekly peak loads prepared by the Parties and obtained from Electric Distributors for their respective systems.

3. Variability of loads within each week, due to weather and other recurring and random factors, as determined by the Office of the Interconnection.

4. Generating unit capability and types for every existing and proposed unit.

5. Generator Forced Outage rates for existing mature generating units, as determined by the Office of the Interconnection, based on data submitted by the Parties for their respective systems, from recent experience, and for immature and proposed units based upon forecast rates related to unit types, capabilities and other pertinent characteristics.

6. Generator Maintenance Outage factors and planned outage schedules as determined by the Office of the Interconnection based on forecasts and historical data submitted by the Parties for their respective systems.

7. Miscellaneous adjustments to capacity due to all causes, as determined by the Office of the Interconnection, based on forecasts submitted by the Parties for their respective systems.

8. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, as limited by the capacity benefit margin considered in the determination of available transfer capability and the probable availability of generation in excess of load requirements in such areas.

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D. Capacity Benefit Margin

The capacity benefit margin initially shall be 3,500 megawatts. Periodically, in consultation with the Members Committee, the Office of the Interconnection shall review and modify, if necessary, the capacity benefit margin to balance external emergency capacity assistance and internal installed capacity reserves so as to minimize the total cost of the capacity reserves of the Parties, consistent with the Reliability Principles and Standards. The Office of the Interconnection will reflect such modification prospectively in its development of the Forecast Pool Requirement for future Planning Periods.

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SCHEDULE 4.1

DETERMINATION OF THE FORECAST POOL REQUIREMENT

A. Based on the guidelines set forth in Schedule 4, the Forecast Pool Requirement shall be determined as set forth in this Schedule 4.1 on an unforced capacity basis.

$$FPR = (1 + IRM/100) * (1 - \text{Pool-wide average } EFOR_D/100)$$

where

average $EFOR_D$ = the average equivalent demand forced outage rate for the PJM Region, stated in percent and determined in accordance with Section B hereof

IRM = the PJM Region Installed Reserve Margin approved by the PJM Board for that Planning Period, stated in percent. Studies by the Office of the Interconnection to determine IRM shall not exclude outages that are deemed to be outside plant management control under NERC guidelines.

B. The PJM Region equivalent demand forced outage rate ("average $EFOR_D$") shall be determined as the capacity weighted $EFOR_D$ for all units expected to serve loads within the PJM Region during the Delivery Year, as determined pursuant to Schedule 5.

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SCHEDULE 5

FORCED OUTAGE RATE CALCULATION

A. The equivalent demand forced outage rate ("$EFOR_D$") shall be calculated as follows:

$$EFOR_D\ (\%) = \{(f_f * FOH + f_p * EFPOH) / (SH + f_f * FOH)\} * 100$$

where

f_f = full outage factor
f_p = partial outage factor
FOH = full forced outage hours
EFPOH = equivalent forced partial outage hours
SH = service hours

B. Calculation of $EFOR_D$ for individual Generation Capacity Resources.

For each Delivery Year, $EFOR_D$ shall be calculated at least one month prior to the start of the Third Incremental Auction for: (i) each Generation Capacity Resource for which a sell offer will be submitted in such Third Incremental Auction; and (ii) each Generation Capacity Resource previously committed to serve load in such Delivery Year pursuant to an FRR Capacity Plan or prior auctions for such Delivery Year. Such calculation shall be based upon such resource's service history in the twelve (12) consecutive months ending September 30 last preceding such auction. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments approved by the Members Committee to adjust the parameters of a designated unit. For purposes of the calculations under this Paragraph B, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered.

1. The $EFOR_D$ of a unit in service twelve or more full calendar months prior to the calculation month shall be the average rate experienced by such unit during the twelve-month period specified above. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

2. The $EFOR_D$ of a unit in service at least one full calendar month but less than the twelve-month period specified above shall be the average of the $EFOR_D$ experienced by the unit weighted by full months of service, and the class average rate for units with that capability and of that type weighted by a factor of [(twelve) minus (the number of months the unit was in service)]. Historical data shall be based on official reports of the Parties under rules and practices set forth in the PJM Manuals.

C. Calculation of average $EFOR_D$ for the PJM Region

The forecast average $EFOR_D$ for the PJM Region in a Delivery Year shall be the average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all of the Generation Capacity Resources within the PJM Region, that are planned to be in service during the Delivery Year, including Generation Capacity Resources purchased from specified units and excluding Generation Capacity Resources sold outside the PJM Region from specified units. Such rate shall also include (i) an adjustment, if any, for capacity unavailable due to energy limitations determined in accordance with definitions and criteria set forth in the PJM Manuals and (ii) any other adjustments developed by the Office of Interconnection and maintained in the PJM Manuals to adjust the parameters of a designated unit when such parameters are or will be used to determine a future PJM Region reserve requirement and such adjustment is required to more accurately predict the future performance of such unit in light of extraordinary circumstances. For the purposes of this Schedule, the average $EFOR_D$ shall be the average of the capacity-weighted $EFOR_D$s of all units committed to serve load in the PJM Region; and for purposes of the $EFOR_D$ calculations under this Paragraph C for any Delivery Year beginning after May 31, 2010, outages deemed to be outside plant management control in accordance with NERC guidelines shall not be considered. All rates shall be in percent.

1. The $EFOR_D$ of a unit not yet in service or which has been in service less than one full calendar year at the time of forecast shall be the class average rate for units with that capability and of that type, as estimated and used in the calculation of the Forecast Pool Requirement.

2. The $EFOR_D$ of a unit in service five or more full calendar years at the time of forecast shall be the average rate experienced by such unit during the five most recent calendar years. Historical data shall be based on official reports of the Parties under rules and practices developed by the Office of Interconnection and maintained in the PJM Manuals.

3. The $EFOR_D$ of a unit in service at least one full calendar year but less than five full calendar years at the time of the forecast shall be determined as follows:

Full Calendar Years of Service	
1	One-fifth the rate experienced during the calendar year, plus four-fifths the class average rate.
2	Two-fifths the average rate experienced during the two calendar years, plus three-fifths the class average rate.
3	Three-fifths the average rate experienced during the three calendar years, plus two-fifths the class average rate.
4	Four-fifths the average rate experienced during the four calendar years, plus one-fifth the class average rate.

SCHEDULE 6

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources or ILR that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. In addition, for Delivery Years through May 31, 2012, resources qualifying under the criteria set forth below may be certified as ILR on behalf of a Party that has not elected the FRR Alternative for a Delivery Year no later than three months prior to the first day of such Delivery Year; provided, however, that for the 2011-2012 Delivery Year only, the ILR certification deadline shall be no later than two months prior to the first day of such Delivery Year. Qualified Demand Resources and ILR generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section H and the PJM Manuals. Qualified Demand Resources and ILR may be provided by a Demand Resource Provider or ILR Provider (hereinafter, "Provider"), notwithstanding that such Provider is not a Party to this Agreement. Such Providers must satisfy the requirements in section I and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and paragraph G of this schedule as applicable, the Office of the Interconnection of the Demand Resource or ILR that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is an ILR resource, a Limited Demand Resource, an Extended Summer Demand Resource or an Annual Demand Resource.

2. A period of no more than 2 hours prior notification must apply to interruptible customers.

3. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

5. An entity offering for sale, designating for self-supply, or including in any FRR Capacity Plan any Planned Demand Resource must demonstrate, in accordance with standards and procedures set forth in the PJM Manuals, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. Providers of Planned Demand Resources must provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to a Base Residual Auction or Incremental Auction. PJM may verify the Provider's adherence to the timetable at any time.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response program and thus available for dispatch during PJM-declared emergency events.

B. The Unforced Capacity value of a Demand Resource and ILR will be determined as:

the product of the Nominated Value of the Demand Resource, or the Nominated Value of the ILR, times the DR Factor, times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections J and K, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR, divided by the total Nominated Value of Demand Resources and ILR in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources and ILR, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. Certified ILR resources shall receive the Final Zonal ILR Price.

E. The Party, Electric Distributor, Demand Resource Provider, or ILR Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in sections C and D for a committed Demand Resource or certified ILR, notwithstanding that such provider is not the customer's energy supplier.

F. Any Party hereto shall demonstrate that its Demand Resources or ILR performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section L and the PJM Manuals. In addition, committed Demand Resources and certified ILR that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

G. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

H. PJM recognizes three types of Demand Resource and ILR:

Direct Load Control (DLC) – Load management that is initiated directly by the Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – Demand Resource or ILR which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

I. Each Provider must satisfy (or contract with another LSE, Provider, or EDC to provide) the following requirements:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;
- supplemental status reports, detailing Demand Resources and ILR available, as requested by PJM;
- Entry of customer-specific Demand Resource and ILR credit information, for planning and verification purposes, into the designated PJM electronic system.
- Customer-specific compliance and verification information for each PJM-initiated Demand Resource or ILR event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all Demand Resource or ILR events, prepared in accordance with the PJM Manuals.

J. The Nominated Value of each Demand Resource or ILR shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load reduction value for a Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource or ILR information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections K and L.

K. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource or ILR information, to verify the amount of load management available, and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource, or certification of such resource as ILR. Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event. PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Providers must submit actual loads and comparison loads for all hours during the day of the Load Management event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the full hours of a load management event, for each customer or DLC program dispatched by the Office of the Interconnection. Demand Resource or ILR resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed and ILR Certified by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

M. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption at the End-Use Customer's Retail Site that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2011. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a

Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than the start of such Delivery Year, an updated project status and detailed measurement and verification data meeting the standards for precision and accuracy set forth in the PJM Manuals. The final value of the Energy Efficiency Resource during such Delivery Year shall be as determined by the Office of the Interconnection based on the submitted data.

7. The Office of the Interconnection may audit, at the Capacity Market Seller's expense, any Energy Efficiency Resource committed to the PJM Region. The audit may be conducted any time including the Performance Hours of the Delivery Year.

Effective Date: 11/7/2011 - Docket #: ER11-3322-001

SCHEDULE 6.1

PRICE RESPONSIVE DEMAND

A. As more fully set forth in this Schedule 6.1 and the PJM Manuals, for any Delivery Year beginning on or after June 1, 2015 (subject to a transition plan, as set forth below), any PRD Provider, including any FRR Entity, may commit that certain loads identified by such PRD Provider shall not exceed a specified demand level at specified prices during Maximum Generation Emergencies, as a consequence of the implementation of Price Responsive Demand. Based on information provided by the PRD Provider in a PRD Plan (and, to the extent such plan identifies a PRD Reservation Price, based on the clearing price in the Base Residual Auction or Third Incremental Auction, as applicable), the Office of the Interconnection shall determine the Nominal PRD Value for the specified loads identified by such PRD Provider by Zone (or sub-Zonal LDA, if applicable). The Office of the Interconnection shall adjust the PJM Region Reliability Requirement and LDA Reliability Requirements, as applicable, to reflect committed PRD. Actual PRD reductions in response to price shall be added back in determining peak load contributions. Any PRD Provider that fails fully to honor its PRD commitments for a Delivery Year shall be assessed compliance charges.

B. End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; or (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

C. Any PRD Provider seeking to commit PRD hereunder for a Delivery Year must submit to the Office of the Interconnection a PRD Plan identifying and supporting the Nominal PRD Value (calculated as the difference between the PRD Provider's Zonal Expected Peak Load Value of PRD and the Maximum Emergency Service Level of Price Responsive Demand) for each Zone (or sub-Zonal LDA, if applicable) for which such PRD is committed; such information shall be provided on a PRD Substation level to the extent available at the time the PRD Plan is submitted. Such plan must be submitted no later than the January 15 last preceding the Base Residual Auction for the Delivery Year for which such PRD is committed; any submitted plan that does not contain, by such January 15, all information required hereunder shall be rejected. A PRD Provider may submit a PRD Plan, or a modified PRD Plan, by the January 15 last preceding the Third Incremental Auction for such Delivery Year requesting approval of additional Price Responsive Demand but only in the event, and to the extent, that the final peak load forecast for the relevant LDA for such Delivery Year exceeds the preliminary peak load forecast for such LDA and Delivery Year. The Office of the Interconnection shall revise such requests (as adjusted, to the extent a PRD Reservation Price is specified, for the results of the Third Incremental Auction) for additional Price Responsive Demand downward, in accordance with rules in the PJM Manuals, if the submitted requests (as adjusted) in the aggregate exceed the increase in the load forecast in the LDA modeled. The Office of the Interconnection shall advise the PRD Provider, following the Third Incremental Auction, of its acceptance of, or any downward adjustment to, the Nominal PRD Value based on its review of the PRD Plan and the results of the auction. Approval of the PRD Plan by the Office of the Interconnection shall establish a firm commitment by the PRD Provider to the specified Nominal PRD Value of Price Responsive Demand at each Zone (or sub-Zonal LDA, if applicable) during the relevant Delivery Year (subject to any PRD Reservation Price), and may not be uncommitted or replaced by any Capacity Resource. Although the PRD Plan may include reasonably supported forecasts and expectations concerning the development of Price Responsive Demand for a Delivery Year, the PRD Provider's commitment to a Nominal PRD Value for such Delivery Year shall not depend or be conditioned upon realization of such forecasts or expectations.

D. All submitted PRD Plans must comply with the requirements and criteria in the PJM Manuals for such plans, including assumptions and standards specified in the PJM Manuals for estimates of expected load levels. The PRD Plan shall explain and justify the methods used to determine the Nominal PRD Value. All assumptions and relevant variables affecting the Nominal PRD Value must be clearly stated. The PRD Plan must include sufficient data to allow a third party to audit the procedures and verify the Nominal PRD Value. Any non-compliance with a Nominal PRD Value for a prior Delivery Year shall be identified and taken into account. In addition, each submitted PRD Plan must include:

(i) documentation, in the form specified in the PJM Manuals, that: (1) where the PRD Provider is a Load Serving Entity, the Relevant Electric Retail Regulatory Authority has provided any required approval (including conditional approval, but only if the Load Serving Entity asserts that all such conditions have been satisfied) of such Load Serving Entity's time-varying retail rate structure and, regardless of whether RERRA approval is required, that such rate structure adheres to PRD implementation standards specified in the PJM Manuals; and (2) where the PRD Provider is not a Load Serving Entity, such PRD Provider has in place contractual arrangements with the relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements, and adheres to PRD implementation standards specified in the PJM Manuals; in such cases, the PRD Provider shall provide the Office of the Interconnection copies of its applicable contracts with end-use customers (including any proposed contracts) within ten business days after a request for such contracts, or its PRD Plan shall be rejected;

(ii) the expected peak load value that would apply, absent load reductions in response to price, to the end-use customer loads at a PRD Substation level, including applicable peak-load contribution data for such customers, to the extent available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iii) the Maximum Emergency Service Level of the identified load given the load's price-responsive characteristics, at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(iv) Price-consumption curves ("PRD Curves") at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level that detail the base consumption level of the identified loads; and the decreasing consumption levels at increasing prices, provided that all identified load reductions must be capable of full implementation within 15 minutes of declaration of a Maximum Generation Emergency by the Office of the Interconnection, and provided further that the specified prices may not exceed the maximum energy offer price cap under the PJM Tariff and Operating Agreement;

(v) the estimated Nominal PRD Value of the Price Responsive Demand at a PRD Substation level if available and otherwise at a Zonal (or sub-Zonal LDA if applicable) level;

(vi) specifications of equipment used to satisfy the advanced metering and Supervisory Control criteria for eligible Price Responsive Demand, including a timeline and milestones demonstrating that such equipment shall be available and operational for the start of the relevant Delivery Year. Such equipment shall comply with applicable RERRA requirements and shall be designed to meet all PRD requirements, including, without limitation, meter reading requirements and Supervisory Control requirements, specified in the PJM Manuals. The PRD Provider shall demonstrate in the PRD Plan that the Supervisory Control equipment enables an automated load response by Price Responsive Demand to the price trigger; provided, however, that the PRD Provider may request in the PRD Plan an exception to the automation requirement for any individual registered end-use customer that is located at a single site and that has Supervisory Control over processes by which load reduction would be accomplished; and provided further that nothing herein relieves such end-use customer of the obligation to respond within 15 minutes to declaration of a Maximum Generation Emergency in accordance with applicable PRD Curves. In addition to the above requirements and those in the PJM Manuals for metering equipment and associated data, metering equipment shall provide integrated hourly kWh values on an electric distribution company account basis and shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including potential transformers and current transformers). The installed metering equipment must be that used for retail electric service; or metering equipment owned by the end-use customer or PRD Provider that is approved by PJM and either read electronically by PJM or read by the customer or PRD Provider and forwarded to PJM, in either case in accordance with requirements set forth in the PJM Manuals; and

(vii) any RPM Auction clearing price below which the PRD Provider does not choose to commit PRD ("PRD Reservation Price"), specifying the relevant auction, Zone (or sub-Zonal LDA if applicable), and, if applicable, a range of up to ten pairs of PRD commitment levels and associated minimum RPM Auction clearing prices; provided however that the Office of the Interconnection may interpolate PRD commitment levels based on clearing prices between prices specified by the PRD Provider.

E. Each PRD Provider that commits Price Responsive Demand through an accepted PRD Plan must, no later than one day before the tenth business day prior to the start of the Delivery Year for which such PRD is committed, register with PJM, in the form and manner specified in the PJM Manuals, sufficient PRD-eligible load at a PRD Substation level to satisfy its Nominal PRD Value commitment. All information required in the PRD Plan to be at a PRD Substation level if available at the time of submission of the PRD Plan that was not provided at the time of submission of such plan must be provided with the registration. The PRD Provider shall also identify in the registration each individual end-use customer with a peak demand of 10 kW or greater included in such Price Responsive Demand, the peak demand of such customers, the Load Serving Entity responsible for serving such customers, and the Load Serving Entities responsible for serving the end-use customers not identified on an individual basis. PJM shall provide notification of such PRD registrations to the applicable electric distribution company(ies) and load serving entity(ies). The PRD Provider shall maintain, and provide to the Office of the Interconnection upon request, an identification of all individual end-use customers with a peak load contribution of less than 10kW included in such Price Responsive Demand, and the peak load contribution of such customers. The PRD Provider must maintain its PRD Substation-level registration of PRD-eligible load at the level of its Zonal (or sub-zonal LDA, if applicable) Nominal PRD Value commitment during each day of the Delivery Year for which such commitment was made. The PRD Provider may change the end-use customer registered to meet the PRD Provider's commitment during the Delivery Year, but such PRD Provider must always in the aggregate register sufficient Price Responsive Demand to meet or exceed the Zonal (or sub-Zonal LDA, if applicable) committed Nominal PRD Value level. A PRD Provider must timely notify the Office of the Interconnection, in accordance with the PJM Manuals, of all changes in PRD registrations. Such notification must remove from the PRD Provider's registration(s) any end-use customer load that no longer meets the eligibility criteria for PRD, effective as of the first day that such end-use customer load is no longer PRD-eligible.

F. Each PRD Provider that is a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Day-Ahead and Real-Time Energy Markets. Each PRD Provider that is not a Load Serving Entity shall be required to identify its committed Price Responsive Demand as price-sensitive demand at a PRD Substation level in the Real-Time Energy Market. The most recent PRD Curve submitted by the PRD Provider in its PRD Plan or PRD registration shall be used for such purpose unless and until changed by the PRD Provider in accordance with the market rules of the Office of the Interconnection, provided that any changes to PRD Curves must be consistent with the PRD Provider's commitment of Price Responsive Demand hereunder.

G. The Obligation Peak Load of a Load Serving Entity that serves end-users registered as Price Responsive Demand in any Zone shall be as determined in Schedule 8 to this Agreement; provided, however, that such Load Serving Entity shall receive, for each day that an approved Price Response Demand registration is effective and applicable to such LSE's load, a Price Responsive Demand Credit for such registration during the Delivery Year, against the Locational Reliability Charge otherwise assessed upon such Load Serving Entity in such Zone for such day, determined as follows:

LSE PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (FZWNSP/FZPLDY) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)] .

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration .

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price

Responsive Demand registered by the PRD Provider of such registration *Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year;

And where the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone. A Load Serving Entity will receive a LSE PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to an LSE in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone for load served by such LSE on a given day.

H. A PRD Provider may transfer all or part of its PRD commitment for a Delivery Year in a Zone (or sub-Zonal LDA) to another PRD Provider for its use in the same Zone or sub-Zonal LDA, through notice of such transfer provided by both the transferor and transferee PRD Providers to the Office of the Interconnection in the form and manner specified in the PJM Manuals. From and after the effective date of such transfer, and to the extent of such transfer, the transferor PRD Provider shall be relieved of its PRD commitment and credit requirements, shall not be liable for PRD compliance charges, and shall not be entitled to a Price Responsive Demand Credit; and the transferee PRD Provider, to the extent of such transfer, shall assume such PRD commitment, credit requirements, and obligation for compliance charges and, if it is a Load Serving Entity, shall be entitled to a Price Responsive Demand Credit.

I. Any PRD Provider that commits Price Responsive Demand and does not register and maintain registration of sufficient PRD-eligible load, (including, without limitation, failing to install or maintain the required advanced metering or Supervisory Control facilities) in a Zone (or sub-Zonal LDA, if applicable) to satisfy in full its Nominal PRD Value commitment in such Zone (or sub-Zonal LDA) on each day of the Delivery Year for which such commitment is made shall be assessed a compliance charge for each day that the registered Price Responsive Demand is less than the committed Nominal PRD Value. Such daily penalty shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Weighted Final Zonal Capacity Price) or ($20/MW-day)]

Where: MW Shortfall = Daily Nominal PRD Value committed in such PRD Provider's PRD Plan (including any permitted amendment to such plan) for the relevant Zone or sub-Zonal LDA – Daily Nominal PRD Value as a result of PRD registration for such Zone or sub-Zonal LDA; and

Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction.

The MW Shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits, provided, however, that the PRD Provider may register additional PRD-eligible end-use customer load to satisfy its PRD commitment.

J. PRD Providers shall be responsible for verifying the performance of their PRD loads during each maximum emergency event declared by the Office of the Interconnection. PRD Providers shall demonstrate that the identified PRD loads performed in accordance with the PRD Curves submitted at a PRD Substation level in the PRD Plan or PRD registration; provided, however, that the previously submitted MESL value shall be adjusted by a ratio equal to the amount by which the actual Zonal load during the declared event exceeded the PJM load forecast underlying the previously submitted MESL value. In accordance with procedures and deadlines specified in the PJM Manuals, the PRD Providers must submit actual customer load levels for all hours during the declared event and all other information reasonably required by the Office of the Interconnection to verify performance of the committed PRD loads.

K. If the identified loads submitted for a Zone (or sub-Zonal LDA) by a PRD Provider exceed during any Emergency the aggregate Maximum Emergency Service Level ("MESL") specified in all PRD registrations of such PRD Provider that have a PRD Curve specifying a price at or below the highest Real-time LMP recorded during such Emergency, the PRD Provider that committed such loads as Price Responsive Demand shall be assessed a compliance charge hereunder. The charge shall be based on the net performance during an Emergency of the loads that were identified as Price Responsive Demand for such Delivery Year in the PRD registrations submitted by such PRD Provider in each Zone (or sub-Zonal LDA, if applicable) and that specified a price at the MESL that is at or below the highest Real-Time LMP recorded during such Emergency. The compliance charge hereunder shall equal:

[MW Shortfall] * [Forecast Pool Requirement] * [(Weighted Final Zonal Capacity Price in $/MW-day)

+ higher of (0.2 * Final Zonal Capacity Price) or ($20/MW-day)] * 365 days

Where: MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA meeting the price condition specified above] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone meeting the price condition specified above)]}.

For purposes of the above provision, the MW Shortfall for any portion of the Emergency event that is less than a full clock hour shall be treated as a shortfall for a full clock hour unless either: (i) the load was reduced to the adjusted MESL level within 15 minutes of the emergency procedures notification, regardless of the response rate submitted, or (ii) the hourly integrated value of the load was at or below the adjusted MESL. Such MW shortfall shall not be reduced through replacement of the Price Responsive Demand by any Capacity Resource or Excess Commitment Credits; provided, however, that the performance and MW Shortfalls of all PRD-eligible load registered by the PRD Provider, including any additional or replacement load registered by such PRD Provider, provided that it meets the price condition specified above, shall be reflected in the calculation of the overall MW Shortfall. Any greater MW Shortfall during a subsequent Emergency for such Zone or sub-Zonal LDA during the same Delivery Year shall result in a further charge hereunder, limited to the additional increment of MW Shortfall. As appropriate, the MW Shortfall for non-compliance during an Emergency shall be adjusted downward to the extent such PRD Provider also was assessed a compliance penalty for failure to register sufficient PRD to satisfy its PRD commitment.

L. PRD Providers that register Price Responsive Demand shall be subject to test at least once per year to demonstrate the ability of the registered Price Responsive Demand to reduce to the specified Maximum Emergency Service Level, and such PRD Providers shall be assessed a compliance charge to the extent of failure by the registered Price Responsive Demand during such test to reduce to the Maximum Emergency Service Level, in accordance with the following:

(i) If the Office of the Interconnection does not declare during the relevant Delivery Year a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level then such registered PRD must demonstrate that it was tested for a one-hour period during any hour when a Maximum Generation Emergency may be called during June through October or the following May of the relevant Delivery Year. If a Maximum Generation Emergency that requires the registered PRD to reduce to the Maximum Emergency Service Level is called during the relevant Delivery Year, then no compliance charges will be assessed hereunder.

(ii) All PRD registered in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.

(iii) A PRD Provider that registered PRD shall be assessed a PRD Test Failure Charge equal to the net PRD capability testing shortfall in a Zone during such test in the aggregate of all of such PRD Provider's registered PRD in such Zone times the PRD Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable Forecast Pool Requirement:

MW Shortfall = [highest hourly integrated aggregate metered load for such PRD Provider's PRD load in the Zone or sub-Zonal LDA] – {(aggregate MESL for the Zone or sub-Zonal LDA) * the higher of [1.0] or [(actual Zonal load – actual total PRD load in Zone) / (Final Zonal Peak Load Forecast – final Zonal Expected Peak Load Value of PRD in total for all PRD load in Zone]}.

The net PRD capability testing shortfall in such Zone shall be reduced by the PRD Provider's summer daily average of the MW shortfalls determined for compliance charge purposes under section I of this Schedule 6.1 in such Zone for such PRD Provider's registered PRD.

(iv) The PRD Test Failure Charge Rate shall equal such PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the Weighted Final Zonal Capacity Price in such Zone or $20/MW-day) times the number of days in the Delivery Year, where the Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price attributable to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in connection with the Base Residual Auction and those committed by such PRD Provider in connection with the Third Incremental Auction. Such charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

M. The revenue collected from assessment of the charges assessed under subsections I, K, and L of this Schedule 6.1 shall be distributed on a pro-rata basis to all entities that committed Capacity Resources in the RPM Auctions for the Delivery Year for which the compliance charge is assessed, pro rata based on each such entity's revenues from Capacity Market Clearing Prices in such auctions, net of any compliance charges incurred by such entity.

N. Aggregate Price Responsive Demand that may be registered shall be limited for the first three Delivery Years that peak load adjustments for Price Responsive Demand are allowed under this Agreement. The maximum quantity of Price Responsive Demand that may be registered by all PRD Providers for the PJM Region as a wholeshall be:

1. 2500 MW for the Delivery Year that begins on June 1, 2016;
2. 3500 MW for the Delivery Year that begins on June 1, 2017; and
3. 4000 MW for the Delivery Year that begins on June 1, 2018.

For Delivery Years in which the region-wide limit is not met, no limit as to the amount of Price Responsive Demand that may register in a Zone (or sub-Zone) shall apply. However, in the event the region-wide limit is met for a Delivery Year, then a portion of such limit shall be assigned to each Zone (or sub-Zonal LDA, if applicable) pro rata based on each such Zone's (or sub-Zone's) Preliminary Zonal Peak Load Forecast for the Delivery Year compared to the PJM Region's Preliminary RTO Peak Load Forecast for such Delivery Year (less, in each case, load expected to be served in such area under the Fixed Resource Requirement). Within each Zone (or sub-Zonal LDA, if applicable) the permitted registrations shall be those quantities within the Zonal (or sub-Zonal LDA) limit with the lowest identified PRD Reservation Prices for their identified loads; and, as between PRD Providers submitting PRD registrations at the same PRD Reservation Price, pro rata based on each such LSE's share of the Preliminary Zonal Peak Load Forecast for such Zone (or sub-Zonal LDA) less load expected to be served under the Fixed Resource Requirement. For Delivery Years in which the region-wide limit is met, any PRD registrations that are not permitted by operation of this section will, to the extent not permitted, not be required to perform in accordance with its registration, not be considered in determining an LSE's PRD Credit or Nominal PRD Value, and not be accounted for in the applicable PRD

Provider's PRD Curves. Nothing in this section precludes price-responsive load from exercising any opportunity it may otherwise have to participate in the day-ahead or real-time energy markets in the PJM Region. For Delivery Years beginning on or after June 1, 2019, there is no limit on the quantity of Price Responsive Demand that may register.

Effective Date: 5/15/2012 - Docket #: ER11-4628-001

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.

B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

SCHEDULE 8

DETERMINATION OF UNFORCED CAPACITY OBLIGATIONS

A. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of a Party that has not elected the FRR Alternative for such Delivery Year shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = OPL x Final Zonal RPM Scaling Factor x FPR

Where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal RPM Scaling Factor = the factor determined as set forth in sections B and C of this Schedule

FPR = the Forecast Pool Requirement

Netting of Behind the Meter Generation for a Party with regard to Non-Retail Behind the Meter Generation shall be subject to the following limitation:

For the 2006/2007 Planning Period, 100 percent of the operating Non-Retail Behind the Meter Generation shall be netted, provided that the total amount of Non-Retail Behind the Meter Generation in the PJM Region does not exceed 1500 megawatts ("Non-Retail Threshold"). For each Planning Period/Delivery Year thereafter, the Non-Retail threshold shall be proportionately increased based on load growth in the PJM Region but shall not be greater than 3000 megawatts. Load growth shall be determined by the Office of the Interconnection based on the most recent forecasted weather-adjusted coincident summer peak for the PJM Region divided by the weather-adjusted coincident peak for the previous summer for the same area. After the load growth factor is applied, the Non-Retail Threshold will be rounded up or down to the nearest whole megawatt and the rounded number shall be the Non-Retail Threshold for the current Planning Period and the base amount for calculating the Non-Retail Threshold for the succeeding planning period. If the Non-Retail Threshold is exceeded, the amount of operating Non-Retail Behind the Meter Generation that a Party may net shall be adjusted according to the following formula:

Party Netting Credit = (NRT/ PJM NRBTMG) * Party Operating NRBTMG

Where: NRBTMG is Non-Retail Behind the Meter Generation

NRT is the Non-Retail Threshold

PJM NRBTMG is the total amount of Non-Retail Behind the Meter Generation in the PJM Region

The total amount of Non-Retail Behind the Meter Generation that is eligible for netting in the PJM Region is 3000 megawatts. Once this 3000 megawatt limit is reached, any additional Non-Retail Behind the Meter Generation which operates in the PJM Region will be ineligible for netting under this section.

In addition, the Party NRBTMG Netting Credit shall be adjusted pursuant to Schedule 16 of this Agreement, if applicable.

A Party shall be required to report to PJM such information as is required to facilitate the determination of its NRBTMG Netting Credit in accordance with the procedures set forth in the PJM Manuals.

B. Following the Base Residual Auction for a Delivery Year, the Office of the Interconnection shall determine the Base Zonal RPM Scaling Factor and the Base Zonal Unforced Capacity Obligation for each Zone for such Delivery Year as follows:

Base Zonal Unforced Capacity Obligation = (ZWNSP * Base Zonal RPM Scaling Factor * FPR) + Forecast Zonal ILR Obligation (for Delivery Years through May 31, 2012) or Zonal Short-Term Resource Procurement Target (for Delivery Years thereafter)

and

Base Zonal RPM Scaling Factor = ZPLDY/ZWNSP x [RUCO / (RPLDY x FPR)]

Where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Delivery Year

ZWNSP = Zonal Weather-Normalized Summer Peak for the summer season concluding four years prior to the commencement of such Delivery Year

RUCO = the RTO Unforced Capacity Obligation satisfied in the Base Residual Auction for such Delivery Year.

RPLDY = RTO Preliminary Peak Load Forecast for such Delivery Year.

For purposes of such determination, PJM shall determine the Preliminary RTO Peak Load Forecast, and the Preliminary Zonal Peak Load Forecasts for each Zone, in accordance with the PJM Manuals for each Delivery Year no later than one month prior to the Base Residual Auction for such Delivery Year. PJM shall determine the Updated RTO and Zonal Peak Load Forecasts in accordance with the PJM Manuals for each Delivery Year no later than one month prior to each of the First, Second, and Third Incremental Auctions for such Delivery Year. PJM shall determine the most recent Weather Normalized Summer Peak for each Zone no later than seven months prior to the start of the Delivery Year, and shall calculate the RTO Weather Normalized Summer Peak as the sum of the Weather Normalized Summer Peaks for all Zones.

C. The Final RTO Unforced Capacity Obligation for a Delivery Year shall be equal to the sum of the unforced capacity obligations satisfied through the Base Residual Auction and the First, Second, Third, and any Conditional Incremental Auctions for such Delivery Year. The unforced capacity obligation satisfied in an Incremental Auction may be negative if capacity is decommitted in such auction. The Final Zonal Unforced Capacity Obligation for a Zone shall be equal to such Zone's pro rata share of the Final RTO Unforced Capacity Obligation for the Delivery Year based on the Final Zonal Peak Load Forecast made one month prior to the Third Incremental Auction The Final Zonal RPM Scaling Factor shall be equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Summer Peak for the summer concluding prior to the commencement of such Delivery Year).

D. 1. No later than five months prior to the start of each Delivery Year, the Electric Distributor for a Zone shall allocate the most recent Weather Normalized Summer Peak for such Zone to determine the Obligation Peak Load for each end-use customer within such Zone.

2. During the Delivery Year, no later than 36 hours prior to the start of each operating day, the Electric Distributor shall provide to PJM for each Party to this Agreement serving load in such Electric Distributor's Zone the Obligation Peak Load for all end-use customers served by such Party in such Zone. The daily Unforced Capacity Obligation of a Party for such Operating Day shall not be subject to change thereafter.

3. For purposes of such allocations, the daily sum of the Obligation Peak Loads of all Parties serving load in a Zone must equal the Zonal Obligation Peak Load for such Zone.

SCHEDULE 8.1

FIXED RESOURCE REQUIREMENT ALTERNATIVE

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

The Fixed Resource Requirement ("FRR") Alternative

A. The Fixed Resource Requirement ("FRR") Alternative provides an alternative means, under the terms and conditions of this Schedule, for an eligible Load-Serving Entity to satisfy its obligation hereunder to commit Unforced Capacity to ensure reliable service to loads in the PJM Region.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

B. Eligibility

1. A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

C. Election, and Termination of Election, of FRR Alternative

1. No less than two months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective, any Party seeking to elect the FRR Alternative shall notify the Office of the Interconnection in writing of such election. Such election shall be for a minimum term of five consecutive Delivery Years. No later than one month before such Base Residual Auction, such Party shall submit its FRR Capacity Plan demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet such Party's Daily Unforced Capacity Obligation (and all other applicable obligations under this Schedule) for the load identified in such plan.

2. An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

3. Notwithstanding subsections C.1 and C.2 of this Schedule, in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.

4. To facilitate the elections and notices required by this Schedule, the Office of the Interconnection shall post, in addition to the information required by Section 5.11(a) of Attachment DD to the PJM Tariff, the percentage of Capacity Resources required to be located in each Locational Deliverability Area by no later than one month prior to the deadline for a Party to provide such elections and notices.

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