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March 10, 2017

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PUBLIC SERVICE COMMISSION

Ms. Talina Mathews, Ph.D.
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

Re: *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Declaratory Order Confirming the Effect of Kentucky Law and Commission Precedent on Retail Electric Customers' Participation in Wholesale Electric Markets* – Case No. 2017-00129

Dear Ms. Mathews:

Please find enclosed for filing with the Commission, an original and ten (10) copies of East Kentucky Power Cooperative, Inc.'s Application for a Declaratory Order in the above styled case. Please return a file-stamped copy to me.

Please contact me with any questions you may have.

Sincerely,

David S. Samford

Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
MAR 10 2017
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A DECLARATORY ORDER CONFIRMING THE EFFECT OF KENTUCKY LAW AND COMMISSION PRECEDENT ON RETAIL ELECTRIC CUSTOMERS' PARTICIPATION IN WHOLESALE ELECTRIC MARKETS	)	Case No. 2017-00129

VERIFIED APPLICATION

Comes now East Kentucky Power Cooperative, Inc. ("EKPC"), by counsel, pursuant to KRS 278.010, 807 KAR 5:001, Section 14, 807 KAR 5:001, Section 19 and other applicable law, and for its Application requesting a Declaratory Order confirming the effect of Kentucky law and Commission precedent on retail electric customers' participation in wholesale electric markets, respectfully states as follows:

I. INTRODUCTION

1. This matter arises from the stated intention of certain unidentified retail electric customers located within EKPC's service territory to participate directly in the PJM Capacity Market's Base Residual Auction in May 2017. Because such actions would be contrary to established Kentucky law and Commission precedent, EKPC respectfully requests the Commission to enter an Order on or before May 10, 2017, which is the start of the annual Capacity Market auction.

2. EKPC seeks an Order from the Commission declaring that:

(a) Under Kentucky law and Commission precedent, retail electric customers within EKPC's service territory[1] are barred from participating in PJM's wholesale markets, either directly or indirectly through a third party, unless through a tariff or special contract approved by the Commission;

(b) Energy efficiency resource providers within EKPC's service territory may only participate in the PJM Capacity Market pursuant to a Commission approved tariff or special contract, specifically to ensure other retail electric customers within EKPC's service territory are not: (i) unfairly or unlawfully disadvantaged and discriminated against; (ii) subjected to inefficient service; and (iii) forced to unfairly, unjustly and unreasonably subsidize the energy efficiency resource provider's participation in the PJM wholesale market;

(c) PJM is subject to the Commission's jurisdiction to enforce its prior Orders in cases in which PJM has been granted voluntary intervention and has given acknowledgements and consents;

(d) PJM's decision to allow one or more retail energy efficiency resource providers located within EKPC's service territory to participate in its Capacity Market in a manner inconsistent with Commission precedent is unlawful, unreasonable and a violation of Kentucky law; and

[1] As a Generation and Transmission Cooperative, EKPC does not have a service territory. However, each of EKPC's sixteen Owner-Members are Distribution Cooperatives that do have a certified service territory. For sake of simplicity, this Application will refer to the aggregate geographical footprint of each Owner-Member's certified service territory as being EKPC's service territory. This approach is consistent with EKPC's interactions with PJM's wholesale markets.

(e) EKPC and/or its Owner-Members may terminate electric service to any energy efficient resource provider who violates Kentucky law, a Commission Order, rule or regulation or Commission approved tariff pursuant to 807 KAR 5:006, Section 15.

3. Finally, EKPC respectfully requests the Commission to affirm Staff Opinion 2017-004 in all respects.[2]

II. FILING REQUIREMENTS

4. Pursuant to 807 KAR 5:001 Section 14(1), EKPC's mailing address is P.O. Box 707, Winchester, Kentucky 40392-0707. EKPC's electronic mail address to receive service is psc@ekpc.coop. Applicant's counsel should be served at mdgoss@gosssamfordlaw.com; david@gosssamfordlaw.com and ebuckley@gosssamfordlaw.com.

5. Pursuant to 807 KAR 5:001, Section 14(2), EKPC is a Kentucky corporation, in good standing, and was incorporated on July 9, 1941.

6. Pursuant to 807 KAR 5:001, Section 19(2), the grounds for EKPC's request for a Declaratory Order are set forth below.

7. Pursuant to 807 KAR 5:001 Section 19(3), EKPC is serving a copy of the Application to the Kentucky Attorney General's Office of Rate Intervention, PJM Interconnection, LLC and Mr. Richard Drom.[3]

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[2] A copy of Staff Opinion 2017-004 is attached hereto and incorporated herein as Exhibit 1.

[3] EKPC is serving a copy of this Application upon Mr. Drom as a courtesy. Mr. Drom has held himself out to PJM and EKPC as being counsel for one or more energy efficiency resource providers in the EKPC service territory, but has not yet provided EKPC with information that would allow it to verify that representation. In the event that Mr. Drom is unable to disclose the identity of the client(s) he represents in any motion to intervene in this proceeding, EKPC will move to strike said motion. EKPC reserves all rights to challenge, strike, deny, dispute or disagree with the contents of any motion or substantive response that might be filed in this action by the Attorney General's Office, PJM, Mr. Drom's clients or any other party that seeks to intervene.

III. OVERVIEW OF KRS CHAPTER 278

8. Pursuant to KRS 278.040(2), the jurisdiction of the Commission "shall extend to all utilities in this state," and the Commission "shall have exclusive jurisdiction over the regulation of rates and service of utilities."

9. The term "rate" means "any individual or joint fare, toll, charge, rental, or other compensation for service rendered or to be rendered by any utility, and any rule, regulation, practice, act, requirement, or privilege in any way relating to such fare, toll, charge, rental, or other compensation, and any schedule or tariff or part of a schedule or tariff thereof." KRS 278.010(12). The term "service" means "any practice or requirement in any way relating to the service of any utility…and in general the quality, quantity, and pressure of any commodity or product used or to be used for or in connection with the business of any utility," according to KRS 278.010(13).

10. According to KRS 278.010(3), a "utility" is "any person…who owns, controls, operates, or manages any facility used or to be used for or in connection with: (a) [t]he generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses…." A "retail electric supplier" is "any person, firm, corporation, association, or cooperative corporation … engaged in the furnishing of retail electric service." KRS 278.010(4). "Retail electric service" means "electric service furnished to a customer for ultimate consumption…." KRS 278.010(7).

11. A "Generation and Transmission Cooperative" or "G&T" is "a utility formed under KRS Chapter 279 that provides electric generation and transmission services." KRS 278.010(9). A "Distribution Cooperative" means "a utility formed under KRS Chapter 279 that provides retail electric service." KRS 278.010(10).

12. Utility rates should be "fair, just and reasonable" in order to satisfy the requirements of KRS 278.030(1). Likewise, a utility must also "furnish adequate, efficient and reasonable service, and may establish reasonable rules governing the conduct of its business and the conditions under which it shall be required to render service." KRS 278.030(2).

13. Each retail electric supplier in Kentucky has been assigned an exclusive certified service territory under the provisions of KRS 278.016 and KRS 278.017. Moreover, each retail electric supplier has "the exclusive right to furnish electric retail service to all electric-consuming facilities located within its certified territory…." KRS 278.018(1).

14. As set forth in KRS 278.170(1), utilities are prohibited from giving any "unreasonable preference or advantage to any person...."

15. The Commission has been granted authority to determine the reasonableness of demand-side management plans proposed by any utility under its jurisdiction, according to KRS 278.285. The term "demand-side management" means "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand, including home energy assistance programs," according to KRS 278.010(17).

16. Utility demand side management programs may not "result in any unreasonable prejudice or disadvantage to any class of customers." KRS 278.285(1)(e).

IV. BACKGROUND

A. Overview of EKPC

17. EKPC is a not-for-profit, rural electric cooperative corporation established under KRS Chapter 279 with its headquarters in Winchester, Kentucky. Pursuant to various agreements, EKPC provides electric generation capacity and electric energy to its sixteen Owner-Member

distribution cooperatives, which in turn serve approximately 530,000 Kentucky homes, farms and commercial and industrial establishments in eighty-seven (87) Kentucky counties.

18. EKPC is a "utility" as that term is defined in KRS 278.010(3)(a) and a generation and transmission cooperative as that term is defined in KRS 278.010(9). Each of EKPC's sixteen Owner-Members is a "utility" under KRS 278.010(3)(a), as well as being a "distribution cooperative" under KRS 278.010(10) and a "retail electric supplier" under KRS 278.010(4).

19. In total, EKPC owns and operates a total of approximately 2,955 MW of net summer generating capability and 3,257 MW of net winter generating capability. EKPC owns and operates coal-fired generation at Cooper Station in Pulaski County, Kentucky (341 MW) and Spurlock Station in Mason County, Kentucky (1,346 MW). EKPC also owns and operates natural-gas fired generation at Smith Station in Clark County, Kentucky (753 MW (summer)/989 MW (winter)) and Bluegrass Station in Oldham County, Kentucky (501 MW (summer)/567 MW (winter)), and landfill gas-to-energy facilities in Boone County, Kentucky (3 MW), Laurel County, Kentucky (3 MW), Greenup County, Kentucky (2 MW), Hardin County, Kentucky (2 MW), Pendleton County, Kentucky (3 MW) and Glasgow, Kentucky (1 MW). Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW). EKPC's record peak demand of 3,507 MW occurred on February 20, 2015.

20. EKPC owns 2,940 circuit miles of high voltage transmission lines in various voltages. EKPC also owns the substations necessary to support this transmission line infrastructure. Currently, EKPC has seventy-four (74) free-flowing interconnections with its neighboring utilities.

B. Overview of PJM

21. According to a PJM factsheet, PJM "serves as the regional transmission organization [("RTO")] for a 243,417 square mile area that covers 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."[4] This geographical region encompasses 61 million Americans, includes 1,389 distinct generation sources comprising 171,648 MWs of electric generation capacity.[5] PJM delivers more than 792 million megawatt hours ("MWh") each year over 81,000 miles of transmission lines.[6] PJM's peak demand is 165,492 megawatts and PJM's annual billings are over $42 billion.[7]

22. PJM administers a Capacity Market for electric generating capacity. The Capacity Market is based around PJM's Reliability Pricing Model ("RPM"), which "includes requirements and incentives designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – not just generating plants, but demand response and energy efficiency programs as well."[8] PJM describes the nature of the Capacity Market this way: "The essential elements of the RPM capacity market are procurement of capacity three years before it is needed through a competitive auction; locational pricing for capacity that varies to reflect limitations on the transmission system and to account for the differing need for

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[4] *See* "PJM Statistics", http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjm-statistics.ashx (Nov. 9, 2016).

[5] *See id.*

[6] *See id.*

[7] *See id.*

[8] *See* "PJM Markets", http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjms-markets-fact-sheet.ashx (Jan. 26, 2016).

capacity in various areas of PJM; and a variable resource requirement to help set the price for capacity."[9] The Capacity Market operates through a base residual auction held in May of each year and three incremental auctions held in February, August and November.

23. PJM also operates an Energy Market consisting of the Day-Ahead market and the Real-Time market. According to PJM:

> The Day-Ahead Market is a forward market in which hourly prices are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The Real-Time Market is a spot market in which current locational marginal prices are calculated at five-minute intervals based on actual grid operating conditions and are published on the PJM website. PJM settles transactions hourly and issues invoices to market participants weekly.[10]

24. PJM also administers various markets for financial transmission rights and ancillary services.

C. The Integration of Kentucky Power Company into PJM

25. The first Kentucky utility to become a fully-integrated member of PJM was Kentucky Power Company ("Kentucky Power"). In the course of the proceeding, PJM offered the Commission several assurances that Kentucky Power's participation in PJM would not adversely impact the Commission's jurisdiction or ratepayer protections in KRS Chapter 278. For instance, PJM stated, "The transfer of functional control of AEP's transmission facilities to PJM does not erode the Commission's jurisdiction; instead, it enhances the Commission's jurisdiction by providing the Commission with new regulatory tools and resources to

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[9] *See id.*

[10] *See id.*

meet its statutory requirements pursuant to KRS Chapter 278."[11] One entire section of PJM's brief was even entitled, "Maintaining the Commonwealth's Status as a Low Cost *Bundled* State".[12] Elsewhere, PJM invited the Commission to be proactive in placing limitations upon PJM's interactions with Kentucky stakeholders:

> The Commonwealth now has the opportunity to spell out its requirements first, and to partner with PJM on building the market, as opposed to waiting for those systems to be designed to meet Virginia's requirements. *The Commission now has the opportunity to place conditions on its approval of the application that benefit the Commonwealth*, instead of being in the position where the Commission has to adapt to the Virginia requirements.[13]

26. After an initial denial by the Commission of its request to integrate into PJM by Order entered on July 17, 2003, in Case No. 2002-00475,[14] Kentucky Power filed a request for rehearing. The rehearing request addressed several concerns which had been identified by the Commission. After granting the request for rehearing, the Commission eventually approved Kentucky Power's integration into PJM by Order entered May 19, 2004 (the "Kentucky Power Integration Order"). In so doing, the Commission opined:

> Another major concern expressed in the July 17, 2003 Order was that approving the transfer of control of Kentucky Power's transmission assets to PJM could erode this Commission's existing authority to protect Kentucky retail customers. The Commission notes that Paragraph 4 of the Stipulation is consistent with existing state authority and preserves our right, pursuant to KRS 278.285, to review any demand-side management programs that may be offered

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[11] *In the Matter of the Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.LC. Pursuant to KRS 278.218*, PJM Post-Hearing Brief, Case No. 2002-00475, p. 3 (filed May 9, 2003). A copy of PJM's Post-Hearing Brief is attached hereto and incorporated herein as Exhibit 2.

[12] *See id.*, p. 5 (emphasis added).

[13] *Id.*, p. 17 (emphasis added).

[14] *See* Order, Case No. 2002-00475 (Ky. P.S.C. July 17, 2003).

> by PJM to Kentucky Power. No such program will be offered directly by PJM to Kentucky retail customers.[15]

27. Notably, the "Stipulation" referred to by the Commission in the Kentucky Power Integration Order was agreed to and executed by both Kentucky Power and PJM. Therein, the signatories not only clearly acknowledged that Kentucky Power is a necessary party to any PJM demand response program activity, but also acknowledged that the Commission retains full authority over all such demand response activity. That document stated, in relevant part:

> Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power.... Any such programs would be subject to the applicable rules of the Commission and Kentucky law.[16]

28. The Commission required PJM and Kentucky Power to jointly submit the Stipulation and Settlement Agreement to the Federal Energy Regulatory Commission ("FERC") in order to gain the federal agency's unconditional approval of the terms of the Agreement and the Kentucky Power Integration Order accepting it. On June 14, 2004, FERC issued an Order that approved the unconditional settlement, which it summarized, in relevant part, as follows.

> Paragraph 4 provides that any PJM-offered demand side response or load interruption programs will be made available to AEP-Kentucky for its retail loads (at AEP-Kentucky's election) and that no such program will be made available by PJM directly to a retail customer of AEP-Kentucky.
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> ....

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[15] Kentucky Power Integration Order, p. 9 (Ky. P.S.C. May 19, 2004). A copy of the Kentucky Power Integration Order is attached hereto and incorporated herein as Exhibit 3.

[16] Kentucky Power Integration Order, Appendix A, Paragraph 4.

> Paragraph 7 provides that nothing in the Kentucky Stipulation alters Kentucky laws, rules, or policies that service to retail customers be provided through the provisions of bundled retail electric service.[17]

D. The Integration of Duke Energy Kentucky, Inc. into PJM

29. Duke Energy Kentucky, Inc. ("Duke") sought permission to leave the Midwest Independent System Operator ("MISO") and join PJM in an application filed on May 20, 2010. The matter was docketed as Case No. 2010-00203.[18] PJM again requested leave to intervene, which was granted on August 12, 2010. Following a hearing in the case, each party was directed to file briefs on several issues of concern to the Commission. In its brief, PJM commented upon "[a]spects of FERC Order 719-A bearing upon the offering by [Duke] of its end-use customers of demand response *and energy efficiency resources* in PJM's markets, and establishing the commission's discretion as a Retail Electric Regulatory Authority."[19] PJM specifically confirmed that the Commission could "opt out" of FERC rules applying to demand response and energy efficiency.[20]

30. The Commission entered an Order conditionally approving Duke's transition from MISO to PJM on December 22, 2010 (the "Duke Integration Order"). One of the conditions specifically required PJM's acknowledgment that the Commission would not allow retail electric

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[17] *In the Matter of New PJM Companies and PJM Interconnection, LLC*, Order, Docket No. ER03-2620009, p. 4, 107 FERC ¶ 61,272 (F.E.R.C. June 17, 2004). A copy of the FERC Order is attached hereto and incorporated herein as Exhibit 4.

[18] *In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control* of its *Transmission Assets from the Midwest Independent System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment*, Application (filed May 10, 2010).

[19] *See* Post-Hearing Brief of PJM Interconnection, LLC, Case No. 2010-00203, p. 11 (filed Nov. 19, 2010) (emphasis added). A copy of PJM's Brief is attached hereto and incorporated herein as Exhibit 5.

[20] *See id.*, p. 13.

customers to participate in PJM's wholesale markets absent cooperation with Duke and Commission pre-approval:

> To ensure clarity for all parties concerning the need for the Commission's prior approval, we will condition the approval of membership in PJM upon Duke Kentucky's commitment that no retail customer will be allowed to participate directly or through a third party in a PJM demand-response program until either: (1) the customer has entered into a special contract with Duke Kentucky and that contract has been filed with, and approved by, the Commission; or (2) Duke Kentucky receives Commission approval of a tariff authorizing such customer participation. In addition, we will require PJM to file a written acknowledgment of this requirement and require PJM to publicize this requirement according to its demand-response program rules.[21]
>
> ....
>
> No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.[22]

31. PJM filed a letter in response to the Duke Integration Order on December 29, 2010. The correspondence expressly disclaimed any jurisdiction of the Commission over PJM and merely confirmed that the Commission had imposed a condition upon Duke, of which PJM confirmed its awareness.[23]

32. Following receipt of PJM's letter, the Commission entered an Order on January 6, 2011, pointing out the deficiencies in PJM's correspondence. The Commission's Order stated, in relevant part:

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[21] Duke Integration Order (Ky. P.S.C. Dec. 22, 2010), p. 16. A copy of the DEK Integration Order is attached hereto and incorporated herein as Exhibit 6.

[22] *Id.*, p. 18.

[23] *See* Letter from Terry Boston to Jeff Derouen, Case No. 2010-00203, Post-Case Correspondence File (Dec. 29, 2010). A copy of the letter from Mr. Boston is attached hereto and incorporated herein as Exhibit 7.

On December 22, 2010, the Commission issued an Order granting [Duke Kentucky] conditional approval to transfer its transmission assets from the operational control of the [Midwest ISO] to [PJM]. That Order imposed six conditions precedent that needed to be agreed to by Duke Kentucky, *and one condition precedent to be agreed to by PJM.* The one condition imposed upon PJM was also one of the six conditions imposed on Duke Kentucky. That condition, set forth as finding paragraph 6 on page 18 of the December 22, 2010 Order, provided that:

> No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.

Duke Kentucky and PJM were required to indicate in writing within seven days of the date of the Order if they individually agreed to accept and be bound by the conditions imposed therein.

On December 29, 2010, Duke Kentucky filed a letter stating that it accepted and agreed to be bound by the six conditions imposed on it by the December 22, 2010 Order and noted that its move to PJM is contingent upon Duke Energy Ohio's successful move to PJM. On that same date, PJM filed a letter acknowledging that a requirement was imposed on Duke Kentucky which prohibited retail customers from participating in a PJM demand-response program without prior Commission approval. However, PJM's letter did not acknowledge that this same condition was imposed on PJM by finding paragraph 9 of the December 22, 2010 Order. *Consequently, without PJM's agreement to honor this condition, a customer of Duke Kentucky could enroll in a PJM demand-response program if, at the time of enrollment, Duke Kentucky does not object to PJM, either intentionally or due to inadvertence. Such participation by a customer of Duke Kentucky would be in direct violation of Duke Kentucky's tariff, Ky. P.S.C. Electric No. 2, First Revised Sheet No. 21, Section 5, which prohibits the resale of electricity by customers.*

The condition imposed on PJM by our December 22, 2010 Order mirrors the commitment made by PJM in 2004 in conjunction with Kentucky Power Company's application to transfer functional control of its transmission assets to PJM. In that case, the transfer to PJM was approved upon PJM's agreement that:

> Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. . . . Any such programs would be subject to the applicable rules of the Commission and Kentucky law.
>
> Based on a review of PJM's December 29, 2010 letter, the Commission finds that one of the conditions precedent to Duke Kentucky's transfer of transmission assets to PJM has not been satisfied.
>
> IT IS THEREFORE ORDERED that the conditional approval granted in our December 22, 2010 Order has not become unconditional...(emphasis added).[24]

33. In response to the Commission's January 6, 2011 Order, PJM tendered another letter to the Commission which omitted the disclaimer of Commission jurisdiction and expressly acknowledged that the condition articulated by the Commission applied just as much to PJM as it did to Duke:

> PJM acknowledges that under the Conditions set forth in the Commission's Order, no retail customer of Duke Kentucky is allowed to participate in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.[25]

E. The Integration of EKPC into PJM

34. With the Kentucky Power Integration Order and Duke Integration Order both having achieved status as final and non-appealable Orders, the scope and extent of the prohibition

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[24] Order, Case No. 2010-00203, pp. 1-3 (Ky. P.S.C. Jan. 6, 2011). A copy of the Order is attached hereto and incorporated herein as Exhibit 8.

[25] Letter from Terry Boston to Jeff Derouen, Case No. 2010-00203, Post-Case Correspondence File (Jan. 11, 2011). A copy of the letter is attached hereto and incorporated herein as Exhibit 9.

on direct or indirect participation in PJM's wholesale markets by retail electric customers was settled and certain by the time EKPC sought to become a fully-integrated member of PJM in 2012. PJM itself had equated demand response to energy efficiency on numerous occasions and it was understood that the effects of demand response and energy efficiency programs were similar. On May 3, 2012, EKPC filed an application seeking permission to transfer functional control of its electric transmission grid to PJM and participate in PJM's RPM Capacity Market (the "Integration Application").[26]

35. The Attorney General's Office, Gallatin Steel, PJM, Kentucky Utilities Company and Louisville Gas & Electric Company all intervened in the case, which included two rounds of information requests from the Commission, the opportunity for Intervenors to file testimony, a round of information requests from Intervenors and a public hearing.

36. The Commission entered an Order on December 20, 2012, which approved EKPC's Integration Application, thereby granting EKPC permission to transfer functional control of its transmission system to PJM and the ability to participate in PJM's RPM Capacity Market (the "EKPC Integration Order").

37. As part of its deliberations, the Commission specifically considered the legality and reasonableness of allowing customers within EKPC's service territory to participate directly in PJM's Capacity Market and Energy Market. The EKPC Integration Order includes an extended discussion of the method by which retail electric customers could appropriately participate in PJM's wholesale markets under Kentucky law:

> EKPC has requested that, in conjunction with membership in PJM, each of its customers' interruptible loads under contact and under its

[26] EKPC participated in PJM's Energy Market and made firm transmission reservations within the PJM region beginning in 2005, but remained its own balancing authority. The Integration Application applied only to EKPC's transmission lines that were rated at 138 kV or above. EKPC's 69 kV transmission circuits remain subject to EKPC's operational control, although such control is coordinated with PJM.

> Direct Load Control program be authorized to be included in PJM's Demand Response program as of the date of membership. *The Commission recognizes that EPKC is not requesting authority for the retail customers who participate by contract or tariff in an interruptible load control program to participate, either directly or through a third party, in any PJM Demand Response program. Rather, the request is for authorization for EKPC, as the generation supplier, to be the participant in the PJM Demand Response programs so that EKPC can bid into PJM the interruptible load that is available to EKPC under contract or tariff.*
>
> The Commission recognizes that the PJM Demand Response program can be an effective planning tool with potential benefits for both EKPC and PJM, and we encourage EKPC to have a dialogue with its customers to utilize this tool in such a way as to maximize those benefits. *We find that EKPC's participation in the PJM Demand Response program on behalf of its 16 member cooperatives and their retail customers is reasonable, provided that each existing or new interruptible load contract or tariff has been filed with and accepted or approved by the Commission. In the event that EKPC determines in the future that it will be beneficial to its system to allow retail interruptible customers to participate, directly or through third parties, in the PJM Demand Response program, EKPC and its member cooperatives will need prior Commission approval of new contracts or amendments to existing contracts and tariff.*[27]

38. The EKPC Integration Order later states this unambiguous mandate: "[a]ny customer on the EKPC system that seeks to participate directly or through a third party in the PJM Demand Response program shall do so under the terms of an EKPC special contract or tariff that has been approved by the Commission."[28]

39. EKPC became a fully-integrated member of PJM as of June 1, 2013. Its experience in PJM has been generally favorable and has resulted in several million dollars in savings to EKPC's Owner-Members and their retail electric customers. EKPC stands ready to negotiate a

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[27] EKPC Integration Order, pp. 17-18 (Ky. P.S.C. Dec. 20, 2012). A copy of the EKPC Integration Order is attached hereto as Exhibit 10.

[28] *Id.*, p. 21.

special contract with any energy efficiency resource provider in its service territory so that all Kentucky parties benefit.

F. PJM is Allowing Retail Electric Customers Within EKPC's Service Territory to Participate in its Capacity Market by Selling Energy Efficiency Resources Without the Involvement or Agreement of EKPC or Commission Approval

40. In November of 2016, EKPC became aware that one or more entities either had bid, or were in the process of bidding, energy efficiency resource products originating in EKPC's service territory in the PJM Capacity Market. EKPC's attempts to identify the bidder(s) were unavailing as PJM refused to disclose such information. EKPC is uncertain whether the energy efficiency resource products were bid, or are being bid, into the PJM Capacity Market directly by a retail electric customer or by a third-party acting on the retail electric customer's behalf.

41. On November 18, 2016, EKPC requested an Advisory Opinion from Commission Staff regarding the scope of Kentucky law and the EKPC Integration Order. After reviewing the PJM integration proceedings involving EKPC, Kentucky Power and Duke, EKPC stated its request for an Advisory Opinion as follows:

> EKPC understands that Commission precedent and Kentucky law would prohibit any retail customer within the EKPC system from directly, or indirectly through a third-party, participating in any demand response, energy efficiency or load curtailment program without first entering into a contract with EKPC that is reviewed and approved by the Commission.[29]

42. On January 25, 2017, Richard Drom, of the Washington, D.C. law firm of Eckert Seamans Cherin & Mellott, LLC, tendered a letter on behalf of an undisclosed client that opposed

[29] Letter from David S. Samford to Talina Mathews, Ph.D. (Nov. 18, 2016). A copy of the request for an Advisory Opinion is attached hereto and incorporated herein as Exhibit 11.

EKPC's understanding of Kentucky law and Commission precedent and claimed that energy efficiency resources are subject to the "exclusive" jurisdiction of FERC.[30]

43. The Commission Staff issued its Advisory Opinion on February 2, 2017. The Staff's analysis of the questions presented was comprehensive and authoritative:

> Staff begins its analysis with KRS Chapter 278. Under KRS 278.040(2), "The jurisdiction of the commission shall extend to all utilities in this state [and] [the commission] shall have exclusive jurisdiction over the regulation of rates and service of utilities...." A "utility" is defined as "any person ... who owns, controls, operates, or manages any facility used or to be used for or in connection with: (a) the generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses." EKPC is a provider of electric generation and transmission services: it is a "generation and transmission cooperative" as defined in KRS 278.010(9); and it is a utility subject to the Commission's jurisdiction. Each of EKPC's 16 member distribution cooperatives is a provider of retail electric service; each is a "distribution cooperative" as defined in KRS 278.010(10); and each is a utility subject to the Commission's jurisdiction.
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> Every utility subject to the Commission's jurisdiction "shall furnish adequate, efficient and reasonable service...." KRS 278.030(2). In furtherance of its role as a provider of electric generation and transmission service, EKPC has a long-term power contract with its 16 member distribution cooperatives. That contract obligates EKPC to supply, and the 16 member distribution cooperatives to purchase from EKPC, no less than 95 percent of the member distribution cooperatives' collective total load.
>
> As providers of retail electric service, each of EKPC's 16 member distribution cooperatives has a certified territorial boundary under the Territorial Boundary Act, KRS 278.016 – 278.018. That act grants a provider of retail electric service an exclusive territory, or franchise, with the right to be free from competition within its certified boundary. More specifically, that act provides that, "[E]ach retail electric supplier shall have the exclusive right to furnish retail electric service to all electric-consuming facilities located within its certified territory...." KRS 278.018(1). Significantly, the Kentucky General Assembly has not enacted any statute that allows retail electric customers to choose their generation supplier or to

[30] Letter from Richard A. Drom to Richard G. Raff (Jan. 25, 2017). A copy of the correspondence from Mr. Drom is attached hereto and incorporated herein as Exhibit 12.

participate in any fashion in wholesale electric markets. Thus, there is no competition in Kentucky's electric supply market and it remains fully regulated.

In authorizing EKPC to integrate as a full member of PJM, the Commission explicitly prohibited retail electric customers from participating in any PJM demand response program in the absence of an EKPC tariff or customer contract on file with the Commission. The same prohibition was set forth in the Commission's Orders authorizing Duke and Kentucky Power, respectively, to integrate into PJM. While the Commission's Orders do not include a discussion of the reasons for this prohibition, the fact that Kentucky has not restructured its electric markets and does not allow retail customers to choose their generation supplier fully supports the prohibition. Absent restructured electric markets, EKPC, as the wholesale power supplier to its 16 member distribution cooperatives, has a statutory obligation to have at all times sufficient electric capacity and energy to meet the load requirements of its member distribution cooperatives. As a participant in PJM's Reliability Pricing Model ("RPM"), EKPC is obligated to purchase sufficient generating capacity from the PJM capacity market to meet its forecasted load requirements while, in turn, EKPC sells its available generating capacity into the PJM capacity market. In the event that a retail customer on EKPC's system wishes to participate in a demand response program, such participation needs to be through either a tariff or a contract on file with the Commission so that EKPC has accurate knowledge of the level of the load expected on its system. Only by knowing this information about its load can EKPC adequately plan to have sufficient generating capacity to meet its statutory obligation to serve its load, while at the same time avoiding the cost (which would ultimately be passed on to retail customers) of, and need to purchase, excess capacity for load that it will not have to serve due to a customer's participation in a demand response program.

Staff is of the opinion that PJM's January 11, 2011 letter to the Commission, sent in response to the provision in the Duke integration Order prohibiting retail customers' participation in PJM's wholesale demand response program except under a special contract with Duke or a Duke filed tariff, is an explicit acknowledgement by PJM of the Commission's authority to impose such restrictions. The restrictions established by the Commission in the EKPC, Duke, and Kentucky Power integration Orders, respectively, with respect to retail customers' participation in any PJM demand response program are squarely within the Commission's regulatory authority over jurisdictional utilities and are not preempted by any statute, regulation, rule, or tariff under the jurisdiction of the FERC. The Commission has not by establishing such restrictions asserted any jurisdiction over non-utility, third-party retailers, including EER providers.

Staff also takes notice that in the recent case of *FERC v. Electric Power Supply Ass'n, et al.,* 136 S. Ct. 760, 763 (2016), the United States Supreme Court, in discussing FERC Order No. 719 on demand response participation in organized wholesale markets, stated that, the Rule allows any State regulator to prohibit its consumers from making demand response bids in the wholesale market. Thus, this Supreme Court decision fully supports the Commission's authority to establish prohibitions in the EKPC integration Order relating to the conditions under which retail customers may participate in a PJM demand response program.

In basic terms, energy efficiency produces a similar result as demand response: they both reduce a customer's load which, in turn, reduces demand on the utility supplier's system. They differ in the respect that energy efficiency is typically a permanent reduction in load, while demand response is typically a temporary reduction or shifting of load during certain hours of the day. However, they both have the same impact by reducing the load of the supplying utility and by doing so the generating capacity that the utility is obligated to purchase is reduced.

While none of the prior Commission Orders authorizing a jurisdictional utility to integrate into PJM addressed the issue of retail customers' participating in a PJM Energy Efficiency program, it is unclear whether those programs were in place at the time any of those integration Orders were issued. However, based on the Commission's consistent requirement that the integration into PJM by EKPC, Duke, and Kentucky Power, respectively, be expressly conditioned on a prohibition against retail customers participating in a PJM demand response program, it is clear that such prohibitions reflect Kentucky's statutory scheme for regulating electric service. Kentucky statutes do not permit competition in the provision of retail electric service and they require retail electric suppliers to meet the load of their respective customers. There is no provision authorizing retail electric customers to participate directly, or through a third party, in any wholesale electric market, be it a demand response program or an energy efficiency program.

Finally, Staff notes that the Commission did not "approve" EKPC's last IRP in Case No. 2015-00134, nor has the Commission ever approved any IRP filed by an electric utility. Pursuant to

> Commission regulation, 807 KAR 5:058, Section 11(3), the procedures for review of an IRP state that, "Based on its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings." In accordance with that regulation, the Staff issued its report on EKPC's IRP in Case No. 2015-00134, and after issuing that report and allowing an opportunity for comments, the Commission issued an Order acknowledging that the "Staff Report represents final substantive action in this matter," and closed the case. An electric utility's IRP merely represents a snapshot in time of the future actions intended to be taken based on forecasted conditions. As circumstances change over time, so do the utility's intended actions. Nothing in a utility's IRP or in the Staffs report thereon creates a basis to claim that the utility cannot revisit those issues or seek a written legal opinion from staff on issues addressed therein.
>
> In summary, Staff is of the opinion that since Kentucky has not restructured its electric markets and there is no statute authorizing electric competition, the prohibitions set forth in prior Commission Orders on retail customers participating in any PJM demand response programs would apply with equal force to any PJM energy efficiency programs. In imposing those restrictions, the Commission was exercising its regulatory authority under Kentucky law, KRS Chapter 278, and was not, and is not, asserting any jurisdiction over any non-utility, such as an EER provider.[31]

44. On or about February 16, 2017, PJM notified EKPC that, despite the Staff Opinion, it intended to allow third-parties (specifically including but not necessarily limited to Mr. Drom's client(s)) to participate in the upcoming incremental capacity auction to be held on February 27-28, 2017 and/or the base residual auction to be held on May 10, 2017. PJM further advised that it: 1) could not disclose the identity of the entities within EKPC's service territory that had been, or would be, participating in the auctions; 2) viewed Staff Opinion 2017-004 as non-binding and unpersuasive; and 3) did not believe it was subject to the Commission's jurisdiction in any respect. Moreover, PJM advised that if it was subsequently determined that third-parties were in fact

[31] Staff Opinion 2017-004, pp. 4-7.

wrongfully allowed to participate in the capacity auctions, they would have done so "at their own risk."

IV. REQUEST FOR DECLARATORY ORDER

A. Under Kentucky Law, Retail Electric Customers are Not Authorized to Participate in Wholesale Electric Markets Unless Through a Utility's Tariff or Special Contract

45. EKPC adopts and incorporates the averments of paragraphs 1 through 44 above as if set forth fully herein.

46. Kentucky has not restructured its electric market. Accordingly, EKPC has a statutory and contractual duty to provide its Owner-Members with sufficient electric generating capacity and electric energy to meet their respective demands.

47. EKPC meets its Owner-Members' capacity and energy needs by purchasing capacity and energy from PJM, while also selling its capacity and energy to PJM. The acts of forecasting, planning and executing capacity and energy purchases and sales in PJM is a "service" that is performed by a "utility" that is subject to Commission jurisdiction. The payments associated with the capacity and energy delivered by EKPC to its Owner-Members, as retail electric suppliers, who then resell that capacity and energy to their retail electric customers are tendered pursuant to "rates" that are subject to the Commission's jurisdiction.

48. If EKPC is unable to accurately ascertain the amount of energy efficiency resources being bid into the PJM Capacity Market from within its service territory, it will be unable to accurately estimate and bid its load into the Capacity Market. As a result, EKPC will very likely overestimate its native load and acquire more capacity resources in the PJM Capacity Market than what is actually necessary to serve EKPC's true load. The amount of energy efficiency resources bid into the PJM Capacity Market would equate to phantom load for EKPC.

49. Essentially, if no special contract were arranged, EKPC would overbuy capacity in PJM by the amount of the phantom energy efficiency resource. The payment by EKPC's 530,000 customers to PJM for this phantom load would be effectively funneled through PJM back to the anonymous energy efficiency resource provider. This is a deadweight loss for EKPC's customers, and an unjust enrichment for the anonymous energy efficiency resource provider. Instead, if a special contract were arranged between EKPC and the energy efficiency resource provider and approved by the Commission, EKPC would purchase the appropriate amount of capacity in PJM reflecting the contracted energy efficiency resource. The resulting reduction in EKPC payments to PJM would be appropriately and transparently shared between EKPC's customers and the contracted energy efficiency resource provider. EKPC's obligation to serve throughout its service territory requires it to be aware of its retail customers' relationships with PJM. A surreptitious arrangement between PJM and a retail customer in the EKPC service territory leaves EKPC customers exposed to unexpected costs and potentially reliability concerns. To minimize cost impacts to its customers, EKPC would be forced to guess how much phantom load there might be in procuring capacity in PJM. This increase in EKPC load uncertainty has the potential to create reliability concerns.

50. The EKPC Integration Order, the Duke Integration Order and the Kentucky Power Integration Order all foresaw the many problems associated with having phantom load being bid into the Capacity Market and Energy Market. Participation by a retail electric customer in PJM's wholesale markets needs to be through either a tariff or a special contract on file with the Commission so that a utility has accurate knowledge of the level of the native load expected on its system. Accordingly, each Order expressly requires any retail electric customer that desires to participate in PJM's wholesale markets, whether directly or indirectly through a third party, to do

so via a tariffed program or special contract with the applicable utility and that is approved by the Commission.

51. There is no provision of KRS Chapter 278 authorizing retail electric customers to participate directly, or through a third party, in any wholesale electric market. To the contrary, there is an overwhelming of body of legal authority that prohibits such participation, to wit:

a. Kentucky's extensive and well-developed statutory framework for regulating retail electric service;[32]

b. The Kentucky Certified Territories Act which preserves exclusive service territories for each of EKPC's Owner-Member distribution cooperatives;[33]

c. Kentucky's law defining "demand-side management" that clearly encompasses energy efficiency when expressly including "any conservation, load management, or other utility activity intended to influence the level or pattern of customer usage or demand, including home energy assistance programs;"[34]

d. The Commission's explicit reservation of its jurisdiction to "protect Kentucky retail customers;"[35]

e. The Commission's mandate that PJM must file "a written acknowledgment" of the requirement to only allow retail electric customers to participate in a wholesale market through their utility pursuant to a Commission approved tariff or special

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[32] *See generally* KRS Chapter 278.

[33] *See* KRS 278.016, *et seq*.

[34] *See* KRS 278.010(17).

[35] Kentucky Power Integration Order, p. 9.

contract, coupled with a further requirement that PJM must "publicize this requirement according to its demand-response program rules;"[36]

f. The Commission's refusal to change its conditional approval of Duke's integration into PJM into an unconditional approval in light of PJM's insufficient acknowledgment as to the scope and extent of the Commission's limitations on retail electric customers' participation in a PJM Capacity Market;[37]

g. The Commission's finding that allowing PJM to directly or indirectly allow a retail electric customer to participate in the PJM Capacity Market without doing so pursuant to a Commission approved tariff or special contract would amount to a violation of a utility tariff;[38]

h. The Commission's acknowledgement that EKPC was seeking permission in its integration case to allow its retail electric customers to participate in the PJM Capacity Market *only* through a Commission approved tariff or a special contract entered into by EKPC and approved by the Commission;[39]

i. The general requirement in Kentucky law that utilities may not give any "unreasonable preference or advantage to any person..."[40] or, in the specific context of demand side management programs, approve any plan that would "result in any unreasonable prejudice or disadvantage to any class of customers;"[41] and

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[36] Duke Integration Order, p. 16.

[37] Order, Case No. 2010-00203, pp. 1-3 (Ky. P.S.C. Jan. 6, 2011).

[38] *See id.*

[39] *See* EKPC Integration Order, pp. 17-18.

[40] KRS 278.170(1).

[41] KRS 278.285(1)(e).

j. Staff Opinion 2017-004 which analyzes applicable federal precedent and persuasively concludes that such authority does not pre-empt, limit or restrict the Commission's application of Kentucky law in this instance.[42]

52. Likewise, PJM has itself equated demand resource and energy efficiency programs as being similar for purposes of state regulation and has given the Commission an unconditional and unambiguous promise that it would not facilitate the participation of retail electric customers in the Capacity Market absent Commission approval, to wit:

a. PJM assured the Commission that the transfer of functional control of Kentucky Power's transmission facilities to PJM would "not erode the Commission's jurisdiction; instead, it enhances the Commission's jurisdiction by providing the Commission with new regulatory tools and resources to meet its statutory requirements pursuant to KRS Chapter 278," and that the Kentucky's status as a "low cost bundled state" would be maintained;[43]

b. PJM specifically invited the Commission to be proactive in placing limitations upon PJM's interactions with Kentucky stakeholders, stating:

> The Commonwealth now has the opportunity to spell out its requirements first, and to partner with PJM on building the market, as opposed to waiting for those systems to be designed to meet Virginia's requirements. *The Commission now has the opportunity to place conditions on its approval of the application that benefit the Commonwealth*, instead of being in the position where the Commission has to adapt to the Virginia requirements;[44]

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[42] Staff Opinion 2017-004, pp. 5-6.

[43] *See* PJM Post-Hearing Brief, Case No. 2002-00475, pp. 3, 5 (filed May 9, 2003).

[44] *Id.*, p. 17 (emphasis added).

c. PJM admitted that FERC Order 719A "establish[ed] the [Commission's] jurisdiction as a Retail Electric Regulatory Authority" over "end-use customers of demand response and energy efficiency resources....;"[45] and

d. PJM acknowledged that "no retail customer of Duke Kentucky is allowed to participate in any PJM demand response program until that customer has entered into a special contract...which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation."[46]

53. PJM's assertion to EKPC that energy efficiency resource providers acting contrary to Kentucky law and Commission precedent will be doing so "at their own risk" is a hollow assurance in light of the fact that EKPC will have no means to identify such providers and PJM is unwilling to disclose their identity.

54. EKPC seeks a Declaratory Order that, under Kentucky law and Commission precedent, retail electric customers within EKPC's service territory are barred from participating in PJM's wholesale markets, either directly or indirectly through a third party, unless through a tariff or special contract approved by the Commission.

B. Retail Electric Customers that Participate in a Wholesale Market Directly or Through a Third Party are Forcing Other Retail Electric Customers to Subsidize Their Participation in a Manner that is Unfair, Unjust, Inadequate Inefficient and Unreasonable

55. EKPC adopts and incorporates the averments of paragraphs 1 through 54 above as if set forth fully herein.

56. By being unaware of phantom load on its system, EKPC will either purchase excess capacity and energy from PJM or fail to fully sell available capacity and energy to PJM.

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[45] PJM Post-Hearing Brief, Case No. 2010-00203, p. 11 (filed Nov. 19, 2010).

[46] Letter from Terry Boston to Jeff Derouen, Case No. 2010-00203, Post-Case Correspondence File (Jan. 11, 2011).

57. In periods when EKPC expects to be short of capacity or energy, EKPC will purchase capacity and energy from PJM based upon estimates that cannot currently take into account phantom load from unknown energy efficiency resources. As a result, EKPC's Owner-Members, and ultimately their retail electric customers, will pay for capacity and energy that was not needed.

58. Alternatively, in periods when EKPC expects to be long on capacity or energy, EKPC will hold back capacity and energy based upon estimates that cannot take into account phantom load from energy efficiency resources. As a result, EKPC's Owner-Members, and ultimately their retail electric customers, will fail to realize the full potential of sales of capacity and energy into PJM.

59. By contrast, retail electric customers who participate in PJM's capacity market, either directly or through a third-party, will receive payments from PJM for the capacity that they deliver into PJM as a financial windfall and be unjustly enriched.

60. The result is that EKPC's Owner-Members, and ultimately their retail electric customers, will either be making excess payments to PJM or failing to achieve the maximum economic value from sales to PJM, all while other retail electric customers are able to separately and uniquely benefit from participation in the PJM Capacity Market.

61. By participating in the PJM Capacity Market in a manner other than through an approved tariff or special contract with EKPC, a retail electric customer is creating a service condition that is inadequate, inefficient and unreasonable. Moreover, the retail electric customer is causing other retail electric customers within EKPC's service territory to subsidize its participation in the PJM Capacity Market in manner that is unfair, unjust and unreasonable from a rate perspective.

62. EKPC seeks a declaration from the Commission that energy efficiency resource providers within EKPC's service territory may only participate in the PJM Capacity Market pursuant to a Commission approved tariff or special contract, specifically to ensure other retail electric customers within EKPC's service territory are not: (i) disadvantaged and discriminated against; (ii) unfairly or unlawfully subjected to inefficient service; and (iii) forced to unfairly, unjustly and unreasonably subsidize the energy efficiency resource provider's participation in the PJM wholesale market.

C. PJM is Subject to Commission Jurisdiction for Purposes of Enforcing the Commission's Orders and PJM's Own Acknowledgements and Consents

63. EKPC adopts and incorporates the averments of paragraphs 1 through 62 above as if set forth fully herein.

64. It is well established that a party is subject to a tribunal's jurisdiction and Orders whenever it voluntarily requests to participate in the formal proceedings of the tribunal and is allowed to do so.[47]

65. PJM filed a motion to intervene as a party in Case No. 2012-00169 on May 15, 2012. PJM's motion was granted by Commission Order entered June 4, 2012. In filing the motion to intervene, PJM submitted itself to the jurisdiction of the Commission for purposes of that

[47] *See Frankfort Kentucky Nat. Gas Co. v. City of Frankfort*, 123 S.W.2d 270, 272 (1938):

> A finding and order of such commissions as the Public Service Commission of Kentucky, while not a judgment with the attributes of a final judgment or decree of a judicial tribunal, has the effect of a legislative act as to the parties to the proceeding and is very far reaching in its operation. Broadly speaking, the order of the Commission is conclusive when made within the scope of its authority and binding upon all parties except as a review thereof may be had by the courts. The courts ascribe to the findings of some classes of commissions, when supported by evidence, "the strength due to the judgments of a tribunal appointed by law and informed by experience." (citations omitted).

See also Wood v. Wood, 1 Ky.L.Rptr. 358, 78 Ky. 624, 628 (Ky. 1880).

proceeding and the issues affecting PJM as set forth in the Commission's December 20, 2012 EKPC Integration Order.

66. PJM also filed motions to intervene as a party in the Kentucky Power integration case (Case No. 2002-00475) and the Duke integration case (Case No. 2010-00203). PJM's motions were granted by the Commission. In filing the motions to intervene and participating in those proceedings, PJM submitted itself to the jurisdiction of the Commission for purposes of the proceedings and the issues affecting PJM as set forth in the Commission's May 19, 2004 Kentucky Power Integration Order, the December 22, 2010 Duke Integration Order and the January 6, 2011 PJM Acknowledgment Order therein.

67. PJM itself equated demand response to energy efficiency in its filings with the Commission in its post-hearing brief in the Duke integration case and invited the Commission to impose conditions that would preserve its jurisdiction and authority and benefit the Commonwealth.[48] Thus, the question of whether PJM may allow energy efficiency resources from within EKPC's service territory to be bid into its Capacity Market is an issue that lies squarely within the jurisdiction of the Commission and was a part of the Commission's Orders in Case No. 2002-00475, Case No. 2010-00203 and Case No. 2012-00169.

68. EKPC seeks a Declaratory Order stating that PJM is subject to the Commission's jurisdiction to enforce its prior Orders in cases in which PJM has been granted voluntary intervention and has given certain acknowledgements and consents.

[48] PJM Post-Hearing Brief, Case No. 2010-00203, pp. 11 (filed Nov. 19, 2010); PJM Post-Hearing Brief, Case No. 2002-00475, p. 17 (filed May 9, 2003).

D. PJM is Knowingly Aiding and Abetting Undisclosed Third Parties in the Unlawful and Unreasonable Violation of Commission Orders and Kentucky Law

69. EKPC adopts and incorporates the averments of paragraphs 1 through 68 above as if set forth fully herein.

70. PJM has advised EKPC that it will allow retail electric customers within EKPC's service territory to participate in its Capacity Market.

71. By virtue of its acknowledgments and consents given in prior integration cases, PJM knows or should know that its actions are inconsistent with, and in fact contrary to, prior Commission Orders and Kentucky law and its own acknowledgments and consents on this very subject.

72. EKPC seeks a Declaratory Order that PJM's decision to allow one or more energy efficiency resource providers located within EKPC's service territory to participate in its Capacity Market in a manner inconsistent with Commission precedent is unlawful, unreasonable and a violation of Kentucky law.

E. Any Customer Directly or Indirectly Participating in PJM's Capacity Market without Doing so Through an Approved Tariff or Special Contract is Subject to Disconnection Under 807 KAR 5:006, Section 15.

73. EKPC adopts and incorporates the averments of paragraphs 1 through 72 above as if set forth fully herein.

74. The EKPC Integration Order mirrors the prior Kentucky Power Integration Order and Duke Integration Order in terms of expressing the limitation upon retail electric customers to participate in a PJM wholesale market. By participating directly or indirectly in the Capacity Market without doing so through a Commission approved tariff or special contract, a retail electric customer within the EKPC service territory is violating the EKPC Integration Order.

75. EKPC's Owner-Members, as distribution cooperatives and retail electric suppliers, have tariffs which generally prohibit the sale, subletting, disposal of electric service *or any part thereof* by a retail electric customer unless done through a special contract or tariff.[49] Any retail electric customer that participates in a wholesale market would be doing so in violation of said tariffs.

76. Any retail electric customer that bids energy efficiency resources into PJM's Capacity Market in a manner other than through an approved tariff or special contract is violating the EKPC Integration Order and EKPC's Owner-Members' tariffs.

77. EKPC seeks a Declaratory Order that it and/or its Owner-Members may terminate electric service to any energy efficiency resource provider who violates Kentucky law, a Commission Order or a Commission approved tariff, pursuant to 807 KAR 5:006, Section 15.

V. CONCLUSION

78. The EKPC Integration Order and prior Commission precedent all make it clear that a retail electric customer may not participate in a PJM wholesale market absent doing so through a Commission approved tariff or special contract. Despite this, and in light of its prior participation in three integration cases, PJM is knowingly allowing one or more retail electric customers within EKPC's service territory to bid energy efficiency resources into its Capacity Market. The actions

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[49] *See, e.g.*, Big Sandy Rural Electric Cooperative Corporation, Revised Tariff Sheet No. 4 (May 1, 1996); Blue Grass Energy Cooperative Corporation, P.S.C. KY No. 1, Original Sheets 7-8 (Jan. 1, 2002); Clark Energy Cooperative, Inc., P.S.C. No. 2, Original Sheet No. 12 (Mar. 3, 2008); Cumberland Valley Electric, Inc., P.S.C. Ky. No. 4, Original Sheet No. 28 (Mar. 1, 2001); Grayson Rural Electric Cooperative Corporation, P.S.C. No. 3, Original Sheet No. 18 (Oct. 28, 1992); Inter-County Rural Electric Cooperative Corporation, P.S.C. No. 7, Revision #5, Sheet No. 22 (Feb. 29, 1996); Jackson Energy Cooperative Corporation, P.S.C. No. 5, 1st Revised Sheet No. 103 (May 1, 2011); Licking Valley Rural Electric Cooperative Corporation, Second Revised Sheet No. 29 (Feb. 16, 1999); Nolin Rural Electric Cooperative Corporation, P.S.C KY No. 10, 5th Revision Sheet No. 6 (Mar. 4, 2015); Owen Electric Cooperative, Inc., P.S.C. No. 6, Original Sheet No. 55 (Aug. 15, 1997); Shelby Energy Cooperative, Inc., P.S.C. KY No. 9, Original Sheet No. 233 (Oct. 1, 2013); South Kentucky Rural Electric Cooperative Corporation, P.S.C. KY No. 7, Original Sheet No. R-3 (Jan 15, 2000); and Taylor County Rural Electric Cooperative Corporation, P.S.C. KY No. 5, Sheet No. 17 (Oct. 28, 1992). Copies of these tariffs are collectively attached hereto and incorporated herein as Exhibit 13.

of PJM and the unidentified bidder(s) will be harmful and prejudicial to the remainder of EKPC's retail electric customers and will result in service that – through no fault of EKPC – is inefficient and unreasonable and in rates that – again through no fault of EKPC – are unfair, unjust and unreasonable.

WHEREFORE, on the basis of the foregoing, EKPC respectfully requests the Commission to:

1) Expeditiously consider this Application for a Declaratory Order and issue an Order prior to the May 10, 2017 Base Residual Auction in PJM's Capacity Market;

2) Grant the declaratory relief sought herein, to wit:

   (a) Under Kentucky law and Commission precedent, retail electric customers within EKPC's service territory are barred from participating in PJM's wholesale markets, either directly or indirectly through a third party, unless through a tariff or special contract approved by the Commission;

   (b) Energy efficiency resource providers within EKPC's service territory may only participate in the PJM Capacity Market pursuant to a Commission approved tariff or special contract, specifically to ensure other retail electric customers within EKPC's service territory are not: (i) unfairly or unlawfully disadvantaged and discriminated against; (ii) subjected to inefficient service; and (iii) forced to unfairly, unjustly and unreasonably subsidize the energy efficiency resource provider's participation in the PJM wholesale market;

(c) PJM is subject to the Commission's jurisdiction to enforce its prior Orders in cases in which PJM has been granted voluntary intervention and has given certain acknowledgements and consents;

(d) PJM's decision to allow one or more energy efficiency resource providers located within EKPC's service territory to participate in its Capacity Market in a manner inconsistent with Commission precedent is unlawful, unreasonable and a violation of Kentucky law; and

(e) EKPC's Owner-Members may terminate electric service to any energy efficiency resource provider who violates Kentucky law, a Commission Order or Commission approved tariff, pursuant to 807 KAR 5:006, Section 15; and

3) Affirm Staff Opinion 2017-004 in all respects.

Done this 10th day of March, 2017.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
COUNTY OF CLARK)

Comes now David Crews, Senior Vice President of Power Supply of East Kentucky Power Cooperative, Inc., in my official capacity, and, after being duly sworn, I do hereby solemnly swear that the averments set forth above are true and correct to the best of my knowledge and belief as of this 10th day of March, 2017.

DAVID CREWS, Senior Vice President of Power Supply East Kentucky Power Cooperative, Inc.

Signed before me, the NOTARY PUBLIC, by David Crews, Senior Vice President of Power Supply of East Kentucky Power Cooperative, Inc., after being duly sworn, on this 10th day of March, 2017.

Gwyn M. Willoughby
NOTARY PUBLIC, Commission # 500144

My Commission Expires 11-30-17

GWYN M. WILLOUGHBY
Notary Public
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My Commission Expires Nov 30, 2017

Respectfully submitted,

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Counsel for East Kentucky Power Cooperative, Inc.

EXHIBITS

SERVICE LIST

This will certify that, in addition to sending a pdf via email as a courtesy, a true and correct copy of the foregoing Verified Application was served by depositing same in the custody and care of the U.S. Mail, postage pre-paid on this 10th day of March, 2017, addressed to the following:

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February 2, 2017

PSC STAFF OPINION 2017-004

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Eckert Seamans Cherin & Mellott, LLC
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Re: Request for Advisory Opinion clarifying Commission Order dated December 20, 2012 in Case No. 2012-00169

Dear Messrs. Samford and Drom,

The Commission received on November 18, 2016, a letter from Mr. Samford on behalf of East Kentucky Power Cooperative, Inc. ("EKPC") requesting a Commission Staff Opinion regarding the ability of retail customers on the EKPC system to participate directly or indirectly in any demand response, energy efficiency, or other load control program established by PJM Interconnection, LLC ("PJM"). Citing prior Commission precedent, Mr. Samford asserts that under Commission precedent and Kentucky law, retail customers on EKPC's system are prohibited from participating directly, or indirectly through a third-party, in any demand response, energy efficiency, or load control program without first entering into a contract with EKPC and then filing that contract with the Commission for review and acceptance or approval.

On January 25, 2017, a letter was received by electronic mail from Mr. Drom on behalf of an unnamed entity that operates under the terms of a PJM tariff to work with retail customers to provide energy efficiency resources ("EER") into the PJM wholesale market. Mr. Drom asserts that providers of EER operate in interstate commerce and are neither subject to the Commission's jurisdiction nor required to obtain any Commission approval before participating in any PJM energy efficiency program.

This opinion represents Commission Staff's interpretation of the law as applied to the facts presented, is advisory in nature, and is not binding on the Public Service Commission should the issues be formally presented for Commission resolution.

As background for Mr. Samford's request, he provides the following facts:

> EKPC is a not-for-profit generation and transmission rural electric cooperative corporation, formed under KRS Chapter 279, which provides wholesale electricity to its sixteen Owner-Member distribution cooperatives, which in turn serve approximately 525,000 Kentucky homes, farms and commercial and industrial customers in eighty-seven (87) Kentucky counties.
> By Order entered December 20, 2012, [in Case No. 2012-00169[1]] (the "PJM Integration Order"), the Commission approved EKPC's application to transfer functional control of certain transmission facilities to PJM, effective June 1, 2013. The Order states in relevant part that "EKPC has requested ... each of its customers' interruptible loads under contact and under its Direct Load Control program be authorized to be included in PJM's Demand Response program as of the date of membership. The Commission recognizes that EPKC is not requesting authority for the retail customers who participate by contract or tariff in an interruptible load control program to participate, either directly or through a third party, in any PJM Demand Response program. Rather, the request is for authorization for EKPC, as the generation supplier, to be the participant in the PJM Demand Response programs so that EKPC can bid into PJM the interruptible load that is available to EKPC under contract or tariff. The Commission recognizes that the PJM Demand Response program can be an effective planning tool with potential benefits for both EKPC and PJM, and we encourage EKPC to have a dialogue with its customers to utilize this tool in such a way as to maximize those benefits. We find that EKPC's participation in the PJM Demand Response program on behalf of its 16 member cooperatives and their retail customers is reasonable, provided that each existing or new interruptible load contract or tariff has been filed with and accepted or approved by the Commission. In the event that EKPC determines in the future that it will be beneficial to its system to allow retail interruptible customers to participate, directly or through third parties, in the PJM Demand Response program, EKPC and its member cooperatives will need prior Commission approval of new contracts or amendments to existing contracts and tariff. ... Any customer on the EKPC system that seeks to participate directly or through a third party in the PJM Demand Response program shall do so under the terms of an EKPC special contract or tariff that has been approved by the Commission." [citation omitted.]

[1] *Case No. 2012-00169, Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC* (Dec. 20, 2012).

At the time the Order was entered, EKPC was not prepared to bid energy efficiency capacity available throughout its system into the PJM capacity market. Moreover, the rules for bidding energy efficiency as capacity were still uncertain in light of issues relating to the appropriate standards for evaluation, measurement and verification of energy efficiency opportunities. In light of this, the Commission's Order is silent as to whether the same prohibitions that apply to a customer's direct or indirect participation in PJM's Demand Response program would also apply to customers seeking to participate directly or indirectly in PJM's Energy Efficiency program.

In Case No. 2010-00203,[2] the Commission approved an application by Duke Energy Kentucky, Inc. ("Duke") to integrate into full membership in PJM. In granting approval, the Commission imposed a similar restriction on retail customers participating in the PJM markets. The Duke Order stated that, "No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation."[3]

In response to the restriction in the Duke Order on retail customers participating in the PJM demand-response program, PJM filed a letter with the Commission stating that, "PJM acknowledges that under the Conditions set forth in the Commission's Order, no retail customer of Duke Kentucky is allowed to participate in any PJM demand response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation."[4]

The Commission imposed a similar restriction in 2004 when it approved Kentucky Power Company's (Kentucky Power") application to integrate into full membership in PJM. In that Order the Commission stated that, "Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. . . . Any such

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[2] *Case No. 2010-00203, Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment* (Dec. 22, 2010).
[3] Id., at 18.
[4] Letter from Terry Boston to Jeff Derouen, Case No. 2010-00203, Post-Case Correspondence File (Jan. 11, 2011).

> programs would be subject to the applicable rules of the Commission and Kentucky law.[5]

As background for Mr. Drom's position, he asserts that:

> The activities of an EER provider are subject to the exclusive jurisdiction of the federal Energy Regulatory Commission ("FERC").
>
> The Commission lacks the legal authority to review the activities of non-utility, third-party retailers, including EER providers.
>
> The Commission's December 20, 2012 Order in Case No. 2012-00169 approving EKPC's integration into PJM contains no discussion or finding with respect to energy efficiency programs and that Order does not preempt PJM's tariff providing for EER programs. The provision in the Commission's December 20, 2012 Order that prohibits retail customers from participating directly or through a third party in a PJM demand response program except under the terms of an EKPC contract or tariff applies only to the activities of a Commission jurisdictional utility and not to a non-jurisdictional entity such as an EER provider.
>
> By Order entered on April 13, 2016 in case No. 2015-00134, the Commission approved EKPC's last integrated resource plan ("IRP") and included therein a Staff Report that discussed EKPC's intent to aggressively implement high efficiency lighting programs that were to be promoted and marketed by third-party EER providers. The Staff Report noted that retailers were expected to develop marketing and incentive initiatives to promote these programs and nothing in the Staff Report conditions the participation by retailers upon receiving approval from either EKPC or the Commission. The April 13, 2016 Order in Case No. 2015-00134 prevents EKPC from now challenging EER providers from operating in EKPC's territory.

Staff begins its analysis with KRS Chapter 278. Under KRS 278.040(2), "The jurisdiction of the commission shall extend to all utilities in this state [and] [t]he commission shall have exclusive jurisdiction over the regulation of rates and service of utilities...." A "utility" is defined as "any person ... who owns, controls, operates, or manages any facility used or to be used for or in connection with: (a) the generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses." EKPC is a provider of electric generation and transmission

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[5] *Case No. 2002-00475, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218* (May 19, 2004), at 9 and Appendix A at Paragraph 4.

services; it is a "generation and transmission cooperative" as defined in KRS 278.010(9); and it is a utility subject to the Commission's jurisdiction. Each of EKPC's 16 member distribution cooperatives is a provider of retail electric service; each is a "distribution cooperative" as defined in KRS 278.010(10); and each is a utility subject to the Commission's jurisdiction.

Ever utility subject to the Commission's jurisdiction "shall furnish adequate, efficient and reasonable service...." KRS 278.030(2). In furtherance of its role as a provider of electric generation and transmission service, EKPC has a long-term power contract with its 16 member distribution cooperatives. That contract obligates EKPC to supply, and the 16 member distribution cooperatives to purchase from EKPC, no less than 95 percent of the member distribution cooperatives' collective total load.[6]

As providers of retail electric service, each of EKPC's 16 member distribution cooperatives has a certified territorial boundary under the Territorial Boundary Act, KRS 278.016-278.018. That act grants a provider of retail electric service an exclusive territory, or franchise, with the right to be free from competition within its certified boundary. More specifically, that act provides that, "[E]ach retail electric supplier shall have the exclusive right to furnish retail electric service to all electric-consuming facilities located within its certified territory...." KRS 278.018(1). Significantly, the Kentucky General Assembly has not enacted any statute that allows retail electric customers to choose their generation supplier or to participate in any fashion in wholesale electric markets. Thus, there is no competition in Kentucky's electric supply market and it remains fully regulated.

In authorizing EKPC to integrate as a full member of PJM, the Commission explicitly prohibited retail electric customers from participating in any PJM demand response program in the absence of an EKPC tariff or customer contract on file with the Commission. The same prohibition was set forth in the Commission's Orders authorizing Duke and Kentucky Power, respectively, to integrate into PJM. While the Commission's Orders do not include a discussion of the reasons for this prohibition, the fact that Kentucky has not restructured its electric markets and does not allow retail customers to choose their generation supplier fully supports the prohibition. Absent restructured electric markets, EKPC, as the wholesale power supplier to its 16 member distribution cooperatives, has a statutory obligation to have at all times sufficient electric capacity and energy to meet the load requirements of its member distribution cooperatives. As a participant in PJM's Reliability Pricing Model ("RPM"), EKPC is obligated to purchase sufficient generating capacity from the PJM capacity market to meet its forecasted load requirements while, in turn, EKPC sells its available generating capacity into the PJM capacity market. In the event that a retail customer on EKPC's system wishes to participate in a demand response program, such participation needs

[6] *Case No. 2012-00503, Petition and Complaint of Grayson Rural Electric Cooperative Corporation for an Order Authorizing Purchase of Electric Power at the Rate of Six Cents per Kilowatts of Power vs A Rate in Excess of Seven Cents Per Kilowatt Hour* (Dec. 18, 2015).

to be through either a tariff or a contract on file with the Commission so that EKPC has accurate knowledge of the level of the load expected on its system. Only by knowing this information about its load can EKPC adequately plan to have sufficient generating capacity to meet its statutory obligation to serve its load, while at the same time avoiding the cost (which would ultimately be passed on to retail customers) of, and need to purchase, excess capacity for load that it will not have to serve due to a customer's participation in a demand response program.

Staff is of the opinion that PJM's January 11, 2011 letter to the Commission, sent in response to the provision in the Duke integration Order prohibiting retail customers' participation in PJM's wholesale demand response program except under a special contract with Duke or a Duke filed tariff, is an explicit acknowledgement by PJM of the Commission's authority to impose such restrictions. The restrictions established by the Commission in the EKPC, Duke, and Kentucky Power integration Orders, respectively, with respect to retail customers' participation in any PJM demand response program are squarely within the Commission's regulatory authority over jurisdictional utilities and are not preempted by any statute, regulation, rule, or tariff under the jurisdiction of the FERC. The Commission has not by establishing such restrictions asserted any jurisdiction over non-utility, third-party retailers, including EER providers.

Staff also takes notice that in the recent case of *FERC V Electric Power Supply Ass'n, et al., 136 S. Ct. 760, 763* (2016), the United States Supreme Court, in discussing FERC Order No. 719 on demand response participation in organized wholesale markets, stated that, "[T]he Rule allows any State regulator to prohibit its consumers from making demand response bids in the wholesale market." Thus, this Supreme Court decision fully supports the Commission's authority to establish prohibitions in the EKPC integration Order relating to the conditions under which retail customers may participate in a PJM demand response program.

In basic terms, energy efficiency produces a similar result as demand response: they both reduce a customer's load which, in turn, reduces demand on the utility supplier's system. They differ in the respect that energy efficiency is typically a permanent reduction in load, while demand response is typically a temporary reduction or shifting of load during certain hours of the day. However, they both have the same impact by reducing the load of the supplying utility and by doing so the generating capacity that the utility is obligated to purchase is reduced.

While none of the prior Commission Orders authorizing a jurisdictional utility to integrate into PJM addressed the issue of retail customers' participating in a PJM Energy Efficiency program, it is unclear whether those programs were in place at the time any of those integration Orders were issued. However, based on the Commission's consistent requirement that the integration into PJM by EKPC, Duke, and Kentucky Power, respectively, be expressly conditioned on a prohibition against retail customers participating in a PJM demand response program, it is clear that such prohibitions reflect Kentucky's statutory scheme for regulating electric service. Kentucky statutes do not permit competition in the provision of retail electric service and they require retail electric suppliers to meet the load of their respective customers. There is no provision authorizing retail electric customers to participate directly, or through a third party, in any wholesale electric market, be it a demand response program or an energy efficiency program.

Finally, Staff notes that the Commission did not "approve" EKPC's last IRP in case No. 2015-00134, nor has the Commission ever approved any IRP filed by an electric utility. Pursuant to Commission regulation, 807 KAR 5:058, Section 11(3), the procedures for review of an IRP state that, "Based on its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings." In accordance with that regulation, the Staff issued its report on EKPC's IRP in Case No. 2015-00134, and after issuing that report and allowing an opportunity for comments, the Commission issued an Order acknowledging that the "Staff Report represents final substantive action in this matter," and closed the case. An electric utility's IRP merely represents a snapshot in time of the future actions intended to be taken based on forecasted conditions. As circumstances change over time, so do the utility's intended actions. Nothing in a utility's IRP or in the Staff's report thereon creates a basis to claim that the utility cannot revisit those issues or seek a written legal opinion from staff on issues addressed therein.

In summary, Staff is of the opinion that since Kentucky has not restructured its electric markets and there is no statute authorizing electric competition, the prohibitions set forth in prior Commission Orders on retail customers participating in any PJM demand response programs would apply with equel force to any PJM energy efficiency programs. In imposing those restrictions, the Commission was exercising its regulatory authority under Kentucky law, KRS Chapter 278, and was not, and is not, asserting any jurisdiction over any non-utility, such as an EER provider.

This letter represents Commission Staff's interpretation of the law as applied to the facts presented. This opinion is advisory in nature and not binding on the Commission should the issues herein be formally presented for Commission resolution. Questions concerning this opinion should be directed to Richard Raff, Commission General Counsel, at (502) 782-2588.

Sincerely,

Richard G. Raff

Richard G. Raff
General Counsel

RR/kg

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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

DROP BOX

In the Matter of:	)	
APPLICATION OF KENTUCKY POWER	)	
COMPANY D/B/A AMERICAN ELECTRIC	)	
POWER FOR APPROVAL, TO THE	)	
EXTENT NECESSARY, TO TRANSFER	)	**CASE NO. 2002-00475**
FUNCTIONAL CONTROL OF	)	
TRANSMISSION FACILITIES LOCATED	)	
IN KENTUCKY TO PJM INTERCONNECTION,	)	
L.L.C. PURSUANT TO KRS 278.218	)	

POST HEARING BRIEF OF PJM INTERCONNECTION, LLC

I. INTRODUCTION

PJM Interconnection, LLC (hereinafter PJM) wishes to thank the Kentucky Public Service Commission (hereinafter Commission) for its prompt attention to this important matter. Since neither the Commission's staff nor any intervenor sponsored a witness, PJM's brief will focus on issues raised through cross-examination, describe PJM in general and enumerate the benefits that PJM will bring to the Commonwealth. As discussed in Section II, *infra*, AEP's decision to join PJM:

- Enhances the Commission's jurisdiction
- Supports the Commonwealth's status as a low-cost state
- Is consistent with the Commonwealth's native load requirements
- Establishes a sound participant funding cost allocation procedure for transmission upgrades
- Improves reliability of service to the citizens of the Commonwealth from today

- Provides the Commonwealth with the benefits described in Mr. Hinkel's testimony, including a proven congestion management system, reliable electric system operations, proven regional planning process, an effective market monitor, and independent governance

PJM takes no position on any retail rate issues that may be associated with the above-captioned case but wishes to serve as a resource to the Commission as an unbiased provider of information. PJM urges the Commission to find, based on the unrebutted record evidence, that AEP's application to transfer functional control of its transmission assets to PJM is for a proper purpose and is in the public interest.

II. DISCUSSION

Pursuant to KRS 278.218, AEP filed an application before the Commission for approval to transfer functional control of its transmission facilities located in Kentucky to PJM. KRS 278.218(2) states that, "The Commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest." In any formal administrative hearing before the Commission, the Commission is the trier of fact of the evidence brought before it in the hearing. *Owen County Rural Electric Co-op. Corp. v. Public Service Commission of Kentucky*, 689 S.W. 2d 599. If a party is aggrieved by an order of the Commission, that party may bring an action against the Commission in the Franklin Circuit Court to set aside or vacate the Commission's Order on the ground that "... it is unlawful or unreasonable." (KRS 278.410) The matter then, pursuant to KRS 278.440, "... shall be heard and decided by the court upon the evidence submitted to the Commission as shown by the record, and no other evidence shall be received." *Stephens v. Kentucky Utilities Company*, 569 S.W. 2D 155.

In the above-captioned case, the Commission must rely on the written record, which consists solely of AEP and PJM testimony. The Commission Staff and intervenors expressed through their cross-examination concerns about the following: 1) jurisdiction; 2) maintaining the Commonwealth's status as a low cost state; 3) native load preference; and 4) who pays for transmission upgrades. PJM has answered these questions as detailed below and demonstrated how its markets support these critical goals. The record also contains testimony demonstrating the unrefuted facts concerning the PJM marketplace and the enhancements it brings customers.

A. THE COMMISSION's JURISDICTION IS PRESERVED AND ENHANCED

The transfer of functional control of AEP's transmission facilities to PJM does not erode the Commission's jurisdiction; instead, it enhances the Commission's jurisdiction by providing the Commission with new regulatory tools and resources to meet its statutory requirements pursuant to KRS Chapter 278. As is now the case, the Commission will retain jurisdiction over planning and siting, and oversight over retail rates. Most importantly, the Commission will retain jurisdiction over AEP's power dispatch and purchasing practices consistent with the Pike County Doctrine. *Pike County Light & Power Util. Comm'n*, 465 A.2d 735, 738 (Pa. 1983). The Kentucky Industrial Utility Customers (hereinafter Industrials) questioned whether transferring functional control to PJM would give FERC more control over Kentucky Power's generation. (Tr. at 124-25). The record evidence undisputedly demonstrates that PJM will not dispatch AEP's system differently than AEP does today. (Tr. at 32). After transferring functional control of AEP's transmission assets to PJM, the Commission will retain the full scope of jurisdiction that it exercises today. AEP will still own its transmission assets. AEP admits that the Commission has the capability to disallow costs that are not prudently incurred. (Tr. at 38). Pursuant to its jurisdictional authority, the Commission will be able to disallow imprudently incurred costs after AEP transfers functional control to PJM.

PJM provides new regulatory tools that will enhance the Commission's jurisdiction in carrying out its statutory functions in the area of purchase power costs, planning, siting and reliability oversight. The transparent market price will serve as a tool and the transmission market price provides easily ascertainable market data which can be used by the Commission to judge the reasonableness of AEP's purchasing practices in the Commission's fuel adjustment clause proceedings. This is not easy to do today given the lack of price transparency. With PJM, the Commission will have a benchmark, for each hour, to judge whether AEP's decision to dispatch one of its mid-merit or peaking units was a preferable choice over purchasing from the marketplace.

Moreover, for the first time, the Commission will have access to an independent market monitor in the Kentucky Power region that can be called upon to prepare reports and undertake analysis of any market power abuses that may be alleged by the Commission, retail customers, or wholesale customers in the Commonwealth. Finally, in its planning and siting deliberations, the Commission will have access to an unbiased regional view, as described by Mr. Hinkel (Hinkel at 13-15), which will help it determine whether a particular upgrade is needed.

Equally important, the Commission and PJM will have a Memorandum of Understanding that will establish a strong communications and working relationship. The MOU between the MACRUC states and PJM has successfully precluded misunderstandings and disagreements regarding transmission asset deployment and operations.

PJM commits to assure that the Commission is apprised of opportunities to participate in PJM's stakeholder processes. For example, PJM will not bypass the jurisdictional siting authority. (Tr. at 102). PJM commits to meet on a one-on-one basis with the Commission to evaluate various planning proposals. (Tr. at 79). As discussed *infra*, the Memorandum of Understanding between the Commission and PJM will establish formal communications between the Commission and PJM's Board and staff. Moreover, PJM will work with the states on funding requirements to allow for Commission and Commission staff participation at key stakeholder meetings in addition to direct meetings with the PJM Board.

B. MAINTAINING THE COMMONWEALTH'S STATUS AS A LOW COST BUNDLED STATE

The Commonwealth's native load customers will receive the same if not better services at the same rates that they do today after AEP transfers functional control to PJM. PJM has both bundled and unbundled states in its current footprint, and has no preference whether a particular state unbundles or not.[1] As discussed *infra*, PJM brings benefits through the wholesale market to both bundled and unbundled states.

AEP states that it chose to join PJM, in part, because the generation production costs are higher in PJM than in MISO. (Tr. at 20). One should not assume on the basis of this rationale that AEP's low cost power dedicated to Kentucky will flow out of AEP's

[1] PJM works with the retail choice states to tailor wholesale programs that support their retail choice programs. PJM is equally committed to working with the bundled states on issues that are important to them.

service territory. As noted by Mr. Baker, Kentucky Power's status as a low cost company is based on an annual average. (Tr. at 52). There are hours in the year when AEP will be able to buy cheaper power from PJM's markets. As Mr. Ott testified, low cost generators that currently serve the Commonwealth's load will still serve the load after AEP is integrated into the PJM. (Tr. at 71).

Mr. Ott sponsored an analysis to determine the economic benefits of forming a larger regional energy market that would incorporate AEP's control area into a single regional RTO also including the control areas of PJM/PJM West, Dayton Power and Light, and Dominion. The analysis demonstrates conclusively that from either a cost-of-service perspective or a perspective as applied to retail customers, assuming the use of marginal clearing price in the wholesale market, potential annual savings to wholesale load serving entities in AEP is very substantial. These savings will translate into real end-use customer savings for Kentucky consumers as the Commission exercises its jurisdiction to assure that retail rates are just and reasonable.

From a cost-of-service perspective, Mr. Ott stated that $80 million in savings[2] would accrue to AEP load serving entities. (Tr. at 158). AEP's increased generation production costs reflect the increased economic sales it would make into the larger regional market. (Tr. at 157). Although Mr. Ott rightfully deferred to opine on the extent to which AEP's Pool Agreement would allocate these savings to Kentucky Power customers, Mr. Baker indicated that the profits from incremental sales would flow back to Kentucky as a result of the AEP Pool Agreement. (Tr. at 21).

[2] By joining PJM, AEP can decrease its net purchase power costs by $420 million, while realizing only a $340 million increase in generation production costs. This nets to produce $80 million in savings.

From a PJM market rules perspective, which assumes that the bilateral contracts in force today were struck at marginal spot prices in the wholesale marketplace, potential annual savings to load serving entities of $61 million[3] would accrue. (Tr. at 156). The analysis also indicates that the transmission congestion charges of $14.7 million to be paid by AEP load serving entities are entirely hedged by transmission congestion credits that those entities are eligible to request from their generation supply resources to their aggregate demand locations. (Ott's Study Table 2).

The availability of PJM's voluntary spot markets into which AEP may offer incremental sales and seek arbitrage opportunities will not degrade service to native load customers. Mr. Ott recognized that Kentucky Power has low cost generation available from the Big Sandy facility. However, savings would accrue from joining PJM during those hours when Big Sandy is not available (such as during scheduled maintenance outages). (Tr. at 163). Mr. Baker also noted that Big Sandy is a low cost generator, but that AEP will be able to make incremental sales, which will flow through to the Commonwealth under the terms of the AEP Pool Agreement. (Tr. at 21). Mr. Baker noted that there currently are periods when Big Sandy is not the marginal unit, and other units are run instead of Big Sandy. (Tr. at 53). During such times, AEP would be able to offer Big Sandy into PJM's voluntary spot market and to purchase cheaper power from another source; the benefit from the incremental sale would flow to the Commonwealth through the AEP Pool Agreement. (*Id.*; Tr. at 57). These considerations establish that the Commonwealth will benefit as a result of the transfer of functional control of AEP's

[3] AEP generation revenues would increase by $570 million annually, once again reflecting increased sales into the broader wholesale marketplace, and benefiting Kentucky via the AEP Pool Agreement, as Mr. Baker explained. (Tr. at 21).

transmission facilities to PJM, and will see some savings during off-peak hours and during scheduled and unscheduled maintenance.

In short, low cost power will not leave the Commonwealth. PJM's markets are voluntary. AEP can self-schedule to serve its native load in the Commonwealth. The Commission has jurisdiction over AEP's rates. PJM's transparent market will provide information for each hour of the year for the Commission to use to evaluate the reasonableness of AEP's decisions to self-schedule Big Sandy to serve native load. Equally important, AEP admitted the Commission has the authority to disallow costs. (Tr. at 38).

C. NATIVE LOAD PREFERENCE

At the hearing, Mr. Hinkel was asked whether PJM will be able to give priority to the Commonwealth's native load customers in compliance with KRS 278.214. (Tr. at 72). Mr. Hinkel responded that native load customers, along with firm power customers, would receive the highest priority under PJM's emergency rules. (Tr. at 72). If there is an emergency on Kentucky Power's transmission service, PJM will follow its emergency procedures to curtail interruptible non-firm and other users; if those curtailments do not resolve the emergency, then, and only then, would Network Integration Service Customers (including native load customers) and firm service customers be interrupted on a pro rata basis. (Tr. at 75). How a particular utility would handle such curtailment would be governed by the curtailment rules on file with the Commission and would be subject to its oversight. In addition, Mr. Hinkel states in his testimony that, PJM's procedure for curtailment is overall in agreement with KRS 278.214, in that the priority is to Network Integration Transmission customers (including native load customers) and firm users of the transmission system. (Tr. at 16). Mr. Hinkel also testified that serving native load is the highest priority. (Tr. at 75). What PJM will do is no different than what AEP does today. AEP operates on an integrated system basis. The Commission has not found that AEP is in violation of the statute.

D. PJM'S COST ALLOCATION PROCEDURES FOR TRANSMISSION UPGRADES

PJM can require its member transmission owners to build transmission infrastructure when necessary to meet reliability needs. (Tr. at 75, 95). Such requirements are still subject to state siting processes which the planning process is designed to complement by providing transparent information on who is benefiting and who is paying the costs as noted above. At the hearing, Mr. Hinkel was asked whether KRS 278.212 was consistent with PJM's cost allocation procedures for merchant generation interconnections and line upgrades. (Tr. at 131). Mr. Hinkel explained that PJM uses a participant funding methodology by allocating costs to the entity that caused that particular upgrade to be needed. (Tr. at 83). Under PJM processes, the Interconnection Customer is required to pay the costs associated with the minimum upgrade necessary to accommodate its interconnection request. (PJM OATT Sec. 37.3)[4] The Transmission Owner is responsible for the remaining costs, which will be borne under Schedule 6 of the PJM Operating Agreement. *Id.* If additional economic capacity is created, and if the Interconnection Customer will use that capacity, then the

[4] Section 37.3 of the PJM OATT was provided to the Commission in PJM's Answers to Hearing Data Requests, which was filed with the Commission on April 1, 2003.

Interconnection Customer will be required to pay a portion of the costs of the facilities and the upgrades. *Id.*

E. BENEFITS OF JOINING PJM

By joining PJM, AEP and its customers will realize numerous proven benefits, as shown by the record and discussed below. If AEP delays its participation in PJM or another RTO, then those benefits will be delayed and the opportunity to advance the public interest will be deferred. PJM's expert witness Mr. Hinkel explained the benefits of AEP's membership in PJM and clarified misconceptions contained in the questions asked by staff and intervenors.

1. Energy Markets

Fundamentally, it must be remembered that PJM's spot markets are **voluntary**. They operate effectively as a balancing market and provide an option for load serving entities to "fill in the gaps" when there is a mismatch between load and demand. The spot markets are not substitutes for a utility self-scheduling its low cost generation to meet its native load obligations. Instead, the spot markets provide liquidity when AEP's balancing needs require AEP to look at other options. It also provides a market for AEP's excess generation to be sold in the marketplace rather than sitting idle without the benefits flowing back to the AEP customers.

As a member of PJM, AEP could participate in the spot market or could elect to self-supply or bilaterally purchase energy to meet demand. Market transparency, in either case, allows market participants to make better economic choices. (Hinkel at 3). Even with AEP's resources, it currently acquires off-system energy through bilateral contracts. Under those circumstances, market participants do not know what others are paying for electricity in the wholesale market. (Hinkel at 3). PJM's price transparency will bring benefits to the Commonwealth by providing market information to market participants.

PJM's energy markets allow market participants to lock-in sale and purchase prices in advance and Locational Marginal Pricing (LMP) allows market participants to see the energy price at the demand location and at the supply location. This shows the actual cost of using a congested path for transmission and encourages the most efficient use of transmission. (Ott at 5). Under the current system used by AEP in the Commonwealth, costs are socialized so there is no direct incentive to build efficient transmission and locate generation in a cost-competitive manner. LMP sends appropriate price signals that encourage the construction of transmission and generation at the places where it is most needed, and maximizes economic gains.

For example, the high cost of transmission in an area will encourage transmission development, in turn reducing congestion and lowering costs. (Hinkel at 9). LMP demonstrates the value of a proposition of building transmission in a given location, thereby allowing investors in transmission to make a prudent business case for investment decisions.

PJM provides both protection and price disclosure because it is a large, liquid, transparent wholesale market. (Hinkel at 9). By participating in PJM, wholesale customers and the local utility can purchase the lowest cost generation available in a given hour. (Ott at 3). Such purchases are consistent with security constrained economic dispatch,[5] which optimizes generation every five minutes to meet load. (Ott at 3)

2. Congestion Management

PJM uses locational marginal prices (hereinafter LMP) calculated in the energy market to manage transmission congestion economically. (Hinkel at 10). This is an improvement over the current congestion management system used in the Commonwealth, whereby AEP uses NERC's transmission loading relief procedures. As Mr. Hinkel testified, when there is congestion on the PJM transmission system, unlike today, transmission customers have the option of avoiding curtailment by agreeing to pay transmission congestion charges. *Id.* By contrast, today transmission would face a TLR curtailment and loose all the benefits of a given transaction. A major benefit of the LMP system is that socialization of costs is avoided, since only those entities that cause congestion pay for congestion. *Id.* Additionally, as price signal information is provided by a transparent energy market, LMP-based transmission congestion charges reveal price information necessary for identifying economic transmission or generation enhancements to eliminate the transmission congestion on a long-term basis. *Id.*

AEP currently redispatches generation when there is congestion on its transmission system. (Ott at 4). The cost of redispatch is currently borne by the company's retail and wholesale customers through fuel adjustment clauses and base rate changes. (Ott at 5). PJM's LMP-based market will allocate redispatch costs to cost-causers, and establish energy prices at each demand and supply location enabling market participants to react more efficiently to price signals. (Ott at 5). Market participants can

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[5] The term "security constrained economic dispatch" refers to PJM's process that uses the bids in the market place, the current conditions on the system, load, and generation to determine the least cost generation dispatch that recognizes the physical limitations of the system. (Tr. at 91).

hedge themselves against congestion costs through the use of FTRs. (Hinkel at. 11; Ott at 6). Finally, the use of LMP significantly reduces the need for reliance on TLR procedures.

3. Reliable Electric System Operations

PJM brings additional benefits to the Commonwealth by serving as a neutral entity in charge of reliability. Currently, AEP and the other utilities that have not joined an RTO, perform their reliability functions individually. PJM looks at the entire system and enforces reliability rules. This avoids situations where market participants lean on the system, which threatens reliability. Equally important, PJM has consistently met and exceeded[6] NERC's reliability standards. (Hinkel at 12). Customers in the Commonwealth will obtain an immediate benefit from this increased reliability.

In addition, PJM sets a regional reserve margin by means of a comprehensive stakeholder process. If the Commission issued an order requiring a lower reserve margin than PJM's regional reserve margin, AEP would be required by PJM to meet the regional reserve margin. However, if the Commission set a higher reserve margin than PJM's regional reserve margin, PJM would support the Commission's order although the costs of such higher reserves would need to be allocated on a state specific basis just as they would be today. This is an improvement over the status quo where the reserve margin is set in the AEP operating agreement with little state review or ability to modify.

4. Proven Regional Planning Process

PJM provides an open planning process that will provide the Commission with access to information prior to the utility filing a siting application. PJM's open

[6] Attachment C, Operations Summary for Summer 2002, to Mr. Hinkel's testimony demonstrates that the integration of the PJM markets and reliability activities during peak load conditions has met and exceeded NERC standards during the peak months of June and July 2002.

process provides a balanced record for use by the Commonwealth's Power Siting Board, and as discussed supra, PJM's "but for" analysis is completely consistent with the Commonwealth's position on participant funding.[7] Mr. Hinkel's testimony explains that PJM's open and non-discriminatory regional planning process for generation and transmission promotes the public interest.

The success of PJM's planning process is evidenced by the statistics for growth and development. As shown in the response to the data request from the hearing, the current approved regional plan contains $726 million of transmission upgrades, $200 million are baseline upgrades (responsibility of the TOs) and the remainder are direct interconnection facilities and network upgrades required for generation projects (responsibility of the developer). Over 7,000 MW of new generation has been placed in-service since 1999 and another 4,000+ MW of generation are under construction. (*PJM's Post Hearing Response to Data Request*, filed with the Commission on April 14, 2003).

5. Generation Interconnection Procedures

Mr. Hinkel states that the PJM region is relatively more attractive for generation developers because PJM's generation interconnection rules are well established, transparent and non-discriminatory. (Hinkel at 15). This will provide the Commonwealth with more options as it judges future long term contracts to meet load. In addition, PJM's procedures put in a recognized participant funding mechanism available immediately. This avoids unnecessary costs that would otherwise be borne by retail ratepayers.

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[7] On November 15, 2002, the Commission filed comments, in RM01-12-000, stating that participant funding was needed. PJM's "but for" analysis satisfies the Commissions request.

6. Effective Market Monitor

Mr. Hinkel's prefiled direct testimony commented that the Commission will benefit by the information that it will receive from PJM's Market Monitoring Unit if AEP joins PJM. (Hinkel at 16). PJM's effective market monitor will provide the Commission with an additional regulatory resource. PJM's market monitor provides unbiased factual reports of market conditions and specific events. *Id.* The market monitor will investigate events on which the Commission requests an investigation and submit a report to the Commission. (Hinkel at 16). In addition, the market monitor publishes the annual "State of the Market Report," which will provide the Commission with information specific to AEP.

7. Independent Governance

PJM's stakeholder process provides market participants with a mechanism to have significant input into the day-to-day issues that affect PJM's markets and operations. (Hinkel at 7). Equally important, the PJM Board of Managers is advised by the Members and Reliability Committees, while maintaining its independence by not allowing direct communication between the Board members and the individual PJM members. *Id.* Significantly, the Memorandum of Understanding between the Board and the PJM state commissions establishes a vehicle for the Commission to communicate directly to the Board. (Hinkel at 5, 6).

These are all improvements markedly different than today where the Commonwealth's direct interaction with the AEP board is limited at best. Furthermore, there is not an open process to examine AEP's practices short of the Commission taking on the burden of opening an investigation and undertaking its own intensive review after having to subpoena documents from AEP in order to get to the heart of the issue. Through an open participatory stakeholder process, PJM's decision making and information is done fully in the open. Moreover, PJM is using technology including web broadcasts to ensure that state commissions can participate in these proceedings. Again, PJM is further committed to working with the states on funding requirements to allow for Commission and Commission staff participation at key stakeholder meetings in addition to direct meetings with the PJM Board.

F. COMMON MARKET

Portions of the hearing dealt with questions about whether AEP should have chosen PJM over MISO. PJM's position is that each transmission owner, its regulators, and its other stakeholders should evaluate which RTO is best on the merits, and PJM can best contribute to that process by striving to perform well and earn the trust of all concerned. In any event, the development of the Common Market with MISO, SPP and TVA[8] will render the distinction between PJM and MISO moot. The Commonwealth will benefit as the result of each of these entities operating under compatible market rules.

By approving AEP's application, the Commonwealth will have all of its utilities operating pursuant to a compatible set of market rules, which will improve

8 On April 16, 2003, the Tennessee Valley Authority (TVA) executed a Memorandum of Understanding with PJM and MISO to facilitate a joint and common energy market. Given TVA's pivotal role in the Commonwealth, there will be better coordination of electricity flows going north to south and east to west. The press release is available at: http://www.pjm.com/contributions/news-releases/2003/20030416-mpt1.pdf

market coordination and communication. Moreover, PJM and MISO have committed to eliminate the seam between the two RTOs. (Hinkel at 15).

G. PJM ACCOMODATES REGIONAL STRUCTURES

PJM does not believe in the "one size fits all" philosophy, as demonstrated by the highly successful formation of PJM West, where PJM has adapted its market rules to meet local needs, and accommodate diverse stakeholders and market participants. Mr. Hinkel's prefiled testimony demonstrates that PJM has over seventy-five years of experience operating a regional transmission grid, and over six years of proven experience with markets. (Hinkel at 3). As Mr. Hinkel states in his prefiled testimony PJM West is an example of PJM's flexibility because Allegheny Power belongs to a different reliability council, East Central Area Reliability Coordinating Council (ECAR) than the rest of PJM. (Hinkel at 4). PJM's agreements and operations accommodate regional differences.

H. VIRGINIA'S ACTIONS PROVIDE AN OPPORTUNITY FOR THE COMMONWEALTH

In light of the Virginia delay,[9] The Commonwealth now has the opportunity to spell out its requirements first, and to partner with PJM on building the market, as opposed to waiting for those systems to be designed to meet Virginia's requirements. The Commission now has the opportunity to place conditions on its approval of the application that benefit the Commonwealth, instead of being in the position where the Commission has to adapt to the Virginia requirements. For example, should the

[9] Under the Virginia legislation, although causing a delay in transfer of control in Virginia until July 1, 2004, each utility is required to file an application by July 1, 2003. Each electric utility must be fully integrated into an RTO before the end of next year thus putting boundaries around the Commission action and reaffirming its overall intent to move forward with AEP in a FERC-approved RTO.

Commonwealth have a particular reliability requirement, PJM is in a better position to build those into the system now. Otherwise, PJM would have to "bolt on" the requirements at a later time at far greater costs. It is always better to design the system upfront than to continually employ software patches. PJM stands ready to partner with the Commission and its staff to meet any such design needs unique to and reasonably required by the Commission.

I. INDUSTRIALS' HYPOTHETICALS ARE NOT REALISTIC

As noted *supra*, the Industrials chose not to sponsor a witness in the above captioned proceeding. Instead, during the hearing, the Industrials asked three series of hypotheticals that the Commission should recognize as not being probable: 1) couldn't PJM file at FERC and ask for a change to its dispatch authority to be able to dispatch for more reasons than relieving congestion? (Tr. at 32); 2) couldn't PJM file at FERC to make the voluntary hourly and day-ahead markets mandatory, so that the utility would have to buy its requirements back from the PJM markets? (Tr. at 40); and 3) couldn't PJM change the dispatch must-run criteria to be more or less stringent? (Tr. at 124-125). These proposals are contrary to PJM's market philosophy, PJM's history, and the fiduciary duties of the PJM Board. PJM assures the Commission that it has no plans to make such filings.

Moreover, PJM and the regulatory paradigm have three levels of protection to prevent such unrealistic scenarios becoming reality. First, participation in PJM allows a high level of stakeholder input. (Hinkel at 7). Therefore, in order for one of the far reaching hypotheticals to become a reality, it would first need approval by the PJM Members Committee. Before a proposal is voted on at the Members Committee, it goes through an open stakeholder process in which all PJM members and state commissions have the opportunity to participate in the discussions. Next, the PJM Board would need to approve the proposal before it was filed at FERC. The Board members have three fiduciary duties which would prevent them from approving the sort of proposals suggested in the Industrial's hypotheticals: 1) to promote the safe and reliable operation of the bulk power facilities in the region; 2) to create and operate robust, competitive, and non-discriminatory electric power market in the PJM region; and 3) to avoid undue influence over the operation of the bulk power facilities by any market participant or group of market participants. (Hinkel at 3-4). Finally, FERC would have to approve the filing; during the proceeding, PJM members and state commissions would undoubtedly oppose such filings. Again, PJM assures the Commission that it has no plans to make such filings.

III. CONCLUSION

PJM urges the Commission to find that AEP's application to transfer functional control of its transmission assets to PJM is for a proper purpose and in the public interest. PJM provides transparency that will assist the Commission to better assess the reasonableness of AEP's purchase power decisions. PJM does not take away any authority that the Commission has over those decisions. Similarly, as explained *supra*, the transfer of functional control to PJM will not impact the Commonwealth's status as a low cost state.

The Commission must base its decision on the evidence in the written record of this case. The benefits of joining PJM are provided in Mr. Hinkel's testimony and summarized in this brief. No party rebutted or even provided testimony challenging the benefits in Mr. Hinkel's testimony. Therefore, PJM urges the Commission to expeditiously approve AEP's application to transfer functional control of its transmission assets to PJM.

Respectfully submitted,

PJM Interconnection, L.L.C.

By ______________________

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May 9, 2003

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Post-Hearing Brief was served by Regular U.S. Mail , postage prepaid on the 9th day of May, 2003 upon:

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218	)	CASE NO. 2002-00475

ORDER

On August 25, 2003, the Commission granted the requests of Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") and PJM Interconnection, L.L.C. ("PJM") for rehearing of the Commission's July 17, 2003 Order which denied Kentucky Power's application to transfer functional control of its transmission assets to PJM.

Kentucky Power owns facilities that are used to generate, transmit, and distribute electricity to 174,000 retail customers in 20 counties in eastern Kentucky. Thus, Kentucky Power is a utility as defined by KRS 278.010(3)(a) and is subject to the regulatory jurisdiction of this Commission. PJM is an independent transmission operator that has been approved by the Federal Energy Regulatory Commission ("FERC") as a regional transmission organization ("RTO"). PJM is subject to the regulatory jurisdiction of the FERC.

Kentucky Power's request to transfer functional control of its transmission facilities to PJM falls within the purview of KRS 278.218. Enacted by the Kentucky General Assembly in 2002, this statute prohibits a utility from transferring ownership or control of its assets unless it has received the prior approval of the Commission. The standard of review established by the statute is that, "The Commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest." This statute, which applies to the transfer of ownership or control of assets, was enacted to supplement the Commission's then-existing authority under KRS 278.020(4) and 278.020(5) to review and approve the transfer of ownership or control of a utility.

Kentucky Power is a wholly owned subsidiary of American Electric Power Company ("AEP"), a multi-state registered public utility holding company. For many years AEP has owned five electric utility companies in the Midwest that collectively provide service to parts of the following seven states: Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP's operations in the Midwest are now collectively referred to as "AEP-East."

In 1998, AEP announced a merger with Central and South West Corporation ("CSW"). CSW owned four utilities that operated in parts of Arkansas, Louisiana, Oklahoma, and Texas. Since the merger with AEP, the territory formerly served by CSW is now commonly known as "AEP-West."

As part of FERC's approval process for the AEP/CSW merger, AEP negotiated a settlement with certain Ohio intervenors. The settlement included an obligation that

AEP-East join an RTO, an obligation adopted by FERC and expressed as a condition of the merger.[1]

CASE HISTORY

Kentucky Power filed its application on December 19, 2002 requesting approval to transfer functional control of its transmission assets to PJM. The Attorney General of the Commonwealth of Kentucky, Kentucky Industrial Utility Customers, Inc., and PJM requested and were granted intervention. Following a procedural schedule that provided for discovery and the filing of prepared direct testimony, a public hearing was held on March 25, 2003. Post-hearing briefs were filed and the Commission issued an Order on July 17, 2003 denying Kentucky Power's application.

The Commission's denial of Kentucky Power's application was based, in part, on the absence of any Kentucky-specific cost/benefit analysis to demonstrate that the proposed transaction was in the public interest. The evidence of record at that time did not show that Kentucky Power's membership in PJM would produce any benefits for the public without adversely affecting the utility or its quality of service. To the contrary, the record showed significant, quantifiable annual membership costs, with no quantifiable benefits flowing to Kentucky Power or its ratepayers. The July 17, 2003 Order also discussed a number of other reasons why PJM membership was not in the public interest, including the apparent inability of PJM to comply with KRS 278.214, which requires, in certain specified circumstances, transmission priority for retail service.

[1] *American Electric Power Co. & Cent. & S.W. Corp.*, 90 F.E.R.C. ¶ 61,242 (Mar. 15, 2000), *aff'd sub nom, Wabash Valley Power Ass'n v. FERC,* 268 F.3d 1105 (D.C. Cir. 2001).

The Commission subsequently granted rehearing to afford Kentucky Power an opportunity to provide a Kentucky Power-specific cost/benefit study. Rehearing was also granted to PJM on the cost/benefit issue, as well as on issues relating to PJM's operational rules and requirements. A procedural schedule was then established which provided for the filing by Kentucky Power and PJM of cost/benefit studies and prepared direct testimony. Subsequent to filing those documents, the Commission convened a series of informal conferences among the parties to clarify and refine the issues. As a result of these conferences and the cooperative efforts of the parties, an Agreed Stipulation ("Stipulation") was filed on April 19, 2004.

FERC PROCEEDINGS

FERC, in furtherance of its decision to condition the AEP/CSW merger on RTO membership, approved the transfer of functional control of the transmission assets of the AEP-East utilities, including Kentucky Power to PJM, on April 1, 2003. Subsequent to this Commission's decision to deny Kentucky Power's request to join PJM, FERC initiated a proceeding to determine what options might be available to resolve the conflict between FERC's position and that of Kentucky (and Virginia, which by state law is unable to approve RTO membership prior to June 30, 2004). FERC then issued preliminary conclusions that the decision of this Commission (and the Virginia law) was preventing the economic utilization of facilities and resources, as those terms are used in Section 205(a) of the Public Utilities Regulatory Policy Act of 1978 ("PURPA"), and set for hearing that issue and whether FERC should invoke that Section of PURPA to preempt the decision of this Commission (and the law of Virginia). This Commission is an active participant in that FERC proceeding, which is docketed as FERC Case No. ER03-262-009.

SUMMARY OF STIPULATION

The Stipulation, attached hereto as Appendix A, has been signed by all parties to this case. It recommends that the Commission now approve Kentucky Power's application for authority to transfer functional control of its transmission facilities to PJM, subject to specified terms and conditions. Those terms and conditions address, among other issues, the findings set forth in the Commission's July 17, 2003 Order regarding the voluntary nature of PJM's energy market, our continuing authority to protect retail customers, and PJM's curtailment protocols.[2] In addition, the parties recommend that the Commission file the Stipulation with FERC as an offer of full settlement of Docket No. ER03-262-009, as applied to the Commonwealth of Kentucky.[3]

COMMISSION ANALYSIS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that the Stipulation, in conjunction with Kentucky Power's cost/benefit analysis, adequately addresses the issues discussed in our July 17, 2003 Order as the basis for denying Kentucky Power's application. That Order noted the absence of a Kentucky Power-specific cost/benefit analysis and discounted the analysis filed by PJM because there was no demonstration that the net benefits it showed for AEP-East would result in net benefits for Kentucky Power itself. The cost/benefit study filed on rehearing by Kentucky Power estimated the net economic impact of PJM membership for the

[2] Stipulation, Paragraphs 1, 3, and 5.

[3] Stipulation, Paragraph 10.

period 2004-2008. The study compared a base case scenario in which Kentucky Power and AEP were not part of PJM to a scenario in which they are fully integrated into PJM. The study was based on a simulated dispatch analysis conducted for AEP by Cambridge Energy Research Associates using the General Electric Multi-Area Production Simulator production cost simulation model.[4]

The benefits identified in the cost/benefit study are: (1) greater off-system sales profits; (2) net revenues from the sale of financial rights to transmit power on the AEP-East transmission system; and (3) avoided contract costs for services that will now be performed by PJM. The costs included in the analysis consist of approximately $3.9 million per year as Kentucky Power's allocated share of the PJM administrative costs that will be borne by AEP. Total nominal benefits to Kentucky Power over the 5-year period are estimated to be $33.1 million, with estimated net benefits of $13.4 million after recognizing Kentucky Power's share of the PJM administrative costs.[5] Of the total benefits identified for the 5-year period, $24.3 million are attributed directly to Kentucky Power's increased profits from off-system sales. These off-system sales profits are shared with retail customers through Kentucky Power's monthly system sales clause.

The July 17, 2003 Order also expressed concern that membership in PJM could result in a mandatory requirement that Kentucky Power sell the output of its generation

[4] PJM used this same model in preparing the cost/benefit analysis of AEP-East which it presented as part of its original testimony.

[5] Baker Testimony on Rehearing, Exhibit JCB-1.

into the PJM market.[6] Paragraph 1 of the Stipulation affirms the voluntary nature of the PJM energy market for purchases and sales of energy and affirms that AEP can elect to either participate in PJM's spot energy market to meet Kentucky Power's native load energy requirements, contract bilaterally with other entities to supply energy, or schedule its own generation to meet those requirements.

The Stipulation specifies that AEP, on behalf of Kentucky Power, will retain its existing rights to "self-schedule" its resources to meet its native load's energy needs.[7] The Stipulation also affirms that this Commission will retain its existing authority to conduct fuel adjustment and base rate proceedings to investigate and establish the level of energy and generation costs recoverable in Kentucky Power's retail rates. This affirmation of this Commission's authority, coupled with the voluntary nature of PJM's energy market for meeting Kentucky Power's native load energy requirements, provides adequate assurances that Kentucky Power's retail energy costs will continue to be fair, reasonable, and relatively stable over time, and not subject to market price variations.

Another reason for the Commission's denial of PJM membership was that the transfer of control of Kentucky Power's transmission assets to PJM would be inconsistent with the Commission's duty to enforce KRS 278.214, which provides that retail customers be the last to suffer curtailment or interruption of service resulting from an electric system emergency. Pursuant to Paragraph 3a of the Stipulation, PJM will not direct AEP or Kentucky Power to interrupt retail customers as a result of capacity

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[6] July 17, 2003 Order at 20.

[7] In the event that FERC proposes mandatory purchases or sales of energy into PJM's market, the Stipulation provides that PJM and the other parties are obligated not to contest AEP's decision to not participate in any such mandatory market.

deficiencies elsewhere on the PJM system so long as AEP has maintained adequate capacity in accordance with PJM's reserve methodology.

In the event of a transmission emergency, PJM is responsible only for determining the location, quantity, and timing of any curtailment. PJM is not responsible for determining or directing the manner in which load is to be curtailed during an emergency. Pursuant to Paragraph 3b of the Stipulation, PJM will direct AEP to curtail retail load only after PJM has exercised all other available opportunities to remedy an emergency without curtailing retail load.[8] Finally, the Stipulation provides in Paragraph 3d that the approval of Kentucky Power's membership in PJM will not alter this Commission's existing authority over the application by Kentucky Power of curtailment practices to its retail customers.

Based on the Stipulation's provisions on curtailment, it appears that PJM will not be in violation of KRS 278.214 since it will not be determining or directing which customers should be curtailed during an emergency. Rather, that task will remain with Kentucky Power. Consequently, approving the proposed transfer of control will have no impact on the enforceability of KRS 278.214, which is now pending judicial review.[9]

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[8] In order to ensure reliability, the Stipulation appropriately recognizes the need to be able to utilize curtailment in extraordinary circumstances such as where load shedding would be beneficial to preventing separation from the Eastern Interconnection, preventing voltage collapse or in order to restore system frequency following a system collapse. Stipulation, Paragraph 3. These extraordinary remedies are appropriately recognized and are consistent with the requirements of the North American Electric Reliability Council and the East Central Area Reliability Council.

[9] See *Kentucky Power Co. d/b/a American Electric Power v. Martin J. Huelsmann, et al.,* Civil Action No. 03-47JMH (E.D. Ky. filed July 18, 2003) and *Kentucky Power Co. d/b/a American Electric Power v. Public Service Comm'n of Kentucky*, Civil Action No. 03-CI-901 (Franklin Circuit Court, Ky. filed July 22, 2003).

The Commission had also expressed concern in the July 17, 2003 Order that Kentucky Power could be required to pay twice for adequate generating reserves: once through its owned and purchased generation, and again through PJM tariff charges.[10] The Stipulation clarifies this issue by making clear that, so long as AEP-East maintains adequate capacity in accordance with applicable PJM capacity requirements, AEP-East and the retail customers provided generation service by AEP-East will not be obligated to pay PJM to maintain adequate capacity within the PJM footprint.[11] In addition, the parties have attached to the Stipulation the detailed methodology used by PJM to determine an adequate reserve margin. The Commission is familiar with that methodology and finds that it is reasonable for use on the PJM system.

Another major concern expressed in the July 17, 2003 Order was that approving the transfer of control of Kentucky Power's transmission assets to PJM could erode this Commission's existing authority to protect Kentucky retail customers. The Commission notes that Paragraph 4 of the Stipulation is consistent with existing state authority and preserves our right, pursuant to KRS 278.285, to review any demand-side management programs that may be offered by PJM to Kentucky Power. No such program will be offered directly by PJM to Kentucky retail customers.

Finally, Paragraph 5 of the Stipulation provides that this Commission shall continue to establish Kentucky Power's rates based upon its assets included in retail rate base. This will also preserve our authority under 807 KAR 5:058 to review Kentucky Power's Integrated Resource Plan as we have done historically. Furthermore,

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[10] Order at 15.

[11] Stipulation, Paragraph 2.

the Stipulation makes clear that nothing therein, or the Commission's approval thereof, shall be construed to alter the jurisdictional authority of the Commission.

In conclusion, the Commission finds that, subject to the terms of the Stipulation, Kentucky Power's application to transfer functional control of its transmission assets to PJM is for a proper purpose and is consistent with the public interest pursuant to KRS 278.218(2), and should, therefore, be approved. This approval is strictly subject to the express terms of the Stipulation, and is contingent upon the approval by FERC of a Unilateral Offer of Settlement based upon this Order (and the attached Stipulation) in full settlement of Case No. ER03-262-009 as applied to the Commonwealth of Kentucky. The parties to the Stipulation are directed to prepare the necessary documents for this Commission's joinder in the submittal to FERC as part of this approval process.

IT IS THEREFORE ORDERED that:

1. Kentucky Power is granted conditional authority to transfer functional control of its transmission assets to PJM subject to the FERC accepting, without additions or modifications, an offer of full settlement, consisting of this Order and the attached Stipulation, as applied to the Commonwealth of Kentucky in FERC Docket No. ER03-262-009 (and related sub-dockets).

2. The parties to this case shall prepare the necessary documents for the Commission's joinder in the filing of this Order and attached Stipulation as a full settlement as applied to the Commonwealth of Kentucky in FERC Docket No. ER03-262-009 (and related sub-dockets).

3. In the event that this Order and attached Stipulation are accepted without additions or modifications by FERC as a full settlement as applied to the Commonwealth of Kentucky in Docket No. ER03-262-009 (and related sub-dockets), the conditional approval granted herein shall be unconditional, and this case shall be closed, upon the filing of a FERC order accepting the full settlement.

4. In the event that this Order and attached Stipulation are not accepted without additions or modifications by FERC as a full settlement as applied to the Commonwealth of Kentucky in Docket No. ER03-262-009 (and related sub-dockets), the conditional approval granted herein shall be null and void and further proceedings shall then be scheduled to determine whether Kentucky Power's pending application is in compliance with KRS 278.218.

Done at Frankfort, Kentucky, this 19th day of May, 2004.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2002-00475 DATED May 19, 2004

RECEIVED

APR 19 2004

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY D/B/A AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218	) CASE NO. 2002-00475

AGREED STIPULATION

The undersigned parties (parties), by counsel, hereby advise the Kentucky Public Service Commission ("Commission" or "KPSC") that the parties have agreed by written stipulation as follows:

WHEREAS, on December 19, 2002 Kentucky Power Company d/b/a American Electric Power ("Kentucky Power") filed an application, pursuant to KRS 278.218 requesting approval to transfer control of certain transmission facilities to PJM Interconnection L.L.C. ("PJM"); and

WHEREAS, this Commission held an evidentiary hearing on said application on March 25, 2003; and

WHEREAS, on July 17, 2003 this Commission issued an Order denying the requested transfer; and

WHEREAS, in response to rehearing applications filed by Kentucky Power and PJM, the Commission granted rehearing on August 25, 2003 in order to obtain a Kentucky Power cost/benefit study and for the parties to provide additional testimony on issues raised in the rehearing applications of Kentucky Power and PJM concerning certain of the findings made by this Commission in its July 17, 2003 Order; and

WHEREAS, Kentucky Power filed a cost/benefit study in accordance with the Commission's Order on December 23, 2003; and

WHEREAS, on November 25, 2003 the Federal Energy Regulatory Commission ("FERC") in Docket No. ER03-262-009 made certain preliminary findings concerning the actions of this Commission related to the Kentucky Power application and ordered an evidentiary hearing concerning such findings; and

WHEREAS, following an evidentiary hearing, on March 12, 2004, a FERC Administrative Law Judge issued an Initial Decision confirming the FERC's preliminary findings; and

WHEREAS, continued litigation involving Docket No. ER03-262-09 before the FERC and this proceeding could be lengthy and costly; and

WHEREAS, as a matter of state law the Commonwealth of Kentucky has an industry structure of vertically integrated electric utilities serving retail customers through the provision of bundled retail electric service;

NOW THEREFORE, the parties hereby agree, stipulate and recommend to the Commission that it issue an Order approving Kentucky Power's application submitted to the Commission on December 19, 2002 to transfer functional control of its transmission facilities to PJM subject to the following terms and conditions:

1. The parties agree and stipulate that this approval is premised on PJM's operation of markets that are designed such that AEP Service Corporation's (AEP) purchases of capacity and energy, and sales of capacity and energy to, the PJM Capacity Credit Market and PJM Interchange Energy Market on behalf of its operating companies are voluntary.[1] AEP's cost of service to retail customers is subject to appropriate Commission review through rate proceedings. The parties agree to resist any proposal to mandate PJM member participation in PJM's Capacity Credit Market or Interchange Energy Market to effect sales or purchases of capacity or energy. In addition, the parties will not contest if AEP seeks not to participate in any other mandatory purchases or sales of capacity or energy in the PJM Capacity Credit Market or PJM Interchange Energy Market that FERC may subsequently propose. Nothing in this Stipulation is intended to address whatever authority FERC

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[1] **As to meeting capacity obligations, the PJM Interchange Energy Market is the vehicle wherein AEP is required to specify the availability of its capacity resources solely in order to ensure that PJM can call upon such capacity in the event of a generation capacity deficiency emergency. AEP has the option to meet its capacity offer obligations as well as its other obligations to serve its native load through self-scheduling. "Self-scheduling" means the designation by a utility of its own resources to meet its load obligations.**

may have with respect to remedies for anticompetitive behavior or the position of the parties concerning same.

2. PJM agrees to provide information as necessary and to provide due consideration to the findings of this Commission and other Commissions within its footprint for PJM to determine the appropriate reserve margin necessary to maintain safe and reliable service. Nothing stipulated in this agreement shall supercede PJM's obligation to ensure an adequate reserve margin consistent with maintaining an acceptable level of reliability. This level of reliability shall be maintained consistent with applicable reliability principles and standards.[2] Integrating AEP into PJM will provide a larger base of generation in the PJM footprint. As a result, PJM anticipates that the integration of AEP into PJM should result over time in lower reserve margins than AEP would otherwise be required to maintain, all other things remaining equal. So long as AEP maintains adequate capacity in accordance with applicable PJM capacity requirements, AEP and retail customers provided generation service by AEP will not be obligated to pay PJM to maintain adequate capacity within the PJM footprint.

3. PJM agrees to implement curtailment protocols as follows:

   a. PJM will not direct AEP to curtail the retail customers of any AEP operating company including Kentucky Power for capacity deficiencies elsewhere on the PJM system so long as AEP has maintained adequate capacity in accordance with applicable requirements;
   b. PJM will not direct AEP to curtail retail load in any AEP-specific state jurisdiction, including Kentucky, for a transmission system emergency unless PJM has exercised all other available opportunities to remedy the emergency without curtailing such retail load;
   c. The foregoing curtailment protocols shall apply except in extraordinary circumstances such as where load shedding would be beneficial to preventing separation from the Eastern Interconnection, preventing voltage collapse, or in order to restore system frequency following a system collapse.
   d. Nothing in the approval of this application shall alter this Commission's authority over the application by Kentucky Power of curtailment practices to its retail customers.

4. Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail

[2] PJM's methodology for determining such reserve margin is set forth in Attachment A.

customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. Kentucky Power may, at its election, offer demand side response programs to its retail customers. Any such programs would be subject to the applicable rules of the Commission and Kentucky law.

5. Nothing in this Stipulation shall be construed to alter the jurisdictional authority of the KPSC or the FERC or the parties' respective positions concerning same. Should the Commission approve this Stipulation, such approval shall not be construed as approval of the removal of Kentucky Power assets from rate base and the authority to determine revenue requirements for such assets. The KPSC shall retain its existing jurisdiction to, and shall continue to, establish retail electric rates for Kentucky Power based upon its assets included in retail rate base. Nothing in this Stipulation shall preclude Kentucky Power from taking any legal position in any rate proceeding or judicial review thereof with respect to the KPSC's jurisdiction.

6. Nothing in this Stipulation or the Commission's approval thereof shall be deemed to alter in any way the existing obligation of Kentucky Power Company under the laws of the Commonwealth of Kentucky to seek a certificate of public convenience and necessity prior to commencing to construct an electric generation facility or transmission facilities.

7, Nothing in this Stipulation alters in any way the laws of the Commonwealth or rules or policies of this Commission which provide that service to retail customers be provided through the provision of bundled retail electric service.

8. The parties hereby stipulate that the Commission may rely upon the testimony submitted in this proceeding in support of this Stipulation.

9. The parties will endeavor to obtain prompt approval of this Stipulation by the Commission, no more than thirty (30) days from the date of its submission.

10. Upon approval of this Stipulation by the Commission, the parties recommend that the Commission file this Stipulation with the Federal Energy Regulatory Commission as an offer of full settlement of Docket No. ER03-262-009, as applied to the Commonwealth of Kentucky. In the event that this Commission or the FERC does not accept this Stipulation in its entirety and the FERC does not accept this Commission's Offer of Full Settlement

based on this Stipulation and the Commission's Order adopting it as applied to the Commonwealth of Kentucky, then each of the signing parties and the KPSC shall retain the right to terminate this Stipulation. In the event of such action by this Commission or the FERC, within five (5) business days any undersigned party may give notice exercising its right to terminate this Stipulation, provided that the undersigned parties may by unanimous consent, elect to modify it to meet the issues raised by the Commission or the FERC. Should any undersigned party choose to terminate this Agreement, in such eventuality, the agreement shall be considered void and have no binding precedential effect, and the parties reserve their rights to fully participate in all relevant proceedings notwithstanding their agreement to the terms of this Stipulation.

Dated this 19th day of April, 2004.

HAVE SEEN AND AGREED:

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pjm

ATTACHMENT A

PJM Generation Adequacy Analysis:

Technical Methods

Capacity Adequacy Planning Department

PJM Interconnection, L.L.C.

October 2003

Introduction

Reliability requirements for a bulk power system are typically separated into two distinct, but related, functional areas: Adequacy and Security. As defined by NERC, adequacy refers to "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[1] Security, as defined by NERC, refers to "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[1] A well planned and adequate power system will lead to a secure system in day to day operations.

Generation adequacy, or the sufficiency of generation supply to meet expected demand, is one of the fundamental components of electric system adequacy assessment. This paper examines the analytical methods and models that PJM uses to assess the generation adequacy of the region. These techniques are based on sound, proven engineering theory and the physics of the bulk electric power grid. These methods, originally developed in the 1960s, have served PJM well over the ensuing decades in providing a safe and reliable electric system.

The generation adequacy standard PJM is obligated to meet is defined in Section 1 of the MAAC Reliability Principles and Standards[2], which states:

> "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effects of connections to other pools, and network transfer capabilities within the MAAC systems."

This "one day in ten year" loss-of-load expectation (LOLE) is the standard observed in most NERC regions and is the basis for determining PJM's required Installed Reserve Margin (IRM). The probabilistic nature of this standard requires that the tools used to determine the required IRM also be probabilistic. The tool developed and used by PJM for this purpose essentially uses a convolution of expected load distributions with expected capacity availability distributions to determine the loss-of-load probability (LOLP) of the PJM system.[3,4] The model includes all factors listed in the MAAC Section 1 criteria stated above. The specific statistical techniques used by the model include:

1 Probability Density Functions
2 Convolution Functions
3 Markov equations of a four-state model [7]
4 The Central Limit Theorem

5 Monte Carlo sampling
6 The First Order Statistic
7 Correlation and regression techniques and residuals
8 Testing for normality of probability distributions
9 Confidence interval determination.

In addition to determining the required PJM Installed Reserve Margin, PJM performs a number of other related analyses including evaluation of the reliability value of load management programs, capacity emergency transfer objective studies, winter weekly reserve target studies, and peak period planned maintenance assessments (see Citations 28, 29, 30). These planning study results are often directly applied in system operations. For example, the determination of the winter weekly reserve target is applied in the succeeding winter period by Operations to ensure that planned outages are coordinated to minimize system risk and maintain compliance with the MAAC Section 1 criteria.

The main section of this paper explains why and how PJM's modeling and analysis techniques are used to assess generation adequacy from a planning perspective. It also includes the results of benchmarking analysis performed to assess the consistency of our planning model with operational experience. The main section also underscores the integrated nature of planning and operations functions at PJM by outlining the direct impacts of each function on the other.

The main section of the paper is followed by a list of references which provide the conceptual basis for PJM adequacy tools and methods. Also included is a glossary which defines the terms and acronyms used throughout the paper. The Citations and References cited at the end of this paper provide the pertinent technical details and further explanations of the concepts and techniques presented in the main section. This paper itself is a summary of numerous reports and documents that describe the techniques in greater detail and are available at the PJM Interconnection Office.

Section 1

Reserve Requirement Analysis

The primary purpose of the Reserve Requirement Study is to determine the Installed Reserve Margin (IRM) required by PJM to meet the MAAC "1 in 10" LOLE standard. While the requirement is based on MAAC criteria, it is applied uniformly across the entire PJM region regardless of NERC reliability council boundaries. The Reserve Requirement Study is performed annually by Capacity Adequacy Department staff at PJM with extensive stakeholder review through the PJM Committee structure. The IRM ultimately recommended by the Committees and approved by the PJM Board is based on consideration of the analytical results and application of engineering judgment to reflect the influence of factors not explicitly considered in the analysis.

PRISM (Probabilistic Reliability Index Study Model) is the computer application used by PJM to calculate reliability indices to determine installed capacity reserve requirements. PRISM is a Web-based software tool that was recently developed based on the GEBGE model. GEBGE is a legacy FORTRAN program that had been used by PJM for adequacy studies since the mid 1960's.

The Reserve Requirement Study is based on a data model that has five principal components:

1) 52 weekly mean peak loads
2) 52 weekly standard deviations of the loads reflecting both forecasting error and weather variability
3) 52 weekly mean generating capacity values
4) 52 weekly available capacity distributions based on characteristics of the generators (forced outage rates, planned outage requirements, etc.)
5) A deterministic Capacity Benefit Margin (CBM) value between PJM and the external regions

The external regions included in the model (collectively referred to as the "world") include ECAR, SERC, NPCC, MAIN, SPP, and MAPP. Studies can be performed on a single area (PJM only) basis or on a two-area basis (PJM and adjacent regions). The determination of reserve requirements is done on a two-area basis to recognize the reliability value of interconnection with external regions. The data model for both the load and capacity representations is based on physical, geographic location.

The Reserve Requirement Study also produces the Forecast Pool Requirement (FPR) which is the IRM converted to units of unforced capacity. Unforced capacity (UCAP) represents the expected megawatt output of a unit that is, on average, not experiencing a forced outage. UCAP is used to assign capacity obligations and to measure compliance with those obligations. UCAP is also the units on which the PJM capacity markets are based.

The Reserve Requirement Study assesses the adequacy needs of the pool for each of the next five years. Results are primarily influenced by the characteristics of the generating units, variability of load, expected amount of new generation, load forecast error, and available capacity assistance from adjacent regions. The IRM is officially approved on a one year-ahead basis. Once approved, the IRM is held constant for the duration of a full planning period (June 1 through May 31 of the following year).

Two Area Model

The Reserve Requirement Study models two separate areas: Area 1 is the study region (PJM) and Area 2 is the electrically significant region connected to PJM (the "world"). As a result, the bulk electric power grid of most of the Eastern Interconnection is modeled. Geographically, this area includes most of the U.S. and Canada between the Atlantic Ocean and the Rocky Mountains. The bulk electric power grid generally includes all elements connected to the 138 kV and higher voltage level system.

The Reserve Study model includes three primary components: load, capacity, and the transmission link that connects PJM with the world area. The value of the simultaneous capability of the transmission link, under peak load conditions, is known as the Capacity Benefit Margin (CBM).[13, 14] The load and capacity models are probabilistically based, whereas the transmission link is represented by a single, expected value. As detailed in the Capacity Benefit Margin section of this paper, the determination of the expected transmission link is based on a probabilistic weighting of results from a series of power flow simulations.[15] A geographical representation of the Reserve Requirement Study model is shown in Diagram 1. A conceptual representation showing the three primary modeling components is depicted in Diagram 2.

Diagram 1

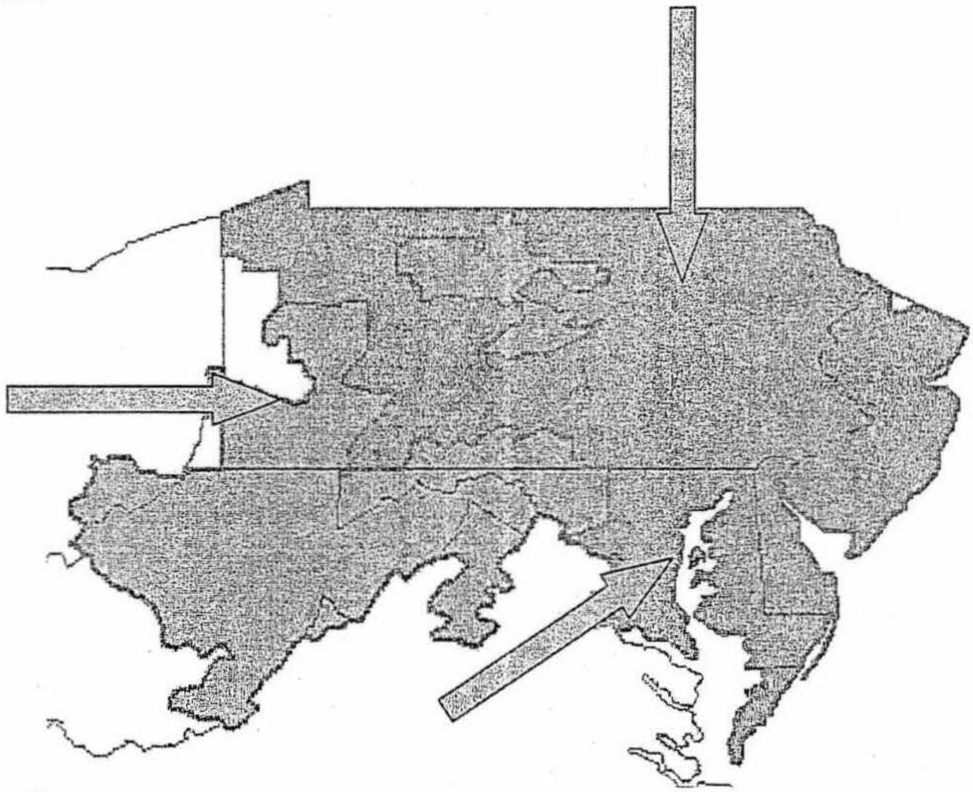
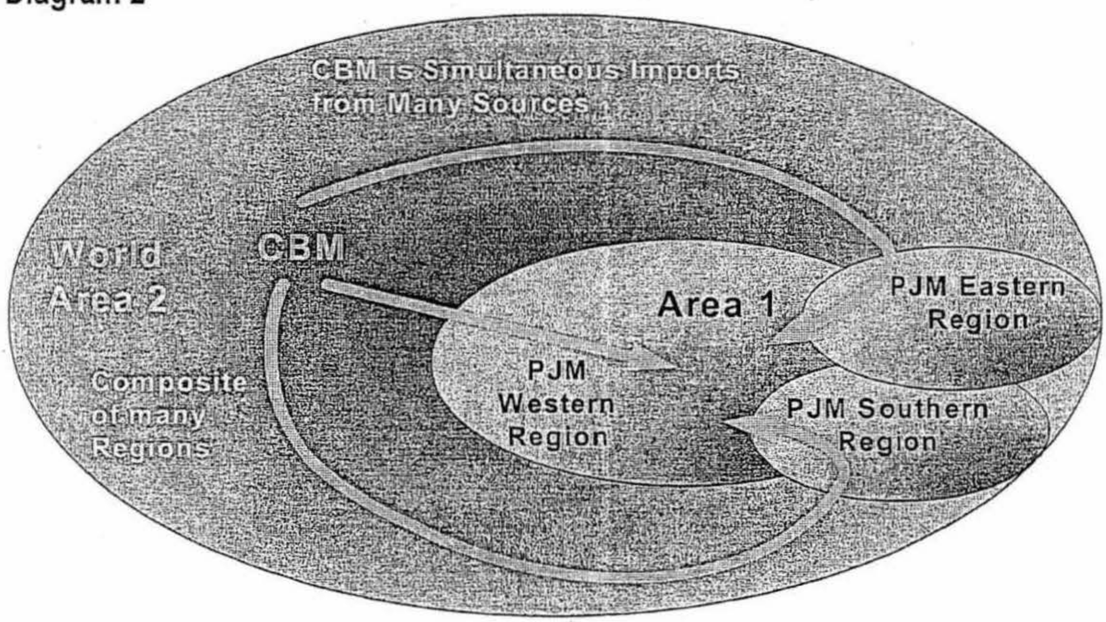


Diagram 2



PJM Region

Data for the PJM Region model is supplied by stakeholders (primarily Generators and the Electric Distribution Companies) and is also collected from PJM data systems. Stakeholder data is thoroughly reviewed by PJM staff to ensure accuracy. Three cases are currently developed for the Reserve Requirement Study to represent the three possible PJM configurations:

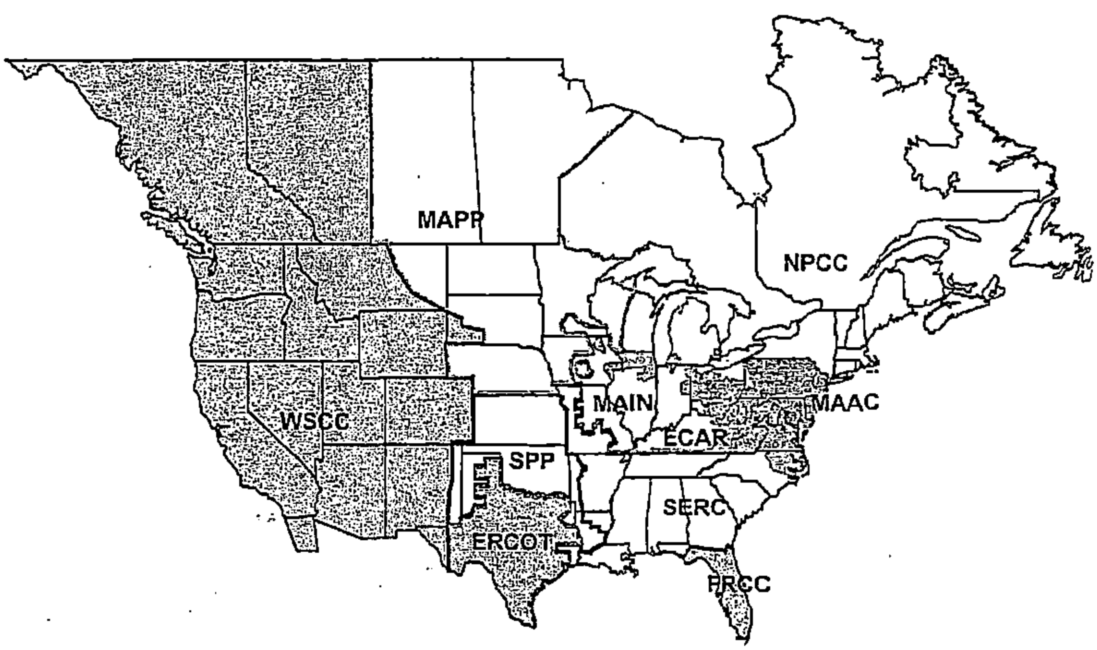
1) the MAAC region only
2) the MAAC region plus Allegheny Power
3) the MAAC region plus Allegheny Power, Commonwealth Edison, AEP, Dayton Power & Light and Dominion Virginia Power

These regions comprise the green/bluish-green area depicted in Diagram 3.

World Region (Eastern Interconnection minus PJM, ERCOT, and FRCC)

The world region is the area electrically interconnected to the PJM region. Diagram 3 shows this as the area in white. Regions in Texas, Florida, and west of the Rocky Mountains are not strongly interconnected to PJM and therefore are not modeled in the study. Diagram 3 shows the areas not modeled in the study in yellow.

Diagram 3



Single Transmission Tie (CBM = 3500 MW)

The model includes a single, bi-directional transmission tie between the two study regions. This tie represents the transmission system's ability to deliver capacity resources into PJM under peak demand periods. Power flow studies using Monte Carlo generator outage techniques[15] indicate that this value is 3500 MW. The 3500 MW emergency import capability is defined to be the Capacity Benefit Margin and is reserved for adequacy purposes and is therefore not available for firm transmission service under non-emergency conditions. Preserving this CBM for reliability purposes effectively reduces the calculated IRM by two to three percentage points. This collective benefit is shared pro-rata by all load serving entities in the PJM region.

Recent studies [22, 23] of the expanded PJM region indicate that PJM's emergency import capability (EIC) now exceeds 3500 MW. Statistical studies [17, 18, 19, 20], however, indicate that the vast majority of the reliability benefit of interconnection is supplied by the first 3500 MW of import capability. For this reason, CBM has been effectively capped at 3500 MW. Reserving import capability in excess of 3500 MW provides a minimal amount of additional benefit. Any EIC in excess of 3500 MW is therefore not reserved for reliability purposes and can be used to increase the amount of firm Available Transmission Capability available to the marketplace.

PRISM - Probabilistic Reliability Index Study Model

The models and analytical techniques used for generation assessment are based on numerous technical papers [5, 6, 11, 12] and on the physical nature of how generating machines, peak demand period loads and the transmission system interact in the delivery of energy across the bulk power grid. PJM has successfully used these techniques for more than 35 years in determining pool wide reserve requirements.

The PRISM (Probabilistic Reliability Index Study Model) tool uses SAS [24] software as an analytic engine and Oracle [25] as a database to enhance the PJM staff's abilities to assess adequacy requirements. The tool's focus is on creating a probabilistic generation model and load model and convolving the two to determine the probability of load exceeding available capacity. The generation and load models are based on the latest available information which offers the best predictor of future adequacy requirements.

PRISM analyses a weekly distribution of the expected peak loads and a distribution of the expected available capacity level in each study area. Each weekly load distribution is modeled to be normal (i.e. Gaussian). These distributions are based on the load data for the previous five years and the five year average generator availability statistics respectively. These two distributions are then convolved as depicted in Diagram 4. Two weeks are depicted in this diagram: one pertaining to a high demand peak week and the other to a low demand, non-summer week.

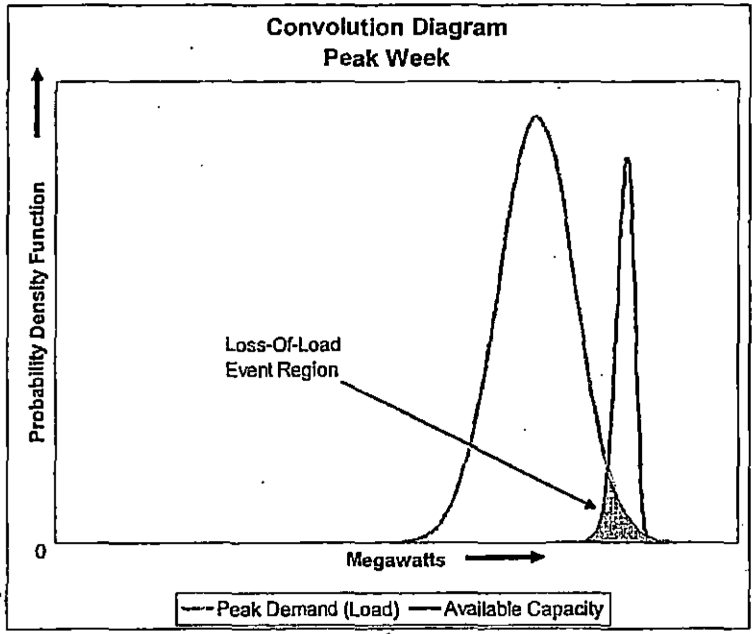
As depicted in Diagram 4, if load exceeds available capacity (the green line is to the right of the blue line), demand is unable to be served and a loss of load event occurs. The probability of a loss of load event occurring in that particular week is simply the area under the curves and shaded in red on the diagrams. The loss of load probability is therefore a joint probability calculation – the load level must be at a certain

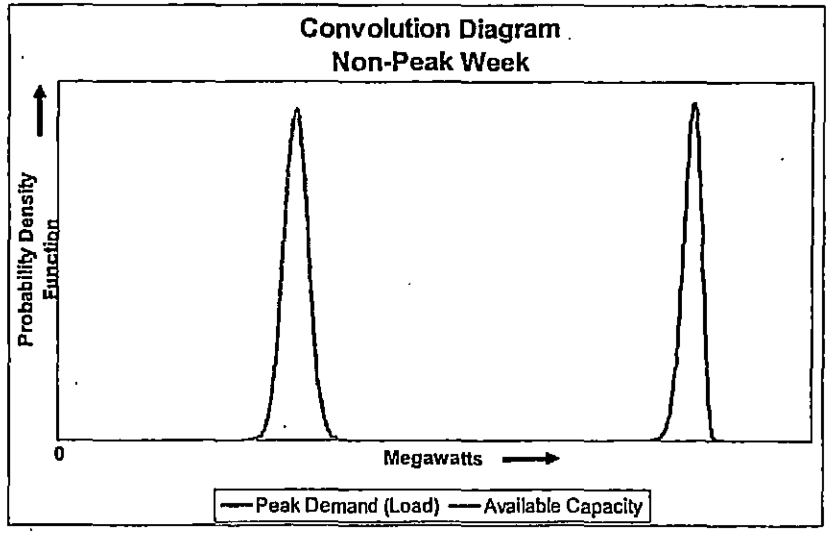
MW value coincidently with the available capacity level being below that same MW value. It is important to note that this model assumes independence between the load distribution and the capacity distribution.

Diagram 4 clearly shows that the loss of load probability (LOLP) is much greater on a peak week than on a non-peak week. This is due primarily to the load distribution, which has a higher mean and higher standard deviation during the peak week. This increases the potential for overlap (or red shaded area) between the two curves. Note the standard deviation of the capacity distribution is relatively small. This is due to the large number of units within PJM. With over 700 units, the possible range of system unit average unavailability decreases significantly and clusters around the mean. **This tight standard deviation on the capacity distribution applies to both peak and non-peak weeks and serves to reduce the loss of load probability.**

PRISM performs the convolution calculation for each week of the year and for each area of the model. The weekly LOLPs are then summed to determine the seasonal LOLPs, which are summed to produce the annual LOLP. The annual LOLP is the value that must meet the MAAC standard of a "1 in 10" loss of load expectation.

Diagram 4





The details of the model development are described below.

Load Model

The general shape of the load distribution is based on metered control area loads over a five year period. Hourly loads from each year are normalized based on the respective annual peaks to remove the effects of load growth. Basing the shape on five years of history is judged to be the appropriate period that both balances having a sufficient number of data points to reduce volatility and ensuring the model reflects recent load characteristics.

The load model used in the Reserve Requirement Study is "magnitude-ordered". This means that the weekly load data is not considered in chronological order but is ordered instead within each season of each year from the highest to the lowest. The loads are then averaged across the five year period based on this magnitude ordering (i.e. the highest weekly loads are combined across the years, the second highest weekly loads are combined and so forth through 52 weeks). The 25 points collected for each week (the 5 weekday peaks from each of the 5 years) then define the mean and standard deviation of the load distribution for that particular week. This "magnitude-ordered" approach results in an annual load profile that benchmarks very well with actual load experience. A load model approach that simply combined loads across years based on "calendar-ordering" (i.e. the first week of each June combined, the second week of each June combined, etc.) would tend to flatten out the load shape and result in an anomalous load profile that does not resemble any annual profile observed in operations.

Diagram 5 shows the distribution of daily peaks occurring on the five weekdays of a particular week. This normal distribution is characterized by its mean and standard deviation and is assumed to be identical for each of the five weekdays within a particular week. [26] PRISM develops 52 of these distributions, one associated with each week of the planning period. The value of the most probable weekly peak is determined from this curve based on use of the First Order Statistic. The First Order Statistic [27] empirically predicts the expected highest observation within a sample of a fixed size, where the population mean and standard deviation are known. For the most probable peak (MPP) calculations, the population is defined by the weekly load distribution and the sample size is five (one for each weekday of the week). From the First Order Statistic table [27], this sample size yields a First Order statistic of 1.16295 and is inputted into the formula below:

$$MPP = \mu + 1.16295\sigma$$

This formula states that, if 5 data points are randomly sampled from the distribution on Diagram 5, the expected value of the highest of the 5 data points (corresponding to the weekly peak) would be 1.16295 standard deviations above the distribution mean. The expected weekly peaks (or most probable peaks (MPPs)) across an entire planning period are plotted on the y axis in Diagram 6 (red line).

Another input to the load model is the historical load growth rate and the monthly peak demand forecast. The load shape is adjusted to essentially replace the historical load growth reflected in the metered loads with the current forecasted load growth for the future study period. Historical load growth is removed by normalizing loads based on the respective annual peaks. This adjustment ensures that the resulting load model is a more accurate predictor of future adequacy requirements.

The load model also recognizes the increased forecast uncertainty associated with longer planning horizons. This is accomplished through application of a unified increase in error for each week based on the length of the planning horizon under study. The increase in error is referred to as the Forecast Error Factor (FEF) [31]. The FEF adjustment is made each week according to the formula:

$$MPP = \mu + 1.16295\sigma_{\text{Total}} \,,$$

where:

$$\sigma_{\text{Total}} = \sqrt{\sigma^2 + FEF^2} \,.$$

Thus the FEF adjustment has the effect of increasing the weekly load distribution standard deviations associated with planning periods further out in the future. The Reserve Requirement Study load models typically use an FEF of 0.5% error in the first planning period and increase this value by 0.5% for each succeeding planning period of the study. [17, 18, 19, 21, 31] The maximum FEF value is a 3% error and occurs six years forward in time.

The distribution of daily peaks within a week is assumed to be normal. [10] Analysis of historical daily peaks for each week of the year supports this assumption. [26] Historical data for sixty percent of the weeks are strictly normally distributed. Those weeks that are not strictly normally distributed have distributions that are bell shaped but exhibit some skewness. In particular the summer (peak) weeks show some negative skewness (i.e. the median daily peak is greater than the mean daily peak).

Using a normal distribution to represent these weeks is a conservative assumption, since it aligns the mean and median daily peaks and shifts the distribution to the right increasing the likelihood of exceeding the available capacity. Please refer to the Citations, primarily numbers 10 and 26, for a detailed description of the data and statistical testing and verification performed to demonstrate that a normal distribution for each week's daily peaks is appropriate.

Diagram 5

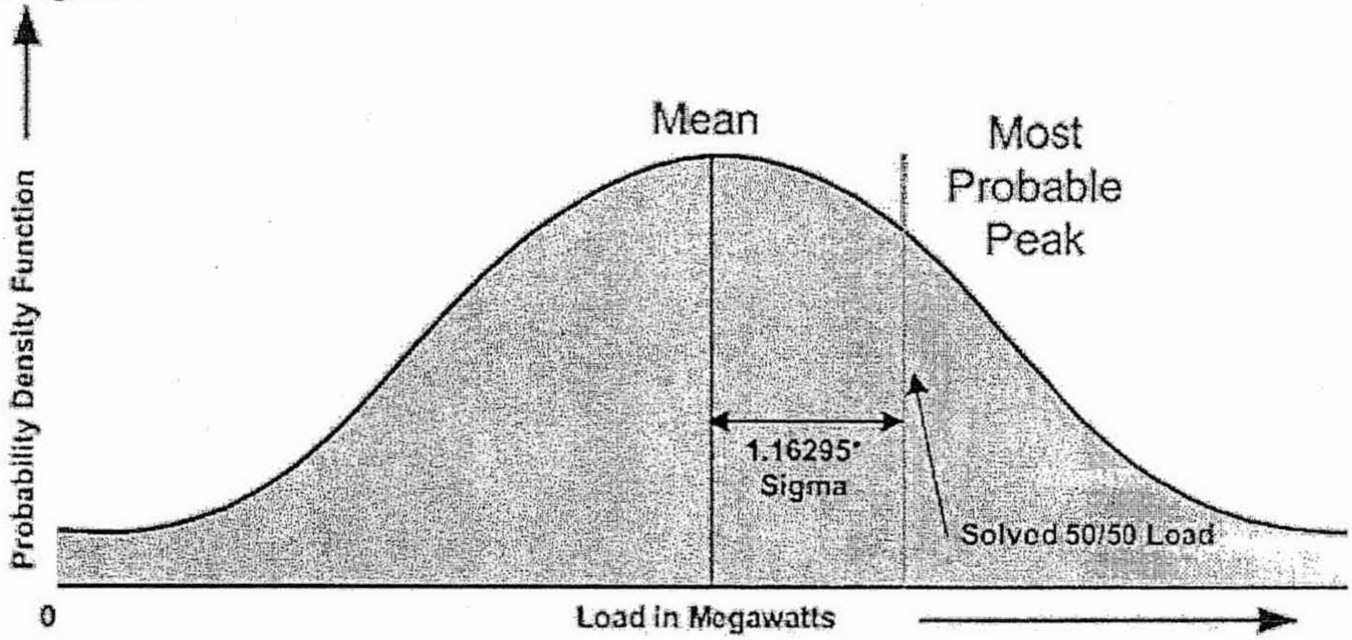


Diagram 7 emphasizes the point that each weekly load point on the annual load shape does not represent a single value, but is itself the most probable peak drawn from an entire distribution of possible peaks. A load distribution similar to the one depicted in Diagram 5 is associated with each weekly peak plotted in Diagram 6. This approach ensures that every possible load level, not just the expected or average load level, is considered in our adequacy analysis.

Diagram 6 – Load Shape

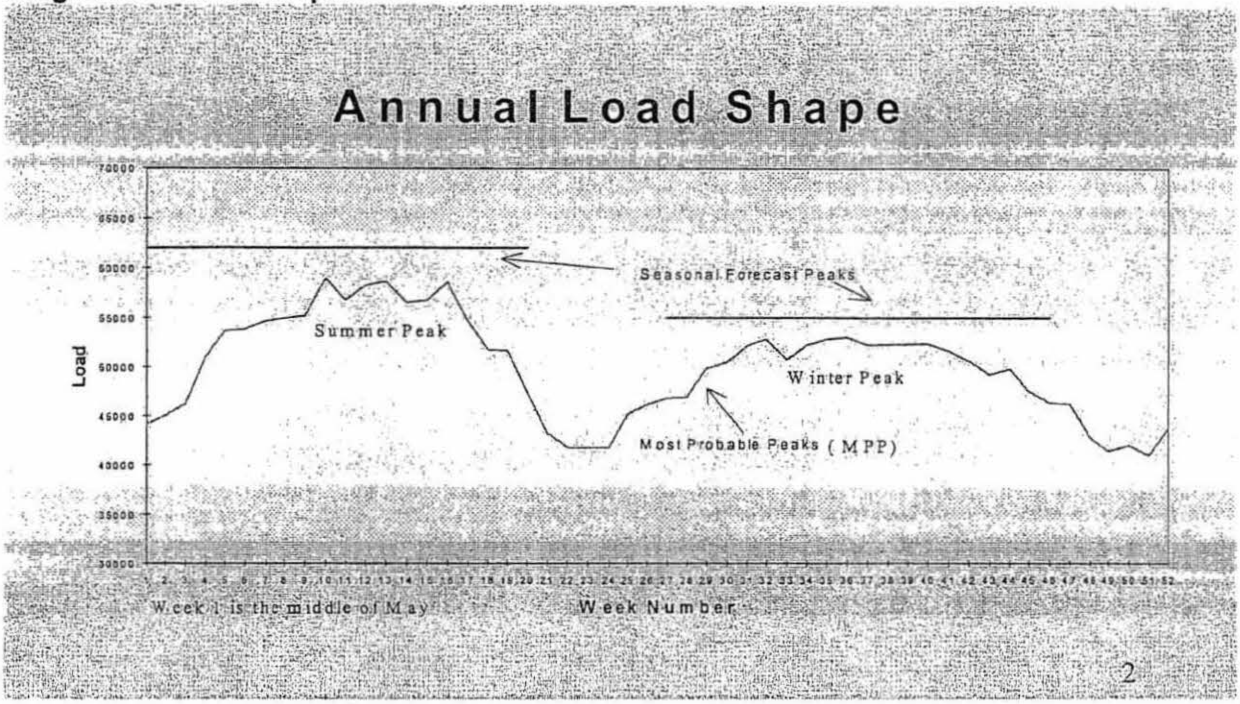
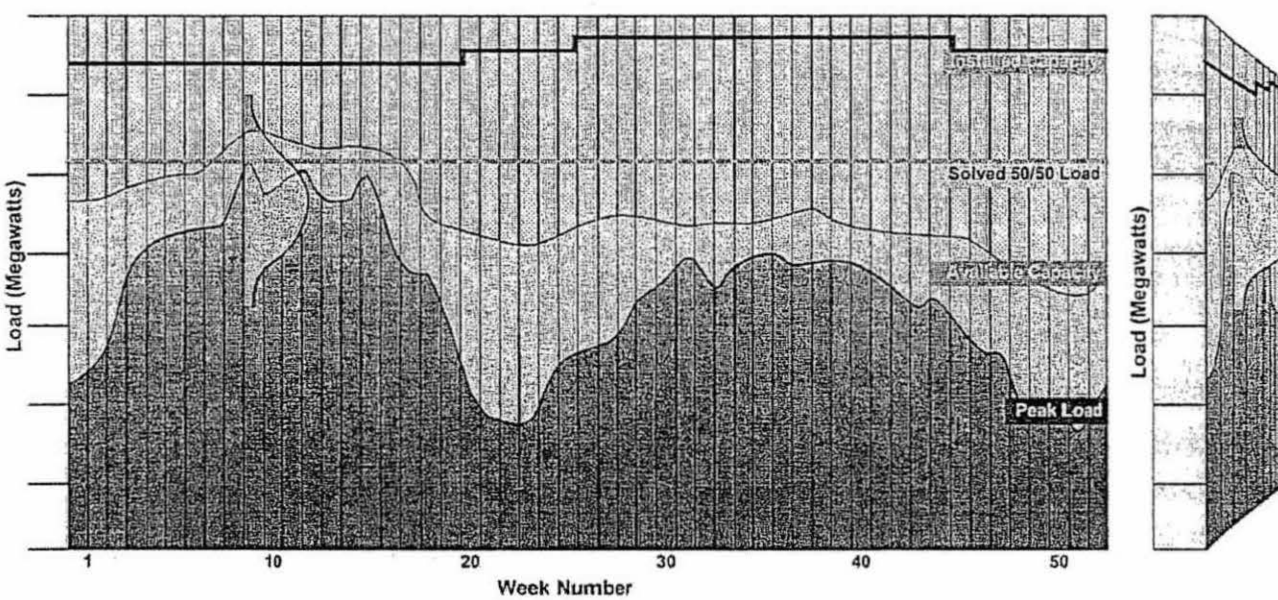


Diagram 7 – Load Shape combined with Weekly Load Distribution



The Green line represents the Available capacity. The tail of the weekly load distribution shown above the green line represents a loss-of-load event. Picture this diagram in 3 dimensions with the bell shape load extending up out of the page as shown in the image to the right.

Capacity Model

The PRISM capacity model explicitly models each generating unit in each area. The following input data is required for each unit:

1. Name
2. Location
3. Summer and Winter Capacity Ratings
4. Effective Equivalent Demand Forced Outage Rate (EEFORd)
5. Two State Variance
6. Planned Maintenance Requirements

The EEFORd statistic [7, 8, 32] is effectively the forced outage rate of the unit (which is an all-hours performance measure) adjusted to reflect the availability of the unit only over the hours during which it is "in demand" or required to produce energy. The two-state variance statistic [31, 32] is a single value which captures the effect of up to twelve partial outage states of the unit. The maintenance data specify the number of weeks per year required for planned maintenance. The calendar scheduling of that maintenance is optimized by PRISM by coordinating it with the maintenance requirements of all other units in that study area. These input statistics are fully developed in the Citations and References to this paper, primarily in Citation numbers 31 and 32.

The volume of data required to develop a capacity model for a 700 unit PJM region and a world area of over 4500 units is significant. Data warehousing technologies and SAS software [24, 25] have been developed to expedite the storage and extraction of this data. These new tools have dramatically reduced the amount of staff time required to produce the capacity models and allow sensitivity analyses to be performed in a much more efficient manner.

Generation statistics are generally based on the most recent five years of historical performance. This time period is consistent with that used for load model development and effectively balances the need for data timeliness with relative stability across years. Data reporting generally comports with Generation Availability Data Systems (GADS) standards. GADS [33] standards are established by NERC. Members submit the details of generating unit outage events through the Web-based eGADS tool [33]. PJM staff performs checks on these data and uses the Generator Outage Report Program (GORP) to produce all the statistics used in the capacity model development. The PJM Generator Unavailability Subcommittee (GUS), a stakeholder body of experts in generator performance analysis, advises PJM staff on the definitions and use of the performance statistics.

NERC compiles class average performance data for various generators based on type, fuel supply and megawatt size [34]. PJM uses this class average data for the world units and future units in the PRISM model. An in-house application makes the necessary calculations to produce the statistics needed for EEFORd, variance, and the planned outage factor used to estimate planned maintenance. New generating units roll actual performance data into their historical base as it becomes available. NERC updates the class average generator data on an annual basis.

To develop the weekly capacity distributions, PRISM first addresses the need for planned maintenance outages. Each generating unit is assigned an expected number of weeks per year to be out on a planned outage event. PRISM considers the maintenance requirements of all units in a particular area and determines for each week which units, if any, will be on a scheduled planned outage. The general goal is to schedule planned outage events in periods, such as the spring or fall, where the risk of a loss-of-load event is small. If the planned outage requirements of all units can not be accommodated in the non-peak periods, then PRISM may schedule units for maintenance during the peak periods. PRISM also allows the user to manually enter a planned outage schedule for all units if a known pattern is required for analysis. Manually specifying a planned outage pattern is typically how actual events seen in operations are modeled. Each week in the model has its own planned outages scheduled unit by unit.

An examination of operations experience [21, 35] indicates that, on average, for the MAAC region PJM has one large generating unit out over the summer peak period due to any one of several reasons (extended forced outage, Nuclear Regulatory Commission-ordered shutdown, ramp up/ramp down time, etc.). To reflect this typical level of generator unavailability over the summer period, a large generating unit is manually scheduled out over the peak period in the Reserve Requirement Study. This adjustment is a conservative assumption that results in a higher reserve requirement of about one to two percentage points. Further discussion of this topic is provided in Section 2.

Capacity Benefit Margin

The determination of the transmission system's ability to import energy from outside the PJM Control Area under peak demand periods is based on power flow analysis of the bulk electric power grid. The models are developed based on cases from the NERC Multi-area Modeling Working Group (MMWG). Each year, the MMWG produces up to nine planning models useful for analyzing power flows anywhere in the Eastern Interconnection. The nine models capture a range of operating conditions such as summer, winter, fall and spring peak periods, shoulder periods and minimum load periods. The objective of the models is to form the basis for assessment under all operating conditions. The models are developed through a collaborative process involving extensive stakeholder input and review.

PJM has a defined analytical process, the Emergency Import Capability Study (EICS) [15], that outlines the various assumptions and techniques used to determine the Capacity Benefit Margin (CBM). This study examines peak summer conditions and assesses the transmission system's ability to supply energy to the borders of the PJM Control Area simultaneously from all interconnected regions. All systems within the Eastern Interconnection are assumed to be under peak loading conditions.

In the power flow based EICS, the selection of generating unit forced outages is performed using a Monte Carlo selection routine. The forced outage rate for each unit is given as the EEFORd, with this statistic indicating a unit's random availability. This statistic is used to influence a random selection of generating unit outages for assessment of the transmission grid under peak load conditions. By employing a Monte Carlo technique to select generator outage patterns, the power flow analysis has moved toward a probabilistic approach for a large contributing aspect of the determination of transmission capability. The selection of units to be forced out plays a key role in the final determination of the emergency import capability. The current peak load emergency import capability reserved as CBM is 3500 MW. [13]

PRISM Solution Algorithm

The reliability program's capacity model uses each generating unit's capacity, forced outage rate, and planned maintenance requirements to develop a cumulative capacity outage probability table for each week of the planning period. Planned maintenance scheduling can be specified by the user or performed by the program.

Outage statistics of generating units are maintained for twelve outage states [33] (from unit "full on" to unit "full out"). PRISM cannot model these partial outages explicitly. The solution is the modified two-state variance representation for partial outages.[32] This two-state variance is used by PRISM to modify both the unit capacity and the effective forced outage rate to provide a statistically accurate representation of the 12 basic partial outage states. PRISM models a unit either full on or full off, but with the modified capacity and EEFORd the effect of the partial outages are captured. The result is a significantly better representation of the true availabilities of the generating units.

After scheduling planned outages, PRISM calculates a cumulative probability table for every week of the year based on the units in service and not on maintenance. The program then calculates the system LOLE at a given load level. PRISM calculates, on a weekly basis, the probability of every possible load level (represented by 21 intervals describing the area under a normal distribution for that interval) occurring simultaneously with every possible generation availability level (from the cumulative probability table). Any combination of load and capacity which results in the load level exceeding the generation available level contributes to the probability of a negative capacity margin (loss-of-load). In a two-area calculation, the probability that the other area will have an excess capacity margin, within the value of the tie size, is then subtracted from the first area's probability of loss of load.

The probability of zero margin or less is summed for each of the 21 intervals and then multiplied by 5 (5 weekdays per week) to give the loss-of-load expectation for that particular week. [3, 5, 6, 11, 12, 31] (Based on previous study findings, the loss of load probability over weekends and holidays is assumed to be zero.) The individual weekly LOLE's are then summed over the entire year to determine the annual LOLE. The annual PJM LOLE is currently required to be no worse than one day in ten years as mandated by MAAC. The reliability program reaches its solution by adjusting the load distribution, as opposed to attempting to outage generating capacity, until the annual LOLE is equal to one day in ten years.

A brief numerical example of the calculations is shown in the following illustration. The loss of load calculations shown in red corresponds to the red loss-of-load region shown in the above convolution diagram (Diagram 4). This example is a two-area solution that assumes the two areas will share reserves but that neither region will invoke load shedding to assist the other. This reflects the practice that PJM actually observes in operations.

![pjm logo]

ILLUSRATION OF TWO AREA Loss-Of-Load-Probability(LOLP) METHOD (NO LOSS OF LOAD SHARING)

Area A: 50 MW (5 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 30 MW load; 20 MW reserve
Area B: 60 MW (6 - 10 MW units with 20% Equivalent Demand Forced Outage Rate(EFORd) each); 40 MW load; 20 MW reserve

Area B				Area A						
				A outage, MW	0	10	20	30	40	50
				A probability	0.32768000	0.40960000	0.20480000	0.05120000	0.00640000	0.00032000
				Help available	20	10	0	0	0	0
				Help needed	0	0	0	10	20	30
B outage MW	B Proability	Help Available	Help needed							
0	0.26214400	20	0		0.08589935	0.10737418	0.05368709	0.01342177	0.00167772	0.00008389
10	0.39321600	10	0		0.12884902	0.16106127	0.08053064	0.02013266	0.00251658	0.00012583
20	0.24576000	0	0		0.08053064	0.10066330	0.05033165	0.01258291	0.00157286	0.00007864
30	0.08192000	0	10		0.02684355	0.03355443	0.01677722	0.00419430	0.00052429	0.00002621
40	0.01536000	0	20		0.00503316	0.00629146	0.00314573	0.00078643	0.00009830	0.00000492
50	0.00153600	0	30		0.00050332	0.00062915	0.00031457	0.00007864	0.00000983	0.00000049
60	0.00006400	0	40		0.00002097	0.00002621	0.00001311	0.00000328	0.00000041	0.00000002
								0.05120000	0.00640000	0.00032000

Key

Key			
1	No help needed; no loss of load	Probablity:	0.84892713
2	A gets help from B; loss of load avoided in A	Probablity:	0.03523215
3	A does not get help from B; loss of load only in A	Probablity:	0.01696072
4	B gets help from A; loss of load avoided in B	Probablity:	0.06543114
5	B does not get help from A; loss of load only in B	Probablity:	0.02772173
6	Loss of load in A & B	Probablity:	0.00572713
		TOTAL:	**1.00000000**

LOLP in A = Prob (3) + Prob. (6) = 0.02268785
LOLP in B = Prob (5) + Prob. (6) = 0.03344886
LOLP in System = Prob (3) + Prob. (5) + Prob. (6) 0.05040957

0.05792000 A Zero Tie Size , LOLP in A
0.03523215 B (2) Help from B for A

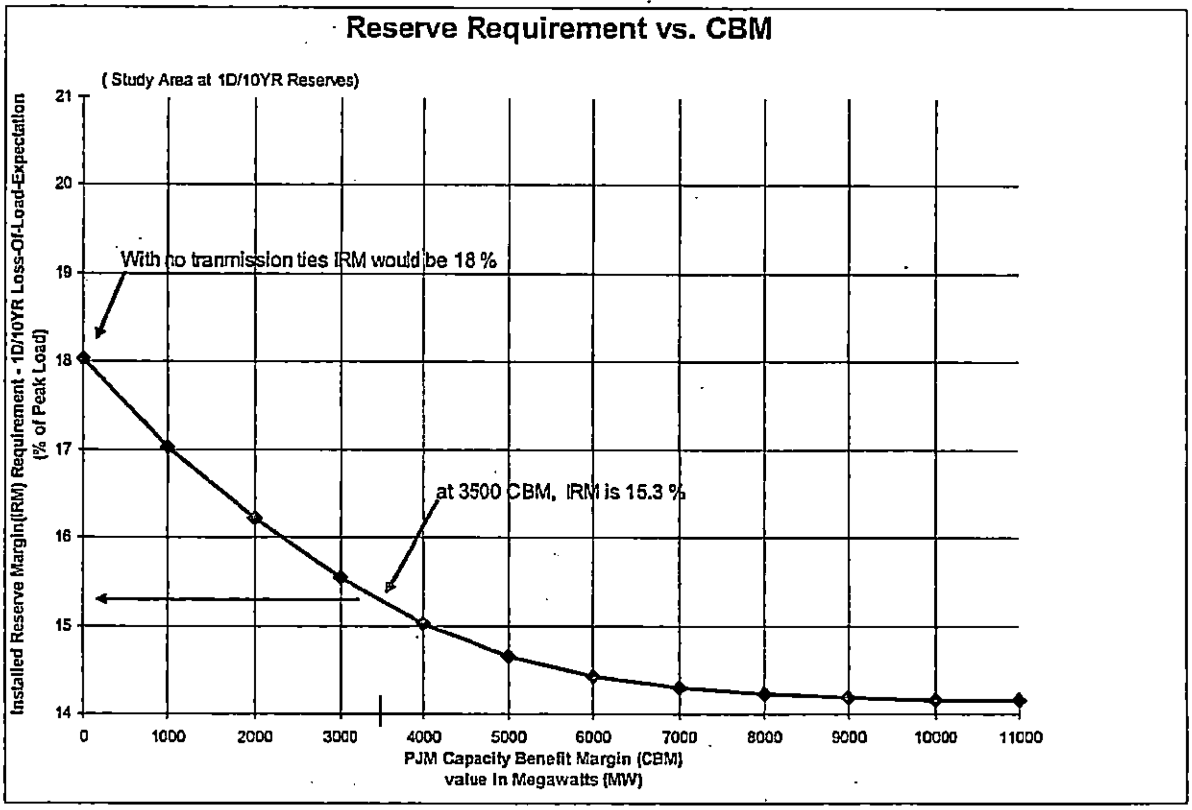
0.02268785 A-B LOLP in A with Tie

The example calculations above display the techniques used to convolve the load model needs with the generator units' availability. This exhaustive technique, known as enumerated states, [36, 37, 38, 39, 40] produces the loss of load expectation (LOLE) at a given reserve level. If that LOLE is a value other than one day in ten years, PRISM shifts the annual load shape, in aggregate up or down, performs the distribution convolution again, determines the new LOLE and continues with this iterative technique until the desired LOLE is obtained. Once an LOLE of one day in ten years is obtained, the ratio of the PJM area's installed generation to its annual peak is the calculated Installed Reserve Margin (IRM).

PRISM does not use Monte Carlo sampling because, through the use of probabilistic distributions, the calculations consider every possible load and capacity state. The program does not produce any confidence interval associated with the results because the results represent the exact loss of load expectation (based on the study assumptions), not a statistically estimated parameter. Monte Carlo techniques necessarily provide an expected result with a certain confidence level because an infinite number of simulations would be required to produce the exact result with 100% confidence.

As seen in the above calculations the advantage of being tied to neighboring systems is that they can lend assistance during times of need when an individual area needs to avoid a loss-of-load event. Critical factors in these calculations are the amount of MW assistance that are needed, the ability of the other area to have excess to help (largely driven by load diversity between PJM and the world area) and finally the ability of the transmission system, via the Capacity Benefit Margin, to deliver the excess from the other area.

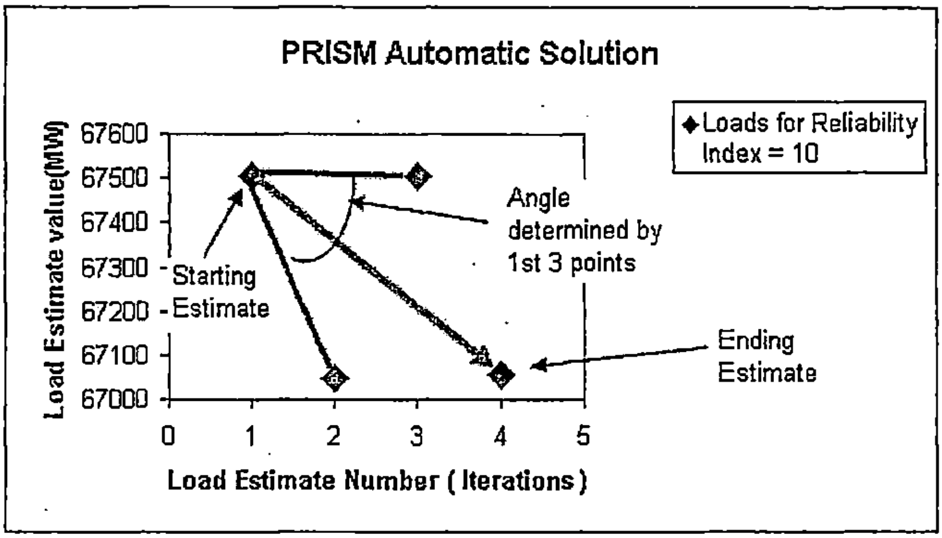
Diagram 8



The benefit of interconnection is depicted in Diagram 8. This diagram plots the PJM Installed Reserve Margin (IRM) against the Capacity Benefit Margin (CBM). As CBM increases, the potential amount of external capacity assistance increases and hence the PJM reserve requirement is reduced. As illustrated in the graph, the reliability benefit from increasing CBM reaches a saturation point around 6000 MW. At an import level of 6000 MW, the need for and availability of assistance from external regions are exhausted. The steepest portion of the curve is in the 0 MW to 3000 MW range and represents the most valuable portion of the CBM. Based on this graph and other considerations, the CBM value is fixed at 3500 MW.

A unique feature of PRISM is that a given reliability index can be set, say 1 event every 25 years, and the program will determine the solved load that meets this reliability index. PRISM does this by using an initial guess, similar to the way Newton-Raphson solutions work, and then doing a four part iteration to determine a next guess at the required load. [31] For a two-area study, PRISM uses a four part process. The initial estimate is used first, then Area 2 load is held constant while Area 1 load is varied, and then Area 1 load is held constant while Area 2 load is varied. Based on the results of the first three steps, the fourth step sets a new load for both Area 1 and Area 2. These loads are selected based on the slope of the blue lines depicted in Diagram 9. The solution process ends when either the maximum number of iterations is exceeded or the loads yield a reliability index within a specified tolerance of the desired index. This automatic solution allows PRISM to determine the required reserve margin based on a user-defined reliability index (i.e. one day in ten years).

Diagram 9



Example calculations of the automatic solution process:

RUN NO. 1 ————

Area1 Load		Area1 RI	Area2 Load	Area2 RI-
Part1	67504.00	8.01085	285178.00	9.59950
Part2	67048.85	10.0380	285178.00	10.0089
Part3	67504.00	8.19631	284823.62	10.1528
Part4	67056.34	9.99760	285179.28	9.99989

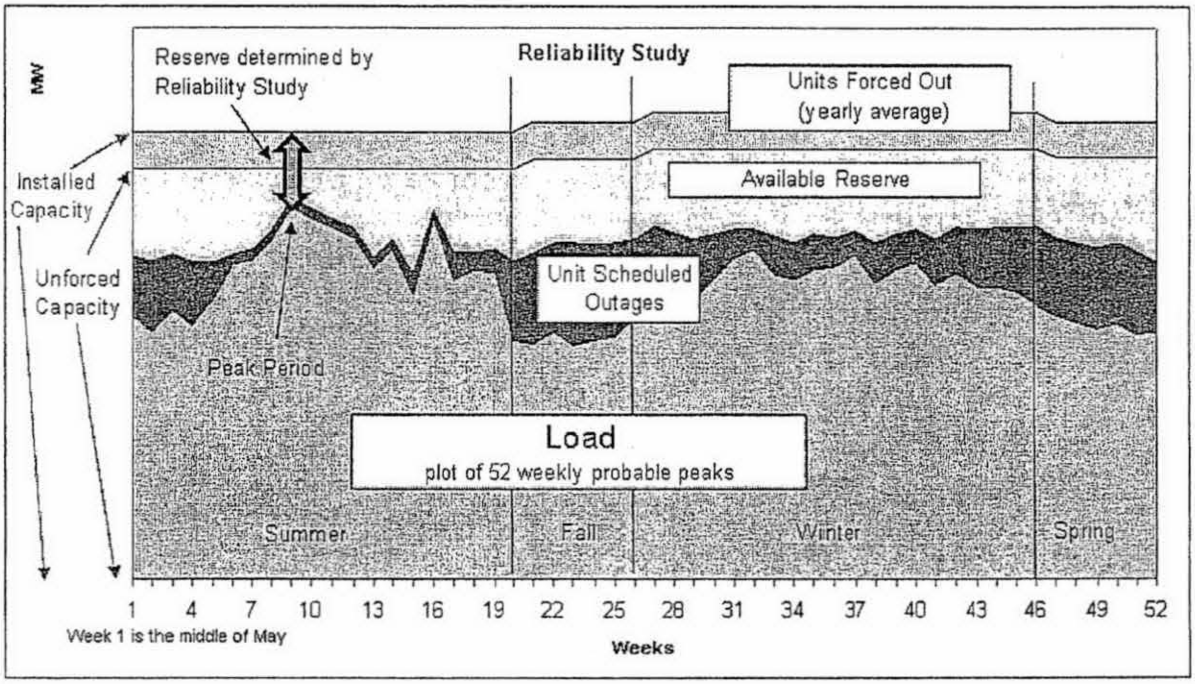
RI = Reliability Index (years/day)

RUN NO. 2 ————

Area1 Load		Area1 RI	Area2 Load	Area2 RI-
Part1	67056.34	9.99760	285179.28	9.99989
Part2	67055.84	9.99791	285179.28	9.99990
Part3	67056.34	9.99760	285179.19	9.99989
Part4	67056.34	9.99760	285179.28	9.99989

Diagram 10 graphically depicts the results of the final iteration of a one day in ten year case from PRISM. The blue area represents the weekly peak demand levels, the maroon area represents the capacity on a planned outage and the light green area represents the capacity forced out. The vertical red arrow represents the installed reserves over the annual peak required to meet the desired reliability index.

Diagram 10 – Annual Load and Capacity Profile



ALM Factor Calculation

Active Load Management (ALM) [16, 41] refers to several different types of demand side programs that are implemented by PJM as one of the final steps before a loss of load event is initiated. Some examples of ALM are radio controlled activation of residential air conditioners and water heaters and contractual agreements with commercial and industrial customers to cut load upon notification. ALM does not include load curtailment achieved by promoting more efficient lighting and motors. These and other similar measures are referred to as Passive Load Management. ALM also does not include economic demand-side management programs which are voluntary, are not subject to PJM operational control, and therefore receive no capacity credit.

The reliability value of Active Load Management for Installed Capacity Accounting purposes is determined by calculating an ALM Factor using PRISM. This calculation is performed in units of load carrying capability (LCC). [9, 31] LCC refers to the amount of load, expressed in megawatts that a given resource can serve at a reliability index of one day in ten years. In this analysis, the aggregate pool ALM amount is represented as a hypothetical generating unit with a zero forced outage rate and zero planned outage events. The LCC of the aggregate ALM amount is the difference between the solved load from the base case without the "ALM generator" and the solved load from the case with the "ALM generator":

ALM LCC = Load served with ALM – Load served without ALM

The ratio of the ALM LCC to the total amount of ALM in the pool is the ALM Factor. This factor typically ranges from about 0.95 to 0.99. This number means that every 100 MW of ALM effectively reduces the load requiring reserves in PJM by 95 to 99 MW. This ALM Factor is then used in the capacity obligation setting process to reduce the obligations of those entities with ALM customers.

Two other tests are performed related to the assessment of ALM programs. The first is to verify that the full reliability value of ALM is realized in the summer period. This test justifies the granting of full year capacity credit to ALM programs that may cover only the summer period. The second test is to verify that the full reliability value of ALM is realized in ten or fewer interruptions per year. Ten interruptions is the current requirement for granting ALM capacity credit. Recent tests indicate that the reliability value of ALM saturates in the range of four to seven interruptions, well below the ten interruption requirement. [19, 21, 31] A detailed discussion of these ALM tests is included in the Citations and References, primarily citation numbers 17, 21, 31, and 41.

Committee Review and Approval

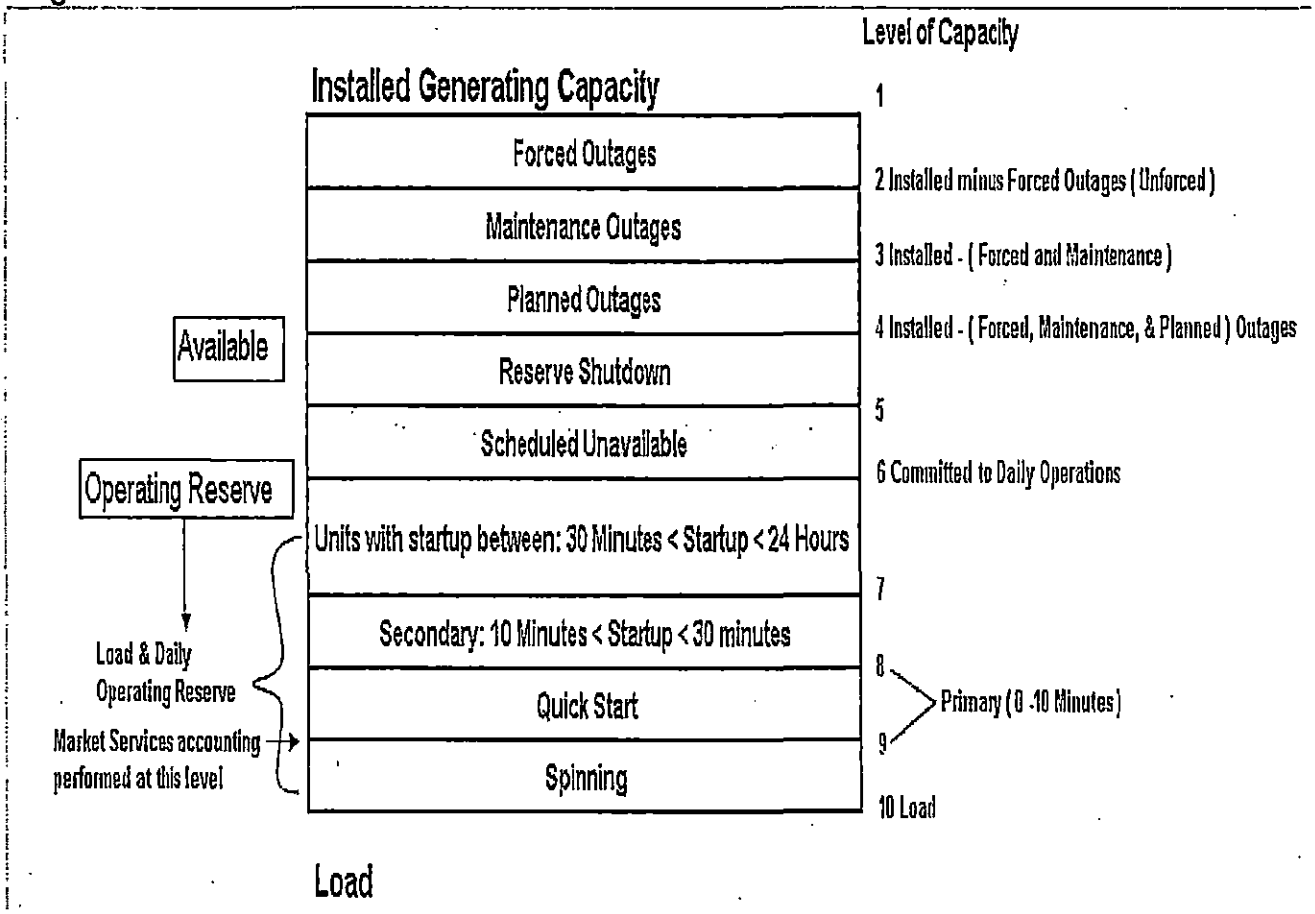
The ultimate authority over the determination of the approved Installed Reserve Margin and ALM Factor rests with the PJM Board of Managers. A supporting stakeholder committee structure is in place to advise and make recommendations to the PJM Board as necessary. Technical subcommittees, the Generator Unavailability Subcommittee and the Load Analysis Subcommittee, and PJM Staff , provide data input and begin initial review of the study results. All technical reports are passed up to the Members Planning Committee. The Planning Committee then forwards its recommendation to the Reliability Committee (RC). At the RC level, a formal vote is taken on the Installed Reserve Margin and ALM Factor and that recommendation is submitted to the PJM Board for final consideration.

Section 2

Benchmarking of Study Results with Operations

Diagram 11 shows how the same piece of generating equipment can have various values and requirements associated with it. Typically the planning processes used to measure a given unit's ability to deliver under peak load conditions are the areas shown in blue. The summer net dependable rating of a unit is the PJM Installed Capacity listed as level 1. This is the level for all adequacy analysis performed by PRISM. The PJM capacity market metric is the unforced capacity level indicated as level 2. The levels shown in red, levels 6 -9, are the typical levels at which operations measures compliance for security assessments. In all cases, each level is a measurement that is needed to assess different bulk system grid requirements. This diagram highlights the point that, while adequacy assessments and security assessments may be performed using different metrics, both consider the reliability values of generators. These values are, in fact, equal under both assessments when measured on a similar basis.

Diagram 11



All modeling techniques and assumptions for the Reserve Requirement Study are reviewed with stakeholders. Typically, the first draft of the modeling assumptions and workplan for the annual study is distributed for feedback starting in November for a study that begins to be performed in January. One of the typical modeling issues to address is how to match expected operational experience with the probabilistic adequacy assessments. The PJM staff takes a lead on this by interfacing with the PJM operational staff and developing technical solutions and options for correlating operational events seen on the bulk power grid with the modeling methods used in the PJM System Planning Division.

The frequency of large PJM generating unit outages for the MAAC region over the summer period was investigated from 1996-2000 and the results are tabulated in Diagram 12. [21, 33, 35] (Analysis for the summers of 2001, 2002 and 2003 is currently being performed). Large units were defined to be those with summer ratings greater than 600 MW. GADS outage events for the ten highest load days for the five year period were extracted and the number of large units out for any reason other than forced was tabulated:

Diagram 12

Year	Number of Large PJM Units Out
1996	3
1997	0
1998	1
1999	0
2000	2

The numbers in the table represent the greatest number of large generating units out on any of the ten highest load days. This number is conservative in the sense that it does not capture the possibility that an even greater number of large units could have been out on any of the other summer days. Based on these results, the standard modeling practice in the Reserve Requirement Study is to schedule one large generating unit out over the summer period for the model that comprises the MAAC region. For a study model twice the size of the MAAC region, as stated as case 3 on page 6, two large units are scheduled out over the summer period.

The proper modeling of generation units requires that any new unit falling under PJM's control area comply with submitting applicable data. This includes reporting using the eGADS web based system and transmittal of telemetry data to the PJM control center. PJM staff is working closely with the market integration companies to ensure that the proper data is obtained and verified in a timely manner.

Summer Maintenance Assessment

One of the activities of the PJM System Planning Division staff is reviewing and summarizing actual dispatcher logs of daily activities over the past year. Of particular interest are the planned outages over the peak summer period. The maintenance outage events of the summer period are reviewed to assess if any market participants are subject to penalty charges. The last several peak period maintenance assessments have indicated 100% compliance and resulted in no penalties for any PJM member. [33, 35]

Benchmarking of Frequency of Voltage Reduction Events

Findings show that PJM has implemented 11 voltage reductions over the last 13 years (1990 - 2002 inclusive). [21, 35] Of these 11, two were for test purposes and occurred at 9 PM and 3 AM. Five of the 11 were due to local transmission problems. That leaves the following four events due to a true system-wide capacity deficiency:

1/19/94 5% Voltage Reduction and Manual Load Dump
5/20/96 5% Voltage Reduction
5/8/00 5% Voltage Reduction
8/9/01 5% Voltage Reduction

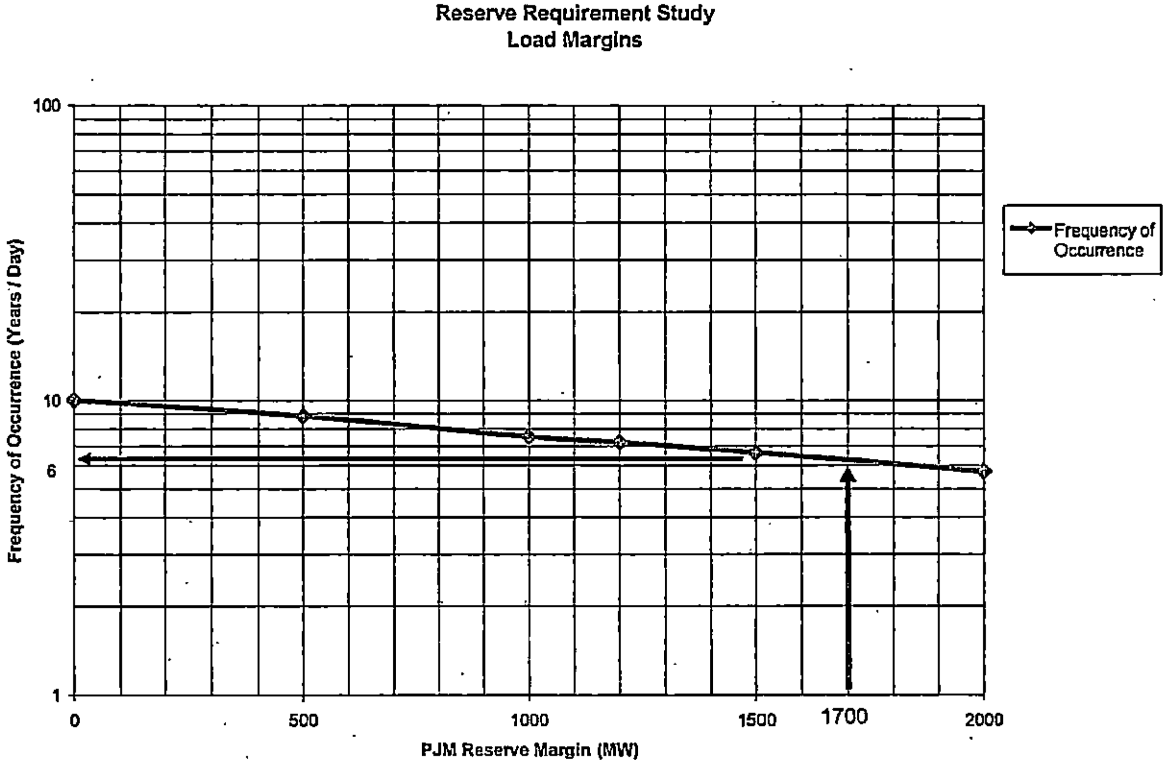
The January 1994 event was due to extraordinary weather conditions which led to a series of common cause failures stemming from fuel unavailability. The risk of common cause failures is not captured in the PRISM model, but work has begun to include this risk in future adequacy studies. That leaves 3 voltage reduction events in 13 years that PRISM would be expected to "predict".

The "1 in 10" criterion refers to the likelihood of having a 0 or negative reserve margin where:

reserve margin = available capacity – load

Voltage reductions are implemented at positive reserve margins. They are called at the operator's discretion following issuance of a primary reserve alert. A primary reserve alert is generally issued at a reserve margin of about 1700 MW. Voltage reductions are generally implemented when reserve margins drop to between 1200 MW and 1700 MW.

Diagram 13



PRISM analysis was performed to assess how often the adequacy model predicts the occurrence of a primary reserve alert, assuming these events occur at a reserve margin of 1700 MW. Diagram 13 depicts the likelihood of reserve margins ranging from 0 MW to 2000 MW. This diagram indicates the frequency with which a given reserve margin should occur (frequency is on the y axis and is expressed in years per occurrence). The y axis uses a logarithmic scale. The graph indicates that a reserve margin of 1700 MW should occur about once every six years (or twice in 12 years). Three primary reserve alerts (or four including January 1994) have been issued by Operations in the 13 year period from 1990 through 2002. The occurrence of operational events compared to the PRISM results are therefore well within the bounds of sampling error and indicate that PRISM does benchmark well with operating experience.

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Glossary

AEP

American Electric Power, a company and control area within ECAR.

Active Load Management (ALM)

Active Load Management applies to interruptible customers whose load can be interrupted at the request of the PJM OI. Such a request is considered an emergency action and is implemented prior to a voltage reduction.

ALM Factor

Ratio of ALM aggregate Load Carrying Capability (LCC) to total amount of ALM in PJM. The ALM LCC is determined by modeling ALM in the PJM reliability program. The ALM Factor is reviewed and changed, if necessary, each planning period by the Reliability Committee and PJM Board for use in determining the capacity credit for ALM.

APS

Allegheny Power System, a control area within ECAR that was the first portion of expansion of the PJM footprint and markets. Adjacent to the western portion of the MAAC region.

Available Transfer Capability (ATC)

The amount of energy above "base case" conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions. ATC is the First Contingency Incremental Transfer Capability reduced by applicable margins.

Bulk Power Electric Supply System

All generating facilities, bulk power reactive facilities, and high voltage transmission, substation and switching facilities. Also included are the underlying lower voltage facilities that affect the capability and reliability of the generating and high voltage facilities in the PJM Control Area.

Capacity

Ability to deliver both firm energy to load located electrically within the Interconnection and firm energy to the border of the PJM Control Area for receipt by others.

CBM

Capacity Benefit Margin, expressed in megawatts, is a single value that represents the simultaneous imports into PJM that can occur during peak PJM system conditions. The capabilities of all transmission facilities that interconnect to the PJM Control Area with neighboring regions are evaluated to determine this single value.

Capacity Emergency Transfer Objective (CETO)

The import capability required by a subarea of PJM to satisfy the MAAC "1 in 10" adequacy requirement. This value is compared to the Capacity Emergency Transfer Limit (CETL) which represents the subarea's actual import capability as determined from power flow studies. The subarea satisfies the criteria if its CETL is equal to or exceeds its CETO. CETO/CETL analysis is typically part of the Deliverability demonstration.

ComEd

Commonwealth Edison is a control area within the Mid-America Interconnected Network. The Commonwealth Edison control area is in the state of Illinois principally centered around the Chicago metro area.

Control Area

An electric power system or combination of electric power systems bounded by interconnection metering and telemetry. A common generation control scheme is applied in order to:

- match the power output of the generators within the electric power system(s) plus the energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council of NERC;
- maintain power flows on Transmission Facilities within appropriate limits to preserve reliability; and
- provide sufficient generating Capacity to maintain Operating Reserves in accordance with Good Utility Practice.

Demand

See Load

ECAR

East Central Area Reliability Coordination Agreement. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ECAR Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Ohio, Michigan, Indiana, Kentucky, West Virginia, Virginia, Tennessee, Pennsylvania, and Maryland.

Eastern Interconnection

The bulk power systems in the eastern portion of North America. The area of operation of these systems is bounded on the east by the Atlantic Ocean, bounded on the west by the Rocky Mountains, bounded on the south by the Gulf of Mexico and Texas, and includes the Canadian provinces of Quebec, Ontario, Manitoba and Saskatchewan. This is one of the three major interconnections within NERC.

EEFORd

Effective Equivalent Demand Forced Outage Rate. The forced outage rate used for reliability and reserve margin calculations. For each generating unit, this outage rate is the sum of the EFORd plus ¼ of the equivalent maintenance outage factor.

EFORd

Equivalent Demand Forced Outage Rate. The portion of time a unit is in demand, but is unavailable due to a forced outage.

eGADS

Web based Generator Availability Data Systems. Data is collected for both event and performance data in order to track projection of generating units' unavailability as required for PJM adequacy and capacity market calculations. This is based on the NERC GADS data reporting requirements, which in turn are based on IEEE Standard 762.

EICS

Emergency Import Capability Studies. A series of power flow studies that assess the capabilities of all PJM transmission facilities connected to neighboring regions under peak load conditions to determine the simultaneous import capability.

EMOF

Equivalent Maintenance Outage Factor. For each generating unit modeled, the portion of time a unit is unavailable due to maintenance outages.

ERCOT

Electric Reliability Council of Texas. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the ERCOT Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Texas and is one of the three major interconnections within NERC.

FEF

Forecast Error Factor. A value that can be entered in the reliability program PRISM per planning period that indicates the percent increase of uncertainty in the forecasted peak loads. The FEF generally increases 0.5% per year as the planning horizon is lengthened.

FERC

The Federal Energy Regulatory Commission.

FOR

Generating Unit Forced Outage Rate. A statistic based on eGADS event data that indicates the likelihood a unit is unavailable due to forced outage events over the total time considered. There is no attempt to separate out forced outage events when there is no demand for the unit to operate.

Forecast Peak Load

Expected peak demand based on weather normalized load techniques. The forecast peak load is an hourly integrated total, in megawatts, indicating the load value given or higher has a 50 % probability of actually occurring.

Forecast Pool Requirement (FPR)

The amount, stated in percent, equal to one hundred plus the percent reserve margin for the PJM Control Area required pursuant to the Reliability Assurance Agreement (RAA), as approved by the Reliability Committee pursuant to Schedule 4 of the RAA. Expressed in units of "unforced capacity".

FRCC

Florida Reliability Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the FRCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the state of Florida.

GEBGE

See PRISM

Generating Availability Data System (GADS)

A computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Outage Rate Program (GORP)

A computer program maintained by the PJM Generator Unavailability Subcommittee that uses GADS data to calculate outage rates and other statistics.

Generator Forced/Unplanned Outage

An immediate reduction in output, capacity, or complete removal from service 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. A reduction in output or removal from service of a generating unit in response to changes in or to affect market conditions does not constitute a Generator Forced Outage.

Generator Maintenance Outage

The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility approved by the PJM OI.

Generator Planned Outage

The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the PJM OI.

Generator Unavailability Subcommittee (GUS)

A PJM subcommittee, reporting to the Planning Committee, that is responsible for computing outage rates and other statistics needed by the Reliability Committee for calculating capacity obligations.

Good Utility Practice

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 is 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 practices, methods, or acts generally accepted in the region.

IRM

Installed Reserve Margin. The percent of aggregate generating unit capability above the forecasted peak load that is required for adherence to meet a given adequacy level. Expressed in units of installed capacity.

Load

Integrated hourly energy used either located electrically within the PJM Control Area or delivered to the border of the PJM Control Area for receipt by others. Loads are reported and verified to the tenth of a megawatt (0.1 MW).

Load & Capacity Subcommittee (L&CS)

A PJM subcommittee, reporting to the Planning Committee that assists PJM staff in performing the annual Reserve Requirement Study and maintains the reliability analysis documentation.

Load Analysis Subcommittee (LAS)

A PJM subcommittee, reporting to the Planning Committee that supplies the PJM peak and seasonal load forecasts.

LCC

Load Carrying Capability, typically expressed in megawatts. The amount of load that a given resource or resources can serve at a predetermined adequacy standard (typically one day in ten year).

LOLE

Generation System Adequacy is determined as Loss of Load Expectation (LOLE) and is expressed as days per year. This is a measure of how often, on average, the available capacity is expected to fall short of the demand. LOLE is a statistical measure of the frequency of failure and does not quantify the magnitude or duration of failure. The use of LOLE to assess Generation Adequacy is an internationally accepted practice

LOLP

Loss of Load Probability, which is the probability that the system cannot supply the load peak during a given interval of time, has been used interchangeably with LOLE within PJM. LOLE would be the more accurate term if expressed as days per year. LOLP is more properly reserved for the dimensionless probability values. LOLP must have a value between 0 and 1.0.

MAAC

The Mid-Atlantic Area Council, a reliability council under §202 of the Federal Power Act, established pursuant to the MAAC Agreement dated August 1994 or any successor.

A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAAC Region through coordinated operations and planning of generation and transmission facilities. The MAAC Control Area is operated in the states of Pennsylvania, Maryland, Delaware, New Jersey, and Virginia.

MAIN

Mid-America Interconnected Network. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAIN Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Illinois, Wisconsin, Missouri, and Michigan.

MAPP

Mid-Continent Area Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the MAPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Montana and Canadian provinces of Saskatchewan and Manitoba.

MMWG

Multi-area Modeling Working Group. The NERC MMWG includes direct representation from the NERC Regions in the Eastern Interconnection, as well as a working group power flow and dynamics coordinator(s), a liaison representative of the NERC staff, and corresponding representatives from the ERCOT and WSCC Regions. The group is charged with the responsibility for developing and maintaining a library of power flow and dynamics base cases for the benefit of NERC members for use by the Regions and their member systems in planning and evaluating future systems and current operating conditions.

MPP

The Most Probable Peak Load is used in the PJM reliability program PRISM. This is the expected weekly peak load corresponding to the 50/50 load forecast based on a sample of 5 weekday peaks.

NERC

The North American Electric Reliability Council, a reliability council responsible for the oversight of regional reliability councils established to ensure the reliability and stability of the regions.

NPCC

Northeast Power Coordinating Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the NPCC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of New York, Main, Vermont, New Hampshire, Connecticut, Rode Island, Massachusetts, Canadian provinces of Ontario, Quebec, Nova Scotia, New Brunswick, and Prince Edward Island.

PC

Planning Committee. A technical committee that is charged with oversight of technical issues in configuration, analysis, planning and operation of the bulk electric power grid in the PJM Control Area. There are technical subcommittees that report to this Committee including: Relay Subcommittee, Load Analysis Subcommittee, Generator Unavailable Subcommittee, Load and Capacity Subcommittee, and Transmission and Substation Design Subcommittee

pcGAR

Personal computer based Generator Availability Report. The pcGAR is a database of all NERC generator data and provides reporting statistics on generators operating in North America. This data and application is distributed by NERC annually, with interested parties paying a set fee for this service.

Peak Load

See Forecast Peak Load

Peak Season

Peak Season is defined to be those weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week begins on a Monday and ends on the following Sunday, except for the week containing the 36th Wednesday, which ends on the following Friday.

PJM ISO

PJM Independent System Operator

PJM Open Access Same-Time Information System (PJM OASIS)

The electronic communication system for the collection and dissemination of information about Transmission Services in the PJM Control Area established and operated by the PJM OI in accordance with FERC standards and requirements.

Planning Period

The twelve months beginning June 1 and extending through May 31 of the following year, provided as changing conditions may require, the Reliability Committee may recommend other Planning Periods to the PJM Board of Managers.

PRISM

Probabilistic Reliability Index Study Model. PRISM is the PJM planning reliability program. PRISM replaced GEBGE which was a FORTAN language program. The models are based on statistical measures for both the load model and the generating unit model. This is a computer application developed by PJM that is a practical application of probability theory and is used in the planning process to evaluate the generation adequacy of the bulk electric power system.

Power Flow

Models and studies that determine the power flowing through transmission facilities based on various load and generating unit conditions. Typically, an iterative Newton-Raphson solution technique is used to determine the network flows in the transmission facilities based on Kirchhoff's and Ohm's laws which govern solution convergence.

R.I.

Reliability Index. The reliability index is a value that is used to assess the bulk electric power system's future occurrence for a loss-of-load event. A RI value of 10 indicates that there will be, on average, a loss of load event every ten years.

RAA (Reliability Assurance Agreement)

One of four agreements that define authorities, responsibilities and obligations of participants and the PJM OI. This agreement also defines the role of the RAA Reliability Committee. The agreement is amended from time to time, establishing obligation standards and procedures for maintaining reliable operation of the PJM Control Area. The other principal PJM agreements are the Operating Agreement, the PJM Transmission Tariff, and the Transmission Owners Agreement.

RAA-RC

Reliability Assurance Agreement Reliability Committee

R-Study

PJM Reserve Requirement Study, which is performed annually. The primary result of the study is a single calculated percentage, the R factor, that represents the amount above peak load that must be maintained to meet the MAAC adequacy criteria. The MAAC adequacy criteria is based on a probabilistic requirement of experiencing a loss-of-load event, on average, once every ten years.

SERC

Southeastern Electric Reliability Council. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SERC Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Virginia, North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Arkansas, Kentucky, Louisiana, Missouri, Texas, and West Virginia.

SPP

Southwest Power Pool. A regional reliability council of NERC responsible for ensuring the adequacy, reliability, and security of the bulk electric supply systems of the SPP Region through coordinated operations and planning of generation and transmission facilities. This electric Control Area is operated in the states of Kansas, Oklahoma, Texas, Arkansas, Louisiana, and New Mexico.

Weather Normalized Loads

A load adjustment technique approved by the Load Analysis Subcommittee to compensate load data for weather conditions. The adjustment changes the load values to those associated with a 50 / 50 probability of occurrence. (i.e. the load value given or higher has a 50 % probability of actually occurring). This technique is typically associated with forecasting peak load values.

World

Refers to the area electrically connected to the PJM Control Area. Could include ECAR, NPCC and SERC or most of the Eastern Interconnection depending on the study requirements.

ECAR DOCUMENT NO. 8

REQUIREMENTS FOR ACTUAL AND FORECASTED DEMAND AND ENERGY DATA

Approved by the Coordination Review Committee
May 27, 1998

Approved by the ECAR Executive Board
July 27, 1998

East Central Area Reliability Coordination Agreement

Document No. 8

REQUIREMENTS FOR ACTUAL AND FORECASTED DEMAND AND ENERGY DATA

Introduction

This document contains the requirements for member systems reporting of actual and forecasted load data. These data are to be used for analysis of generation adequacy and transmission reliability.

Standards

1. Actual and forecast demands and net energy for load data, required for the analysis of the reliability of the interconnected transmission systems, shall be developed by member systems and maintained by the ECAR Executive Office on an aggregated regional, subregional, power pool, and individual system basis.

2. Interruptible demands and direct control load management programs and data shall be identified and documented.

3. Reported energy and demand data shall exclude generating plant auxiliary load and the load of storage systems of generation suppliers, such as pumped storage hydro plants.

Requirements

1. Member systems shall provide the following data to ECAR, on the schedule and in the format required by the GRP Procedure Manual:

    a. Historical Data – Requirements and Own Ultimate Customer Load

        1) Integrated hourly demands (MW) for the nominal 8,760 hours of the preceding year
        2) Monthly and annual peak demands (MW) and energy (GWh) for the preceding year

    b. Forecasted Data – Requirements and Own Ultimate Customer Load

        1) Monthly peak demand (MW) for ten years beginning with the reporting year assuming that direct-control DSM and interruptible loads are not curtailed.

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2) Corresponding demand (MW) of direct-control DSM systems and interruptible loads.

3) Monthly energy (GWh) for two years beginning with the reporting year

4) Annual energy (GWh) for ten years beginning with the reporting year.

c. Forecasted Data - Connected Load (Transmission Providers only)

1) Monthly peak demand (MW) for ten years beginning with the reporting year assuming that direct-control DSM and interruptible loads are not curtailed.

2) Corresponding demand (MW) of direct-controlled DSM systems and interruptible loads.

2. Load data reported to government agencies shall be consistent with that reported to ECAR in compliance with this document.

3. Member systems shall provide the following to ECAR, upon request:

a. Assumptions, methods, and manner of addressing uncertainties in the development of the submitted load forecasts.

b. Documentation of how demand and energy effects of all DSM programs and interruptible loads are addressed.

Reference

NERC Planning Standards (September, 1997) section II.D., System Modeling Data Requirements, Actual and Forecast Demands.

Definitions

Requirements Service – Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning).

Requirements and Own Ultimate Customer Load – This load includes Requirements Service as defined above, plus the reporting party's own ultimate customer load, plus losses.

Connected Load – Connected load is the load served by a Transmission Provider, including the load of Transmission Dependent Utilities (TDUs) and all other ultimate loads on its system, as well as losses. TDU load should be included only to the extent it is served by the Transmission

Provider, excluding offsetting local generation, unless that generation also is to be reported to ECAR.

Direct-control Demand Side Management (DSM) – DSM refers to customer demand that can be curtailed by direct control of the system operator by interruption of power supply to individual appliances or equipment on customer premises.

ECAR DOCUMENT NO. 15

ASSESSMENT OF ECAR-WIDE INSTALLED GENERATING CAPACITY

Approved by the Coordination Review Committee
May 27, 1998
Approved by the ECAR Executive Board
July 27, 1998

East Central Area Reliability Coordination Agreement

Document No. 15

ASSESSMENT OF
ECAR-WIDE INSTALLED GENERATING CAPACITY

Introduction

This document requires the submission of data for use in an annual assessment of the adequacy of the projected, aggregate, generating capacity resources in ECAR. It also establishes the criterion to be used in assessing this adequacy. This criterion has been derived for application to the overall ECAR region and is not intended to be utilized for assessing the individual systems in ECAR.

Standards

Data shall be provided so that the overall reliability of ECAR's bulk electric system may be reviewed and assessed, both existing and as planned, to ensure conformance with ECAR planning requirements and with NERC Planning Standards.

Requirements

Members shall submit the following data for a ten-year forecast period, for use in the assessment of ECAR-wide installed generating capacity, in accordance with the GRP Procedure Manual:

1. Forecasted demand data in accordance with ECAR Document 8;

2. Actual and projected generating unit capabilities, service dates, retirement dates, and seasonal ratings (for existing units, data shall be consistent with that reported in response to Document 4); and

3. Schedules of projected firm transactions to supply demand within the ECAR region from sources outside the region or to supply demand outside the region from sources within the region.

Guides

Experience indicates that for nominal projected conditions, a DSCR index for the ECAR region of one to ten days per year is currently consistent with marginal but satisfactory regional power supply adequacy for the ten-year assessment period.

The calculated DSCR index is the composite of many variables and not the result of action by a single member. Therefore, it is used only to evaluate the overall regional power supply adequacy and to identify unusual situations which may degrade the regional reliability. Reactions to those situations should be taken individually by the member companies of ECAR within their financial, regulatory, and physical constraints and technical ability to respond.

References

NERC Planning Standards (September 1997) Section I.B., System Adequacy and Security, Reliability Assessment.

Definitions

Dependence on Supplemental Capacity Resources (DSCR) – The DSCR index is the number of actual or forecasted days per year that the ECAR region has to rely on: (a) capacity resources outside ECAR; (b) directly controlled load management or interruptible loads within ECAR; or (c) reducing area demand to the extent that such supplemental resources are not available.

The calculation of forecasted DSCR is based on a probabilistic analysis of the capability of the region's generating resources to supply the aggregate total internal demand of the region during daily peak load periods.

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107 FERC ¶ 61,272
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

New PJM Companies
and PJM Interconnection, L.L.C.

Docket No. ER03-262-009

ORDER APPROVING CONTESTED SETTLEMENT

(Issued June 17, 2004)

I. Introduction

1. PJM Interconnection, L.L.C. (PJM), American Electric Power Service Corporation (AEP) as agent for certain operating companies of the American Electric Power Service Corporation, and the Public Service Commission of the Commonwealth of Kentucky (Kentucky Commission) (collectively, Settling Parties) submitted an Offer of Settlement (Settlement). The Settling Parties state that the Settlement, if approved without condition or modification, would render moot that portion of the on-going proceeding in Docket No. ER03-262-009 which addresses the laws, rules, and regulations of Kentucky.

2. In this order, the Commission approves the contested Settlement without condition or modification. The Commission also provides clarification, as requested. The Settlement represents a reasonable resolution of the complex matters at issue in this proceeding as they pertain to the laws, rules, and regulations of Kentucky.

II. Backgroud

A. Kentucky Commission Proceeding

3. On December 19, 2002, AEP's Kentucky operating company, Kentucky Power Company (AEP-Kentucky) filed an application with the Kentucky Commission requesting approval to transfer functional control of its transmission assets to PJM. On July 17, 2003, the Kentucky Commission issued an order denying AEP-Kentucky's request, finding that AEP-Kentucky had not shown that the benefits to Kentucky from joining PJM outweighed the costs. The order also indicated that the Kentucky Commission could not grant such approval because PJM's tariff is inconsistent with a

Kentucky statute with respect to curtailment. On August 25, 2003, the Kentucky Commission granted rehearing of AEP-Kentucky's request, allowing it to submit a Kentucky-specific analysis. The cost-benefits analysis was filed on December 23, 2003, and a hearing before the Kentucky Commission was scheduled to begin on April 21, 2004.

4. On April 19, 2004, two days prior to the scheduled hearing date, all of the parties in the AEP-Kentucky case entered into an Agreed Stipulation (Kentucky Stipulation), recommending that the Kentucky Commission approve AEP-Kentucky's application, subject to specified terms and conditions. On May 19, 2004, the Kentucky Commission granted conditional authority to AEP-Kentucky to transfer functional control of its transmission assets to PJM, subject to the Commission accepting the Kentucky Stipulation without any additions, modifications or conditions.

B. AEP Proceedings before the Commission

5. On November 25, 2003, the Commission issued an order[1] setting for hearing, inter alia, the question of whether the Commission should exempt AEP from the provisions of Kentucky and Virginia law or rule or regulation that would prevent AEP from voluntarily joining PJM under section 205(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA).[2] On March 12, 2004, the Administrative Law Judge in that proceeding issued an Initial Decision.[3] AEP and the Kentucky Commission filed exceptions to the Initial Decision.

6. In an opinion being issued contemporaneously with this order, the Commission affirms the Initial Decision, finding that the Commission may act under section 205(a) of the PURPA and permit AEP to integrate into PJM over the objection of the Commonwealth of Virginia.[4] As a result of our approval of the Settlement in this order, the companion opinion does not need to address any of the exceptions to the Initial Decision raised by the Kentucky Commission in that proceeding.

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[1] New PJM Companies, et al., 105 FERC ¶ 61,251 (2003).

[2] 16 U.S.C. § 824a-1(a) (2000).

[3] New PJM Companies, et al., 106 FERC ¶ 63,029 (2004) (Initial Decision).

[4] New PJM Companies, et al., 107 FERC ¶ 61,271 (2004).

III. Offer of Settlement

7. On June 1, 2004, the Settling Parties submitted the Settlement pursuant to Rule 602 of the Commission's Rules of Practice and Procedure.[5] The Settling Parties agree, stipulate, and recommend that the Commission approve the Settlement without additions, modifications, or conditions. They further recommend that the Commission find this proceeding moot as to the laws, rules, and regulations of the Commonwealth of Kentucky.

8. The Settlement and the Kentucky Commission's approval of AEP-Kentucky's application are based on the Kentucky Stipulation. The major provisions of the Kentucky Stipulation are discussed below:

- Paragraph 1 of the Kentucky Stipulation provides that the Kentucky Commission's approval is premised on PJM's operation of markets that are designed such that AEP's purchases and sales of capacity and energy in PJM's regional capacity and energy markets on behalf of its operating companies are voluntary. Paragraph 1 also recognizes that AEP's retail cost of service is subject to appropriate review by the Kentucky Commission. Paragraph 1 also states that the parties "agree to resist" any proposal to mandate PJM member participation in PJM's Capacity Credit Market or Interchange Energy Market. Paragraph 1 expressly notes, however, that the Kentucky Stipulation does not address the Commission's authority with respect to remedies for anticompetitive behavior, and it preserves the rights of the signatory parties to take a position on any alleged anticompetitive withholding.

- Paragraph 2 requires PJM to provide information and give due consideration to the findings of the Kentucky Commission and other state commissions within the PJM footprint for PJM to determine the appropriate reserve margin necessary to maintain safe and reliable service. Paragraph 2 also specifies that nothing in the stipulation shall supercede PJM's obligation to ensure an adequate reserve margin consistent with maintaining an acceptable level of reliability, consistent with applicable reliability principles and standards. Further, Paragraph 2 recognizes PJM's anticipation that AEP's participation in PJM should result over time in lower reserve margins than AEP would otherwise be required to maintain, all else being equal.

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[5] 18 C.F.R. § 385.602 (2003).

- Paragraph 3 specifies provisions related to PJM's curtailment protocols.
    - PJM will not direct AEP to curtail the retail customers of any AEP operating company for capacity deficiencies elsewhere on the PJM system so long as AEP has maintained adequate capacity in accordance with the applicable requirements.
    - PJM will not direct AEP to curtail retail load in any AEP-specific state jurisdiction, including Kentucky, for a transmission system emergency unless PJM has exercised all other available opportunities to remedy the emergency without curtailing such retail load.
    - The curtailment protocols apply except in extraordinary circumstances such as where load shedding would be beneficial to preventing separation from the Eastern Interconnection, preventing voltage collapse, or in order to restore system frequency following a system collapse.
    - Nothing in the approval of the Kentucky Stipulation shall alter the Kentucky Commission's authority over the application by AEP-Kentucky of curtailment practices to its retail customers.
- Paragraph 4 provides that any PJM-offered demand side response or load-interruption programs will be made available to AEP-Kentucky for its retail loads (at AEP-Kentucky's election) and that no such program will be made available by PJM directly to a retail customer of AEP-Kentucky.
- Paragraph 5 provides that nothing in the Kentucky Stipulation shall be construed to alter the jurisdictional authority of the Commission or the Kentucky Commission. Paragraph 5 also provides that the Kentucky Commission's approval of the Kentucky Stipulation shall not be construed as approval of the removal of the AEP-Kentucky assets from rate base and the authority to determine revenue requirements from such assets. Finally, Paragraph 5 affirms the Kentucky Commission's jurisdiction over AEP-Kentucky's retail rates.
- Paragraph 6 provides that nothing in the Kentucky Stipulation, or its approval by the Kentucky Commission, shall be deemed to alter AEP-Kentucky's existing obligation under Kentucky law to seek a certificate of public convenience and necessity prior to commending construction of generation or transmission facilities.
- Paragraph 7 provides that nothing in the Kentucky Stipulation alters Kentucky laws, rules, or policies that service to retail customers be provided through the provisions of bundled retail electric service.

- Paragraphs 8, 9 and 10 address procedures for the approval of the Kentucky Stipulation, including each party's right to terminate if the Commission does not accept it and the May 19 Kentucky Commission Order as an offer of full settlement of this proceeding as to Kentucky.

IV. Comments

9. On June 1, 2004, PJM filed a supplemental statement in support of the Settlement.

10. Notice of the Settlement was issued on June 2, 2004, with initial comments due on June 10, 2004 and reply comments due on June 14, 2004.

11. Edison Mission Energy, Edison Mission Marketing & Trading, Inc. and Midwest Generation EME, LLC, and the Commission Trial Staff filed initial comments in support of the Settlement. Cinergy Services, Inc. (Cinergy) filed initial comments in support of the Settlement, but requests clarification of one issue. The Coalition of Municipal and Cooperative Users of New PJM Companies' Transmission (Muni-Coop Coalition) filed initial comments conditionally opposing the Settlement. Public Service Electric and Gas Company and PSEG Energy Resources & Trade LLC (collectively, PSEG) filed initial comments conditionally supporting the Settlement.

12. The Kentucky Commission, PJM, and FirstEnergy Service Company filed reply comments.

13. On June 15, 2004, the Muni-Coop Coalition filed a Statement of position in response to the reply comments. It states that the reply comments do not allay its concerns and that its opposition to the Settlement should be treated as no longer conditional.

14. The issues raised in the comments and reply comments are discussed below.

V. Discussion

15. As discussed below, the Commission approves the contested Settlement without condition or modification. The Commission finds that the concerns raised by the Muni-Coop Coalition in its conditional opposition to the Settlement have been adequately explained by the Kentucky Commission and/or PJM and thus do not pose an impediment to approval of the Settlement. The Commission also provides requested clarifications. Finally, the Commission also notes that the Settlement does not change the authority of this Commission or of the Kentucky Commission. In sum, the Commission approves the Settlement as a reasonable resolution of the complex matters at issue in this proceeding as they pertain to the laws, rules, and regulations of Kentucky.

A. LMP Market-Based Structure

16. Cinergy supports the Settlement so long as AEP, like any other market participant, will be bound by all aspects of the currently effective Amended and Restated Operating Agreement of PJM, the PJM Open Access Transmission Tariff, and the applicable Reliability Assurance Agreement. Cinergy notes that as a full participant in the PJM structured market, AEP's net settlement obligation with the PJM RTO Interchange Energy market will be dependent on the locational value of energy, and, therefore, self-scheduling to meet native load energy requirements may result in residual settlement obligations based not only on quantity deviations between total energy generated and total load, but also based on the impacts of congestion and losses. Cinergy therefore requests that the Commission clarify that nothing in the Kentucky Stipulation exempts AEP from full integration into the PJM LMP-based market structure.

17. The Commission grants clarification. Since AEP will become a member of PJM, it will sign the requisite agreements and abide by any resulting obligations. The Commission finds that nothing in the Settlement exempts AEP from meeting the obligations of a PJM member and signatory to the relevant PJM Agreements. In fact, Paragraph 2 of the Kentucky Stipulation states, for example, "Nothing stipulated in this agreement shall supercede PJM's obligation to ensure an adequate reserve margin consistent with maintaining an acceptable level of reliability." Of course, as long as AEP supplies the energy needed to meet its own needs and maintains adequate capacity to meet PJM's determination of AEP's capacity requirements, AEP will not be obligated to purchase energy or capacity in PJM's markets.

B. Curtailments During Emergencies

1. PJM's Authority Over Curtailments

18. The Settling Parties state that the curtailment provisions in the Settlement are consistent with PJM's existing practices, which specify that under transmission system emergencies, actions are to be directed at the area where the problem arises. However, for informational purposes, the Settling Parties included a pro forma revision to PJM's Operating Agreement. The Settling Parties state that the revision will be submitted for filing following a stakeholder process prior to the effective date of AEP's integration into PJM.

19. The Muni-Coop Coalition notes that in its July 17, 2003 Order, the Kentucky Commission found that AEP-Kentucky's participation in PJM would be inconsistent with a Kentucky statute[6] which provides that retail customers be the last to suffer curtailment

[6] Section 278.214 of the Kentucky Revised Statute.

or interruption of service resulting from an electric system emergency. To address the Kentucky statute's requirements, the Muni-Coop Coalition asserts that it appears that the Kentucky Stipulation establishes certain priorities of service during emergency conditions that would grant a discriminatory preference to Kentucky retail service. Specifically, the Muni-Coop Coalition states that the provisions of the Kentucky Stipulation can be interpreted as exempting Kentucky retail customers from curtailment under conditions in which other customers within PJM's footprint would be subject to curtailment. The Muni-Coop Coalition argues that a provision which would provide Kentucky retail customers a higher priority of service than is furnished to others in the PJM footprint would be unjust, unreasonable and unduly discriminatory and contrary to the principles of Order No. 2000.[7]

20. As noted above, the Settling Parties state that the curtailment principles are consistent with PJM's existing practices. However, the Muni-Coop Coalition questions why the curtailment provisions are deemed necessary, if PJM's existing practices already establish such protections. Further, the Muni-Coop Coalition contends that the pro forma tariff language which was submitted with the Settlement for informational purposes does not provide enough detail on how many control zones will be used and how curtailment and load shedding will be applied across the control zones. Further, in its statement of position, the Muni-Coop Coalition seeks assurance that the Settlement terms will not change to conform to section 13.6 of the PJM tariff. The Muni-Coop Coalition contends that without such information, it is impossible to determine whether the Kentucky Stipulation deviates from existing PJM practices.

21. In its reply comments, PJM states that the Settlement does not change the curtailment provision contained in section 13.6 of PJM's tariff, which states that "[i]f multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, Curtailments will be proportionately allocated among Native Load Customers, Network Customers, and Transmission Customers taking Firm Point-to-Point Transmission Service." PJM further explains that curtailment of wholesale transmission tariff transactions under section 13.6 do not necessarily require load shedding. However, when PJM must shed load to resolve a transmission system emergency, PJM will do so,

[7] See Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,033 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶31,092, petitions for review dismissed sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

to the extent practicable, on a non-discriminatory and functional basis so that the minimum load is shed to resolve the problem and prevent it from spreading. When such emergency circumstances arise, PJM will inform the electric distribution company serving load of the quantity and location of load that must be shed, and the distributor, which directly serves the affected load, will effectuate the load-shedding. PJM states that this is its existing practice and is not a special procedure created only for AEP or as a result of the Settlement.

22. The Commission finds that the terms of the Settlement will not need to change to conform with PJM's tariff. In addition, the Commission notes that the Kentucky Commission in its May 19, 2004 Order, explains that PJM will not be in violation of the Kentucky statute, since it will not be determining or directing which customers would be curtailed during an emergency. Rather, that task will remain with AEP-Kentucky. In the event of a transmission emergency, PJM is only responsible for determining the location, quantity, and timing of any curtailment. PJM is <u>not</u> responsible for determining or directing the manner in which load is to be curtailed during an emergency.

23. Under the Settlement language at issue here, the issue is not whose transmission service is curtailed first or last, but whether end users will be shed before other options are exhausted. We construe the Settlement as requiring that shedding of end users be a last resort, after PJM has exhausted all other options that do not involve shedding end users. We understand the Settlement language to not provide AEP any additional rights regarding curtailment than it would otherwise have. On this basis, the Settlement is acceptable.[8]

2. <u>**AEP-Kentucky as a Separate Control Zone**</u>

24. PSEG conditions its support of the Settlement based on its understanding of the curtailment provisions. PSEG understands that the first three subparts of Paragraph 3 of the Kentucky Stipulation are designed to recognize the current status of AEP as a physically-separate control zone. PSEG understands that a separate control zone is necessary because, at present, there is insufficient transmission transfer capacity between the area covered by the "classic PJM," the Allegheny Power transmission zone, the Commonwealth Edison Company transmission zone and the new AEP-Kentucky transmission zone. PSEG further believes that the curtailment protocols are transitional in nature, and will be terminated when the operational restriction requiring treatment of

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[8] We further note that if the transmission of service provided by a utility to a class of customers is of inferior quality compared to the service provided by the utility to its native load, lower rates may be warranted.

the AEP-Kentucky as a separate control zone have been alleviated. The Muni-Coop Coalition argues that the determination of whether AEP will be its own control zone should not be left for later resolution, because it is fundamental to understanding how the existing curtailment and load shedding practices will be applied.[9]

25. In its reply comments,[10] PJM responds that the Commission does not have to decide the control zone in which AEP will reside before it approves the Settlement. PJM's control zones have been established, as its "footprint" has grown, to accommodate requirements, such as ancillary services and load-shedding considerations, which are better addressed in a geographic area smaller than the entire PJM region. PJM explains that its tariff permits one or more control zones to be established in each of the ECAR and MAIN reliability regions, but does not prescribe the boundaries of the operational zones. In addition, PJM explains that it will soon be making a final determination regarding the most efficient control zone structure for the newly integrated companies and will file with the Commission any conforming or related tariff changes. PJM states that it will advise the Commission at that time of the control zone in which AEP will reside.

26. In its Statement of position, the Muni-Coop Coalition notes that the scope and effect of the Kentucky Stipulation load-shedding provisions will depend in substantial measure upon the configuration of the control zones. Depending on what control zone AEP is folded into, the Muni-Coop Coalition avers it could enjoy greater protection from curtailment during an emergency. The Muni-Coop Coalition believes that the Commission needs information on control zones in order to evaluate this aspect of the Settlement.

27. We believe that it is premature to address this issue. When PJM makes its filing in July, all parties will have the opportunity to evaluate the control zone issue and file comments with the Commission addressing their concerns.

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[9] The Muni-Coop Coalition also suggests that PJM is delaying submitting the pro forma amendment to the PJM Members Committee, contrary to the spirit of collaboration with stakeholders envisioned by Order No. 2000. Muni-Coop coalition's Initial Comments at 7, n.4.

[10] PJM styles its reply on this issue as a response to the Muni-Coop Coalition's initial comments.

C. Voluntary Participation in PJM Markets

28. The Muni-Coop Coalition notes that the Kentucky Commission's approval of AEP-Kentucky's participation in PJM is based in part on the voluntary nature of AEP-Kentucky's participation in the PJM energy market for purchases and sales of energy. The Muni-Coop Coalition contends that the language in Paragraph 1 of the Kentucky Settlement has the effect of prohibiting PJM from contesting a decision by AEP to opt out of complying with a Commission mandate. The Muni-Coop further states that Paragraph 1 seems to bind PJM to join AEP in "resisting" any proposal for mandatory participation, regardless of its merits. The Muni-Coop questions whether it is appropriate for PJM to agree to in advance to resist any proposal that would require any level of market participation, without regard to the merits, such as a requirement to sell into a market to mitigate the effects of high market concentration. The Muni-Coop Coalition contends that for PJM to agree in advance to "resist" any proposal seems inadvisable as a matter of preserving RTO independence and discretion.

29. The Muni-Coop Coalition also states that Paragraph 1 raises the question of whether the benefits of the PJM expansion will be realized if AEP is free to keep its entire fleet of generators on the sidelines. The Muni-Coop Coalition states that if AEP is free to self-schedule all or most of its fleet of generators, Paragraph 1 could be viewed as a potential justification for a "new and exceedingly potent form of market power."

30. In its reply comments, PJM states that voluntary participation is a hallmark of the PJM markets. PJM states that because the Kentucky Commission had expressed concern that membership in PJM would result in a mandatory requirement that AEP-Kentucky sell the output of its generation into the PJM market, the Kentucky Stipulation affirms that participation in the PJM market is voluntary. PJM states that the Muni-Coop Coalition misunderstand this aspect of the Kentucky Stipulation when it suggests that PJM could not advocate mandatory participation in circumstances in which sales into a market might be required for some period to mitigate the effects of high market concentration. PJM notes that the Kentucky Stipulation explicitly preserves PJM's (and other signatory parties') ability to address anticompetitive withholding, notwithstanding the voluntary nature of the markets.

31. The Commission finds that Settlement is premised on PJM's markets being voluntary. The Commission finds nothing in the Settlement changes this premise. Moreover, the May 19, 2004 Kentucky Commission Order explains that Paragraph 1 of the Kentucky Stipulation affirms the voluntary nature of the PJM energy market for purchases and sales of energy. It further affirms that AEP can elect to either participate in PJM's spot energy market to meet AEP-Kentucky's native load energy requirements, contract bilaterally with other entities to supply energy, or schedule its own generation to meet those requirements. In addition, the order explains that in the event that the

Commission proposes mandatory purchases or sales of energy into PJM's market, the Kentucky Stipulation provides that PJM and the other parties are "obligated not to contest AEP's decision to not participate in any such mandatory market." The Commission finds that under the terms of the Settlement, PJM is free to advocate any position before this Commission that it deems appropriate. PJM is only restricted in contesting an AEP decision not to participate in a mandatory market; PJM is not restricted in advocating the pros or cons of such a market.

32. Finally, the Muni-Coop Coalition raises a concern about a new form of market-power abuse which could occur if AEP keeps its entire fleet of generators on the sidelines. The Commission finds that this concern is unfounded. First, while market purchases and sales are voluntary, the experience of other vertically integrated members of RTOs indicates that in any given time period they are likely to have either an excess to sell or a shortfall to cover due to normal variation in supply and load, and will actively participate in the market for these purposes. Second, nothing in the Settlement or the Kentucky Stipulation prohibits the Commission from exercising its authority under the Federal Power Act[11] to address market-power concerns. In fact, the last sentence of Paragraph 1 notes that the Kentucky Stipulation does not address the authority of the Commission with respect to remedies for anti-competitive behavior.

The Commission orders:

The Settlement is in the public interest and is hereby approved, as discussed in the body of this order.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.

[11] 16 U.S.C. § 824b (2000).

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November 19, 2010

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
Kentucky State Board on Electric Generation & Transmission Siting
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2010-00203

Dear Mr. Derouen:

Please find enclosed an original and 11 copies of the Post Hearing Brief of PJM Interconnection, LLC, in the Application of Duke Energy Kentucky to transfer control of its transmission assets from the MISO to PJM.

Should you have any questions or concerns, please do not hesitate to contact me.

Sincerely,

Jason R. Bentley
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305 Ann Street, Suite 308
Frankfort, KY 40601
(502) 875-1176

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
NOV 19 2010
PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR APPROVAL TO TRANSFER FUNCTIONAL CONTROL OF ITS TRANSMISSION ASSETS FROM THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR TO THE PJM INTERCONNECTION REGIONAL TRANSMISSION ORGANIZATION AND REQUEST FOR EXPEDITED TREATMENT)))))))))

Case No. 2010-00203

POST-HEARING BRIEF OF
PJM INTERCONNECTION, L.L.C.

TABLE OF CONTENTS

I. INTRODUCTION

PJM Interconnection, L.L.C. (PJM) hereby submits its post-hearing brief for consideration by the Kentucky Public Service Commission (Commission) in the above-referenced matter. PJM appreciates the opportunity to summarize certain points and issues raised during the cross-examination of Duke Energy Kentucky (DukeKY) witnesses, in order to provide the Commission a clearer understanding of the record on which the Commission may base its decision in this proceeding.

The discussion in Section II, *infra,* addresses four specific topics raised on a number of occasions during the cross-examination of Duke's witnesses:

- The manner in which DukeKY's share of PJM Regional Transmission Expansion Plan costs will be determined upon DukeKY's integration with PJM;
- Recognition of regional peak load diversity in the PJM capacity construct: how it provides benefits to DukeKY by lowering the Installed Reserve Margin (IRM) effective for DukeKY when the Duke zone peak is recognized as coincident with the PJM peak;
- The impact of available types of transmission service *(i.e.,* network transmission service and firm point-to-point transmission service) on DukeKY's ability to sell capacity to load in PJM; and
- Aspects of FERC Order 719-A that 1) bear upon the offering by DukeKY or its end-use customers of demand response and energy efficiency resources into PJM's markets, and 2) establish the Commission's discretion as a Relevant Electric Retail Regulatory Authority (RERRA).

PJM's position before the Commission is as a provider of information, and PJM takes no position on any retail rate issues that may be associated with the above-captioned case. PJM urges the Commission to find that DukeKY's application to transfer functional control of its transmission assets to PJM is for a proper purpose and meets the public interest standard established by KRS 278.218.

II. DISCUSSION

A. The manner in which DukeKY's share of PJM Regional Transmission Expansion Plan costs will be determined upon Duke's integration with PJM.

PJM performs regional transmission planning for the transmission facilities within its footprint pursuant to the RTEP Protocol included in Schedule 6 of PJM's Operating Agreement. This Protocol requires PJM to plan transmission expansions "in order to meet the demands for firm transmission service . . . in the PJM Region."[1] PJM "consolidate[s] the transmission needs of the region into a single plan" to maintain reliability and support competition "in the PJM Region."[2] The "PJM Region" is defined as the geographic area encompassing the electrical loads served by PJM.[3] Cost allocation for facilities included in RTEP is governed by Schedule 12 of the PJM Open Access Transmission Tariff (OATT). Schedule 12 contains two allocation methods for owners selecting incremental rate treatment: one for facilities 500 kV and above (collectively, the "Regional Facilities") and one for facilities below 500 kV ("Lower Voltage Facilities").[4] Costs for Regional Facilities are allocated on an "annual load-ratio share basis" to

[1] PJM Operating Agreement Paragraph 1.1.
[2] *Id.* Paragraph 1.4(a).
[3] *Id.* Paragraph 1.35A.
[4] There are several classes of facilities with differing definitions that receive similar allocations, but, for purposes here, it is sufficient to describe the class labeled "Lower Voltage Facilities."

all loads in PJM.[5] The costs of Lower Voltage Facilities are allocated using a "beneficiary pays" approach that employs a computer model to calculate distribution factors representing a measure of the effect of the load of each Zone or Merchant Transmission Facility on the transmission constraint that requires the Lower Voltage Facility. These provisions implement FERC *Opinion No. 494*, which decided cost allocation for the PJM region.

In both the Midwest ISO and PJM, projects allocated to specific beneficiaries or loads continue to bear those costs if they depart the RTO. The costs of historical beneficiary-specific projects are not allocated to new RTO members because those costs were previously allocated to existing members. For Regional Facilities, however, the Midwest ISO and PJM have different approaches to calculating postage-stamp regional transmission rates. The Midwest ISO allocates 20 percent of the costs for projects at 345 kV and above across the entire Midwest ISO region, but it does so on a "one-time" basis at the time the project is approved.[6] The cost responsibility of every transmission owner's zone within the Midwest ISO therefore becomes "fixed" for that project and is not "reset" each year. This means that an existing transmission owner's zone departing the Midwest ISO cannot avoid responsibility for costs previously allocated.

The PJM OATT does not work this way. Instead, its postage-stamp rate allocation for Regional Facilities and Necessary Lower Voltage Facilities[7] is "reset" every year. Specifically, cost responsibility is allocated *annually* to PJM Transmission Owner zones on a load-ratio share

[5] PJM OATT, Schedule 12 § (b)(i)(A).

[6] Midwest ISO ASM Tariff, Attach. FF § III.A.2.c.ii.

[7] "Necessary Lower Voltage Facilities" are upgrades that operate below 500 kV but that are necessary to support the Regional Facilities. *See* PJM Tariff, Schedule 12 § (b)(i).

basis.[8] Because cost responsibility is (re)allocated annually, new members' zones have to pay for them because their loads are included in those calculations.[9]

B. Recognition of regional peak load diversity in the PJM capacity construct: how it provides benefits to DukeKY by lowering the Installed Reserve Margin (IRM) effective for DukeKY when the Duke zone peak is recognized as coincident with the PJM peak.

Each of the alternatives available to a Load Serving Entity (LSE) to satisfy its capacity obligation in PJM—bidding Capacity Resources into the Reliability Pricing Model (RPM) auctions or supplying Capacity Resources on a Fixed Resource Requirement (FRR) basis—provide reliability benefits to the region and to DukeKY by assuring that enough Capacity Resources are available to satisfy planning reserve margins required to maintain a Loss of Load Expectation (LOLE) in PJM of one day in ten years, the industry standard. RPM is designed to ensure that sufficient Capacity Resources are committed on a three-year forward basis to satisfy installed reserve obligations by providing incentives to ensure ongoing or new investment in electricity resources that will be forthcoming to maintain the future reliability of the regional grid. The alternative approaches available to satisfying a capacity obligation provide an LSE with flexibility to manage its capacity obligation to minimize the risks and costs of meeting regional reliability standards.

The Reliability Pricing Model (RPM) is one of two alternatives available to LSEs participating in PJM's capacity construct. RPM replaced a former capacity market that provided insufficient incentives for investment in Capacity Resources because it was a short term market

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[8] PJM OATT, Schedule 12 § (b)(i)(A).
[9] *Duquesne Withdrawal Rehearing Order*, 124 FERC ¶ 61,219 at P 164.

that did not commit capacity on a sufficiently forward basis and did not reflect the locational value of capacity. Additionally, the former market resulted in significant price volatility which created uncertainty and increased costs as the market approached Capacity Resource shortage conditions. Volatility resulted because the availability of one or more MWs above the reliability requirement would drive the price to zero, and one or more MWs below the reliability requirement would drive the price to the deficiency charge. RPM also includes market power mitigation procedures that reduce consumers' risks by reducing the opportunity and incentives to exercise market power. RPM's Variable Resource Requirement mechanism (VRR) more accurately reflects the value of capacity as a function of the quantity of resources available by establishing smoother price transitions, thereby mitigating the price volatility associated with the former capacity market which essentially had a vertical demand curve.

The RPM VRR defines the demand for Capacity Resources in electrically cohesive sub-regions of PJM, and intersects with a capacity supply curve to determine the price that winning suppliers will receive. The VRR is structured around the cost of service for the least expensive capacity to build, and in that respect is designed to limit total ratepayer payments over the long run to what they would have been if the same level of resources were acquired under traditional cost-of-service regulation to meet the industry standard of ensuring that the probability of load loss not exceed one day in ten years.

RPM improved on the design of the former capacity market by redefining the period when capacity must be available. As explained in the direct testimony of DukeKY witness Jennings,[10] RPM's three-year forward auction and incremental auctions allow planned

[10] *See* Direct Testimony of Kenneth J. Jennings at 3.

generation capacity, planned and existing demand response and energy efficiency resources, and merchant transmission facilities to compete with existing generation resources.

RPM also introduced a locational aspect to capacity commitment in PJM to reflect the fact that the value of capacity is a function of limitations on the transmission system's ability to deliver electricity into an area and differences in the need for capacity in various areas of PJM, called Locational Deliverability Areas (LDAs). By prompting the development of new Capacity Resources or maintenance or deferred retirement of existing Capacity Resources on a sub-regional basis, RPM reflects the transmission limits that may prevent distant resources from meeting local resource adequacy requirements. As a result, RPM payments made to Capacity Resources in various LDAs in the PJM footprint differ to reflect the value of capacity in different sub-regions within PJM.

The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit an FRR Capacity Plan and meet a fixed Capacity Resource requirement rather than to participate in the RPM. The FRR Alternative allows an LSE to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions as the means to satisfy its capacity obligation, as long as it satisfies a number of conditions. The principal conditions are that: 1) an LSE electing the FRR alternative is required to submit an FRR Capacity Plan to satisfy the unforced capacity obligation (UCAP obligation) for all load in an FRR Service Area, including all expected load growth in the FRR Service Area; 2) an LSE electing the FRR alternative is subject to a minimum term of five consecutive Delivery Years in which the FRR alternative is in effect; 3) an LSE electing the FRR alternative with capacity in excess of its reliability requirement is required to set aside a "buffer" of three percent to address uncertainties associated with future load forecasts and future supply resource availability; and 4) an LSE electing the FRR alternative also is subject to a sales cap on how much of its excess capacity can be offered in RPM auctions, equal to the lesser of 25 percent of each FRR entity's UCAP obligation or 1300 MW.[11]

DukeKY is a vertically integrated company. As Duke Witness Burner[12] explained during the evidentiary hearing, any capacity charges for which DukeKY is responsible as an LSE would be offset by revenues received by DukeKY generation, regardless of whether DukeKY participates as a bidder in the RPM auctions or elects the FRR alternative.

DukeKY customers should not have any exposure to additional capacity costs because DukeKY is "long" from a generation perspective.[13] DukeKY has generating resource capacity that is more than adequate to meet its own requirements. As such, DukeKY will be able to satisfy its capacity obligations under either the RPM or FRR alternative, and have additional Capacity Resources that it can bid into the RPM auctions. According to DukeKY, any revenues received from sales of excess Capacity Resources in the RPM auctions will be shared with customers through the Profit Sharing Mechanism (Rider PSM).

PJM's Installed Reserve Margin (IRM) is used to establish an LSE's capacity obligation for both the RPM and FRR alternatives in PJM.[14] As Duke Witness Jenning explains,[15] PJM's

[11] PJM Manual 18, Section 11.7, p. 139.
[12] Hearing November 3, 2010, Cross Examination of Bob Burner, Video transcript at 14:48:42 (media file 01:27:12/02:50:17 and 01:42:07/02:50:17).
[13] The record indicates that Duke has approximately 1100 MW of generation resources and that its all-time peak is 912 MW. Hearing November 3, 2010, Cross Examination of Bob Burner, Video transcript at 14:56:00 (media file 1:24:33/02:50:17).
[14] The IRM establishes the capacity requirement in the FRR alternative. It also informs the shape of the Variable Resource Requirement Curve in the RPM alterative, where under certain circumstances more capacity could be procured than is called for by the IRM, but only if the overall quantity obtained results in a lower cost than would result if the amount of capacity procured was equal to the IRM.

capacity framework is structured to commit capacity under RPM or the FRR alternative to meet PJM's IRM, which corresponds to the PJM reliability requirement of one event in ten years loss of load expectation (LOLE) as set by ReliabilityFirst Corporation, the NERC Reliability Entity for PJM.[16] As a result of the scope of the PJM footprint, the PJM practice of reserve sharing across the RTO, the load diversity within PJM, and the concomitant fuel diversity and amount of resources available to satisfy the resource requirements of its member LSEs, the IRM established by PJM is lower than the reserve margin that Duke would require as a stand-alone entity dependent entirely on its own resources to satisfy the industry standard LOLE of one event in ten years. This is so because when taking into account PJM's coincident peak, the Duke zone load to which PJM's IRM requirement will apply is anticipated to be approximately four percent less than Duke's non-coincident, stand-alone zonal load.[17]

C. The impact of available types of transmission service, *i.e.* Network Transmission Service and Firm Point-to-Point Transmission Service, on Duke's ability to offer capacity to load in PJM.

A question was raised during the hearing as to whether DukeKY, cognizant of the publicly available results of RPM auction clearing prices, would be able to sell capacity to load inside PJM if it remained in the Midwest ISO. Duke witness Swez responded[18] that under that circumstance, Duke would be unable to sell capacity into PJM because there is not Available

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[15] *See* Direct Testimony of Kenneth J. Jennings at 5.
[16] *Id.* at 5, line 4 ff.
[17] PJM is currently analyzing the impact of the integration of DukeKY and Duke Energy Ohio on load diversity within PJM. The average zonal diversity for a Transmission Owner in PJM is currently 4.2 percent, rendering the effective IRM in PJM as 10.66 percent for the 2010/2011 delivery year, compared to 11.94 percent for the Midwest ISO for that planning year. *See* 2010 PJM Reserve Requirement Study, Appendix E, p. 95 at http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2010-pjm-reserve-requirement-study.ashx.
[18] Hearing November 3, 2010, Cross Examination of John Swez, Video transcript at 16:50:00 (media file 10:55/01:02:34).

Transmission Capacity (ATC) available to deliver DukeKY capacity located within the Midwest ISO to the load in PJM. Witness Swez's response to a question from the attorney representing the Midwest ISO indicated that there would be no physical change of asset configuration if Duke were integrated with PJM, leaving open the question why DukeKY's excess capacity resources would be available for sale in PJM under the PJM integration scenario but not so available if Duke remained in the Midwest ISO.

If DukeKY's generation resources were located inside PJM, they would be designated as Network Resources, and Duke would be in position to offer its capacity into the RPM auctions or otherwise sell capacity to LSEs located in PJM. This is because FERC's *pro forma* transmission tariff, as well as PJM's Open Access Transmission Tariff (OATT), provide for two major kinds of Transmission Service: Point-to-Point Service and Network Integration Service. Point-to-Point Transmission Service uses the PJM system for the transmission of capacity and energy between a point of receipt and a point of delivery, which can be into, out of, or through the PJM Control Area. Network Transmission Service (PJM Network Integration Transmission Service) is used for the transmission of capacity and energy from network generating resources to PJM network loads. Each network customer can integrate its current and planned Network Resources to serve its network load in a manner comparable to that in which Load Serving Entities who are also transmission owners utilize PJM RTO Transmission Service Facilities to serve their native load customers.[19] If DukeKY remained in the Midwest ISO and sought to sell capacity in the RPM

[19] PJM Manual 2: Transmission Service Request, p. 7.

auctions, it would need to rely upon Firm Point-to-Point Service[20] to deliver capacity to load inside PJM; and as Duke witness Swez pointed out, there is not sufficient ATC to do so.[21]

D. Aspects of FERC Order 719-A bearing upon the offering by DukeKY or its end-use customers of demand response and energy efficiency resources into PJM's markets, and establishing the Commission's discretion as a Retail Electric Regulatory Authority (RERRA).

DukeKY witness Jennings explained[22] that PJM's market rules permit end-use customers aggregated by Curtailment Service Providers[23] (CSPs) or LSEs to commit Demand Resources into PJM's Capacity Market, thereby diminishing the capacity obligation such LSEs are required to satisfy. Witness Jennings also explained that it is not DukeKY's intention to have its retail customers participate directly in PJM's Capacity Market with Demand Resource commitments through it as the LSE or through a CSP. Witness Jennings acknowledged that DukeKY, as an LSE, could propose such a program, but that provisions of FERC Orders 719 and 719-A

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[20] PJM OA section 1.8 defines Capacity Resources, and section 7.5 establish requirements for their deliverability into PJM: "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.

[21] Hearing November 3, 2010, Cross Examination of John Swez, Video transcript at 16:50:00 (media file 10:55/01:02:34).

[22] Hearing November 3, 2010, Cross Examination of Ken Jennings, Video transcript at 16:07:17 (media file 02:35:52/02:50:34).

[23] PJM OA, section 1.3.1B.02 provides a definition for "CSP".

regarding the exercise of the discretion of a Relevant Electric Retail Regulatory Authority (RERRA) pursuant to those Orders could preclude DukeKY from doing so.[24]

FERC Order 719-A requires that RTOs and ISOs not accept bids from CSPs[25] that aggregate the demand response of the customers of utilities that distributed four million MWh or less in the previous fiscal year, unless the RERRA permits such participation.[26] DukeKY distributed approximately 3.8 million MWh in 2009,[27] and hence neither a CSP nor DukeKY itself would be able to offer Demand Resources into PJM's Markets, unless the Commission expressly authorizes the participation of the end use customers in the Duke Zone for which permission to participate in PJM's markets as a Demand Resource is sought.[28] Even if DukeKY were to distribute over 4 million MWh annually, while it would be able to participate in PJM's

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[24] Hearing November 3, 2010, Cross Examination of Ken Jennings, Video transcript at 16:10:00 (media file 02:38:33/01:02:34).

[25] Rather than "CSP", FERC uses the phrase "aggregator of retail customers" (ARC) to refer to an entity that aggregates demand response bids.

[26] Order 719-A, FERC Stats. & Regs. ¶ 31,292 at P 60. "Therefore, we direct RTOs and ISOs to amend their market rules as necessary to accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC. RTOs and ISOs may not accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be into organized markets by an ARC, or (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC."

[27] Duke Energy Kentucky, Inc., FERC Financial Report, FERC Form I, Year ending 2009, Submittal 20100428-8024, April 15, 2010, at pg. 304.

[28] With respect to "4 million MWh <u>or less</u>" requirement, at the point at which a CSP registers an end-use customer, pursuant to PJM rules, the EDC/LSE must verify whether the load is permitted or conditionally permitted by the RERRA to participate in PJM's DSR programs. If the EDC/LSE asserts that the load is permitted or conditionally permitted (which condition the EDC/LSE asserts has been satisfied) to participate in the DSR program, then either the EDC/LSE must provide to the Office of Interconnection with evidence from the RERRA indicating that the RERRA permits or conditionally permits the end-use customer to participate in the PJM DSR program. Evidence from the RERRA shall be in the form of either: (a) an order, resolution or ordinance of the RERRA permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the RERRA's legal counsel attesting to or (c) an opinion of the state Attorney General, on behalf of the RERRA, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation. For exact language quotes, please refer to the Economic and Emergency Load Response Programs provided in Schedule 1 of the OA or OATT, Attachment-K Appendix (Schedule 1 of the Operating Agreement and Attachment K-Appendix of the PJM Tariff are substantively identical).

Demand Response Program, the Commission may still "opt out" under the FERC rules by specifically prohibiting the participation of end use customers in the Duke Zone in those programs.

III. CONCLUSION

PJM thanks the Commission for the opportunity to offer the summations provided herein, and urges the Commission to find that DukeKY's application to transfer control of its transmission assets to PJM is for a proper purpose and in the public interest, satisfying the requirements of KRS 278.218.

Dated this 19th day of November, 2010.

Respectfully submitted,

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CERTIFICATE OF SERVICE

It is hereby certified that a copy of the foregoing was served via hand-delivery the 19th day of November, 2010, upon the following:

Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

It is hereby certified that a copy of the foregoing was served via U.S. Mail, postage prepaid, this 19th day of November, 2010, upon the following service list:

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR APPROVAL TO TRANSFER FUNCTIONAL CONTROL OF ITS TRANSMISSION ASSETS FROM THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR TO THE PJM INTERCONNECTION REGIONAL TRANSMISSION ORGANIZATION AND REQUEST FOR EXPEDITED TREATMENT	)	CASE NO. 2010-00203

ORDER

On May 20, 2010, Duke Energy Kentucky, Inc. ("Duke Kentucky") filed an application for authority to transfer functional control of its transmission facilities from the Midwest Independent System Transmission Operator ("Midwest ISO") to the PJM Interconnection Regional Transmission Organization ("PJM"). The Midwest ISO and PJM, both of which are Regional Transmission Organizations ("RTOs"), requested and were granted full intervention in this case.

By Order dated June 24, 2010, a procedural schedule was established for this case which included: (1) the filing of testimony by Duke Kentucky in support of its application; (2) two rounds of discovery on Duke Kentucky; (3) an opportunity for intervenors to file testimony; (4) one round of discovery on intervenors; (5) a formal hearing; and (6) the filing of post-hearing briefs. Neither the Midwest ISO nor PJM filed intervenor testimony. A public hearing was held on November 3, 2010 and all parties filed post-hearing briefs. The matter now stands submitted for decision.

STANDARD OF REVIEW

Duke Kentucky's request falls within the Commission's jurisdiction under KRS 278.218, which governs a change in ownership or control of assets of an electric utility where those assets have an original book value of $1,000,000 or more. That statute provides, in part, that "[t]he commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest."[1] While the statute does not define "public interest," the Commission has, in the context of a transfer of a utility, interpreted the "public interest" as follows:

> [A]ny party seeking approval of a transfer of control must show that the proposed transfer will not adversely affect the existing level of utility service or rates <u>or</u> that any potentially adverse effects can be avoided through the Commission's imposition of reasonable conditions on the acquiring party. The acquiring party should also demonstrate that the proposed transfer is likely to benefit the public through improved service quality, enhanced service reliability, the availability of additional services, lower rates or a reduction in utility expenses to provide present services. Such benefits, however, need not be immediate or readily quantifiable.[2]

While the application in this case involves the transfer of functional control of utility assets, rather than a transfer of ownership of a utility, the same criteria applies in determining whether the proposed transfer satisfies the "public interest" standard.[3]

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[1] KRS 278.218(2).

[2] Case No. 2002-00018, Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmbH, at 7 (Ky. PSC May 30, 2002).

[3] Case No. 2002-00475, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218 (Ky. PSC Aug. 25, 2003).

Duke Kentucky's Application

Duke Kentucky's proposed move from the Midwest ISO to PJM is directly tied to the move of its parent, Duke Energy Ohio, Inc. ("Duke Ohio"), from the Midwest ISO to PJM. Nearly all of the transmission facilities used to serve Duke Kentucky's customers are owned by Duke Ohio. The only transmission assets owned by Duke Kentucky are 18 138 kV high-side connections, including breakers and switches, to the Duke Ohio transmission system. Duke Kentucky states that, since it is not interconnected to any other utility in the Midwest ISO, realignment with PJM will keep outage coordination and related functions of these 18 connections under the functional control of a single transmission operator. That operator, PJM, will also control the Duke Ohio transmission system to which Duke Kentucky's facilities are connected.

With its interconnectivity to the Duke Ohio system and its effective status as a transmission dependent utility, Duke Kentucky states that it is in the public interest for it to make the same move, from the Midwest ISO to PJM, as Duke Ohio. That move will permit Duke Kentucky to participate fully in PJM markets and avoid potential inefficiencies, operational complexities, and additional costs that would result from creating a Midwest ISO/PJM seam that would affect Duke Kentucky's generation as well as its load.[4]

Prior to transferring its transmission assets to PJM, Duke Kentucky is required to obtain the approval of this Commission, as well as that of the Federal Energy Regulatory Commission ("FERC"). Duke Kentucky filed a joint application with Duke

[4] Duke Kentucky's application, at 15.

Ohio for FERC approval of their realignment with PJM, and FERC has granted that approval.[5]

Duke Kentucky's application cites various benefits to Duke Ohio of the proposed realignment, including lower RTO administration fees, a portion of which are allocated to Duke Kentucky, and aligning co-owners of Duke Ohio's jointly owned generating units into a single RTO for future investment planning and improved efficiencies in Ohio's competitive wholesale and retail power supply markets. Duke Kentucky's application points out that, even if it does not move from the Midwest ISO to PJM, once Duke Ohio moves to PJM, all of Duke Kentucky's generation, which is located in Ohio and Kentucky, will be in PJM, since it is dependent on the Duke Ohio transmission system. Unless Duke Kentucky also moves to PJM, the Duke Kentucky generation will be in PJM but the load will be in the Midwest ISO, creating potential inefficiencies and additional, unnecessary costs.[6]

Duke Kentucky states that PJM's capacity market should facilitate off-system sales and that the three-year forward-looking nature of the PJM market should provide a greater degree of certainty with regard to future capacity prices. Duke Kentucky also states that its ability to engage in off-system sales will likely be enhanced in the PJM market and that this will benefit both Duke Kentucky and its customers because of its off-system sales profit-sharing mechanism, Rider PSM, which was implemented in

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[5] FERC Docket Nos. ER10-1562-000 and ER10-2254-000, Order dated October 21, 2010.

[6] Duke Kentucky referred to this arrangement as one requiring it to pseudo-tie its load to PJM through the Midwest ISO and pseudo-tie its generation from PJM to the Midwest ISO.

conjunction with the acquisition of Duke Kentucky's existing generating facilities from Duke Ohio.

Duke Kentucky performed a financial analysis to determine the level of benefits that would likely result from joining PJM rather than remaining in the Midwest ISO. That analysis reflected the sale of both capacity and energy in the Midwest ISO market compared to the PJM market. The study included the estimated costs of RTO realignment, the level of capacity reserve requirements in each RTO, and the level of excess capacity and energy that would be available to sell into each market. The Duke Kentucky analysis showed that membership in PJM would be more financially beneficial to ratepayers than remaining in the Midwest ISO.[7]

In addition to the benefits of avoiding inefficiencies related to creating a Midwest ISO/PJM seam and the likely enhancement of off-system sales, Duke Kentucky offers the following commitments as part of its effort to demonstrate that its proposed move from the Midwest ISO to PJM is in the public interest:

1. Duke Kentucky will not seek to recover in base rates or in any adjustment mechanism any exit fee imposed by the Midwest ISO in conjunction with the move to PJM.[8]

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[7] Duke Kentucky requested and was granted confidential protection for its financial analysis, and copies were made available to intervenors on a confidential basis.

[8] Duke Kentucky clarified and expanded on this commitment at the November 3, 2010 hearing by also committing not to seek a deferral of the Midwest ISO exit fee.

2. Duke Kentucky will not seek to double-recover in a future rate case the transmission expansion fees that it may be charged by both the Midwest ISO and PJM in the same period or overlapping periods.

3. Duke Kentucky will hold its customers harmless from the costs of integration into PJM.

Based on these commitments, the previously discussed enhancements in off-system sales if it joins PJM, and the avoidance of costs and operational complexities that will be experienced if it is not in the same RTO as Duke Ohio, Duke Kentucky states that the transfer of control of its transmission facilities from the Midwest ISO to PJM will be in accordance with the law, for a proper purpose, and in the public interest.

PJM's Position

PJM did not file testimony or issue any information requests, but it did file a post-hearing brief. In its brief, PJM focuses on a number of issues that were raised at the November 3, 2010 hearing.

The first of those issues is PJM's methodology for allocating among its members the costs of new transmission projects included in the PJM Regional Transmission Expansion Plan. For new transmission projects in PJM that will operate at 500 kV or above, known as "Regional Facilities," costs are allocated to all loads on an annual load-ratio share basis. For new transmission projects that will operate at below 500 kV, costs are allocated on a "beneficiary pays" basis, as determined by a computer model that analyzes the transmission constraint that necessitates the new facility. PJM allocates the cost of the Regional Facilities, including any lower-voltage facilities needed to support the Regional Facilities, on an annual basis. Consequently, new members in

PJM are required to pay their load-ratio share of the Regional Facilities approved prior to their membership.

The next issue discussed by PJM is its capacity market and the ability of generation-owning members of PJM to bid all of their capacity into the Reliability Pricing Model ("RPM") auctions and then buy back at market prices sufficient capacity to meet the needs of their load. Alternatively, generation owners can select a Fixed Resource Requirement ("FRR") whereby they reserve sufficient capacity to serve their load, with the ability to bid any excess into the RPM market, subject to certain limits. PJM also explained that, under either RPM or FRR, Duke Kentucky will be required to maintain a capacity reserve margin that is set by PJM. However, that margin will be lower than what would be needed on a stand-alone basis due to the load diversity of Duke Kentucky's non-coincident peak and the PJM coincident peak.

PJM also discussed the types of transmission services it offers and the impact of those services on Duke Kentucky's ability to sell capacity into the PJM market. Currently, as a non-member of PJM, Duke Kentucky is unable to sell capacity into PJM because it must rely on point-to-point transmission service and there is not sufficient transmission capacity available to make such sales. However, if Duke Kentucky becomes a member of PJM, its generation will be designated as network resources, and it will then be eligible for network transmission service which would allow for the sale of capacity into the PJM market.

Finally, PJM addressed its rules for retail customers participating in PJM's demand-response programs. PJM allows retail customers to participate in such programs either directly or through Curtailment Service Providers. However, if the utility sells less than 4 million MWh annually, which Duke Kentucky does, the prior approval of the relevant electric retail regulatory authority must be obtained for demand response to be offered into PJM. For those utilities that sell in excess of 4 million MWh annually, the relevant electric retail regulatory authority has the ability to prohibit retail customers from participating in demand response; but, absent such a prohibition, PJM will allow participation.

MISO's Position

The Midwest ISO also did not file testimony, but it did issue two information requests to Duke Kentucky and it responded to an information request from Duke Kentucky. In its post-hearing brief, the Midwest ISO states that it recognizes that RTO membership is voluntary, and it fully supports its members' rights to elect to withdraw. The Midwest ISO characterizes the issue here as not being Duke Kentucky's contractual right to realign, but Duke Kentucky's failure to satisfy either the proper purpose or the public interest criteria set forth in KRS 278.218. Based on a claim of insufficient evidentiary support for the realignment, the Midwest ISO opposes Duke Kentucky's move to PJM and recommends that the transfer be denied.[9]

[9] The Midwest ISO's post-hearing opposition to Duke Kentucky's transfer seems to be in contrast to both its request to intervene "to either clarify Duke's responses or respond to issues more directly," Midwest ISO Motion to Intervene at 3, and its testimony in a prior case that, upon a utility's request to exit, the Midwest ISO "would not be in a position to protest, other than to provide what we could provide in terms of facts to the Commission for their consideration." Case No. 2010-00043, Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control if Its Transmission System to Midwest Independent Transmission System Operator, Inc., September 15, 2010 Hearing, video transcript, 16:33-16:35. See also Duke Kentucky's post-hearing brief at 3-4.

The Midwest ISO claims that Duke Kentucky has failed to demonstrate that there will not be adverse effects on service or rates resulting from its proposed move from the Midwest ISO to PJM. It also claims that Duke Ohio is the focus and intended beneficiary of the realignment with PJM, and that Duke Kentucky's decision to realign was not made independently, but was pre-ordained by its transmission dependence on Duke Ohio and by Duke Ohio's decision to exit the Midwest ISO and join PJM.

According to the Midwest ISO, Duke Kentucky has provided little information in support of its decision to realign with PJM other than the financial interests associated with Duke Ohio selling generation into the PJM capacity market. It argues that Duke Kentucky has not adequately supported claims of operational complexities, potential inefficiencies, and additional costs to pseudo-tie its generation to the Midwest ISO as a means of remaining a member while Duke Ohio moves to PJM. It also contends that Duke Kentucky's criticism of pseudo-tying arrangements is inconsistent with the existing operation of Duke Ohio and Duke Kentucky generation physically located in PJM.

The Midwest ISO also asserts that Duke Kentucky's failure to meet the statutory criteria for approval of the proposed transfer creates a number of alternatives for the Commission, including: (1) denying the application now; (2) deferring a decision until Duke Kentucky files supplemental information to support its application; (3) approving the application now but delaying the actual transfer date until January 1, 2014; or (4) approving the application now but prohibiting the imposition of any realignment costs or risks on ratepayers, while providing that any benefits of the realignment be shared with ratepayers.

The Midwest ISO's brief also raises a number of other issues that were not fully developed in the record, including the impact of Duke Kentucky's exit on the potential membership of another utility, East Kentucky Power Cooperative, Inc. ("East Kentucky Power"), the negotiation of a transmission path through PJM in lieu of membership in PJM, and whether PJM may ultimately acquire control of Duke Kentucky's generating facilities.

ANALYSIS AND FINDINGS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that Duke Kentucky has provided the minimum level of evidence, consisting of testimony and financial analysis, to support its decision to move from the Midwest ISO to PJM. While a more comprehensive and detailed analysis by Duke Kentucky might have obviated the need to impose additional commitments on the transfer, we are not persuaded by the Midwest ISO's arguments that the move to PJM should be denied.

It is clear that Duke Kentucky's decision to align with PJM was made as a direct result of Duke Ohio's alignment with PJM. However, standing alone, that fact does not nullify Duke Kentucky's decision, since that decision is supported by sufficient evidence. Had Duke Kentucky not been so dependent on the Duke Ohio transmission facilities for serving the Kentucky load, a more in-depth analysis of the costs and benefits of the transfer would have been expected.

We recognize that Duke Kentucky could potentially remain in the Midwest ISO, even though Duke Ohio moves to PJM. Other utilities have developed pseudo-tie arrangements for individual generating plants when the generation is not in the same

RTO as the load. For example, the East Bend generating plant, which is jointly owned by Duke Kentucky and Dayton Power and Light, is now entirely in the Midwest ISO because Duke Ohio's transmission is in that RTO. But, since Dayton Power and Light is a member of PJM, the portion of East Bend owned by Dayton Power and Light is pseudo-tied to PJM. Although Duke Kentucky did not develop specific estimates of the costs associated with pseudo-tying all of its generation to the Midwest ISO, while the transmission serving its load is in PJM, it is clear that avoiding the need for such arrangements will eliminate the incremental costs and administrative complexities associated with such pseudo-tie arrangements.

There is no dispute that Duke Kentucky's interest in realigning with PJM is directly related to the realignment of its parent, Duke Ohio. Given Duke Kentucky's transmission dependence on Duke Ohio, this interest is understandable and appropriate. However, even though the Commission recognizes Duke Kentucky's interest in joining PJM, we must closely examine this move to insure that there is no adverse impact on rates or service and that Duke Kentucky's customers are likely to realize benefits as a result of the RTO realignment. Based on our review of the nature and extent of the commitments offered by Duke Kentucky in its application and testimony, we find it reasonable and necessary to clarify, refine, and expand those commitments as set forth below.

<u>Midwest ISO Exit Fee</u>

Although there was some discussion and clarification at the November 3, 2010 hearing of the projected fees that Duke Kentucky will incur upon exiting the Midwest ISO, there continues to be some uncertainty regarding the exact nature and calculation of the fees to be imposed by the Midwest ISO. Accordingly, the Commission will require Duke Kentucky to commit that it will not seek to recover, in base rates or through any type of rate mechanism, an exit fee or any other type of fee imposed by the Midwest ISO as a result of Duke Kentucky's move to PJM, regardless of how that fee is identified or labeled, and regardless of whether or not the recovery of such fee is approved by FERC.

Transmission Expansion Fees

Duke Kentucky has indicated that it will not seek to double-recover in a future rate case the transmission plan expansion fees that it may be charged by the Midwest ISO and PJM in the same period or overlapping periods. However, Duke Kentucky has also indicated that it does not know the amounts of such future fees, nor does it know in what increments or the time period over which it may be charged fees for the Midwest ISO transmission expansion projects approved during the time it was a member of that RTO. In addition, Duke Kentucky is unsure if its final payment for the Midwest ISO expansion plan projects will be made in one lump sum or over a period of years.

In recognition that the primary factor for Duke Kentucky's move to PJM was Duke Ohio's business decision to make that same move, the Commission finds that Kentucky ratepayers should not be at risk for the payment of any Midwest ISO transmission expansion plan costs that exceed those of PJM. Consequently, we will require Duke Kentucky to commit that it will not seek to double-recover in a future rate case the annual, recurring transmission expansion fees that it may be charged by the Midwest ISO and by PJM in the same period or in overlapping periods, nor will it seek rate recovery, or the deferral and amortization of, the transmission expansion plan fees imposed by the Midwest ISO as a result of the exit for projects approved during the time it was a member of the Midwest ISO, regardless of whether or not the recovery of any such fees is approved by FERC.

Integration Costs

Duke Kentucky has stated that it will hold its customers harmless from the costs of integration into PJM. In cases involving any number of parties, the Commission has been exposed to different interpretations of the term "hold harmless," both in relation to unilateral commitments and to multilateral stipulations, such as settlement agreements. For that reason, the Commission will require Duke Kentucky to commit that it will not seek to recover, in base rates or in any type of rate mechanism, any costs of integration into PJM, nor will it seek to defer and amortize any PJM integration costs it incurs in conjunction with its alignment with PJM, regardless of whether or not such costs are approved by FERC.

PJM Capacity Obligation

Duke Kentucky stated at the November 3, 2010 hearing that no decision had yet been made as to whether it would initially bid its generating capacity into PJM's RPM market or whether it would choose the FRR alternative. Although Duke Kentucky testified that it would likely make a decision on this issue by the end of the year, it was unable to state with certainty who would make that decision, and the record does not disclose the specific criteria that will be used by the decision maker. [10]

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[10] November 3, 2010 Hearing, video transcript, 14:55, 15:30-31.

Prior to Duke Kentucky's acquisition of generating capacity in 2006,[11] the Commission had noted its concern that Duke Kentucky's historic practice of purchasing power under a contract with Duke Ohio could potentially result in Kentucky customers being exposed to the volatility of market-priced power. Now, Duke Kentucky is considering the option of bidding its capacity into PJM's RPM market, and then purchasing capacity from that market sufficient for its load and its reserve obligations. However, Duke Kentucky has not filed a comprehensive analysis comparing the costs and benefits of RPM versus FRR, and the evidence before us in this case is insufficient to show that choosing the RPM option will insulate Kentucky customers from volatility in the PJM market. Since Duke Kentucky has not demonstrated that its customers will be protected against market-based prices under the RPM option, the Commission will require Duke Kentucky to commit that it will participate in PJM only under an FRR capacity plan until it requests and receives our approval to participate in the RPM market.

Benefits of PJM Membership

The commitments addressed above relate to maintaining the status quo in that they are intended to insure that Duke Kentucky's transfer of functional control of its transmission assets will not adversely affect its customers. However, the Commission's established interpretation of the "public interest" also requires a demonstration that the

[11] Case No. 2003-00252, Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6), Order issued December 5, 2003.

proposed transfer is likely to provide benefits through improved service or reliability, additional services, lower rates, or reduced costs of providing service.

Duke Kentucky has stated that its ability to sell excess power into the PJM market should have a positive impact on its ability to engage in off-system sales and that this will benefit its customers because of its off-system sales profit-sharing mechanism, Rider PSM. While this is a potential benefit, there are potential risks to participating in the PJM market that could diminish or eliminate any benefit. For example, Duke Kentucky's 2008 integrated resource plan shows its generating capacity to be sufficient to meet its peak demand and maintain a 15 percent capacity reserve margin through 2019. However, expanded environmental regulations or climate change legislation could lead to a decrease in its available coal-fired generation, which would have a direct impact on its future levels of off-system energy and capacity sales. With these uncertainties in mind, the Commission will condition its approval of Duke Kentucky's request to join PJM upon Duke Kentucky's commitment to file a revised Rider PSM, to be effective January 1, 2012, that continues to allocate the first $1 million in annual profits to ratepayers, but shares the profits in excess of $1 million annually in the ratio of 75 percent to ratepayers and 25 percent to shareholders, rather than the current ratio of 50:50.

Duke Kentucky also states that one benefit available through membership in PJM is the ability of retail customers to directly participate in PJM's demand-response programs. As outlined by Duke Kentucky, the PJM process for participation by retail customers requires the utility to first evaluate whether the relevant electric retail regulatory authority permits direct participation by retail customers. Duke Kentucky states that its tariffs do not currently allow such direct participation by its customers and that it does not currently plan to participate in PJM's demand-response programs. Duke Kentucky states that, prior to any future decision on customer participation, it will first seek Commission approval.

To ensure clarity for all parties concerning the need for the Commission's prior approval, we will condition the approval of membership in PJM upon Duke Kentucky's commitment that no retail customer will be allowed to participate directly or through a third party in a PJM demand-response program until either: (1) the customer has entered into a special contract with Duke Kentucky and that contract has been filed with, and approved by, the Commission; or (2) Duke Kentucky receives Commission approval of a tariff authorizing such customer participation. In addition, we will require PJM to file a written acknowledgment of this requirement and require PJM to publicize this requirement according to its demand-response program rules.

<u>Other Midwest ISO Issues</u>

The Midwest ISO's brief raises three issues that were not fully developed in discovery and not addressed at the hearing. As to the issue of how Duke Kentucky's move to PJM might impact a future decision by East Kentucky Power to join the Midwest ISO, we note that this case has been here for almost seven months and East Kentucky Power did not request to intervene or otherwise seek to participate. As to Duke Kentucky's ability to negotiate a transmission path through PJM rather than joining PJM, the feasibility of that option was not fully developed. However, we note that nothing prohibits a utility from proposing an asset transfer merely because some of the proposed benefits might be achieved without a transfer. Finally, as to PJM acquiring control of Duke Kentucky's generating assets, the pending application does not request that authority. Until such time as Duke Kentucky expressly requests and is granted our authority to transfer control of its generation, that generation remains under Duke Kentucky's control, where it is subject to our authority and jurisdiction. For all of these reasons, the Commission finds the Midwest ISO's newly raised issues are unpersuasive.

FINDINGS AND SUMMARY OF DECISION

Based on the evidence of record and being otherwise advised, the Commission finds that:

1. Duke Kentucky's request to transfer functional control of its transmission assets from the Midwest ISO to PJM is for a proper purpose and in the public interest and should be approved subject to Duke Kentucky's acceptance of the six conditions specified below and PJM's acceptance of the one condition specified below related to participating in demand-response programs.

2. Duke Kentucky should not seek to recover, in base rates or any type of rate mechanism, an exit fee or any other type of fee imposed by the Midwest ISO in conjunction with Duke Kentucky's move from the Midwest ISO to PJM, regardless of how that fee is identified or labeled, and regardless of whether or not such fee is approved by FERC.

3. Duke Kentucky should not seek to double-recover in a future rate case the transmission expansion fees that it may be charged by the Midwest ISO and PJM in the same period or overlapping periods, nor should it seek to defer and/or amortize any transmission expansion fees it incurs for Midwest ISO transmission expansion projects

which received approval when it was a member of the Midwest ISO, regardless of whether or not such fees are approved by FERC.

4. Duke Kentucky should not seek to recover, in base rates or any type of rate mechanism, its costs of integration into PJM, nor should it seek to defer and/or amortize any PJM integration costs it incurs in conjunction with its alignment with PJM, regardless of whether or not such costs or fees are approved by FERC.

5. Duke Kentucky should file a revised Rider PSM to provide that, effective January 1, 2012, the first $1 million in annual profits from off-system sales is allocated to ratepayers, with any profits in excess of $1 million split 75:25, with ratepayers receiving 75 percent and shareholders receiving 25 percent.

6. No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.

7. Duke Kentucky should participate in PJM under a FRR capacity plan until it requests and receives this Commission's approval to participate in the RPM capacity market.

8. The Chief Executive Officer of Duke Kentucky should file, within seven days of the date of this Order, a letter accepting and agreeing to be bound by the conditions set forth in finding paragraphs 2 through 7 above.

9. The Chief Executive Officer of PJM should file, within seven days of the date of this Order, a letter accepting and agreeing to be bound by the condition set forth

in Finding No. 6 above and shall publicize that condition according to its demand response rules.

10. The approval of Duke Kentucky's request to transfer functional control of its 138 kV transmission facilities from the Midwest ISO to PJM and its request to join PJM should not diminish the Commission's authority to review and set Duke Kentucky's electric rates based on the value of its property used to provide electric service.

11. The approval of Duke Kentucky's request to transfer functional control of its 138 kV transmission facilities from the Midwest ISO to PJM and its request to join PJM should not diminish Duke Kentucky's existing obligation to:

a. Regularly file for Commission review an integrated resource plan detailing Duke Kentucky's load, specifying appropriate reserve requirements, and identifying sources of energy, demand-side resources, and projected need for new generation and transmission facilities.

b. Provide regulated service to its customers through the provision of bundled generation, transmission, and distribution electric service.

c. File for a certificate of public convenience and necessity prior to commencing construction of an electric generation or transmission facility.

IT IS THEREFORE ORDERED that:

1. Duke Kentucky's request to transfer functional control of its transmission system from the Midwest ISO to PJM is approved subject to the filing, within seven days of the date of this Order, of the written acknowledgements described in finding paragraphs 8 and 9 above.

2. Any customer seeking to participate directly or through a third party in any PJM demand-response program shall do so only in accordance with the procedures set forth in finding paragraph 6 above.

3. Within 20 days of the date of this Order, Duke Kentucky shall file its revised tariff Rider PSM as approved herein, with an effective date of January 1, 2012.

By the Commission

ENTERED
DEC 22 2010
KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Executive Director

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DEC 29 2010

PUBLIC SERVICE COMMISSION

pjm

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December 29, 2010

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort KY 40602-0615

Dear Mr. Derouen:

I am writing in response to the directive contained in the December 22 Order in the Public Service Commission of the Commonwealth of Kentucky ("Kentucky Commission") Case No. 2010-00203, that PJM Interconnection, L.L.C. ("PJM") file with the Kentucky Commission a written acknowledgment of the demand response participation requirement placed upon Duke Energy Kentucky, Inc. ("Duke Kentucky") together with assurances that PJM will publicize such requirement according to its demand response rules.[1] While PJM is a federally regulated entity not subject to state jurisdiction, in furtherance of PJM's commitment to ongoing cooperation and fostering a positive working relationship with the Kentucky Commission, PJM hereby acknowledges the Kentucky Commission's requirement placed upon Duke Kentucky with respect to Duke Kentucky retail customer participation in PJM demand-response programs. Specifically, the demand response participation requirement placed upon Duke Kentucky is stated as follows:

> [W]e will condition the approval of membership in PJM upon Duke Kentucky's commitment that no retail customer will be allowed to participate directly or through a third party in a PJM demand-response program until either: (1) the customer has entered into a special contract with Duke Kentucky and that contract has been filed with, and approved by, the Commission; or (2) Duke Kentucky receives Commission approval of a tariff authorizing such customer participation. In addition, we will require PJM to file a written acknowledgment of this

[1] Case No. 2010-00203, Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of Its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment (Ky. PSC Dec. 22, 2010) (December 22 Order") at 16.

requirement and require PJM to publicize this requirement according to its demand-response program rules.[2]

As discussed in PJM's post-hearing brief, PJM's market rules permit end-use customers aggregated by Curtailment Service Providers ("CSPs") or Load Serving Entities ("LSEs") to commit Demand Resources into PJM's Capacity Market, thereby diminishing the capacity obligation such LSEs are required to satisfy.[3] However, FERC Order 719-A[4] requires that RTOs and ISOs not accept bids from CSPs[5] that aggregate the demand response of the customers of utilities that distributed four million MWh or less in the previous fiscal year, unless the Relevant Electric Retail Regulatory Authority ("RERRA") (in this instance the Kentucky Commission) permits such participation.[6] Duke Kentucky distributed approximately 3.9 million MWh in 2009, and hence neither a CSP nor Duke Kentucky itself would be able to offer Demand Resources into PJM's Markets unless the Kentucky Commission, as the RERRA, determined to "opt-in" and expressly authorize the participation of such Demand Resources in PJM's Markets.[7]

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[2] *Id.*

[3] *See* Case No. 2010-00203, Post Hearing Brief of PJM Interconnection at 11-13.

[4] *Wholesale Competition in Regions with Organized Electric Markets*, Order on Rehearing, Order No. 719-A, Docket No. RM07-19-001, 74 FR 37,776 (Jul. 16, 2009), 128 FERC ¶ 61,059 (July 16, 2009) ("Order 719-A"), *reh'g denied*, Order Denying Rehearing and Providing Clarification, Docket No. RM07-19-002, 129 FERC ¶ 61,252 (Dec. 17, 2009).

[5] Rather than "CSP", FERC uses the phrase "aggregator of retail customers" (ARC) to refer to an entity that aggregates demand response bids.

[6] Order 719-A, FERC Stats. & Regs. ¶ 31,292 at P 60. "Therefore, we direct RTOs and ISOs to amend their market rules as necessary to accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, and (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC. RTOs and ISOs may not accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an ARC, or (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC."

[7] With respect to "4 million MWh <u>or less</u>" requirement, at the point at which a CSP registers an end-use customer, pursuant to PJM rules, the EDC/LSE must verify whether the load is permitted or conditionally permitted by the RERRA to participate in PJM's load response programs. If the EDC/LSE asserts that the load is permitted or conditionally permitted (which condition the EDC/LSE asserts has been satisfied) to participate in the PJM load response program, then the EDC/LSE must provide to the Office of Interconnection evidence from the RERRA indicating that the RERRA permits or conditionally permits the end-use customer to participate in the PJM load response program. Evidence from the RERRA shall be in the form of either: (a) an order, resolution or ordinance of the RERRA permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the RERRA's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the RERRA, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation. For exact language quotes, please refer to the Economic and Emergency Load Response Programs provided in Schedule 1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") as well as the parallel provisions of Attachment K-Appendix of the PJM Open Access Transmission Tariff ("PJM Tariff") (Schedule 1 of the Operating Agreement and Attachment K-Appendix of the PJM Tariff are substantively identical).

Further, in accordance with PJM's load response program rules,[8] PJM does already post on its website a list of those RERRAs that the EDCs or LSEs assert prohibit or condition retail participation in PJM's load response Programs, together with a corresponding reference to the RERRA evidence that is provided to PJM by the EDCs or LSEs. In this case, the Kentucky Commission has directly provided the relevant evidence to PJM concerning the requirement it placed upon Duke Kentucky retail customer participation in PJM load response programs, and therefore PJM will update its website to reflect same.

Thank you for your expedited review of this important matter. I look forward to continuing our work together to improve the operation, efficiency, and reliability of the Commonwealth of Kentucky's electric transmission service.

Sincerely,

Terry Boston

Terry Boston
CEO
PJM Interconnection, LLC

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[8] *See* PJM Economic Load Response section 1.5A.11, Reporting, and the Emergency Load Response reporting section, both of which are provided for in Schedule 1 of the Operating Agreement and Attachment K-Appendix of the PJM Tariff.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR APPROVAL TO TRANSFER FUNCTIONAL CONTROL OF ITS TRANSMISSION ASSETS FROM THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR TO THE PJM INTERCONNECTION REGIONAL TRANSMISSION ORGANIZATION AND REQUEST FOR EXPEDITED TREATMENT	)	CASE NO. 2010-00203

ORDER

On December 22, 2010, the Commission issued an Order granting Duke Energy Kentucky, Inc. ("Duke Kentucky") conditional approval to transfer its transmission assets from the operational control of the Midwest Independent System Operator ("Midwest ISO") to the PJM Interconnection Regional Transmission Organization ("PJM"). That Order imposed six conditions precedent that needed to be agreed to by Duke Kentucky, and one condition precedent to be agreed to by PJM. The one condition imposed upon PJM was also one of the six conditions imposed on Duke Kentucky. That condition, set forth as finding paragraph 6 on page 18 of the December 22, 2010 Order, provided that:

> No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.

Duke Kentucky and PJM were required to indicate in writing within seven days of the date of the Order if they individually agreed to accept and be bound by the conditions imposed therein.

On December 29, 2010, Duke Kentucky filed a letter stating that it accepted and agreed to be bound by the six conditions imposed on it by the December 22, 2010 Order and noted that its move to PJM is contingent upon Duke Energy Ohio's successful move to PJM. On that same date, PJM filed a letter acknowledging that a requirement was imposed on Duke Kentucky which prohibited retail customers from participating in a PJM demand-response program without prior Commission approval. However, PJM's letter did not acknowledge that this same condition was imposed on PJM by finding paragraph 9 of the December 22, 2010 Order. Consequently, without PJM's agreement to honor this condition, a customer of Duke Kentucky could enroll in a PJM demand-response program if, at the time of enrollment, Duke Kentucky does not object to PJM, either intentionally or due to inadvertence. Such participation by a customer of Duke Kentucky would be in direct violation of Duke Kentucky's tariff, Ky. P.S.C. Electric No. 2, First Revised Sheet No. 21, Section 5, which prohibits the resale of electricity by customers.

The condition imposed on PJM by our December 22, 2010 Order mirrors the commitment made by PJM in 2004 in conjunction with Kentucky Power Company's application to transfer functional control of its transmission assets to PJM. In that case, the transfer to PJM was approved upon PJM's agreement that:

> Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power . . . . Any such programs would be

subject to the applicable rules of the Commission and Kentucky law.[1]

Based on a review of PJM's December 29, 2010 letter, the Commission finds that one of the conditions precedent to Duke Kentucky's transfer of transmission assets to PJM has not been satisfied.

IT IS THEREFORE ORDERED that the conditional approval granted in our December 22, 2010 Order has not become unconditional and will not become unconditional until either: (a) PJM clarifies its December 29, 2010 letter to acknowledge the requirement that no customer participate in a PJM demand-response program absent prior Commission approval; or (b) the December 22, 2010 Order is modified in response to a timely application for rehearing filed pursuant to KRS 278.400.

By the Commission

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KENTUCKY PU
SERVICE COMM

ATTEST:

Executive Director

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[1] Case No. 2002-00475, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218 (Ky. PSC May 19, 2004) at 9 and Appendix A thereto at Paragraph No. 4.

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January 14, 2011

RECEIVED
JAN 11 2011
PUBLIC SERVICE
COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort KY 40602-0615

Dear Mr. Derouen:

We are writing in response to the directive contained in the January 6, 2011 Order in the Public Service Commission of the Commonwealth of Kentucky ("Kentucky Commission") Case No. 2010-00203, that PJM Interconnection, L.L.C. ("PJM") file with the Kentucky Commission a further clarification of its December 29, 2010 written acknowledgment of the condition regarding demand response participation by retail customers of Duke Energy Kentucky, Inc. ("Duke Kentucky") together with assurances that PJM will publicize such requirement according to its demand response rules.[1] PJM acknowledges that under the Conditions set forth in the Commission's Order, no retail customer of Duke Kentucky is allowed to participate in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.

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[1] Case No. 2010-00203, Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of Its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment (Ky. PSC Jan. 6, 2011) ("January 6 Order").

With respect to end-use customer participation in PJM's Economic and Emergency Load Response Programs, PJM is bound by the terms of Schedule 1 ("Schedule 1") of its Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), and the parallel provisions of Attachment K – Appendix of the PJM Open Access Transmission Tariff ("PJM Tariff"), both of which have been approved by PJM's regulator, the Federal Energy Regulatory Commission.[2] Under the PJM Operating Agreement provisions, Duke Kentucky is the entity that has ultimate responsibility to approve or deny any such Kentucky end-use customer registrations to participate in PJM's Load Response Programs.[3] Accordingly, PJM and Duke Kentucky file this joint letter to collectively acknowledge the Kentucky Commission's demand response participation requirements placed upon Duke Kentucky and to further elaborate on the PJM and Duke Kentucky administrative procedures that are or will be implemented to ensure that full force and effect are given to the Duke Kentucky demand response participation requirements as set forth in the Kentucky Commission's December 22 Order.

PJM and Duke Kentucky understand that the intent of the Kentucky Commission's December 22 Order is to prohibit Kentucky end-use customer participation in PJM's Load Response Programs unless prior approval is received from the Kentucky Commission. To that end, James E. Rogers, Duke Energy's Chairman, President and CEO, on December 27, 2010 submitted a letter to the Commission accepting all Conditions contained in the Commission's Order of December 22, 2010 in Case Number 2010 00203. Duke Kentucky reiterates its acceptance of the Commission's Condition that no retail customer of Duke Kentucky is allowed to participate in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation. Duke Kentucky will reject any PJM demand response program registrations that do not meet this condition.

Further, in accordance with the Emergency and Economic Load Response Program Operating Agreement provisions, PJM has already established and implemented administrative

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[2] Schedule 1 of the Operating Agreement and Attachment K – Appendix of the PJM Tariff are identical. For convenience, where PJM refers in this letter only to the Operating Agreement, such references are intended to encompass the corresponding provisions of the PJM Tariff.

[3] In accordance with various orders issued by the Federal Energy Regulatory Commission ("FERC") in Docket Nos. RM07-19 and ER09-701, PJM's Operating Agreement provides that when a Curtailment Service Provider registers a resource with PJM, PJM will notify the appropriate electric distribution company or Load Serving Entity of the registration and request verification as to whether the load that may be reduced is subject to another contractual obligation or to laws or regulations of the RERRA that prohibit, condition or permit the end-use customer's participation in PJM's DSR programs. The EDC or LSE will have ten business days to respond to PJM's notification. *See, e.g., Wholesale Competition in Regions with Organized Electric Markets, Order on Rehearing*, Order No. 719-A, Docket No. RM07-19-001, 74 FR 37,776 (Jul. 16, 2009); and *PJM Interconnection, L.L.C.*, Order Conditionally Accepting Proposed Tariff Revisions, Docket Nos. ER09-701-000, -001, 128 FERC ¶ 61,238 (Sept. 14, 2009) ("September 14 Order"). All capitalized terms that are not otherwise defined herein shall have the same meaning herein as they are defined in the Operating Agreement, PJM Tariff or the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("Reliability Assurance Agreement"). The phrase "aggregator of retail customers," or ARC, is used by the FERC to refer to an entity that aggregates demand response bids; in PJM this entity is referred to as a CSP.

procedures requiring all CSPs to register any demand response resources located in any Relevant Electric Retail Regulatory Authority ("RERRA") jurisdiction in the PJM electronic Load Response System ("eLRS") system[4]; such registration automatically triggers a number of notifications to the relevant electric distribution company ("EDC") and Load Serving Entity ("LSE"), which entities are then responsible for approving/denying such registrations. Under these established administrative procedures, end-use customers located in the Commonwealth of Kentucky cannot participate in the PJM Load Response Programs until the Kentucky end-use customer registration has been processed through the PJM eLRS system. As described in more detail in the attached Appendix A, Duke Kentucky designated eLRS Users will receive as many as three notices from PJM for each Duke Kentucky end-use customer registration submitted into the PJM eLRS system. Therefore Duke Kentucky shall have the opportunity to deny such registration or apply for the necessary Commission approvals.

Duke Kentucky commits to request from PJM that the PJM registration emails be sent to no less than 3 individuals who are each trained on how to respond to PJM demand response registration requests. Duke Kentucky will request eLRS system access for each of the 3 individuals. Further, PJM asks CSPs to contact the EDC (Duke Kentucky in this case) to obtain demand resource registration information. Upon such contact, Duke Kentucky will provide the CSP the current Kentucky Commission's rules for direct participation in PJM programs.

For the reasons set forth herein, PJM and Duke Kentucky respectfully request that the Kentucky Commission find that this further clarification of PJM's December 29 letter to the Kentucky Commission satisfies the final outstanding condition precedent to Duke Kentucky's transfer of transmission assets to PJM.

Sincerely,

James B. Gainer /s/

Terry Boston

James B. Gainer
Vice President
Federal Regulatory Policy

Terry Boston
CEO
PJM Interconnection, LLC

---

[4] The eLRS system is a sophisticated PJM system that includes extensive workflow management to ensure all PJM Members can perform their specific administrative tasks associated with PJM Load Response Program participation.

Appendix A

The following is a brief outline of the mechanics of the PJM registration review process. This outline is for illustrative purposes and does not supersede provisions in the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), the PJM Open Access Transmission Tariff ("PJM Tariff"), or market rules and/or operational practices outlined in the PJM governing documents.

1) Electric Distribution Company ("EDC") is set up in eLRS[5] including the following:
   a) Designation of whether the EDC is a large or small EDC (this designation determines the specific Opt in/Opt out Operating Agreement and Tariff registration requirements applicable, and related workflow procedures).
   b) Designation of account number format
   c) Designation of User roles – determine which user can do what type of activity in system
   d) Designation of User notification – determine whether or not the User should receive emails and for what type of activity in the system
      i) For example a User may decide to receive email notification for all registrations submitted in the system for the specific EDC. The EDC may set up as many Users as desired to receive email notification.

2) CSP submits a registration through eLRS
   a) CSP must set up each location that will be registered and include the specific EDC account number, address and variety of other information on the registration and then submit.
   b) A task is created in eLRS for both EDC and LSE to review the registration. The EDC and LSE associated with registrations are notified of the registration and the associated due date for the review (initially set to 8 business days).
   c) If no action has been taken on 8th business day to approve or deny a registration then the appropriate EDC and or LSE will receive another notification that 2 business days remain before the registration is approved (if Opt out/large EDC territory) or denied (if Opt in/small EDC territory).
   d) If no action is taken before the end of the 10th business day then the pending registration is automatically approved (if Opt out/large EDC territory) or denied (if Opt in/small EDC territory) and the appropriate EDC, LSE and ARC receive a final notification that the registration was approved or denied, as applicable, by the eLRS.

3) General
   a) All registration and non-confidential information are available at will through eLRS by the CSP, EDC and LSE, if they are assigned to the registration. Further, this information can be downloaded as necessary by each PJM Member on the registration to ensure all non-confidential information is transparent to PJM Members with a role in the review process.
   b) The registration review process is managed through a workflow engine which generates specific "tasks" to each PJM Member to ensure each PJM Member knows what specific

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[5] eLRS is a sophisticated PJM system that includes extensive workflow management to ensure all members can perform their specific administrative tasks associated with PJM Load Response Programs.

item needs to be done and when. This task list is available to all designated Users by the PJM Member so that multiple people can easily complete the associated task.

For more information, please see the PJM eLRS User Guide found at: http://www.pjm.com/markets-and-operations/etools/~/media/etools/elrs/elrs-user-guide-v2.0.ashx

PJM demand response Training material is located in the demand response section found at: pjm.com|Training.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, LLC	)))))	CASE NO. 2012-00169

ORDER

On May 3, 2012, East Kentucky Power Cooperative, Inc. ("EKPC") filed an application seeking approval, pursuant to KRS 278.218, to transfer functional control of certain transmission facilities to the PJM Interconnection, L.L.C. ("PJM") effective June 1, 2013. EPKC is organized under KRS Chapter 279 as an electric generating and transmission cooperative and is a utility subject to the jurisdiction of the Commission.[1] Intervention in this case was requested by, and granted to: the Attorney General's Office, Rate Intervention Division ("AG"); PJM; Gallatin Steel Company ("Gallatin Steel"); and Kentucky Utilities Company and Louisville Gas and Electric Company ("KU/LG&E").

By Order dated June 7, 2012, the Commission established a procedural schedule for this case which included two rounds of discovery on EKPC, the opportunity for intervenors to file testimony, one round of discovery on intervenors, and a public hearing. Informal conferences were held at the Commission's offices on October 12,

[1] KRS 279.210(1).

19, and 26, 2012. A public hearing was held at the Commission's offices on November 7, 2012, and EKPC has requested the Commission to issue a decision in this case by December 31, 2012, to provide adequate time for EKPC to complete the preliminary steps needed to accomplish the transfer of control by June 1, 2013.

Standard of Review

EKPC's application is subject to the Commission's jurisdiction under KRS 278.218, which governs a change in ownership or control of assets of an electric utility where those assets have an original book value of $1,000,000 or more. That statute provides, in part, that "[t]he commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest."[2] While the statute does not define "public interest," the Commission has, in the context of a transfer of a utility, interpreted the "public interest" as follows:

> [A]ny party seeking approval of a transfer of control must show that the proposed transfer will not adversely affect the existing level of utility service or rates or that any potentially adverse effects can be avoided through the Commission's imposition of reasonable conditions on the acquiring party. The acquiring party should also demonstrate that the proposed transfer is likely to benefit the public through improved service quality, enhanced service reliability, the availability of additional services, lower rates or a reduction in utility expenses to provide present services. Such benefits, however, need not be immediate or readily quantifiable.[3]

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[2] KRS 278.218(2).

[3] Case No. 2002-00018, *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmbH*, at 7 (Ky. PSC May 30, 2002).

This standard establishes a two-step process: First, there must be a showing of no adverse effect on service or rates; and second, there must be a demonstration that there will be some benefits.[4]

While the application in this case involves the transfer of functional control of utility assets, rather than a transfer of ownership of a utility, the same criteria apply in determining whether the proposed transfer satisfies the "public interest" standard.

EKPC's Application

EKPC has almost 3,100 MW of generation and 2,800 miles of transmission lines. It provides generating and transmission service at wholesale to, and is owned by, its 16 member electric distribution cooperatives who, in turn, provide retail electric service to approximately 521,000 customers in 87 Kentucky counties. PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM also operates an energy market and a capacity market. The energy market sets a market price for electricity by matching supply and demand for both a day-ahead and a real-time market. The capacity market uses a three-year planning horizon to create a long-term price signal for the cost of capacity needed to reliably serve load within the PJM system.

EKPC has been a member of PJM since 2005 for purposes of participating in its energy market and to reserve transmission service within the PJM region. This has allowed EKPC the ability to purchase and sell energy in PJM and to reserve firm and

[4] Case No. 2002-00475, *Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218* (Ky. PSC Aug. 25, 2003).

nonfirm transmission service. EKPC's current PJM membership is in its capacity as an "Other Supplier" under the PJM Operating Agreement and as an electric utility under the terms of PJM's Open Access Transmission Tariff ("OATT"). EKPC now requests authority to fully integrate into PJM by transferring to it functional control of all of EKPC's transmission lines and substations that operate at 100 kv and above. If the Commission approves the transfer, EKPC will be required to execute the PJM Transmission Owners Agreement and the PJM Reliability Assurance Agreement, transfer functional control of 100 kv and above transmission assets to PJM, and participate in the PJM markets. EKPC will then have the option of changing its membership status to either a Transmission Owner or a Generation Owner in PJM.

EKPC states that over the past decade it had periodically assessed whether to join a RTO, but concluded that membership would not be cost-effective. Then in 2010, the Commission hired Liberty Consulting Group ("Liberty") to conduct a focused management audit of EKPC. One of the audit findings was that the benefits of membership in a RTO could now well outweigh any costs, and Liberty recommended that EKPC hire an independent consultant to perform a detailed assessment of the costs and benefits of a RTO membership.

As a result, in 2010, EKPC engaged ACES Power Marketing ("ACES") to conduct a preliminary directional analysis of various energy- and capacity-market scenarios. ACES, which provides energy-trading and risk-management services, is owned by EKPC and 18 other power supply cooperatives, and for some years has performed power-marketing functions for EKPC. The ACES analysis concluded that fully integrating into PJM was economically advantageous.

EKPC then decided to engage another independent consultant to provide a more detailed analysis of RTO costs and benefits. After conducting a competitive bidding process, EKPC retained Charles River Associates ("CRA") in 2011 to conduct a second review, which was independent of the ACES directional analysis. The CRA Report, dated March 20, 2012, concluded that the net expected economic benefit of EKPC joining PJM, based on a 10-year present value, was $142 million. The CRA Report was based on an EKPC load forecast performed in 2010 and refreshed in 2011.[5] In accordance with the requirements of the Rural Utilities Service ("RUS"), EKPC began to perform a new load forecast in 2012, which indicated some changes from the refreshed 2010 forecast. A copy of EKPC's interim 2012 forecast was sent to CRA with a request that it supplement its March 20, 2012 Report to reflect this most recent forecast, updated assumptions related to bilateral seasonal capacity swaps, and reduced costs for PJM's Regional Transmission Expansion Plan due to the termination of two major projects.[6] The CRA Supplemental Report, dated September 10, 2012, affirmed all of CRA's prior findings, but reflected a decrease to $131.9 million for the 10-year present value benefits of joining PJM.

CRA concluded that EKPC could achieve three key benefits from membership in PJM:

1. Trade benefits consisting of more efficient commitment and dispatch of EKPC's generating resources leading to lower adjusted production costs for EKPC (i.e., fuel, variable operations and maintenance expenses, and emission costs). By

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[5] EKPC Supplemental Response to AG Data Request Item 31, p.1 of 12, filed Sept. 10, 2012.

[6] *Id.* at 2 of 12.

decreasing impediments to trade and fully participating in PJM's integrated regional energy market, EKPC will be able to purchase more power at lower costs to substitute for higher-cost generation on its own system;

2. Impacts on PJM's capacity market resulting from EKPC being a winter-peaking utility while PJM is a summer-peaking system, which creates advantageous peak-load diversity for EKPC relative to PJM as a whole, results in significantly less planning reserves needed by EKPC, and produces cost savings by maintaining a lower reserve margin. EKPC also requests authority to bid its customers' interruptible load into the PJM demand-response program to provide additional revenue; and

3. Avoided long-term, firm point-to-point transmission charges of approximately $7.5 million annually that EKPC is currently paying.

EKPC also identified three major challenges it must face as a result of not being a fully integrated member of an RTO. First, operating as a stand-alone dispatch control area and balancing authority is becoming increasingly challenging for EKPC, which is surrounded by PJM to the north and east, KU and LG&E to the west, and the Tennessee Valley Authority ("TVA") to the south. Without a RTO membership, EKPC would have to rely upon its own resources or those of its neighbors to match generation to load, which is not always the most economic choice due to transmission constraints.

Second, the cost of securing firm transmission access to regional energy markets is increasing. For EKPC to engage in the sale of excess energy or to make economic energy purchases, it must ensure the availability of a reliable and firm transmission path between the market and the EKPC system. To secure this requisite transmission path, EKPC purchased 400 MW of long-term, firm point-to-point transmission service to facilitate importing power to meet its reserve and economic purchase needs. Maintaining this 400 MW transmission path costs EKPC approximately $7 million per year.

Third, EKPC must maintain an adequate amount of capacity reserve in order to safely and reliably operate its system. Currently, for planning purposes, EKPC has an internal target to maintain a 12 percent capacity reserve margin on its winter peak load, or approximately 360 MW. In addition, EKPC must carry operating reserves during all periods of time. EKPC currently relies on the TEE Contingency Reserve Sharing Group ("TCRSG"), along with TVA, KU, and LG&E, to meet the North American Electric Reliability Council imposed contingency reserve standards. As part of this arrangement, EKPC must hold back 94 MW of reserves it could otherwise sell on the market. This reserve sharing limits EKPC's fleet-wide plant optimization, making its generation dispatch less optimal.

In addition to identifying these three challenges that would be ameliorated by membership in PJM, EKPC indicated that there were a number of non-quantifiable benefits of PJM's membership. They include being better positioned to respond to future federal environmental and regulatory requirements and the structural protections in place to safeguard the integrity and stability of the PJM markets.

<u>Positions of the Parties</u>

<u>AG</u>

The AG is of the opinion that EKPC has met its burden of establishing that the proposed transfer of its transmission assets to PJM is for a proper purpose and is consistent with the public interest. The AG notes that the proposed transfer will not adversely affect EKPC's level of service, but rather will save ratepayers money while allowing the EKPC system to become more efficient and reliable. The AG also recognizes the concerns expressed by KU/LG&E (as discussed below) and recommends that EKPC, PJM, and KU/LG&E develop mutually satisfactory conditions upon which all may agree and which will ensure that no harm will result to the transmission or rates for either utility's members or ratepayers.

Gallatin Steel

Gallatin Steel also supports EKPC's request, asserting that the transfer of control of certain of EKPC's transmission facilities to PJM is for a proper purpose and consistent with the public interest. Gallatin Steel notes that EKPC's full integration into PJM would result in multiple benefits, including lower adjusted production costs due to more efficient generation resource commitment and dispatch, significantly lower planning reserves, and avoided long-term firm point-to-point transmission charges. Gallatin Steel takes no issue with the conclusions in the CRA Report that EKPC would achieve an estimated net benefit should it fully integrate into PJM.

KU/LG&E

KU/LG&E have taken no position on the issue of whether EKPC should or should not be authorized to join PJM. Rather, KU/LG&E have focused exclusively on the potential impacts to the KU/LG&E system and to their respective ratepayers in the event that EKPC becomes a full member of PJM.

EKPC's and KU's systems are heavily interconnected, given the geographic proximity of the two systems and the fact that the companies share 67 interconnection points between their transmission systems. The companies also use each other's facilities to serve their respective customers through numerous load interconnection points. KU/LG&E serve over 100 MW (peak) of their native-load using EKPC's transmission system. EKPC serves approximately 450 MW of its native-load customers' load using KU/LG&E's transmission system. EKPC and KU/LG&E are signatories to a Network Integration Transmission Service Agreement which provides for KU/LG&E to pay EKPC formula rates to use EKPC's transmission system. The EKPC formula rates are set forth in EKPC's OATT, which is under the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Currently, KU/LG&E pay cost-based rates under EKPC's transmission tariff that are calculated using EKPC's transmission-asset rate base. KU/LG&E include these transmission costs in their base rates.

Although KU/LG&E do not object to EKPC's full integration into PJM, KU/LG&E contend that EKPC's full membership in PJM will increase EKPC's transmission rates by changing the calculation methodology to reflect PJM costs and requirements. This will impose new costs and risks on KU/LG&E and their customers unless EKPC and PJM commit to hold KU/LG&E harmless from the impacts of this transaction. KU/LG&E also expressed concerns over the potential negative impact on the TCRSG as a result of EKPC's decision to fully join PJM, and they recommend that if the transaction is approved it should be conditioned on a requirement that EKPC and PJM develop a plan for how EKPC can fulfill its obligations as a member of TCRSG, and require that the plan be completed and vetted with LG&E/KU and TVA.

Stipulation and Recommendation

A Stipulation and Recommendation ("Stipulation") dated November 2, 2012, was filed in the record on November 7, 2012. The Stipulation relates solely to the issues raised by KU/LG&E, and was signed by, and agreed to by, KU/LG&E, EKPC, PJM and the AG. The remaining party to this case, Gallatin Steel, did not agree to the Stipulation, but did sign it as "Hav[ing] No Objection."[7] The Stipulation is in general intended to hold KU/LG&E harmless from any cost increases or other adverse effects they might incur as a result of EKPC joining PJM. The Stipulation provides, in pertinent part, as follows:

1. KU/LG&E, EKPC, and PJM shall work together, subject to FERC approval, to keep the KU/LG&E load served by the EKPC transmission system as part of the KU/LG&E balancing authority by use of a pseudo-tie between PJM and KU/LG&E, with each party bearing its own cost to implement this arrangement;

2. KU/LG&E shall pay for transmission service provided by EKPC for deliveries to the KU/LG&E load in accordance with the terms of the PJM OATT applicable to the EKPC pricing zone, subject to change based on EKPC's revenue requirements;

3. PJM shall not charge KU/LG&E any other rates or charges that are assessed on load in the PJM markets;

4. KU/LG&E will contract with EKPC for ancillary services at the terms and conditions set forth in EKPC's OATT, Schedules 1 and 2, subject to change based on EKPC's costs, not PJM's costs;

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[7] A copy of the Stipulation is attached to this Order as an Appendix and is incorporated herein.

5. EKPC and PJM will work with KU/LG&E and TVA to develop a plan for how EKPC can continue to fulfill its reserve obligation as a member of TCRSG after it becomes a member of PJM;

6. If FERC does not approve the requisite terms of the Stipulation, EKPC agrees to not unilaterally pursue integration into PJM, but EKPC will work in good faith with KU/LG&E to achieve a resolution acceptable to all parties, FERC, and the Commission;

7. EKPC's load served from the KU/LG&E transmission system is within the PJM balancing authority, will be treated as EKPC zonal load, and will pay the KU/LG&E OATT;

8. EKPC and PJM agree to maintain the current interconnection agreement with KU/LG&E, including the amended September 2011 interconnection agreement between EKPC and KU/LG&E;

9. PJM agrees to recognize and honor flowgates identified by LG&E and KU to their reliability coordinator, TVA;

10. PJM agrees to provide KU/LG&E with modeling information and results of analyses related to critical contingencies identified in network integration studies for EKPC; and

11. The Commission shall retain jurisdiction following EKPC's transfer of transmission assets to monitor and enforce the provisions of the Stipulation and shall have jurisdiction over PJM for purposes of enforcing PJM's commitments to the extent not inconsistent with FERC jurisdiction and to the extent any requisite FERC approvals have been granted.

Commission Findings

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that EKPC has filed a significant amount of evidence, consisting of expert testimony and financial analysis, to support its application to join PJM. EKPC filed the CRA Report and Supplemental Report to demonstrate that the benefits of membership in PJM outweigh the costs. CRA performed its cost/benefit analysis using existing state-of-the-art modeling tools: GE MAPS, a dispatch model which estimates the locational marginal price, as well as the North American Electricity and Environment Model ("NEEM"), which takes into account environmental requirements and likely plant retirements. The NEEM modeling outputs (which include fuel cost and variable operation and maintenance costs) were used as inputs into the GE MAPS modeling of prices at different locations in the PJM system.

CRA also utilized their own extensive experience in estimating costs and benefits of RTO membership. CRA used the study period 2013-2022, based upon that experience, and projected costs and benefits on an annual basis throughout the study period, as well as cumulatively for the 10-year period on a net present value basis.

As described in the Supplemental Report, CRA estimated $40 million in trade benefits over the study period. In general, this is the benefit of being able to sell excess generation into the PJM Market, taking into account the production costs associated with that generation as well as the benefit associated with being able to buy needed generation or generation that is less expensive than EKPC can generate at any given time.

CRA also estimated positive PJM capacity market impacts for EKPC by participating in PJM's Reliability Pricing Model ("RPM"). Under the RPM forward market construct, PJM annually conducts an auction in May for generation owners to make capacity available three years in advance of the delivery year and for load serving entities to buy capacity as needed for that delivery year. Thus, in May 2013, PJM will conduct a capacity auction for the June 2016 – May 2017 delivery year. The capacity auction includes not only generation capacity but also demand response and transmission assets as resources. As a participant in RPM, EKPC may bid its entire generation capacity into the market and receive the market price for that generation, while simultaneously purchasing at the market price the generation needed to serve its load. Alternatively, EKPC can elect to self-supply its generation needs by participating under a Fixed Resource Requirement ("FRR") for capacity. Under the FRR, EKPC can use its own generation and any capacity available to it under bilateral contracts to meet its load, with any capacity shortfall or excess being bought or sold in the PJM capacity market at market prices.

EKPC has requested authorization to participate under RPM, although the two other Kentucky jurisdictional utilities in PJM, Duke Energy Kentucky, Inc. and Kentucky Power Company, have always participated under FRR. EKPC notes that it is a winter-peaking utility and now must meet a 12 percent generation planning reserve requirement, which currently equates to 360 MW, in both the winter and the summer season. However, PJM is a summer peaking system and, if EKPC becomes a member of PJM and participates in RPM, EKPC will be required to hold a much smaller planning reserve requirement of 2.8 percent, which currently equates to 70 MW, during the summer season only. The ability to maintain a lower reserve margin is expected to produce additional revenue for EKPC, since any generating capacity in excess of its load and reserve margin can be sold at the PJM capacity market price. These capacity market benefits are substantial, and are expected to yield $137 million over the study period.

In addition to the benefit of EKPC's seasonal load diversity with the PJM system, EKPC will be allowed to maintain a lower reserve margin as a participant under RPM. If EKPC participates under FRR, it would be required to hold back an additional three percent of its reserve requirement, thereby reducing the amount of generation capacity it could sell for delivery into the PJM summer peaking market. This additional hold back of three percent is estimated to reduce EKPC's capacity market benefits by $3 million to $9 million annually.

Due to the three-year future delivery year structure for RPM, capacity auctions for the 2013-2014, 2014-2015, and 2015-2016 delivery years have already taken place. Thus, upon joining PJM, EKPC will be required to initially participate in FRR. Although existing PJM rules require a FRR participant to provide five years notice before switching to RPM, EKPC and PJM will seek a waiver from FERC to allow EKPC to switch at the start of the 2016 RPM auction year.

The final area of benefits to accrue to EKPC is the elimination of the long-term firm point-to-point transmission charges that are associated with the annual reservation of 400 MW of transmission capacity on the PJM system. This transmission capacity currently is needed by EKPC to economically meet its load requirements during certain times of the year. As a member of PJM, EKPC will be entitled to receive transmission service without paying this $7.5 million annual charge, resulting in estimated benefits of $56.1 million over the 2013-2022 study period.

The cost of RTO membership includes annual administrative charges payable to PJM and FERC. Over the 10-year study period, these amount to $35 million to PJM and $7.7 million to FERC. EKPC is also expected to incur one-time costs and ongoing costs for equipment and personnel needed to interface with PJM, for a total of $5.6 million over the study period. Finally, there will be net transmission costs estimated at $53 million over the study period. This category is comprised of two components: EKPC's share of costs for the expansion of transmission facilities throughout the entire PJM region; and EKPC's share of transmission revenues allocated to transmission owning members in PJM for firm point-to-point transmission service. Both of these components are calculated on a pro rata basis to all members.

In summary, CRA estimates that over the 10-year study period, EKPC will see a net economic benefit of approximately $131.9 million associated with membership in PJM. Subject to rounding, as set forth in the CRA Supplemental Report, the estimated cost and benefit values, expressed on a net present value basis, are summarized in the table below:[8]

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[8] *Id.* at 11 of 12.

Category	Costs	Benefits
Administrative Costs	$48.3 Million	
Transmission Costs	$53.0 Million	
Trade Benefits		$40.0 Million
Capacity Benefits		$137.0 Million
Avoided PTP Transmission Charges		$56.1 million
Subtotal	$101.3 Million	$233.1 Million
Net Benefits		$131.9 Million

The Commission finds that EKPC has demonstrated that membership in PJM will not have an adverse impact on its rates or quality of service, and that there will be substantial benefits from cost savings in each of the years covered by the study period, including PJM planning years 2016-2023 in which EKPC seeks to participate in RPM. Consequently, EPKC's request to transfer functional control of its transmission assets to PJM effective June 1, 2013 is for a proper purpose, is consistent with the public interest, and should be approved. The Commission will, therefore, authorize EKPC to execute the PJM owners Agreement and the PJM Reliability Assurance Agreement, copies of which were attached to the EKPC's application as Exhibits 5 and 6, and all other documents and agreements necessary to effectuate EKPC's full integration into PJM. We will also approve EKPC's participation in RPM, with the caveat discussed below relating to annual reporting and reviews.

The Commission further finds that approval of EKPC's Application will not diminish the Commission's jurisdiction or authority with respect to: (1) the Commission's review and prescription of rates for EKPC based upon the value of EKPC's property used to provide electric service; (2) EKPC's obligation of to file any Integrated Resource Plans or any other information required under Commission statute, regulation, or Order; (3) EKPC's obligation to provide bundled generation and transmission service to its members; and (4) EKPC's obligation to obtain any Certificate of Public Convenience and Necessity or Site Compatibility Certificate that may be required prior to commencing construction of an electric generation or transmission facility. In addition to needing Commission approval to join PJM, EKPC also needs approval of FERC and will seek the consent of the RUS. To properly keep the Commission fully informed, EKPC should file a report by the seventh day of each month, beginning with February 2013, describing the prior month's actions related to its efforts to join PJM. The monthly reports should include the status of FERC proceedings and RUS review, copies of any other agency decisions approving, approving with conditions, or denying membership in PJM, and the date that either functional control of EKPC's transmission assets are transferred to PJM or the proposed transfer is terminated.

EKPC has requested that, in conjunction with membership in PJM, each of its customers' interruptible loads under contact and under its Direct Load Control program be authorized to be included in PJM's Demand Response program as of the date of membership. The Commission recognizes that EPKC is not requesting authority for the retail customers who participate by contract or tariff in an interruptible load control program to participate, either directly or through a third party, in any PJM Demand Response program. Rather, the request is for authorization for EKPC, as the generation supplier, to be the participant in the PJM Demand Response programs so that EKPC can bid into PJM the interruptible load that is available to EKPC under contract or tariff.

The Commission recognizes that the PJM Demand Response program can be an effective planning tool with potential benefits for both EKPC and PJM, and we encourage EKPC to have a dialogue with its customers to utilize this tool in such a way as to maximize those benefits. We find that EKPC's participation in the PJM Demand Response program on behalf of its 16 member cooperatives and their retail customers is reasonable, provided that each existing or new interruptible load contract or tariff has been filed with and accepted or approved by the Commission. In the event that EKPC determines in the future that it will be beneficial to its system to allow retail interruptible customers to participate, directly or through third parties, in the PJM Demand Response program, EKPC and its member cooperatives will need prior Commission approval of new contracts or amendments to existing contracts and tariffs.[9] EKPC should review all existing interruptible contracts and its two existing tariffs, designated as Section D–Interruptible Service and Section F–Voluntary Interruptible Service, to ensure compliance with the terms of this Order and the PJM Demand Response program and file revisions as appropriate or needed within 30 days.

With respect to the Stipulation, the Commission finds that the terms, conditions, and commitments contained therein are reasonable and should be accepted as a complete resolution and satisfaction of the issues raised in this case by KU/LG&E. The Commission commends the parties, particularly PJM, for their diligent efforts to work in a collaborative manner to structure an agreement that will ensure no adverse impacts to KU/LG&E, while preserving for EKPC all of the benefits that are projected to accrue from membership in PJM. The Commission also recognizes that on December 5, 2012,

[9] The same requirement for Commission approval of retail customer participation in PJM Demand Response was imposed in Case No. 2010-00203, *Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of Its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization* (Ky. PSC Dec. 22, 2010)

EKPC filed notice that KU/LG&E and TVA have now determined that once EKPC joins PJM, EKPC's continued participation in the TCRSG, as provided for in Article III of the Stipulation, should be terminated. EKPC's notice, which included confirming letters from KU/LG&E and TVA, states that EKPC has given the requisite six months' notice to withdraw from the TCRSG as requested by KU/LG&E and TVA due to their concerns that there are North American Electric Reliability Corporation compliance risks associated with PJM's performance of EKPC's reserve obligations.

EKPC's withdrawal from the TCRSG constitutes a modification of the Stipulation. While the evidence of record indicates that EKPC and LG&E/KU have agreed to the modification, the record does not indicate agreement by the other parties to the Stipulation. Consequently, we will conditionally accept the Stipulation, subject to the filing of documentation that all of the parties have agreed to the modification.

EKPC's membership in PJM does create some degree of risk, particularly with respect to EKPC being granted sufficient transmission rights to be able to serve its own load without having to pay higher prices for energy due to transmission congestion. Consequently, the Commission will require EKPC to file by May 31 of each year a comprehensive report setting forth in detail the amount of transmission rights awarded and purchased; a description of hedging plans and strategies to address transmission congestion and market prices for capacity and energy; a breakdown by category of the prior years' benefits and costs of PJM membership; and a projection of future benefits and costs reflecting the most recent PJM capacity auction results. Based on the Commission's annual review of these reports, actions may be taken as necessary to ensure that EKPC's continued membership in PJM is beneficial to its members and consumers, and that EKPC is participating in PJM in a manner that maximizes all available RTO benefits.

Finally, the Commission finds that the bulk of the trade benefits that EKPC expects to accrue as a member of PJM will flow back to its 16 member cooperatives and their retail customers through the Fuel Adjustment Clause. However, absent a base rate case filing by EKPC, there is no existing mechanism to flow back to customers the capacity market benefits. While we recognize that the capacity market benefits will not actually increase EKPC's revenues until June 2016 and thereafter, those benefits are expected to be more than three times the trade benefits. For this reason, the Commission finds that EKPC's membership in PJM should be conditioned upon EKPC agreeing to file, no later than November 30, 2015, an application for approval of a rate mechanism to flow back to customers the capacity market benefits expected to accrue from membership in PJM. EKPC's Chief Executive Officer should file within seven days of the date of this Order, a letter accepting and agreeing to be bound by this condition.

IT IS THEREFORE ORDERED that:

1. EKPC's request to transfer functional control of its transmission facilities operated at 100 kv and above to PJM is approved subject to the filing, within 10 days of the date of this Order, of: (a) the letter from EKPC's Chief Executive Officer agreeing to file, no later than November 30, 2015, a rate mechanism to flow back to customers the PJM capacity market benefits; and (b) documentation that all parties agree to modify the Stipulation to allow EKPC to withdraw from the TCRSG.

2. The Stipulation, dated November 2, 2012, as modified by the December 5, 2012 filing to extinguish any obligation arising under Article III, is incorporated herein and is conditionally approved subject to the filing of the documentation discussed in Ordering paragraph 1.

3. EKPC shall file within 30 days of the date of this Order any appropriate or needed amendments to existing special contracts or tariffs to reflect that EKPC is authorized to bid any customer's interruptible load into the PJM Demand Response program.

4. Any customer on the EKPC system that seeks to participate directly or through a third party in the PJM Demand Response program shall do so under the terms of an EKPC special contract or tariff that has been approved by the Commission.

5. EKPC shall file monthly status reports as described in the findings above until it has fully integrated into PJM or the transaction is terminated.

6. By May 31 of each year, EKPC shall file with the Commission the comprehensive report detailing transmission rights, hedging strategies, and PJM benefits and cost as more fully described in the findings above.

7. The reports required to be filed by EKPC pursuant to Ordering paragraphs 5 and 6 shall reference the number of this case and shall be retained in EKPC's general correspondence file.

By the Commission

ENTERED

DEC 20 2012

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Case No. 2012-00169

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2012-00169 DATED DEC 2 0 2012

RECEIVED

NOV 07 2012

PUBLIC SERVICE COMMISSION

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation is entered into this 2nd day of November 2012 by and among Louisville Gas and Electric Company ("LG&E"); Kentucky Utilities Company ("KU") (LG&E and KU are hereafter collectively referenced as "the Utilities"); East Kentucky Power Cooperative, Inc. ("EKPC"); Office of the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG") and PJM Interconnection, L.L.C., ("PJM") in the proceeding involving the above parties, which are the subject of this Stipulation and Recommendation, as set forth below. (The Utilities, EKPC, AG and PJM are referred to collectively herein as the "Parties.")

WITNESSETH:

WHEREAS, EKPC filed on May 3, 2012, with the Kentucky Public Service Commission ("Commission") its Application *In the Matter of: The Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, L.L.C.*, and the Commission has established Case No. 2012-00169;

WHEREAS, the Utilities, AG and PJM have been granted intervention by the Commission in this proceeding;

WHEREAS, informal conferences, attended in person or by teleconference by representatives of the Parties and Commission Staff took place on October 12, 19, and 26, 2012, at the offices of the Commission, during which a number of procedural and substantive issues were discussed, including terms and conditions related to the issues pending before the Commission in this proceeding that might be considered by all Parties to constitute reasonable means of addressing their concerns;

WHEREAS, the Parties desire to recommend to the Commission that it enter its Order setting the terms and conditions that the Parties believe are reasonable as stated herein;

WHEREAS, it is understood by all Parties that this agreement is a stipulation among the Parties concerning all matters at issue in these proceedings pursuant to 807 KAR 5:001, Section 4(6);

WHEREAS, the Parties have spent many hours to reach the stipulations and agreements that form the basis of this Stipulation and Recommendation;

WHEREAS, the Parties, who represent diverse interests and divergent viewpoints, agree that this Stipulation and Recommendation, viewed in its entirety, is a fair, just and reasonable resolution of all the issues in this proceeding; and

WHEREAS, the Parties recognize that this agreement constitutes only an agreement among, and a recommendation by, themselves, and that all issues in this proceeding remain open for consideration by the Commission at the formal hearing in this proceeding.

NOW, THEREFORE, in consideration of the premises and conditions set forth herein, the Parties hereby stipulate, agree, and recommend as follows:

ARTICLE I. Agreement to Support EKPC's Integration Into in PJM

Section 1.1. Subject to all of the commitments and conditions contained herein, all Parties agree to support EKPC's request to integrate into PJM.

ARTICLE II. Maintenance of the Utilities' Load Outside of the PJM Markets

Section 2.1. The load served by the Utilities utilizing EKPC's transmission system (the "the Utilities' Load") has been, and the Utilities desire that it continue to be, part of the Utilities' Balancing Authority ("BA") and not treated as being within the PJM markets by virtue of EKPC's integration into PJM. The Utilities and EKPC, in coordination and cooperation with each other and with PJM, and subject to approval by the Federal Energy Regulatory

Commission ("FERC"), shall keep the Utilities' Load outside of PJM as set forth in this Section.

Section 2.1.1. The Utilities' Load shall be pseudo-tied between PJM and the Utilities, so that such load will be in the Utilities' BA. The Utilities, EKPC, and PJM shall cooperate in good faith to determine the specific metering and related equipment and protocols in order to implement the pseudo-tying of the Utilities' Load between PJM and the Utilities' BA. Except as otherwise agreed between PJM and EKPC, each party shall bear its own costs to implement such arrangements, and in no events shall Utilities be responsible for costs incurred by PJM.

Section 2.1.2. The Utilities shall pay for transmission service on the EKPC transmission system for deliveries to the Utilities' Load in accordance with the terms of the PJM Open-Access Transmission Tariff ("OATT"), i.e., the EKPC Transmission Pricing Zone rate, subject to all other provisions of this Article II. The Utilities will be billed by and shall make payments to PJM for such service. The Utilities understand and acknowledge that the EKPC zonal rate, and thus the rate payable by the Utilities, is subject to change in accordance with EKPC's rights under the PJM Tariff and applicable laws and regulations, but such changes shall not contravene any provision in this Article II and will be calculated based on EKPC's transmission revenue requirements using PJM-prescribed and FERC-approved rate calculation methodologies.

Section 2.1.3. Because the Utilities' Load will be in the Utilities' BA and not in the PJM markets, PJM shall not charge the Utilities with any other rates or charges that are assessed on load that is within the PJM Markets pursuant to the PJM tariff, including, but not limited to Regional Transmission Expansion Plan, locational marginal prices, congestion, and administrative costs. This provision applies only to charges for transmission service for the Utilities' Load and does not address costs that may develop in furtherance of possible future, unknown FERC policies or requirements.

Section 2.1.4. With respect to Ancillary Services Schedules 1 (Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service), the Utilities will contract with EKPC to supply such services to the Utilities, who will purchase them based upon the terms and conditions as currently set forth in Schedules 1 and 2 of EKPC's current Open Access Transmission Tariff. EKPC reserves its right to modify the rates for Schedules 1 and 2, and thus the charges payable by the Utilities; however, any such change shall be based only on EKPC's costs and not PJM's costs.

Section 2.1.5. The objective of this Article is to insulate the Utilities' Load from the effects of EKPC's integration into PJM by maintaining arrangements comparable to those that existed prior to EKPC's integration into PJM. If the FERC does not approve all of the terms of this Stipulation and Recommendation that require FERC approval, EKPC shall not unilaterally pursue its integration efforts; rather, recognizing the importance of EKPC fully integrating into PJM on or before June 1, 2013, EKPC and the Utilities shall work with all good faith, best efforts, and reasonable speed to negotiate and achieve modified means by which EKPC may fully integrate into PJM on terms acceptable to the Parties, the Commission, and FERC. If the Parties cannot agree upon such means in a timely manner, each Party reserves its right to make such proposals to the Commission and FERC as it deems appropriate and to protest and contest proposals by the other Party.

Section 2.1.6. The Utilities, EKPC and PJM acknowledge and agree that the EKPC load served from the Utilities' transmission system ("EKPC Load") is within the PJM BA and will be treated as EKPC zonal load. EKPC shall pay for transmission service on the Utilities' transmission system for deliveries to the EKPC Load in accordance with the Utilities' OATT; however, the Utilities shall not charge or allocate to EKPC Load the cost of any transmission project outside the Utilities' service territory arising from regional transmission expansion or planning associated with the Utilities' involvement in the Southeastern Regional Transmission Planning

("SERTP") group, which is the Utilities' planned means of complying with FERC Order No. 1000 and related policies or requirements. This provision applies only to charges for transmission service for EKPC Load and does not address costs that may develop in furtherance of possible future, unknown FERC policies or requirements. In the event Utilities' involvement in the SERTP is not a successful means of complying with FERC Order No. 1000 and related policies or requirements, EKPC reserves the right to challenge the Utilities' subsequent means of complying with FERC Order No. 1000 and related policies or requirements to the extent such subsequent means of compliance would result in increased charges or rates being assessed to the EKPC Load within the PJM BA and treated as EKPC zonal load.

Section 2.2. Any intervention by the Utilities into EKPC's filings with FERC relating to EKPC's integration into PJM shall be in support of these filings with FERC and shall not contest these arrangements or otherwise be of an adversarial nature; however, the Utilities reserve the right to oppose EKPC or PJM concerning any issue(s) that have not arisen in this proceeding, as well as to contest any deviation from EKPC's planned integration into PJM according to the terms of EKPC's application in this proceeding as modified or conditioned by the terms of this Stipulation and Recommendation. For the purposes of this provision, the following issues shall be deemed to have arisen in this proceeding (in addition to those that have actually arisen in this proceeding):

1. EKPC's request to shorten time to be eligible to participate in the Reliability Pricing Model ("RPM") market from 5 years to 3 years;
2. Filing of PJM-EKPC Network Integration Transmission Service ("NITS") Agreement;
3. Transfer of existing EKPC OATT, Point-to-Point, and NITS service agreements and interconnection agreements to the PJM tariff;
4. EKPC revenue requirements (rate) filing and ancillary services filing;
5. Notice of cancellation of EKPC's current OATT; and
6. PJM tariff amendments necessary to reflect EKPC's integration (adding EKPC as a pricing zone, EKPC's rates).

Section 2.3. EKPC agrees to engage in a good faith review of any FERC proceeding filed by the Utilities, either individually or in concert with other utilities, seeking approval of the SERTP as the Utilities' means of complying with FERC Order No. 1000 and related policies or requirements. If, following such review, EKPC agrees with the filing, it will intervene to support the Utilities' application in that proceeding insofar as it is consistent with the provisions and intent of this Stipulation and Recommendation.

Section 2.4. Concerning load switching for maintenance and restoration purposes, the Utilities and EKPC will continue to address load switching on the same terms as exist today.

ARTICLE III. EKPC's Contingency Reserve Sharing Group ("CRSG") Participation

Section 3.1. EKPC and PJM agree to work with the Utilities and TVA to develop a plan for how EKPC can fulfill its obligations (currently 94 MW of reserves) as a member of the CRSG. The Utilities acknowledge that EKPC and PJM have begun this effort. EKPC, the Utilities, and PJM agree to work with all good faith and best practices with TVA to complete the plan timely, with a target completion date of December 31, 2012.

Section 3.2. EKPC and PJM further commit to use all good faith and best practices to resolve all disputes or issues that arise with TVA or the Utilities concerning the CRSG.

Section 3.3. EKPC, PJM, and the Utilities agree that the continuation of the CRSG is contingent upon NERC Standards as they exist today. If NERC Standards change that adversely impact any member of the CRSG, then that party or parties may exercise their rights to withdraw under the current CRSG agreement.

Section 3.4. Immediately upon TVA's issuance of its notice of withdrawal from the CRSG, the provisions of this Article III shall cease to be of any effect, and any and all obligations between any of the Parties to this Stipulation and Recommendation created solely by this Article III shall immediately end.

ARTICLE IV. Transmission System Operations

Section 4.1. EKPC and PJM agree to maintain the current interconnection agreement with the Utilities. PJM agrees that the amended September 2011 interconnection agreement entered into between EKPC and the Utilities does not have to be terminated. PJM can file the interconnection agreement with FERC with a PJM Service Agreement on it as part of the integration. This will ensure continued effective coordination of the Utilities' and EKPC's systems.

Section 4.2. EKPC and the Utilities further agree to operate and coordinate their 69 kV systems according to operating guides, procedures, and practices, written and unwritten, that exist today and impact the Utilities. This provision shall not conflict with the provisions of Section 4.1.

Section 4.3. PJM agrees to recognize and honor flowgates the Utilities identify to their RC, TVA.

The Joint Reliability Coordination Agreement Among and Between Midwest Independent System Operator, Inc.("MISO"), PJM Interconnection, LLC, and Tennessee Valley Authority ("JRCA"), revised May 1, 2009, is in effect as between PJM and TVA. (MISO has withdrawn from the JRCA.) The JRCA addresses the process by which a transmission entity, like the Utilities, identifies flowgates to be included in the Congestion Management Process, the required testing to verify the impacts of the flowgates, the requirements for data exchange to ensure that the identified flowgates are included in models, and the methods by which congestion management is implemented in real time operations.

PJM is committed via the JRCA to recognize and honor flowgates that the Utilities identify to TVA, the Utilities' Reliability Coordinator, if those identified flowgates pass the required testing that is specified in the FERC-approved Congestion Management Process, which is an attachment to the JRCA.

ARTICLE V. PJM Network Integration Study

Section 5.1. PJM agrees to provide to the Utilities modeling information and results of analyses related to critical contingencies identified in network integration studies for EKPC. PJM and EKPC further agree to work with the Utilities in a cooperative way, using all good faith and best practices, to supply to the Utilities such input, modeling, and analytical data concerning the EKPC network integration study as the Utilities reasonably request to understand and analyze any potential impacts to their system that EKPC's full integration into PJM may cause. EKPC, PJM, and the Utilities agree to follow all applicable Critical Energy Infrastructure protocols in their data exchanges. PJM commits to work with the Utilities to ensure a thorough understanding of analyses performed and to discuss alternative measures to mitigate planning criteria violations identified.

ARTICLE VI. Kentucky Public Service Commission's Ongoing Jurisdiction

Section 6.1. The Commission shall retain jurisdiction following the transfer of control from EKPC to monitor and enforce these commitments.

Section 6.2. The Commission shall have jurisdiction over PJM for the limited purpose of enforcing PJM's commitments as set forth in this Stipulation and Recommendation to the extent not inconsistent with the jurisdiction of the FERC; however, the Commission shall have no authority to enforce any *commitment of PJM that is subject to acceptance by FERC but which* acceptance FERC denies.

ARTICLE VII. Miscellaneous Provisions

Section 7.1. Except as specifically stated otherwise in this Stipulation and Recommendation, the Parties agree that making this Stipulation and Recommendation shall not be deemed in any respect to constitute an admission by any Party hereto that any computation, formula, allegation, assertion, or contention made by any other Party in these proceedings is true or valid.

Section 7.2. The Parties agree that the foregoing stipulations and agreements represent a fair, just, and reasonable resolution of the issues addressed herein and are consistent with the public interest for purposes of approving EKPC's full membership in PJM pursuant to KRS 278.218.

Section 7.3. The Parties agree that, following the execution of this Stipulation and Recommendation, the Parties shall cause the Stipulation and Recommendation to be filed with the Commission by November 2, 2012, together with a recommendation that the Commission enter its Order on or before December 31, 2012, implementing the terms and conditions herein.

Section 7.4. Each signatory waives all cross-examination of the other Parties' witnesses unless the Commission disapproves this Stipulation and Recommendation, and each signatory further stipulates and recommends that the application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record (subject to all pending Petitions for Confidential

Treatment and all applicable Confidentiality Agreements) and approved as filed, except as modified by this Stipulation and Recommendation. The Parties stipulate that after the date of this Stipulation and Recommendation they will not otherwise contest EKPC's application in this proceeding, as modified by this Stipulation and Recommendation, during the hearing in this proceeding, and that they will refrain from cross-examination of all witnesses during the hearing, except insofar as such cross-examination supports the Stipulation and Recommendation or EKPC's application subject to the commitments and conditions of this Stipulation and Recommendation.

Section 7.5. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation and Recommendation be accepted and fully incorporated into any Order approving EKPC's application in this proceeding.

Section 7.6. If the Commission issues an Order adopting all of the terms and conditions recommended herein, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such Order.

Section 7.7. The Parties agree that if the Commission does not implement all of the terms recommended herein in its final Order in this proceeding, or if the Commission in its final Order in this proceeding adds or imposes additional conditions or burdens upon the proposed transfer of control or upon any or all of the Parties that are unacceptable to any or all of the Parties, then: (a) this Stipulation and Recommendation shall be void and withdrawn by the Parties from further consideration by the Commission and none of the Parties shall be bound by any of the provisions herein, provided that no Party is precluded from advocating any position contained in this Stipulation and Recommendation; and (b) neither the terms of this Stipulation and Recommendation nor any matters raised during the settlement negotiations shall be binding on any of the Parties to this Stipulation and Recommendation or be construed against any of the Parties.

Section 7.8. The Parties agree that this Stipulation and Recommendation shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

Section 7.9. The Parties agree that this Stipulation and Recommendation shall inure to the benefit of, and be binding upon, the Parties, their successors and assigns.

Section 7.10. The Parties agree that this Stipulation and Recommendation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contemporaneously herewith, shall be null and void, and shall be deemed to have been merged into this Stipulation and Recommendation.

Section 7.11. The Parties agree that, for the purpose of this Stipulation and Recommendation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation. The Parties further agree that the resolution proposed herein is in accordance with law, for a proper purpose, and is consistent with the public interest, all as contemplated by KRS 278.218.

Section 7.12. The Parties agree that neither the Stipulation and Recommendation nor any of the terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein. This Stipulation and Recommendation shall not have any precedential value in this or any other jurisdiction.

Section 7.13. The signatories hereto warrant that they have informed, advised, and consulted with the Parties they represent in this proceeding in regard to the contents and significance of this Stipulation and Recommendation, and based upon the foregoing are authorized to execute this Stipulation and Recommendation on behalf of the Parties they represent.

Section 7.14. The Parties agree that this Stipulation and Recommendation is a product of negotiation among all Parties, and that no provision of this Stipulation and Recommendation shall be strictly construed in favor of, or against, any Party.

Section 7.15. The Parties agree that this Stipulation and Recommendation may be executed in multiple counterparts.

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

East Kentucky Power Cooperative, Inc.

HAVE SEEN AND AGREED:

Mark David Goss, Counsel

Louisville Gas and Electric Company
and Kentucky Utilities Company

HAVE SEEN AND AGREED:

Kendrick R. Riggs, Counsel
Allyson K. Sturgeon, Counsel

Office of the Attorney General of the
Commonwealth of Kentucky, by and through
his Office of Rate Intervention

HAVE SEEN AND AGREED:

Jennifer B. Hans, Assistant Attorney General

PJM Interconnection, L.L.C.

HAVE SEEN AND AGREED:

Jason R. Bentley, Counsel

Gallatin Steel Company

HAVE SEEN AND HAVE NO OBJECTION:

Michael L. Kurtz, Counsel
Kurt Boehm, Counsel

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November 18, 2016

VIA HAND DELIVERY

Ms. Talina R. Mathews, Ph.D.
Executive Director
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

RE: Request for Advisory Opinion

Dear Dr. Mathews:

On behalf of East Kentucky Power Cooperative, Inc. ("EKPC"), please accept this as a request for a written advisory opinion as to the scope of the Commission's December 20, 2012 Order in Case No. 2012-00169 (the "Order"). In that case, the Commission granted permission for EKPC to transfer functional control of its transmission system to PJM Interconnection, LLC ("LLC") as part of EKPC's full integration into the PJM system. However, the Commission expressly prohibited any customer within the EKPC system from either directly or indirectly participating in PJM's Demand Response program without first entering into a contract with EKPC that is approved by the Commission.

EKPC is a not-for-profit generation and transmission rural electric cooperative corporation, formed under KRS Chapter 279, with its headquarters in Winchester, Kentucky. EKPC provides wholesale electricity to its sixteen Owner-Member distribution cooperatives, which in turn serve approximately 525,000 Kentucky homes, farms and commercial and industrial customers in eighty-seven (87) Kentucky counties.

On May 3, 2012, EKPC filed an application with the Commission seeking approval, pursuant to KRS 278.218, to transfer functional control of certain transmission facilities to PJM, effective June 1, 2013. Although EKPC had been a member of PJM since 2005 for purposes of participating in the regional transmission organization's ("RTO") energy market and reserving transmission service within the PJM region, EKPC believed it could realize significant economic and reliability benefits through full integration within PJM. The Commission found EKPC's request sufficiently supported by competent evidence, and thus it approved EKPC's request to fully integrate within PJM by Order entered December 20, 2012 (the "PJM Integration Order"). The Order states in relevant part:

> EKPC has requested that, in conjunction with membership in PJM, each of its customers' interruptible loads under contact and under its Direct Load Control program be authorized to be included in PJM's Demand Response program as of the date of membership. The Commission recognizes that EPKC is not requesting authority for the retail customers who participate by contract or tariff in an interruptible load control program to participate, either directly or through a third party, in any PJM Demand Response program. Rather, the request is for authorization for EKPC, as the generation supplier, to be the participant in the PJM Demand Response programs so that EKPC can bid into PJM the interruptible load that is available to EKPC under contract or tariff. The Commission recognizes that the PJM Demand Response program can be an effective planning tool with potential benefits for both EKPC and PJM, and we encourage EKPC to have a dialogue with its customers to utilize this tool in such a way as to maximize those benefits. We find that EKPC's participation in the PJM Demand Response program on behalf of its 16 member cooperatives and their retail customers is reasonable, provided that each existing or new interruptible load contract or tariff has been filed with and accepted or approved by the Commission. In the event that EKPC determines in the future that it will be beneficial to its system to allow retail interruptible customers to participate, directly or through third parties, in the PJM Demand Response program, EKPC and its member cooperatives will need prior Commission approval of new contracts or amendments to existing contracts and tariff.

Order, pp. 17-18.

The Order goes on to hold:

> Any customer on the EKPC system that seeks to participate directly or through a third party in the PJM Demand Response program shall do so under the terms of an EKPC special contract or tariff that has been approved by the Commission.

Order, p. 21.

At the time the Order was entered, EKPC was not prepared to bid energy efficiency capacity available throughout its system into the PJM capacity market.[1] Moreover, the rules for

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[1] *See* Direct Testimony of Don Mosier, Case No. 2012-00169, pp. 29-30 (filed May 3, 2012).

bidding energy efficiency as capacity were still uncertain in light of issues relating to the appropriate standards for evaluation, measurement and verification of energy efficiency opportunities. In light of this, the Commission's Order is silent as to whether the same prohibitions that apply to a customer's direct or indirect participation in PJM's Demand Response program would also apply to customers seeking to participate directly or indirectly in PJM's Energy Efficiency program.

However, EKPC understands and interprets the Order in the context of prior orders issued in the case where Duke Energy Kentucky, Inc. ("Duke") sought to integrate into full membership in PJM. In Case No. 2010-00203, the Commission held:

> No customer should be allowed to participate directly or through a third party in any PJM demand-response program until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation.[2]

The prohibition in Case No. 2010-00203 is substantively identical to the language in the Order in EKPC's integration case.

In response to the Commission's directive in the Duke case, PJM filed a letter with the Commission on December 29, 2010 which acknowledged that the Commission "has directly provided the relevant evidence to PJM concerning the requirements it placed upon Duke Kentucky retail customer participation in PJM load response programs…." The Commission was unsatisfied with PJM's response, however, and, on January 6, 2011, ordered it to provide further clarification of its understanding of the Commission's conditional approval of the transfer of functional control of Duke's transmission system to PJM. PJM's January 11, 2011 response was clear and unambiguous:

> PJM acknowledges that under the Conditions set forth in the Commission's Order, *no retail customer* of Duke Kentucky is allowed to participate in *any PJM demand-response program* until that customer has entered into a special contract with Duke Kentucky which has been filed with, and approved by, the Commission, or until Duke Kentucky has an approved tariff authorizing customer participation (emphasis added).[3]

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[2] *See In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment*, Order, Case No. 2010-00203, p. 18 (Dec. 22, 2010).

[3] *See* letter from Terry Boston to Jeff Derouen, Case No. 2010-00203, Post-Case Correspondence File (Jan. 11, 2011).

The language in the Duke order is itself adapted from prior Commission precedent allowing Kentucky Power Company to integrate into PJM with the same condition. In Case No. 2002-00475, the Commission held:

> Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. . . . Any such programs would be subject to the applicable rules of the Commission and Kentucky law.[4]

Based upon the foregoing, EKPC understands that Commission precedent and Kentucky law would prohibit any retail customer within the EKPC system from directly, or indirectly through a third-party, participating in any demand response, energy efficiency or load curtailment program without first entering into a contract with EKPC that is reviewed and approved by the Commission. If Staff could confirm or clarify EKPC's understanding and interpretation, it would be much appreciated.

Should you have any questions or require additional information, please do not hesitate to contact me.

Sincerely,

David S. Samford

cc: Mr. Richard Raff
Mr. David Smart
Mr. David Crews

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[4] *In the Matter of the, Application of Kentucky Power Company d/b/a American Electric Power, for Approval, to the Extent Necessary, to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection, L.L.C. Pursuant to KRS 278.218*, Order, Case No. 2002-00475, p. 9 and Appendix A thereto at Paragraph No. 4 (Ky. PSC May 19, 2004).

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January 25, 2017

VIA EMAIL AND FACSIMILE

Mr. Richard G. Raff
General Counsel
Commonwealth of Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, Kentucky 40602-0615
FAX: (502) 564-3460

Re: Response to East Kentucky Power Cooperative's Request for Legal Opinion on Energy Efficiency Resources

Dear Mr. Raff,

I understand that the East Kentucky Power Cooperative ("EKPC") has requested a Legal Staff Opinion concerning the provision of Energy Efficiency Resources[1] ("EERs") within the jurisdictional service territory of EKPC. I respectfully request that you review and consider the following information, prior to rendering an opinion in this matter.

Background

I am an attorney who represents an EER Provider that is operating pursuant to the terms and conditions of the PJM Interconnection, L.L.C. ("PJM") Tariff. The EER Provider operates under the PJM Tariff to work with retailers to develop and sponsor energy efficient lighting programs. It engages in interstate commerce by acquiring the rights to certain EERs from retail suppliers located across the PJM territory (*e.g.*, large hardware stores) and then offering such EERs into the PJM federal wholesale electricity capacity market, pursuant to the terms of the PJM Tariff. This EER Provider intends to participate in the PJM capacity resource markets by submitting EERs, some of which may be located in the EKPC service territory. This EER Provider is not a Kentucky utility and does not have a KPSC tariff.

[1] Capitalized terms used and not otherwise defined herein have the meaning set forth in PJM's Tariff or its Reliability Assurance Agreement.

My client became aware of the subject issue after a PJM employee forwarded my client a copy of the Kentucky Public Service Commission's ("KPSC") December 20, 2012 Order in Case No. 2012-00169 ("12/20/12 Order") that addresses EKPC's entry into PJM. This PJM employee indicated that EKPC believed that the 12/20/12 Order might somehow require an EER Provider to obtain the approval of the KPSC before the EER Provider could participate in PJM's energy efficiency programs with EERs that were located within the jurisdictional service territory of EKPC.

On January 20, 2017, I participated in a conference call with, among others, Ms. Jennifer Tribulski (Counsel for PJM), Mr. David S. Samford (EKPC Regulatory Counsel), and Mr. David Crews (EKPC Senior V.P. of Power Supply). Mr. Samford stated that EKPC had requested that your office provide EKPC with a Legal Staff Opinion concerning the correct interpretation of the 12/20/12 Order.

As discussed herein, Paragraph 4 on page 21 of the 12/20/12 Order[2] does not authorize the KPSC to approve an EER Provider's activities in complying with the PJM Tariff, unless such EER Provider is otherwise subject to the jurisdiction of the KPSC. The activities of an EER Provider pursuant to the PJM Tariff are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC").

KPSC Only Has Authority over Kentucky Electric Utilities

The Kentucky Legislature granted the KPSC authority, in part, over "all utilities in this state. The commission shall have exclusive jurisdiction over the regulation of rates and service of utilities."[3] The Legislature did not grant the KPSC jurisdiction over contracts between retailers and participants under the PJM Tariff.

In a July 24, 2012 KPSC Order in Case No. 2008-00408, the KPSC examined PURPA standards, as well as standards set forth in the Energy Independence and Security Act of 2007, to address Kentucky's Integrated Resource Plan ("IRP") requirements ("7/24/12 Order"). The KPSC noted in the 7/24/12 Order, in part, that "the requirements of the Kentucky IRP standards as currently stated may go beyond our existing authority."[4] As part of the 7/24/12 Order, the KPSC acknowledged that it has the legal authority to approve energy efficiency programs that are conducted by jurisdictional "electric utilities", including EKPC. The KPSC revised Kentucky's IRP standards (including, but not limited to, those addressing energy efficiency resources) in the 7/24/12 Order to apply to electric utilities, as follows:

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[2] "4. Any customer on the EKPC system that seeks to participate directly or through a third party in the PJM Demand Response program shall do so under the terms of an EKPC special contract or tariff that has been approved by the Commission." (12/20/12 Order, p. 21).

[3] KRS § 278.040.

[4] "While the Commission has the authority to inquire into and review the activities of the utilities regarding energy efficiency in conjunction with certificate cases, rate cases, and other investigations, we agree that the requirements of the Kentucky IRP standards as currently stated may go beyond our existing authority." 7/24/12 Order, p. 9.

> Each electric utility shall integrate energy efficiency resources into its plans and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In each integrated resource plan, certificate case, and rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5058).[5]

The 7/24/12 Order also concluded, in part, that "[i]n requiring all jurisdictional electric utilities to adopt this Kentucky IRP Standard, the Commission reaffirms its support for greater energy efficiency and also reaffirms its position that no new administrative regulations are required to do so since we are not modifying any existing regulations."[6] Consistent with the 7/24/12 Order, jurisdictional utilities (such as EKPC and Duke Energy) periodically have sought KPSC approval to participate in energy efficiency activities and have submitted IRP reports to the KPSC that have addressed energy efficiency programs.

EERs Submitted Pursuant to the PJM Tariff are Subject to FERC's Exclusive Jurisdiction

Oversight of (and participation in) PJM's EER program is exclusively subject to the jurisdiction of FERC, which has the sole authority to approve the terms and conditions found in the PJM Tariff. The EER program does not involve the sale or resale or transmission of electricity; PJM Members work with retailers to develop and sponsor energy efficient lighting programs to create permanent, continuous reduction in electric energy consumption. This is a federally-approved program involving contracts between entities in multiple states that participate in a regional resource adequacy market. The U.S. Supreme Court has concluded, for example, that state actions which interfere with FERC's regulation of the wholesale power market, including participation in PJM capacity auction, are preempted by the Federal Power Act.[7]

The 12/20/12 Order Does Not Require an EER Provider to Secure KPSC Approval in Order to Comply With the PJM Tariff.

The 12/20/12 Order addressed the KPSC's approval of EKPC's transfer of functional control of certain facilities to PJM. On page 17 of the Order, the KPSC only discussed the authority of EKPC to participate in PJM's Demand Response Program, as follows:

> EKPC has requested that, in conjunction with membership in PJM, each of its customers' interruptible loads under contact and under its Direct Load Control program be authorized to be included in PJM's Demand Response program as of the date of membership. The Commission recognizes that EPKC is not requesting authority for the

[5] 7/24/12 Order, p. 10 (emphasis added).

[6] 7/24/12 Order, p. 10.

[7] *See, e.g., Hughes v. Talen Energy Marketing, et al.* (S.Ct. April 19, 2016). (The Federal Power Act "allocates to FERC exclusive jurisdiction over "rates and charges . . . received . . . for or in connection with" interstate wholesale sales. §824d(a). Exercising this authority, FERC has approved the PJM capacity auction as the sole rate setting mechanism for sales of capacity to PJM, and has deemed the clearing price *per se* just and reasonable.") (slip at 12)

retail customers who participate by contract or tariff in an interruptible load control program to participate, either directly or through a third party, in any PJM Demand Response program. Rather, the request is for authorization for EKPC, as the generation supplier, to be the participant in the PJM Demand Response programs so that EKPC can bid into PJM the interruptible load that is available to EKPC under contract or tariff. (Emphasis added).

The KPSC also clarified that the need for any future KPSC approval would only be required if EKPC elected to participate in the PJM's Demand Response programs, stating that: "In the event that EKPC determines in the future that it will be beneficial to its system to allow retail interruptible customers to participate, directly or through third parties, in the PJM Demand Response program, EKPC and its member cooperatives will need prior Commission approval of new contracts or amendments to existing contracts and tariff."[8]

Moreover, ordering paragraph 4 of the 12/20/12 Order did not discuss EERs; it only addressed the obligations of EKPC, a KPSC jurisdictional utility, to participate in PJM's Demand Response programs. The 12/20/12 Order does not even include a mention of EERs, which are entirely separate from PJM's Demand Response program. For example, under PJM's Demand Response program, defined and registered resources that are able to reduce demand upon being dispatched by PJM (and in certain instances a local distribution utility) are compensated for possessing such capabilities. In stark contrast, EERs are defined by PJM as resources that are **not** dispatchable; they permanently reduce the need for the grid to produce additional electricity by being energy efficient.[9] EERs, which do not involve the sale or resale of electricity or the dispatch of PJM Demand Resources, are not addressed in the 12/20/12 Order and therefore this Order cannot have created obligations on EERs.

The 12/20/12 Order cannot and does not preempt PJM Tariff language that has been approved by the FERC as part of its regulation of the competitive wholesale electricity market. Oversight of (and participation in) PJM's EER program is exclusively subject to the jurisdiction of FERC, which has approved the PJM Tariff.

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[8] 12/20/12 Order, p. 18 (emphasis added) (citations omitted).

[9] *See, e.g.*, PJM Business Manual 18b, p. 5 ("An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of Schedule 6 (section M) of the Reliability Assurance Agreement. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE Performance Hours) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.")

KPSC's April 13, 2016 Approval of EKPC's IRP Precludes EKPC from Now Challenging Third-Party EER Provider Participation in PJM Programs

As previously discussed, the KPSC does not possess the legal authority to review the activities of non-utility, third-party retailers, including EER Providers. However, **even if** the 12/20/12 Order were to be somehow interpreted to give the KPSC the authority to review the activities of EER Providers operating pursuant to the PJM Tariff in Kentucky, EKPC would still be precluded from challenging such activity because EKPC has already sought and has received the KPSC's approval to allow EER Providers to operate in its territory via its 2015 IRP.

EKPC submitted its 2015 IRP to the KPSC in Case No. 2015-00134. On April 13, 2016, the KPSC issued an Order approving this IRP, thereby completing a "final administrative action" on the EKPC's IRP ("IRP Order"). The IRP Order included a KPSC "Staff Report" that specifically summarized the KPSC Staff's review of the EKPC IRP. The IRP Order declared that the staff review "represents the final substantive action" regarding the IRP.[10]

Of particular importance in the Staff Report is the express discussion of EKPC's plans with respect to its "Residential Efficient Lighting with Retailers Program", the service in which third-party EER Providers participate pursuant to the PJM Tariff. If the IRP Order is not an explicit approval of EER Providers' ability to operate under the PJM Tariff, this Order provides an implicit endorsement of third-party EER Providers work to increase energy efficiency via retail store marketing programs.

Specifically, the Staff Report described EKPC's intent to "transform the market for residential lighting <u>by facilitating a shift in consumer purchasing decisions for the market baseline efficiency to higher efficiency lighting products</u>."[11] The Staff Report also noted that EKPC planned to sponsor "aggressive marketing and promotion activities", which EKPC expected third-party EER providers to promote. The Staff Report expressly stated that "[i]t is expected that retailers will develop their own marketing <u>as well as sponsor local advertising initiatives</u>" [to promote energy efficient lighting.][12] Nothing in the Staff Report conditioned such "retailer" programs upon receipt of approval form either the EKPC or the KPSC. It is this activity (anticipated by EKPC, subsequently approved by the KPSC, and now challenged by EKPC) that EER Providers provide in the PJM region.

Thus, notwithstanding the fact that any challenge to EER Providers' activities is federally preempted, the KPSC's April 13, 2016, Order prevents EKPC from challenging EER Providers operations in its territory.

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[10] *See*, IRP Order, p. 1.
[11] *See*, IRP Order, p. 23.
[12] *See*, IRP Order, p. 23 (Emphasis added).

Permitting EER Providers to Comply with the PJM Tariff Does Not Interfere with EKPC's Exclusive Right to Provide Electricity Service in its Jurisdictional Service Territory.

There is no question that EKPC has the exclusive right to sell retail electricity in its jurisdictional service territory under the supervision of the KPSC.[13] The activities of an EER Provider and retailers, however, do not involve the sale or resale of electricity within the Commonwealth of Kentucky and thus do not fall within the purview of the KPSC. EER Providers conduct activities pursuant to the PJM Tariff involving bilateral contracts for the sale of energy efficient products; there is no retail electricity component to these activities.

Conclusion

Ordering Paragraph 4 of the 12/20/12 Order only applies to the activities of a jurisdictional electric utility, such as EKPC. These approval requirements cannot be applied to a non-jurisdictional entity, such as an EER Provider (which is not a Kentucky electric utility) that is complying with a FERC-approved Tariff to participate in PJM's competitive wholesale energy markets.

Please feel free to contact me if you have any questions regarding these matters, or would like to discuss these issues.

Sincerely,

<u>/s/ Richard A. Drom</u>
Richard A. Drom

Cc: Jenifer Tribulski, Counsel for PJM
David S. Samford, Regulatory Counsel for EKPC (no facsimile number)
David Crews, EKPC Senior V.P. for Power Supply

[13] *See, e.g.*, KRS § 278.018.

(c) That the relocation is associated with other regularly scheduled conversion or construction work and can be done at the same time.
(d) Per consumer-owner request when right-of-way is provided. In such instance consumer-owner will be required to pay for making requested changes.

10. SERVICES PERFORMED FOR CONSUMERS

The Cooperative's personnel shall not while on duty make repairs or perform service to the consumer's equipment or property except in cases of emergency or to protect the public or consumer's person or property. When such emergency services are performed, the consumer may be charged for such service(s) at the rate of time and material(s) used.

11. RESALE OF POWER BY CONSUMERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the consumer shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof, except by written contract approved by the Board of Directors.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

MAY - 1 1996

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Jordan C. Neel
FOR THE PUBLIC SERVICE COMMISSION

DATE OF ISSUE: APRIL 24, 1996 DATE EFFECTIVE: MAY 1, 1996
ISSUED BY: [signature] TITLE: President/General Manager
Issued by authority of an Order of the Public Service Commission of KY in
Case No. 95-383 Dated June 17, 1996.

BLUE GRASS ENERGY
COOPERATIVE CORPORATION

For Entire Territory Served
P.S.C. KY No. 1
Original SHEET NO 7
CANCELLING P.S.C.NO. ___
________ SHEET NO. _____

RULES AND REGULATIONS

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(18) LOCATION OF METERS

Meters shall be easily accessible for reading, testing, and making necessary adjustments and repairs and shall be located at a site designated by Blue Grass Energy personnel.

(19) METER TESTS

Blue Grass Energy will, at its own expense, make periodic tests and inspections of its meters in order to maintain a high standard of accuracy and to conform with the regulations of the Kentucky Public Service Commission. The cooperative will make a test of any meter upon written request of any member. The member will be given the opportunity of being present at such a request test. Should the test made at the member's request show the meter to be accurate within 2% slow or fast, no adjustments will be made to the member's bill and the member will be billed $35.00 to cover the cost of a requested single phase test or $60 for a three phase or demand meter test. Such charge would be subject to the same collection policies as any other amount due and owing the cooperative. Should the test show the meter to be in excess of 2% fast or slow, an adjustment shall be made to the member's bill as prescribed by the Public Service Commission regulations, 807 KAR 5:006, Section 10 (5). If the meter is found to be inaccurate, the cost of the meter test will be borne by Blue Grass Energy.

(20) SERVICES PERFORMED FOR MEMBERS

Blue Grass Energy personnel are prohibited from making repairs or performing services to the member's equipment or property except in cases of emergency or to protect the public or member's person or property. When such emergency services are performed, the member shall be charged for such service(s) at the rate of time and material(s) used, and be it further known that the Cooperative is not liable or responsible in any way for work done on the member's or customer premises for said service calls.

(21) RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively

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DATE OF ISSUE: January 1, 2002 DATE EFFECTIVE: Janu

ISSUED BY: Dan Brewer , President and CEO

ADDRESS:: P. O. Box 990, Nicholasville KY 40340-0990

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
1/1/2002
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

BLUE GRASS ENERGY
COOPERATIVE CORPORATION

For Entire Territory Served
P.S.C. KY No. 1
Original SHEET NO 8
CANCELLING P.S.C.NO. ___
________SHEET NO. ______

RULES AND REGULATIONS

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by Blue Grass Energy and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof.

(22) NOTICE OF TROUBLE

Member or customer should notify Blue Grass Energy immediately, should service be unsatisfactory for any reason, or should there be any defects, trouble or accidents affecting the supply of electricity.

(23) POINT OF DELIVERY

The point of delivery is the point as designated by Blue Grass Energy on the member's premises where current is to be delivered to building or premises, namely, the point of attachment, which is normally the point closest to the utility line. A member or customer requesting a delivery point different from the one designated by the cooperative will be required to pay the additional cost of the special construction. All wiring and equipment, excluding the metering, beyond this point of delivery shall be supplied and maintained by the member.

(24) FAILURE OF METER TO REGISTER

In the event a member's meter should fail to register, the member shall be billed from the date of such failure at the average consumption of the member, based on the twelve months period immediately preceding the failure.

(25) MEMBER's WIRING STANDARD

All wiring of member must conform to Blue Grass Energy requirements and accepted modern standards, as exemplified by the requirements of the National Electrical Safety Code. The cooperative assumes no responsibility in respect to type, standard of construction, protective equipment or the condition of the member's property, and will not be liable for any loss or injury to persons or property occurring on the premises or property of the member. The member will have complete responsibility for all construction, operation, and maintenance beyond the meter. All wiring must have been inspected and accepted by a certified electrical inspector before service

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DATE OF ISSUE: January 1, 2002 DATE EFFECTIVE: Janu[ary 1, 2002]

ISSUED BY: [signature] Dan Brewer, President and CEO

ADDRESS:: P. O. Box 990, Nicholasville KY 40340-0990

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Brent Kirtley
EFFECTIVE
1/1/2002
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

For All Areas Served
Community, Town or City

P.S.C. No. 2

Original SHEET NO. 12

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 1

SHEET NO. ___

RULES AND REGULATIONS

12 RESALE OF POWER BY MEMBER

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof, except by written contract.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE
3/3/2008
PURSUANT TO 807 KAR 5:011
SECTION 9 (1)

DATE OF ISSUE February 1, 2008 **DATE EFFECT** [illegible]008

By Executive Director

ISSUED BY Paul H. Embs
Name of Officer

TITLE PRESIDENT & C.E.O.

RULES AND REGULATIONS

10. MEMBER'S DISCONTINUANCE OF SERVICE
Any member desiring service discontinued or changed from one location to another shall give the Cooperative three (3) day's notice in person or in writing providing such notice does not violate contractual obligations.

11. CONNECT AND RECONNECT CHARGES
The Cooperative will make no charge for connecting service to the member's premises for the initial installation of service provided the connection is made during regular working hours.

The Cooperative will make a service charge of Twenty-five I
($25.00) for reconnecting a service that has been I
disconnected at the original installation location and a
charge of Twenty-five Dollars ($25.00) for connecting any I
subsequent locations during regular working hours and sixty- N
five dollars ($65.00) for connections made after regular N
working hours.

12. RESALE OF POWER BY MEMBERS
All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof.

13. SPECIAL CHARGES
The Cooperative will make a charge of Twenty-five Dollars I
($25.00) for each trip made during regular working hours and I
sixty-five dollars ($65.00) for each trip made after regular N
working hours.

1. To read the meter when the member has failed to read the meter for two (3) consecutive months.
2. To collect a delinquent bill or to collect a returned check.
3. To reconnect a service that has been disconnected for nonpayment of amounts owed to the Cooperative or for violations of these rules and regulations.
4. For any service trip requested by a member to restore electric service when it is determined that the service interruption was caused by a defect in the members wiring or equipment and is not the fault of the Cooperative.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE
MAR 01 2001

Date of Issue: March 1, 2001 Effective Date: March 1, 2001

Issued By: Ted B. Hampton General Manager

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Stephan O Bue
SECRETARY OF THE COMMISSION

6. AVAILABILITY

Available to all customers of the Cooperative for all farm, home, commercial, and industrial uses subject to its established Rules and Regulations. Approval of the Cooperative must be obtained prior to installation of any motor having a rated capacity of five (5) horsepower or more.

7. ACCESS TO PROPERTY

Each customer shall, prior to receiving service, provide any applicable right-of-way easements and/or permits or easements, for the customer's property, required by the Cooperative.

The utility shall, at all reasonable hours, have access to meters, service connections, and other property owned by it and located on customer's premises for purposes of installation, maintenance, meter reading, operation, replacement, or removal of its property at the time service is to be terminated.

8. RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the customer shall be supplied exclusively by the Cooperative, and the customer shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service, or any part thereof, except by written contract approved by the Board of Directors of this Cooperative.

9. CUSTOMER'S LIABILITY AND RESPONSIBILITY

The customer shall assume full responsibility for service upon his/her premises at and from the point of delivery thereof, and for wires, apparatus, devices, and appurtenances hereon used in connection with service. The customer shall indemnify, save harmless and defend the Cooperative against all claims, demands, cost or expense for loss, damage or injury to persons or property in any manner, directly or indirectly arising from, connected with, or growing out of the transmission or use of current by the customer at or on the customer's side of point of delivery.

The customer shall protect the system and/or equipment of the Cooperative on his/her premises and shall not interfere with or alter or permit interference with or alteration of the Cooperative's property or meters except by duly authorized representatives of the Cooperative. Further, except by written permission of the

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

OCT 28 1992

For Entire Territory Served

PSC No. 7

Revision #5 Sheet No. 22

Inter-County RECC
Name of Issuing Corporation Canceling PSC No. 7

Revision #4 Sheet No. 22

RULES AND REGULATIONS

18. Charges for Convenience Type Service: A customer who requires service to convenience type installation such as silo, tobacco or feed barns, water pumps, seasonal camp/cottage,and other like services shall be required to pay for the cost of installation less transformer and meter cost.

19. Interruption of Service: The cooperative will use reasonable diligence to provide a regular and uninterrupted supply of electric power, but in case the electric power shall be interrupted for any cause, the cooperative shall not be liable for damages resulting therefrom.

20. Voltage Fluctuation Caused by Customer: The electric service must not be used in such a manner as to cause unusual fluctuation or disturbances to cooperative's system. Cooperative may require customer, at his own expense, to install suitable apparatus which will reasonably limit such fluctuation.

21. Additional Load: The service connection, transformer, meter and equipment supplied by cooperative for each customer have definite capacity, and no addition to the equipment or load connected thereto will be allowed except by consent of cooperative. Failure to give notice of additions or changes in load and to obtain cooperative's consent for same shall render the customer liable for any damage to any of cooperative's lines or equipment caused by the additional or changed installation.

22. Standby and Resale Service: All purchased electric service (other than emergency and standby service) used on the premises of customer shall be supplied exclusively by cooperative, and the customer shall not directly or indirectly, sell, sublet, assign, or otherwise dispose of the electric service or any part thereof, without permission of cooperative.

23. Notice of Trouble: The customer shall notify the cooperative immediately should the service be unsatisfactory for any reason, or should there be any defects, trouble or accidents affecting the supply of electricity. Such notice, if verbal, should be confirmed in writing.

24. Non Standard Services: The customer shall pay the cost of any special installation necessary to meet his requirements for service at other than standard voltages, or for the supply of closer regulation than required by standard practice.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

DATE OF ISSUE JANUARY 30, 1996 DATE EFFECTIVE 2/1/96
Month Day Year Month Day Year

FEB 29 1996

ISSUED BY Lee Hill TITLE CHIEF EXECUTIVE OFFICER

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Jordan C. Neel
FOR THE PUBLIC SERVICE COMMISSION

RULES AND REGULATIONS

12. CONNECT AND RECONNECT CHARGES

The Cooperative will make no charge for connecting service to the member's premises for the initial installation of service provided the connection is made during regular working hours. The Cooperative will make a service charge of Twenty-Five Dollars ($25.00) for re-connecting the service of any member whose service has been connected one or more times within the preceding twelve months. The service charge shall be Eighty-Five Dollars ($85.00) if made after regular working hours. Reconnect service charges shall not apply to Prepay (T) Electric Service (See Rider) member accounts when such reconnect activities are a function of routine (T) depletion/replenishment of credits to such Prepay account balances. Any service charge will be due and payable (T) at the time of connection or upon notice of said charge.

13. RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof.

14. SPECIAL CHARGES

The Cooperative will make a charge of Twenty-Five Dollars ($25.00) for each trip made or disconnect/reconnect (for non-payment of bills) via automated systems during regular working hours. In the event a trip is necessary for the following reasons after regular working hours the special charge will be Eighty-Five Dollars ($85.00):

1. When a customer requests that a meter be re-read, and the second reading shows the original reading was correct.

2. To reconnect a service that has been terminated for non-payment of bills or for violation of the Utility's Rules or Commission Regulations. A consumer qualifying for service reconnection under Section 15, Winter Hardship Reconnection of this regulation shall be exempt from reconnect charges. Prepay Electric Service (T) member accounts shall be exempt from such charges. (T)

3. To terminate service or to collect a delinquent bill or to collect a returned check. The charge may also be made if the Cooperative Representative agrees to delay termination based on the consumer's agreement to pay by a specific date. The collection charge will only be assessed once per billing period.

4. For any service trip requested by a member to restore electric service when it is determined that the service interruption was caused by a defect in the members wiring or equipment and is not the fault of the Cooperative.

5. For resetting a meter that has been removed at the customer's request.

6. When a customer requests that their existing security light be upgraded to a different type.

7. When a customer requests the cooperative to disconnect their existing service and re-connect to their new entrance due to a customer entrance change.

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
5/1/2011
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Date of Issue: 3-28-11 Effective Date: 5-1-11

Issued By: Donald R Schaefer President and CEO

For All Territory Served

P.S.C. KY No.

Licking Valley Rural Electric Cooperative Corporation

Second Revised Sheet No. 29

Cancelling P.S.C. KY No.

First Revised Sheet No. 29

RULES AND REGULATIONS

providing the service at such delivery point. All wiring and equipment beyond this point of delivery shall be supplied and maintained by the consumer.

CONSUMER'S WIRING STANDARDS

All wiring of consumer's building and premises must conform to distributor requirements and accepted modern standards, as exemplified by the requirements of the National Electrical Safety Code and the National Electric Code.

RESALE OF POWER BY CONSUMERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the consumer shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof, except by written contract approved by the Board of Directors.

RELOCATION OF LINES

The Cooperative will cooperate with all political subdivisions in the construction, improvement or rehabilitation of public streets and highways. It is expected that these political subdivisions will give reasonable notice to permit the Cooperative to relocate its lines to permit the necessary road construction. If the Cooperative's poles, anchors, and other appurtenances are located within the confines of the public right-of-way, the Cooperative shall make the necessary relocation at its own expense. If the Cooperative's poles, anchors or other facilities are located on private property, the political subdivision then shall agree to reimburse the Cooperative. Upon request by consumer-property owner, where facilities are to be relocated, relocation will be considered, provided adequate right-of-way can be obtained for

DATE OF ISSUE February 16, 1999 (month day year) DATE EFFECTIVE February 16, 1999 (month day year)

ISSUED BY Bob Duncan (name of officer) General Manager (title) West Liberty, KY (address)

Nolin RECC
411 Ring Road
Elizabethtown, KY 42701-6767

RULES AND REGULATIONS

11. MEMBER'S DISCONTINUANCE OF SERVICE

(T) REFERENCE: 807 KAR 5:006 Section 13

12. CONNECTION AND RECONNECTION CHARGE

The Cooperative will charge a connect fee of twenty ($20.00) dollars for the initial connection of service. When service has been terminated and the Cooperative is requested to reconnect service to the same member at the same location, a twenty ($20.00) dollar reconnection fee will be charged. The reconnect charge will be due and payable at the Cooperative's office upon notice of said charge prior to connection. No reconnection shall be made after regular working hours unless in the judgment of the management there exists circumstances that will justify the additional expense. The reconnection charge after regular working hours shall be fifty ($50.00) dollars.

13. RESALE OF POWER BY MEMBERS

Electric service used on the premises of the member shall be supplied by the Cooperative and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof, except as may be provided under a co-generation contract between the member and the Cooperative.

14. SERVICE CHARGE

The Cooperative will make no charge for service calls to a member's premises when the fault and repairs are made to equipment owned by the Cooperative. A service charge of twenty ($20.00) dollars will be made to the members account when the fault is on the members' own equipment or for an engineering request where the property proves to be not ready for inspection. Said charges are due and payable upon notice of such charge. The service charge after regular working hours shall be fifty ($50.00) dollars.

15. DISCONTINUANCE OF SERVICE

(T) REFERENCE: 807 KAR 5:006 Section 15.

(T) For non-payment of bills, refer to 807 KAR 5:006 15(1)(f).

DATE OF ISSUE February 2, 2015
DATE EFFECTIVE March 4, 2015
ISSUED BY Michael L. Miller
President & CEO

FOR Entire Territory Served
Community, Town or City
P.S.C. No. 6
Original SHEET No. 55
CANCELING P.S.C. No. 5
Original SHEET No. 15B

Owen Electric Cooperative, Inc.
Name of Issuing Corporation

RULES AND REGULATIONS

27. RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative and the Member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof, except by written contract approved by the Board of Directors of this Cooperative.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

AUG 15 1997

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Jordan C. Neel
FOR THE PUBLIC SERVICE COMMISSION

DATE OF ISSUE July 15, 1997 DATE EFFECTIVE August 15, 1997
ISSUED BY [signature] TITLE President/CEO
Name of Officer
Issued by authority of an Order of the Public Service Commission of Kentucky in Case No.________ Dated________.

	FOR All Territory Served
	PSC KY NO. 9
Shelby Energy Cooperative, Inc.	Original SHEET NO. 233
Shelbyville, Kentucky	CANCELLING PSC KY NO. 8
(NAME OF UTILITY)	Original SHEET NO. 15

RULES AND REGULATIONS

33. RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the member shall not directly or indirectly sell, sublet,
(T) give or otherwise dispose of the electric service or any part thereof, except by written
(T) contract approved by the Board of Directors of the Cooperative.

DATE OF ISSUE April 24, 2013
MONTH / DATE / YEAR

DATE EFFECTIVE October 1, 2013
MONTH / DATE / YEAR

ISSUED BY Debra J. Martin
SIGNATURE OF OFFICER

TITLE President and CEO

BY AUTHORITY OF ORDER OF THE PUBLIC SERVICE COMMISSION IN CASE NO.________ DATED________

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
10/1/2013
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

RULES AND REGULATIONS

SECTION II - SERVICE PROCEDURES

2.10 APPLICATION FOR SERVICE

Each prospective member desiring electric service will be required to sign the Cooperative's form "Application for Membership and for Electric Service" before service is supplied by the Cooperative and provide the Cooperative with necessary easements or right-of-way permits upon their property.

2.20 MEMBERSHIP FEE

The membership fee in the Cooperative shall be $25.00 (twenty-five dollars). The membership fee will be refunded if all bills are paid or applied against any unpaid bills of the member at the time service is discontinued, which will automatically terminate the membership.

2.30 RIGHT OF ACCESS

The Cooperative's identified employees or its agents shall have access to member's premises at all reasonable times for the purpose of meter reading, testing, repairing, inspecting, removing or exchanging any and all equipment belonging to the Cooperative.

2.31 RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively by the Cooperative, and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service or any part thereof.

JAN 15 2000

2.40 MEMBER'S DISCONTINUANCE OF SERVICE

Any member desiring service discontinued or changed from one location to another shall give the Cooperative three (3) days notice in person or in writing providing such notice does not violate contractual obligations.

As an alternative the Consumer may request a disconnection of service by telephone, provided, the person calling can identify the account number or the Consumers' Social (T)
Security number and any other information deemed necessary to reasonably assure that (T)
the request is a proper one.

DATE OF ISSUE: December 22, 1999 DATE EFFECTIVE: January 15, 2000

ISSUED BY: GENERAL MANAGER & C.E.O. SOUTH KENTUCKY R.E.C.C. P.O. BOX 910 SOMERSET, KENTUCKY 42502. Issued by authority of an order of the Public Service Commission of Kentucky in Case No. 99-380 dated December 15, 1999.

STANDBY AND RESALE SERVICE

All-purpose electric service (other than emergency or standby service) used on the premises of any consumer shall, except as hereinafter set forth, be supplied exclusively by the Distributor, and the consumer shall not, directly or indirectly, sell, sublet, assign, transfer, or otherwise dispose of the electric service provided such consumer or any part thereof. It is further provided, however, that Taylor County Rural Electric Cooperative Corporation shall waive individual unit metering, and thus permit transfer or assignment of service provided to a particular consumer, under any and all of those circumstances set forth in Section 3 of 807 KAR 5:046, such administrative regulation having been adopted on March 3, 1981, and said regulation, both in its present form and as it may hereafter be amended, being deemed incorporated herein by reference.

NOTICE OF TROUBLE

Consumer shall notify Distributor immediately should the service be unsatisfactory for any reason, or should there be any defects, trouble, or accidents affecting the supply of electricity. Such notices, if verbal, should be confirmed in writing.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

OCT 28 1992

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: [signature]