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PUBLIC SERVICE COMMISSION

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May 3, 2012

Via Hand-Delivery

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

Re: 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.
PSC Case No. 2012-_______

Dear Mr. Derouen:

Attached herewith you will please find an original and ten (10) copies of East Kentucky Power Cooperative, Inc.'s Application to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, L.L.C.

I hereby request that this Application and copies be filed immediately.

Please advise should you have any questions concerning this filing.

Sincerely yours,

Mark David Goss

Enclosures

cc: Hon. Mike Kurtz, Counsel for Gallatin Steel
Hon. Dennis G. Howard, II, Hon. Lawrence Cook,
Hon. Jennifer Hans (Office of the Kentucky Attorney General Utility Rate Intervention Division)

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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MAY 03 2012

PUBLIC SERVICE COMMISSION

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.) CASE NO. 2012-________

APPLICATION

Comes now East Kentucky Power Cooperative, Inc. ("EKPC"), by and through counsel, pursuant to KRS 278.218, 807 KAR 5:001, Section 8 and other applicable law, and for its Application requesting that the Kentucky Public Service Commission ("Commission") enter an Order approving the transfer of functional control of certain Transmission Facilities[1] to the PJM Interconnection, L.L.C. ("PJM") effective June 1, 2013, respectfully states as follows:

I. Regulatory Filing Requirements

1. EKPC's mailing address is P.O. Box 707, Winchester, Kentucky 40392-0707.

2. Pursuant to 807 KAR 5:001, Section 8(3) a certified copy of EKPC's restated Articles of Incorporation and all amendments thereto have previously been filed of record in Case No. 90-197, the *Application of East Kentucky Power Cooperative for a*

[1] The term "Transmission Facilities" is consistently defined in both Section 1.27 of the PJM Transmission Owners Agreement and Section 1.44 of the PJM Operating Agreement. A schedule of the Transmission Facilities at issue herein is attached as Exhibit DM-1 to the testimony of Mr. Don Mosier.

Certificate of Public Convenience and Necessity to Construct Certain Steam Service Facilities in Mason County, Kentucky.

3. EKPC makes this Application pursuant to KRS 278.218, which requires Commission approval prior to the transfer of ownership or control of a utility's assets with a value of $1,000,000 or greater when the assets will continue to be used to provide service to the utility or its customers.

4. EKPC is an electric cooperative formed under Chapter 279 of the Kentucky Revised Statutes. It has approximately $3.1 billion in assets and currently serves approximately 521,000 customers in 87 Kentucky counties through its sixteen member distribution cooperatives. EKPC owns and/or purchases nearly 3,100 megawatts ("MW") of electric generation capacity and approximately 2,800 miles of electric transmission lines. EKPC is already a member of PJM by virtue of the fact that membership is required in order to participate in PJM's energy market and to reserve transmission service within the PJM region. EKPC became a signatory to the PJM Operating Agreement in 2005 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,[2] however, EKPC is not a signatory to either the PJM Transmission Owners Agreement or the PJM Reliability Assurance Agreement.[3] EKPC may only become fully integrated into PJM upon the transfer of functional control of its

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[2] Since 2005, EKPC has also been a Market Participant within the Midwest ISO ("MISO"). Due to the loss of a direct interconnection with MISO following the transition of Duke Energy Kentucky, Inc. ("Duke") from MISO to PJM in 2012, EKPC will be terminating its membership as a Market Participant in MISO as it fully integrates into PJM. EKPC's was also a part of the MISO reserve sharing group until its discontinuation on December 31, 2009.

[3] EKPC is also a signatory to a PJM Service Agreement for Firm Point-to-Point Transmission Service, a PJM Service Agreement for Non-Firm Point-to-Point Transmission Service, a PJM Service Agreement for Network Integration Transmission Service and other forms and disclosures.

Transmission Facilities to PJM and the execution of the two aforementioned agreements.[4] EKPC will also have the option to change its membership status to that of a Transmission Owner or Generation Owner in PJM.

5. The names and addresses of EKPC's attorneys and representatives who are authorized to receive notices and communications regarding this Application are as follows:

Mark David Goss
David S. Samford
Frost Brown Todd LLC
250 West Main Street, Suite 2800
Lexington, KY 40507-1749
Telephone: (859) 231-0000

Ann Wood
East Kentucky Power Cooperative
4775 Lexington Road
P.O. Box 707
Winchester, KY 40395-0707
Telephone: (859) 744-4812

6. In further support of this Application, EKPC has included the following prepared testimony and exhibits:

- Anthony S. Campbell, President and Chief Executive Officer, will broadly cover the background of EKPC's involvement with regional transmission organizations ("RTOs"), the role of EKPC's Board of Directors in deciding to seek full integration into PJM, the transaction itself and the other approvals or consents that must be obtained. (Exhibit 1);

[4] Section 4.1.2 of the Transmission Owners Agreement provides, "[e]ach Party shall transfer to PJM, pursuant to this Agreement and in accordance with the Operating Agreement, the responsibility to direct the operation of its Transmission Facilities provided that such transfer is not intended to require any change in the physical operations or control over Transmission Facilities."

- Don Mosier, Chief Operating Officer, will describe the internal deliberative process leading to the decision to fully integrate with PJM as well as the operational aspects, benefits and timing of becoming fully integrated (Exhibit 2);
- Michael A. McNalley, will discuss rate and financial impacts (Exhibit 3);
- Ralph Luciani, Vice President, CRA, will describe the results of the economic analysis and the methodology employed as part of that analysis (Exhibit 4);
- PJM Transmission Owners Agreement (Exhibit 5);
- PJM Reliability Assurance Agreement (Exhibit 6); and
- PJM Operating Agreement (Exhibit 7).

II. Overview of the Transfer of Functional Control

A. Background

7. EKPC first considered transferring functional control of its Transmission Facilities to an RTO one decade ago. However, the nature and function of RTOs was still evolving at the time and EKPC ultimately concluded that joining an RTO was not likely to be cost effective.[5]

8. As RTOs continued to develop and mature under the oversight of the Federal Energy Regulatory Commission ("FERC"), EKPC periodically assessed whether membership in an RTO would be cost effective and beneficial for its members. The

[5] See *Application of East Kentucky Power Cooperative, Inc. for Approval of the Transfer of Operational Control of Certain Transmission Facilities to the Midwest Independent System Operator*, Final Order, Case No. 2002-00327, p. 1 (Ky. P.S.C. Sept. 17, 2003).

advisability of reconsidering whether to join an RTO was also highlighted in the Focused Management and Operations Audit of EKPC as conducted by the Liberty Consulting Group ("Liberty"). Liberty concluded, "[t]he benefits of membership [in an RTO] may now exceed the costs; therefore, EKPC should place a high priority on performing an evaluation as soon as possible."[6] In addition, Liberty recommended that, "EKPC should hire an independent consultant to determine the costs and benefits of ISO membership."[7]

9. In 2010, a preliminary directional analysis was conducted by ACES Power Marketing ("ACES"), EKPC's energy marketing agent, which demonstrated that fully integrating into PJM was economically advantageous. To get a second assessment, and after conducting a competitive bidding process, EKPC selected and engaged Charles River Associates ("CRA") to conduct an independent evaluation of the costs and benefits of fully participating in an RTO in 2011. Throughout the evaluation process, EKPC's management was active and involved in providing the information necessary for CRA to formulate its analytical model as well as to assess various scenarios involving variations of the base case used for the analysis. The CRA report concluded that there are numerous qualitative and quantitative benefits to joining PJM.[8] The three key sources of benefits of EKPC joining PJM are:

- More efficient commitment and dispatch of EKPC's generating resources leading to lower "adjusted production costs" for EKPC, as a result of:
    - Elimination of EKPC-PJM transmission charges (de-pancaking); and,

[6] Final Report, Liberty Consulting Group, p. 33 (Apr. 20, 2010).

[7] *Id.*, p. 61.

[8] The CRA Report, in its entirety, is attached at Exhibit RL-2 to the testimony of Ralph Luciani (Exhibit 4 to this Application). CRA also considered whether EKPC should give serious consideration to integrating into MISO. However, the lack of a direct interconnection with MISO made this option cost prohibitive.

- EKPC's participation in a fully integrated regional energy market;

- Advantageous peak load diversity relative to PJM as a whole, which results in carrying significantly lower planning reserves; and
- Avoided long-term firm point-to-point transmission charges that are currently being incurred to ensure that EKPC has the ability to import and export power throughout the year.

10. In sum, CRA determined the economic benefit of joining PJM, based on a 10-year present value, to be approximately $142 million. This benefit would serve to reduce the total power cost to EKPC's 16 member distribution cooperatives by between $1 and $3 per MWh.

11. In addition to CRA's evaluation, EKPC's management also engaged in a parallel due diligence process. EKPC commissioned a legal review of the various agreements that it would be required to execute upon its entry into PJM. EKPC thereafter tendered written questions to PJM that touched upon organizational, operational and financial aspects of the integration process and subsequent participation in PJM. EKPC's managers met with PJM in person and held several conference calls to discuss the details and timeframes associated with fully-integrated membership in PJM.

12. EKPC's Board of Directors was kept abreast of the work of Management and CRA throughout the evaluation process through a series of briefings, updates and presentations by EKPC's Management as well as meetings with managers from PJM and other cooperatives that are currently members of RTOs. The Board was given a copy of CRA's final report and listened to a presentation from Ralph Luciani, the leader of the CRA team, at its March 13, 2012 regular meeting. At a special meeting held on March

22, 2012, EKPC's Board unanimously approved a resolution to take the steps necessary – including seeking appropriate regulatory approvals – to become a fully-integrated member of PJM.

B. Overview of PJM

13. PJM operates as a not-for-profit, federally regulated RTO, headquartered in Valley Forge, Pennsylvania, that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM acts independently and impartially in managing the regional transmission system and the wholesale electricity market, ensuring the reliability of the largest centrally dispatched electric grid in North America. PJM's members, totaling more than 750, include power generators, transmission owners, electricity distributors, power marketers and large consumers.

14. In terms of operations, PJM's staff monitors the high-voltage transmission grid 24 hours a day, seven days a week. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions. PJM dispatches approximately 185,600 MW of generating capacity over 62,591 miles of transmission lines by relying upon telemetric data from approximately 74,000 points on the electric grid. More than 60.1 million people live in the PJM region.

15. PJM also provides an important function within the energy markets by coordinating the continuous buying, selling and delivery of wholesale electricity through its robust, open and competitive Interchange Energy Market ("Energy Market"). PJM's Energy Market establishes a market price for electricity by matching supply with demand using online interfaces to make trading easy for members/customers with continuous

real-time data. The Energy Market is a two-settlement (day-ahead and real-time) market using hourly locational marginal prices and financial transmission rights. As set forth in Section 13.2 of the Operating Agreement, PJM will schedule in advance and dispatch generation on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by sellers within and into the PJM region, continuing until sufficient generation is dispatched to serve the energy requirements of the region and buyers out of the region, as well as the requirements of the PJM Region for ancillary services provided by available generation. Scheduling and dispatch is conducted in accordance with applicable schedules to the PJM Tariff and Operating Agreement. Market participants, such as EKPC, can closely follow energy market fluctuations as they occur and quickly respond to price signals bringing supply resources to the region when demand is high. PJM advertises that it has administered more than $103 billion in energy and energy-service trades since the regional markets opened in 1997.

16. Finally, PJM also manages a sophisticated regional planning process for transmission expansion to ensure the continued reliability of the electric system. PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations and transmission lines. PJM analyzes and forecasts the future electricity needs of the region so that its planning process ensures that the growth of the electric system takes place efficiently, in an orderly fashion, and that reliability is maintained. PJM also administers various demand response initiatives and other efforts to support renewable energy, to help expand supply options and keep prices competitive.

17. The Commission has previously authorized two other jurisdictional utilities – Duke Energy Kentucky, Inc. and Kentucky Power Company – to become members of PJM.[9]

C. The Proposed Transfer of Functional Control of Transmission Facilities

18. EKPC seeks approval to transfer the functional control of its Transmission Facilities to PJM effective June 1, 2013. As part of the transfer of functional control of its Transmission Facilities to PJM, EKPC will be required to execute two new agreements: a) the PJM Transmission Owners Agreement; and b) the PJM Reliability Assurance Agreement.

19. Becoming a signatory to the Transmission Owners Agreement and the Reliability Assurance Agreement will allow EKPC to immediately cancel a firm transmission reservation currently in effect with PJM for 400 MW of transmission rights that is set to expire on December 31, 2016 and resulting in a savings of more than $7 million per year, through that date. This will also permit more efficient sales of EKPC's excess energy due to less frequent transmission constraints and a significantly reduced capacity reserve margin of approximately 70 MW.

20. The Transmission Owners Agreement grants PJM the right and authorization to use the transmission capacity of EKPC's transmission system that is required to provide service under the PJM Tariff and to resell transmission service using such capacity on the transmission system. PJM will compensate EKPC for the use of its

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[9] *See 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*, Final Order, Case No. 2010-00203 (Ky. PSC Dec. 22, 2010); *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*, Final Order, Case No. 2002-00475 (Ky. PSC Aug. 25, 2003).

transmission capacity by distributing certain revenues to EKPC as set forth in the PJM Tariff and the Transmission Owners Agreement.[10]

21. In order to maximize the benefit to EKPC and its Members of becoming fully integrated into PJM, EKPC's existing interruptible load and Direct Load Control resources must be enrolled in PJM's Limited Demand Response Program. As a result, some changes will be required to EKPC's special contracts with interruptible load end-users and EKPC's Direct Load Control tariff to conform them to PJM's Limited Demand Response Program. EKPC and its Members will tender appropriate tariff and contract revisions to the Commission for its review once the Application is approved, but well before the targeted integration date of June 1, 2013.

22. In order for EKPC to participate in the May 2013 Base Residual Auction for the 2016/17 delivery year and to complete the integration by June 1, 2013, the Commission would need to issue a final order approving the transfer of functional control on or before December 31, 2012.

III. Governing Law

23. The transfer of control of a jurisdictional utility's assets is governed by KRS 278.218, which provides:

> (1) No person shall acquire or transfer ownership of or control, or the right to control, any assets that are owned by a utility as defined under KRS 278.010(3)(a) without prior approval of the commission, if the assets have an original book value of one million dollars ($1,000,000) or more and:
>
> (a) The assets are to be transferred by the utility for reasons other than obsolescence; or

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[10] *See* PJM Transmission Owners Agreement, Section 3.3(d).

(b) The assets will continue to be used to provide the same or similar service to the utility or its customers.

(2) The commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest.

24. Thus, a two-prong test for approving the Application is to be applied and must consider: (a) whether the transfer is for a proper purpose; and (b) whether the transfer is consistent with the public interest. Generally speaking, any act taken within the lawful purposes of a corporation may constitute a "proper purpose."[11] With regard to what constitutes the "public interest," Commission precedent provides a sufficient interpretation in the absence of a statutory definition. On this point, the Commission has stated:

> [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.[12]

25. While the application in this case involves the transfer of functional control of utility assets under KRS 278.218, rather than a transfer of ownership of the

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[11] *See e.g. In re Pacific Gas and Electric Company*, Order, 2004 WL 2533627, n. 20 (Cal. P.U.C. Oct. 28, 2004) *citing Webster Mfg. Co. v. Byrnes*, 280 P. 101, 638-39 (Cal. 1929) ("We therefore conclude that, in the absence of a plain declaration to the contrary, 'proper purposes' means any outlay necessary or proper to promote the legitimate objects of a public utility.").

[12] *See Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE Aktiengesellschaft and Thames Water Aqua Holdings GmgH*, Order, Case No. 2002-00018, p. 7 (Ky. PSC May 30, 2002).

utility under KRS 278.020, the same criteria apply in determining whether the proposed transfer satisfies the "public interest" standard.[13] In the context of the transfer of functional control of a utility's transmission assets, the Commission has held that the inquiry "encompasses both network reliability and the cost of electric service…."[14]

IV. Facts Supporting the Application

26. EKPC currently operates as its own dispatch control area and balancing authority, where it is charged with matching generation to its load in a reliable and economic manner. Ever increasing transmission constraints between EKPC and potential counterparties and more stringent regulatory requirements continue to place additional economic pressure on EKPC's ability to operate independently.

27. EKPC faces several other specific operating concerns by continuing to operate as an independent control area and balancing authority. EKPC has a firm transmission reservation with PJM for 400 MW of transmission rights for five years, expiring December 31, 2016, to ensure EKPC can purchase energy from the PJM market; this transmission costs more than $7 million per year. The future availability and the cost of this transmission reservation are uncertain. Sales of EKPC's excess energy are frequently constrained because of limited transmission availability into PJM.

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[13] *See 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*, Final Order, Case No. 2010-00203, pp. 14-15 (Ky. PSC Dec. 22, 2010); *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*, Final Order, Case No. 2002-00475 (Ky. PSC Aug. 25, 2003).

[14] *Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Transfer Functional Control of their Transmission Facilities*, Final Order, Case No. 2005-00471, p. 5 (Ky. PSC July 6, 2006).

28. Additionally, EKPC currently targets a 12 percent capacity reserve margin of approximately 360 MW on its winter peak load to accommodate extreme operating conditions. This reserve margin is significantly higher than the 2.8 percent capacity reserves based on summer peak loads, or approximately 70 MW, that would be required in PJM.

A. Transferring Functional Control of EKPC's Transmission Facilities is for a Proper Purpose

29. While EKPC is unaware of any Commission precedent specifically and narrowly defining a utility's "proper purpose" in the context of applying KRS 278.218, the term has been broadly construed in the scope of utility regulation to refer to any act necessary or proper to promote the legitimate objects of a public utility.[15]

30. As a rural electric cooperative corporation formed under KRS Chapter 279, the legitimate objects of EKPC's enterprise are expressed in its enabling statutes. These include: forming for the "[p]rimary purpose of generating, purchasing, selling, transmitting, or distributing electric energy to any individual or entity...;"[16] and acting to "[c]onstruct, own, lease, operate, and control any facilities across, along, or under any street or public highway, and over any lands belonging to this state or to any county, city, or political subdivision of this state....;"[17] and "mak[ing] any contract necessary or convenient for the full exercise of the powers granted by this chapter, or for any other

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[15] *See e.g. In re Pacific Gas and Electric Company*, Order, 2004 WL 2533627, n. 20 (Cal. P.U.C. Oct. 28, 2004) *citing Webster Mfg. Co. v. Byrnes*, 280 P. 101, 638-39 (Cal. 1929) ("We therefore conclude that, in the absence of a plain declaration to the contrary, 'proper purposes' means any outlay necessary or proper to promote the legitimate objects of a public utility.").

[16] KRS 279.020(1).

[17] KRS 279.110(5).

corporate purpose, subject to any limitations imposed by this chapter…."[18] In addition, EKPC may "[d]o anything not specifically set forth in this section that is reasonably deemed necessary, proper, or convenient for the accomplishment of the purposes of the corporation and is not prohibited by law."[19]

31. Based upon the broad scope of lawful and legitimate purposes set forth in KRS Chapter 279, the transfer of functional control of EKPC's Transmission Facilities is for a proper purpose under Kentucky law.

B. Transferring Functional Control of EKPC's Transmission Facilities is Consistent with the Public Interest

32. The transfer of functional control of EKPC's Transmission Facilities is also consistent with the public interest in that it will preserve or improve network reliability and yield a long-term benefit in the costs of electric service paid by EKPC's members. The transfer will enable EKPC to realize, on a present value basis, approximately $142 million in net savings in the first ten years following integration. Moreover, EKPC will continue as a member of the TEE Contingency Reserve Sharing Group ("TCRSG") which assures that no harm comes to any ratepayers of the other members of the TCRSG.[20] Participation in PJM through the rights and benefits afforded to transmission owners and generation owners will allow EKPC to position itself to efficiently comply with existing and anticipated federal obligations imposed by the U.S. Environmental Protection Agency ("EPA") and the Federal Energy Regulatory

[18] KRS 279.110(7).

[19] KRS 279.110(13).

[20] The utilities which are members of the TCRSG are the Tennessee Valley Authority ("TVA"), Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"). "TEE" is an abbreviation for TVA, EKPC and E.On (n/k/a KU and LG&E).

Commission ("FERC"). Moreover, transferring functional control of EKPC's Transmission Facilities will have no adverse effect upon the Commission's jurisdiction.

1. The Net Benefit to EKPC of Transferring Functional Control of Its Transmission Assets is Consistent with the Public Interest

33. As set forth in the CRA Report, EKPC expects to realize, on a present value basis, net benefits of $142 million over the first ten years after it transfers functional control of its Transmission Facilities and participates in PJM under the Transmission Owners Agreement and the Reliability Assurance Agreement. While there are administrative and transmission costs associated with these activities, they are more than offset by trade benefits, capacity market benefits and avoided long-term firm point-to-point transmission costs that will be realized, as the following chart demonstrates:

Benefits (Costs) to EKPC Joining PJM (in millions of dollars)	**2013-22** (Present Value)
Decrease in Adjusted Production Costs (Trade Benefits)	52.7
Administrative Costs	(48.3)
Transmission Costs	(66.4)
PJM Capacity Market Impacts	147.8
Subtotal Net Benefits (Costs):	85.9
Avoided Long-Term Firm PTP Transmission Charges	56.1
Net Benefits (Costs):	**142.0**

34. CRA concluded that EKPC would be able to generate less power (thereby decreasing production costs) while at the same time increasing its economic off-system purchases.[21] This co-optimization yields a more economic dispatch of generating resources and approximately $52.7 million in net savings over the ten years of the study.

[21] EKPC will assume no new market volatility risk arising from its market transactions. While EKPC's members will have the benefit of being able to realize savings from economic purchases of energy, they will be protected from market volatility by EKPC's ability to always purchase energy at a cost equal to its own avoided cost. Thus, the risks associated with joining PJM are no greater for EKPC's members than what they already assume and, in all likelihood, will be less.

35. CRA also evaluated the estimated administrative costs that EKPC will likely incur upon its participation in PJM as a transmission owner and capacity supplier to be $48.3 million over the ten years of the study. These costs generally arise from administrative costs imposed by PJM ($35 million) and by FERC ($7.7 million) as well as those required for EKPC to internally complete the integration and ongoing administration of the commercial relationship with PJM ($5.6 million). The internal cost estimate specifically includes the additional costs associated with continuing to use ACES to assist and facilitate interactions with PJM in its energy and capacity markets and planning functions.

36. CRA estimates that EKPC will incur costs of approximately $66.4 million over the study period as part of PJM's Regional Transmission Expansion Planning ("RTEP") program, which allocates the total cost of "backbone" transmission line projects for lines rated at 500 kV and above. EKPC will have the opportunity, however, to have the costs of any of its own transmission projects allocated to other utilities to the extent that such utilities would benefit from the addition of the new transmission infrastructure.

37. The highest category of cost savings accrue in the context of EKPC's full participation in PJM's capacity market. Due to the fact that EKPC is a winter peaking system and PJM as a whole is summer peaking, EKPC has the unique opportunity to monetize this diversity through the reduction of its own peak reserve requirements to match those of PJM. Thus, instead of maintaining the current 12% planning reserve requirement in both the winter and summer seasons, EKPC would only be required to maintain a 2.8% installed planning reserve for EKPC's summer peak as a fully

participating member of PJM's Reliability Pricing Model ("RPM").[22] Although CRA's detailed analysis demonstrates that this benefit would be diminished by \$3 million to \$9 million per year if EKPC was not permitted to participate in PJM on an RPM basis beginning with the Base Residual Auction for delivery year 2016/17, the savings remain substantial. Moreover, EKPC will only be able to maximize its capacity benefits if it is permitted to enroll its interruptible load and Direct Load Control resources in PJM's Limited Demand Response Program. The net savings for EKPC to participate fully in PJM through the RPM equates to \$147.8 million over the ten year term of the study.

38. Finally, the CRA Report concludes that upon joining PJM as a transmission owner, EKPC will immediately be able to realize savings associated with the cancellation of the five year 400 MW firm point-to-point transmission service agreement that it currently utilizes. EKPC's members will save approximately \$56.1 million in transmission costs over the ten year study period for which they are currently obligated without suffering any detrimental impact to service reliability and access to the PJM market.

39. The CRA Report also sets forth several qualitative considerations which have been taken into account as part of EKPC's decision to seek full integration into PJM. Among the most significant of these considerations is the difficulty associated with predicting EKPC's future costs arising from PJM's RTEP;[23] the effects of future variations in fuel costs and load growth; and exit obligations. While EKPC takes each of

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[22] The alternative to participating in PJM's RPM is to participate on a Fixed Resource Requirement ("FRR") basis. As CRA's analysis demonstrates, participation on an FRR basis means EKPC must hold back an additional 3% of generation capacity in reserve and would therefore forfeit a significant portion of the benefit available to its members.

[23] RTEP is the subject of Schedule 6 of the PJM Operating Agreement.

these issues seriously, its analysis confirms that CRA's bottom line conclusion is reasonable: "EKPC joining PJM will yield significant economic benefits to EKPC," and "[t]he net benefits to EKPC are relatively robust."[24]

40. In addition to the net benefits calculation performed by CRA, the structure of PJM's energy and capacity markets assure that EKPC's members will not be exposed to volatility in the markets to any extent greater than what they currently face. As set forth in Mr. Mosier's testimony, EKPC will assume no new significant risks arising from its market transactions upon transferring functional control of its Transmission Facilities and operating under the Transmission Owners Agreement and Reliability Assurance Agreement. Moreover, PJM's operations are constantly monitored by an independent firm engaged to assure transparency and integrity in the Energy Market and PJM has several credit protections in place to minimize the risks of member defaults. These structural protections help assure that PJM's markets have the requisite financial integrity and stability to benefit and protect its members. While the benefits of these market structures are difficult to precisely quantify, they are nevertheless real and tangible safeguards which will ultimately benefit EKPC's Members.

2. The Positive Impact to EKPC's Ratepayers Arising from the Net Benefit of Transferring the Functional Control of its Transmission Facilities is Consistent with the Public Interest

41. Transferring functional control of its Transmission Facilities and participating in PJM under the Transmission Owners Agreement and Reliability Assurance Agreement will have a positive impact upon ratepayers within the EKPC system. With unconstrained access to PJM, EKPC's network reliability will not be harmed and will most certainly be improved.

[24] CRA Report, p. 7.

42. Moreover, the ratepayers within the EKPC system will benefit from avoided costs, (arising from reduced production costs and cancellation of the 400 MW firm point-to-point transmission service agreement), reduced reserve requirements resulting in the more efficient dispatch of capacity resources and a general ability to sell and purchase energy in a larger, more efficient marketplace. Some of the rate benefits of EKPC's full participation in PJM will be felt in the short-term, while others will be demonstrated over the longer term.

43. As set forth above, immediately upon entering into the Transmission Owners Agreement and the Reliability Assurance Agreement, EKPC will be able to cancel the 400 MW firm point-to-point transmission service agreement that it currently has in place through PJM. Cancellation of this transmission agreement in combination with eliminating the need to replace the current agreement with a new one at the expiration of its term is anticipated to save EKPC $56.1 million over the ten year study period set forth in the CRA Report.[25]

44. The remaining favorable rate impacts will be realized primarily through EKPC's avoided costs and economic energy purchases. As such, the ability to specifically track these benefits is much more difficult and not susceptible to any particular tracking mechanism. However, EKPC's estimates suggest that the total avoided costs will range from $1 to $3 per MWh during the first ten years following EKPC's integration into PJM.[26] Some of these savings would begin to immediately flow to ratepayers through EKPC's fuel adjustment clause ("FAC"). These savings would

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[25] In addition to cancelling the 400 MW transmission reservation, EKPC will also be able to terminate its membership as a Market Participant in MISO, which will offer additional savings.

[26] A schedule setting forth the details on this estimation is included as Exhibit MM-2 to Mr. McNalley's testimony (Exhibit 3 to Application).

result from being able to reduce the purchased power element of EKPC's FAC through more economic purchases as well as a reduction in fuel costs as fuel used for increased off-system sales reduces EKPC's jurisdictional fuel costs. The cumulative impact of these avoided costs and economic energy purchases is most likely to also directly manifest itself in a variety of other ways including: offset increasing costs in other areas of EKPC's business (particularly environmental costs); increased equity for EKPC's ratepayers with attendant benefits derived from increased financial strength; deferred future rate increases; and possible future rate reductions. Obviously, it would be premature and imprudent to commit to a particular rate treatment of the net benefits anticipated to be derived from the transfer of functional control of the Transmission Facilities, however, as circumstances and business prudence allow, EKPC's ratepayers will realize long-term benefits in the form of one or more of these ratemaking treatments.

3. Other Considerations Demonstrate that Transferring Functional Control of the Transmission Facilities is Consistent with the Public Interest

45. The transfer of functional control of EKPC's Transmission Facilities is also consistent with the public interest because it will not harm any utilities operating adjacent to EKPC and will position EKPC to better navigate through the increasingly complex labyrinth of federal environmental and energy rules and policies. Moreover, the Commission's jurisdiction will not be affected by the transfer of functional control as the Commission will continue to exercise jurisdiction in accordance with Kentucky law.

46. EKPC established the TCRSG in November 2009 in order to comply with North American Electric Reliability Council ("NERC") rules regarding reserve requirements. Although EKPC will not need to remain a member of the TCRSG following its integration into PJM, it plans to remain a member. This will prevent any

possible harm to the other members of the TCRSG while at the same time not imposing any substantial cost to EKPC. PJM has been advised of EKPC's intentions in this respect and is willing to administer EKPC's participation in the TCRSG as necessary. EKPC has been advised by TVA, KU and LG&E that each of them agrees with this arrangement.

47. Additionally, EKPC is working diligently to comply with EPA rules and the Consent Decree to operate its system in the most efficient manner. Joining PJM will allow EKPC more flexibility in satisfying environmental requirements. Moreover, as FERC appears poised to move towards imposing the costs of high voltage transmission expansion projects upon a broader spectrum of utilities under FERC Order 1000, joining PJM will allow EKPC to avoid the uncertainty of future FERC actions through participation in the established RTEP process. Thus, joining PJM on a fully integrated basis will position EKPC to better adjust to changing federal regulatory standards.

48. Finally, the Commission's jurisdiction will not change by granting EKPC permission to transfer functional control of its Transmission Facilities to PJM. The Commission will retain its full jurisdiction and authority over the rates and services of EKPC, including, but not limited to: EKPC's rates to its Members and the pass-through of those rates to retail customers; integrated resource plan proceedings; demand side management programs, and certificate of public convenience and necessity requirements.

49. Although EKPC believes that the foregoing circumstances and considerations amply demonstrate that the proposed transfer is consistent with the public interest, EKPC is also aware that the Commission has approved prior cases involving the transfer of functional control of a jurisdictional utility's Transmission Facilities to an

RTO on a conditional basis. EKPC has examined these prior cases,[27] and stipulates that it will agree to and accept the following conditions:

a) No customer of EKPC will be allowed to participate in any PJM Demand Response Program until that customer has entered into a special contract with EKPC that has been approved by the Commission;[28]

b) Approval of the application will not diminish the Commission's jurisdiction or authority with respect to its review and prescription of rates for EKPC based upon the value of its property used to provide electric service; the obligation of EKPC to file integrated resource plans; the obligation of EKPC to provide bundled generation and transmission service to its members; and EKPC's obligation to obtain a certificate of public convenience and necessity prior to commencing construction of any electric generation or transmission facility.

50. EKPC will also seek the approval of FERC and the consent of the Rural Utilities Service to fully integrate into PJM.

V. Conclusion

51. EKPC has commissioned and conducted a comprehensive and detailed analysis regarding the net benefits to be afforded from transferring functional control of

[27] Due to EKPC's unique equity capital characteristics, many of the conditions imposed upon other utilities in similar proceedings do not readily apply to EKPC or its Members.

[28] As set forth above and in Mr. Mosier's testimony, EKPC anticipates that it would file amendments to its existing interruptible load contracts and its Direct Load Control tariff within a few weeks of the Commission's issuance of a Final Order granting permission for EKPC to fully integrate into PJM.

its Transmission Facilities to PJM and entering into the Transmission Owners Agreement and Reliability Assurance Agreement. That analysis clearly demonstrates that EKPC and its ratepayers will realize favorable material benefits from the transfer of functional control of the Transmission Facilities and full integration into PJM.

WHEREFORE, on the basis of the foregoing, EKPC respectfully requests that:

1) the Commission determine and find that the transfer of functional control of Transmission Facilities requested herein is for a proper purpose and consistent with the public interest;

2) the Commission enter an Order authorizing the transfer of functional control of EKPC's Transmission Facilities to the PJM Interconnection L.L.C. effective June 1, 2013 or as soon thereafter as integration may be reasonably completed;

3) the Commission enter an Order authorizing the enrollment of EKPC's interruptible load and Direct Load Control resources in PJM's Demand Response Program as set forth herein and giving EKPC thirty days following entry of its Final Order in which to file conforming tariffs or contracts; and

4) the Commission enter its Final Order adjudicating this Application on or before December 31, 2012.

Dated this 3rd day of May 2012.

VERIFICATION

The undersigned, pursuant to KRS 278.218, hereby verifies that all of the information contained in the foregoing Application is true and correct to the best of my knowledge, opinion and belief.

East Kentucky Power Cooperative, Inc.

BY: Anthony S Campbell

ITS: President & CEO

COMMONWEALTH OF KENTUCKY

COUNTY OF CLARK

The foregoing Verification was signed, acknowledged and sworn to before me this 3rd of May 2012 by Anthony S. Campbell of East Kentucky Power Cooperative, Inc., a Kentucky corporation, on behalf of the corporation.

Gwyn M. Willoughby

NOTARY PUBLIC

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Respectfully Submitted,

Mark David Goss

MARK DAVID GOSS
DAVID S. SAMFORD
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Counsel for East Kentucky Power Cooperative, Inc.

Exhibit 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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.	)))))	**CASE NO. 2012-________**

TESTIMONY OF
ANTHONY S. CAMPBELL
PRESIDENT AND CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 3, 2012

Q. Please state your name, business address and occupation.

A. My name is Anthony S. Campbell and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am President and Chief Executive Officer of EKPC.

Q. How long have you been employed by East Kentucky Power Cooperative, Inc.?

A. I have been employed by EKPC since June 2009.

Q. Please state your education and professional experience.

A. I received a Bachelor of Science degree in electrical engineering from the Southern Illinois University at Carbondale and a Masters of Business Administration from the University of Illinois at Champaign. Prior to joining EKPC, I served as CEO of Citizens Electric Corporation, a transmission and distribution company located in southeast Missouri.

Q. Please provide a brief description of your duties at EKPC.

A. The Board of Directors has given me, as CEO, the responsibility for managing the Cooperative's business on a day-to-day basis. I carry out the Board's strategic goals within the guidelines and policies developed by the Board.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to broadly cover the background of EKPC's involvement with regional transmission organizations ("RTOs") to date, the role of the EKPC's Board of Directors in deciding to seek full integration into PJM, the transaction itself and the other approvals or consents that must be obtained. In addition, I will discuss the general benefits that full integration into PJM Interconnection, LLC ("PJM") will bring to EKPC and how that integration is for a proper purpose and consistent with the public interest.

I. BACKGROUND

Q. Let us begin by talking about EKPC's involvement in RTOs up till now. Is this the first time that EKPC has considered joining an RTO on a fully integrated basis?

A. No. EKPC first considered transferring functional control of its Transmission Facilities to an RTO one decade ago. In Commission Case No. 2002-00327, EKPC proposed to join the Midwest ISO ("MISO").

Q. What was the result of that case?

A. The nature and functions of RTOs were still evolving and EKPC ultimately concluded that joining MISO was not likely to be cost effective at that time. Accordingly, the application was withdrawn.

Q. What happened after that initial application was withdrawn?

A. EKPC became a member of PJM in 2005 for the limited purposes of having access to purchase and sell power in PJM's Energy Market and to secure transmission rights as necessary. EKPC became a registered market participant of MISO in 2005 for similar reasons. Neither of these actions involved transferring functional control of any of our transmission assets or formal integration into either RTO's system. In addition, EKPC was a member of MISO's reserve sharing group until it was discontinued on

December 31, 2009. Thus, since the withdrawal of our application to join MISO in 2003 and the filing of the Application in this proceeding, we have had peripheral involvement in PJM and MISO, but we have never sought to become fully integrated into either RTO.

Q. What has changed?

A. As RTOs continued to develop and mature under the oversight of the Federal Energy Regulatory Commission ("FERC"), EKPC periodically reassessed whether membership in an RTO would be cost effective and beneficial for its members. The advisability of reconsidering whether to join an RTO was also highlighted in the Focused Management and Operations Audit of EKPC conducted by the Liberty Consulting Group ("Liberty"). As part of its report, Liberty concluded, "[t]he benefits of membership [in an RTO] may now exceed the costs; therefore, EKPC should place a high priority on performing an evaluation as soon as possible." In addition, Liberty recommended that, "EKPC should hire an independent consultant to determine the costs and benefits of ISO membership."

Q. Did EKPC take action after Liberty issued its report?

A. Yes. EKPC originally engaged ACES Power Marketing ("ACES") – our energy marketing agent – to conduct a preliminary survey and analysis of EKPC's market interactions and positions.

Q. What did ACES conclude?

A. ACES conducted a directional study that looked at several options before ultimately concluding that joining PJM made the most economic sense for EKPC.

Q. Is ACES affiliated with EKPC in any way?

A. Yes. EKPC is one of the owners of ACES. Liberty expressed some concern in its report that ACES may not be sufficiently independent. While I did not necessarily share this concern, in light of the long-term nature of a decision to join an RTO, it did make sense for EKPC to engage another consultant to provide a more detailed analysis about the relative benefits of joining an RTO.

Q. How did EKPC select which consultant to engage?

A. EKPC conducted a competitive bidding process and ultimately selected and engaged Charles River Associates ("CRA") to conduct an additional assessment of the costs and benefits of joining an RTO.

Q. Why was CRA selected?

A. We were very impressed with the scope and scale of CRA's prior involvement in conducting cost-benefit analysis for various utilities contemplating membership in an RTO or similar arrangement. The CRA team was very professional and thorough throughout the course of the study.

Q. Please describe EKPC's interactions with CRA.

A. CRA completed its initial evaluation of EKPC's potential membership in a specific RTO on June 29, 2011. The results indicated that it would be economically beneficial for EKPC to join PJM, based on net present value over a 5 year period beginning in 2013. Various sensitivity analyses were performed with all scenarios resulting in positive savings. EKPC subsequently requested that CRA develop an additional sensitivity which would reflect the recent Cross State Air Pollution Rules issued by the EPA. On September 12, 2011 CRA issued a modified report that also showed a net positive benefit over the 5 year time period. In order to review all other reasonable options, EKPC also asked CRA to evaluate EKPC's potential membership in MISO. This update was issued on November 9, 2011. The results again indicated that it was more beneficial for EKPC to join PJM.

To make absolutely certain that the benefits of fully integrating into PJM were clear, we then asked CRA to take a longer look than the 5 year period evaluated. CRA expanded its analysis to cover a 10 year period. This proved to be very fortuitous timing because, around this same time, natural gas prices declined sharply. CRA was able to take this into account and we found that the benefits continued long-term even when considering the declining natural gas prices. CRA completed its analysis and issued its final report on March 20, 2012.

Q. Ultimately, what did CRA conclude?

A. CRA's Report speaks for itself, but in broad strokes, CRA concluded that there are numerous qualitative and quantitative benefits to joining PJM. The three key sources of benefits of EKPC joining PJM derive from more economically efficient dispatching of our generation units and purchases of power, advantages afforded by having peak load diversity in comparison to PJM as a whole and the elimination of a long-standing need of EKPC to secure firm, point-to-point transmission service.

Although there are new costs associated with PJM's regional transmission expansion planning ("RTEP") and various new administrative fees, the estimated net benefit of fully integrating into PJM is $142 million in present value dollars over the first ten years.

Q. Do you have any reservations about the conclusions contained in CRA's report?

A. No. I have read the report several times and I believe it is an accurate depiction of EKPC's current situation and a reasonable forecast of what we should expect to see happen when we fully integrate into PJM.

Q. In addition to the analysis carried out by ACES and CRA, did EKPC undertake any other steps to determine whether full integration into PJM would be beneficial to its members?

A. Yes. In addition to ACES's and CRA's evaluations, EKPC's management engaged in a parallel due diligence process. Mr. Mosier elaborates on the nature of these efforts in greater detail, but I am personally satisfied that we have spent the time necessary to make certain that we are entering into this new and long-term relationship with PJM well-informed of the benefits and obligations that will result.

Q. As President and Chief Executive Officer, are you the person that kept EKPC's Board of Directors informed of the due diligence efforts?

A. Yes. Working with our Board is one of the most important aspects of my position and I made certain that the Board was kept apprised of the work of management and our consultants throughout the process.

Q. Can you give us an idea of the scope and extent of the Board's involvement in the deliberative process?

A. Certainly. The Board of Directors has been substantively involved in the process from the beginning. All told, the topic of RTO membership has been an item on the Board's agenda at twelve of its meetings between May 2010 and March 2012. ACES provided an initial presentation to the Board about PJM on May 11, 2010. That was followed-up by a series of discussions and presentations led by myself and Mr. Mosier throughout the summer and autumn of last year. As part of that early information sharing process, senior representatives from PJM met with the Board of Directors for a question and answer session in connection with its October 2011 meeting. The Board Risk Oversight Committee specifically considered the topic as part of its November 2011 Committee meeting and, the following month, representatives from two G&Ts that are current members of RTOs – including one that is currently a member of PJM – met with the Board to discuss their experiences and what they perceived to be the pros and cons for them operating inside of an RTO.

On December 6, 2011, based upon the results of the above noted reports, presentations and information gained from other parties, EKPC's Board authorized Management to begin substantive discussions and negotiations with PJM regarding the terms of integrating EKPC into its system. In response to that authorization, myself, Mr. Mosier and Mr. McNalley all made separate presentations or reports to the Board regarding various aspects of the negotiations and updates on the evaluative effort in January and February of this year. The Board was given a copy of CRA's report and received a presentation from Mr. Luciani, the leader of the CRA team, at its March 13, 2012 regular meeting. Mr. Amadou Fall of ACES also appeared before the Board on that same date. At a special meeting held on March 22, 2012, EKPC's Board approved a resolution to take the necessary steps – including seeking appropriate regulatory approvals – to become a fully integrated member of PJM. Thus, as you can see, the Board has been closely involved in the process of evaluating full integration into PJM from the outset.

Q. Can you provide a copy of the Board's resolution authorizing EKPC to seek full integration into PJM?

A. Yes. A copy of the resolution is attached to my testimony as Exhibit ASC-1.

Q. How does fully integrating into PJM align with EKPC's strategic plan?

A. Fully integrating into PJM is consistent with EKPC's strategic plan. One of EKPC's strategic objectives is to use its generation and transmission assets to deliver reliable and affordable energy. Integrating into PJM supports this initiative as we will be able to maximize the value of our existing resources, purchase power and dispatch units more economically and avoid costs associated with firm, point-to-point transmission service. In addition, as Mr. McNalley explains in his testimony, participating fully in PJM will help us in our strategic goal of building financial strength and stability.

II. OVERVIEW OF THE TRANSACTION

Q. Let us now talk more specifically about what EKPC is requesting approval to actually do in this proceeding. Can you give us a general description of what EKPC proposes?

A. Yes. EKPC desires to become fully integrated into PJM for the purpose of being able to participate in PJM's Energy Market and RPM capacity market. To do this, we must become signatories to the PJM Transmission Owners Agreement and the PJM Reliability Assurance Agreement and transfer functional control of our Transmission Facilities – a term which is defined in the agreements and specified with particularity in the exhibit to Mr. Mosier's testimony – to PJM in its capacity as system operator. As a fully integrated member of PJM, we will also participate in RTEP and other administrative committees and task forces established by PJM. In short, we intend to work within the PJM construct to achieve the maximum possible benefits for our Members.

Q. Why is Commission approval necessary in this case?

A. Transferring functional control of our Transmission Facilities is covered by KRS 278.218 which requires the Commission to pre-approve the transfer of control of assets that have an original book value of $1 million or more when the assets will continue to be used to provide the same or similar service to EKPC and its Members.

Q. The statute you have referenced includes a two step analysis. First, the Commission must determine whether the transfer of control is for a proper

purpose. Second, it must determine whether the transfer is consistent with the public interest. I understand that you are not an attorney, but can you tell us whether you believe this transfer of functional control of Transmission Facilities is for a proper purpose?

A. Transferring functional control of the Transmission Facilities is clearly for a proper purpose. The Application points out that a "proper purpose" is anything within the legitimate objects of a public utility. As a rural electric cooperative corporation established under KRS Chapter 279, EKPC has a very broad purpose to provide electric service to its members. Fully integrating into PJM will allow us to provide the same, or better, service to our customers at more affordable rates. Therefore, the proposed transfer of functional control of the Transmission Facilities is clearly for a proper purpose under the statute.

Q. The second step of the analysis is to determine whether a transfer of control is consistent with the public interest. This has been interpreted to mean 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. Do you believe that EKPC's existing utility service or rates will be adversely affected by this transfer of functional control of Transmission Facilities?

A. The transfer of functional control of our Transmission Facilities will have no adverse affect on the existing level of EKPC's utility service or rates. To the contrary, EKPC's service will be enhanced and the rate impact should be positive to our Members. Mr. Mosier describes the operational aspects of the transfer of functional control in his testimony and Mr. McNalley describes the rate impact in his testimony.

Q. The Commission has also held that it should be demonstrated that a 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. Will this transfer of functional control satisfy any of those requirements?

A. Yes. Becoming fully integrated into PJM will help with our service quality and reliability as Mr. Mosier explains. The CRA report also details how we will be able to enjoy significant avoided costs and expenses upon our full integration. Mr. McNalley, in his testimony, quantifies that the total estimated savings to Members is between $1 and $3 per MWh. Some of these benefits are immediately quantifiable, while others will be reflected in margins over the long-term. On whole, transferring functional control of our Transmission Facilities to PJM will enhance network reliability and lower the total cost of electric service to EKPC's Members. The transfer of functional control of EKPC's Transmission Facilities is therefore consistent with the public interest.

Q. Are you aware that the Commission has imposed conditions on its approval of similar applications made by other utilities?

A. Yes. As part of our due diligence, we reviewed each of the Commission cases involving the transfer of functional control of transmission assets to or from an RTO.

Q. Is EKPC willing to agree to any of the conditions that the Commission has imposed in the past?

A. Yes. EKPC is willing to agree to two conditions. First, the Commission has required that any demand response programs entered into between PJM and a customer of a jurisdictional utility must be the subject of a special contract between the utility and the customer and that this contract be preapproved by the Commission. We understand the Commission's position on this issue and agree with it. Accordingly, we would agree to a condition that states something along the lines of: "No customer of EKPC will be allowed to participate in any PJM demand response program until that customer has entered into a special contract with EKPC that has been approved by the Commission." Second, the Commission has required utilities to agree that granting approval of the transfer of functional control of transmission assets does not impair or adversely affect the Commission's jurisdiction in any respect. We also agree with that position and therefore would accept a condition which said something along the lines of: "Approval of the Application will not diminish the Commission's jurisdiction or authority with respect to its review and prescription of rates for EKPC based upon the value of its property used to provide electric service; the obligation of EKPC to file integrated resource plans; the obligation of EKPC to provide bundled generation and transmission service to its members; and EKPC's obligation to obtain a certificate of public convenience and necessity prior to commencing construction of any electric generation or transmission facility."

Q. Are there any other conditions which the Commission has imposed in the past which EKPC does not believe should not apply in this particular case?

A. Yes. The Commission has imposed other types of conditions upon investor owned utilities such as cost sharing mechanisms for off-system sales and limitations upon the ability to participate fully in the RPM capacity market. The first type of condition does not apply to EKPC as our equity owners are also our ratepayers. The second type of condition would significantly and materially lessen the value of PJM integration for EKPC and its Members as Mr. Mosier and Mr. McNalley explain in their testimonies. We don't believe that either of these types of conditions should apply in this proceeding.

III. OTHER REGULATORY APPROVALS

Q. Are any other regulatory approvals required for EKPC to become fully integrated into PJM?

A. Yes. We must also receive approval from FERC. In addition, though it is not strictly a regulatory approval, we will seek the consent of the Rural Utilities Service ("RUS") as our largest lender.

Q. What filings are required at FERC?

A. EKPC will be required to make two filings with FERC. First, EKPC will make an initial integration filing which will request FERC approval to reduce the term of the

Fixed Resource Requirement ("FRR") from five years to three years. This reduction will allow EKPC to move to the RPM sooner, subject to Commission approval. FERC has granted this type of relief in prior cases involving other utilities integrating into PJM. The initial integration filing will also be the vehicle for EKPC to have its transmission lines classified for FERC's purposes as either serving a transmission or distribution function. Second, EKPC will file an application to conform PJM's tariff to the fact of EKPC's participation in PJM as a fully integrated member. One of the more significant aspects of this filing will be the updating of EKPC's transmission revenue requirements for purposes of determining EKPC's allocation of transmission revenues within PJM. We do not anticipate any difficulties in obtaining FERC approval. Since both of these filings are non-adversarial in nature, it is likely that they will not be made until the fourth quarter of 2012.

Q. What does RUS require?

Based upon review of the RUS Loan and Mortgage Agreements, we found no explicit requirement for EKPC to seek RUS approval prior to joining PJM. However, since these documents were drafted prior to the contemplation of any RTO membership, EKPC contacted a representative at RUS who confirmed that EKPC should seek the consent of RUS prior to joining. This request will be made in the form of a letter and will contain the economic and operational justification for joining PJM. EKPC does not anticipate any obstacles in receiving RUS's consent.

IV. SUMMARY

Q. Would you like to summarize your testimony?

A. Yes. EKPC has been proactive and diligent in continually assessing the relative costs and benefits of joining an RTO since the idea first arose a decade ago. With the assistance of very capable consultants, we have evaluated alternatives and have settled upon the option that will bring the most value to EKPC and its Members. Our Board has undertaken an extensive and comprehensive effort to understand and evaluate the various issues which come into play as part of a decision of this nature and has strongly endorsed the decision to seek full integration into PJM. This will result in material benefits for our Members and there will most certainly be no adverse service or rate impact as a result. We are willing to agree to the conditions the Commission has imposed in the past which fit our situation and we are working diligently to secure the requisite approval and consent from FERC and RUS. Accordingly, we would respectfully request the Commission to approve the Application.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is for a proper purpose?

A. Yes.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is also in the public interest?

A. Yes.

Q. You are sponsoring one exhibit, the Resolution of the Board of Directors

identified as ASC-1, and incorporating it by reference into your testimony. Can you state whether this exhibit was either prepared directly by you or by someone working under your supervision and direction?

A. Yes. The resolution was prepared by someone working directly under my supervision and direction. I also helped lead the Board meeting in which it was adopted.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY

COUNTY OF CLARK

The undersigned, Anthony S. Campbell, after being duly sworn, deposes and says that he is the President and Chief Executive Officer of East Kentucky Power Cooperative, Inc., and that the matters set forth in the foregoing testimony are true and correct to the best of his knowledge, information and belief.

Anthony S. Campbell

Anthony S. Campbell

Subscribed and sworn to before me by Anthony S. Campbell on this 3rd day of May, 2012.

NOTARY PUBLIC

My Commission expires: MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

Exhibit ASC-1

Board of Directors Resolution

**FROM THE MINUTE BOOK OF PROCEEDINGS
OF THE BOARD OF DIRECTORS OF
EAST KENTUCKY POWER COOPERATIVE, INC.**

At a special meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held via teleconference at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Thursday, March 22, 2012 at 1:00 p.m., EDT, the following business was transacted:

Approval for EKPC to Pursue Membership in the PJM RTO

After review of the applicable information, a motion to approve for EKPC to pursue membership in the PJM RTO was made by Wayne Stratton, seconded by Tom Estes, and passed by the full Board to approve the following:

Whereas, the Board of Directors ("Board") of East Kentucky Power Cooperative, Inc. ("EKPC"), by and through its Strategic Issues Committee, has performed a complete and thorough analysis of the risks and benefits related to membership in a regional transmission organization ("RTO") generally and more specifically related to membership in either the Midwest Independent System Operator (MISO") or the PJM Interconnection, LLC ("PJM");

Whereas, the Strategic Issues Committee recommended and the Board at its December meeting authorized EKPC's management to commence negotiations with PJM for membership in PJM;

Whereas, EKPC management has conducted those negotiations with PJM with the parties developing a final set of terms and conditions that reasonably address EKPC's interests and issues; and

Whereas, EKPC and its agents and consultants have conducted further analyses and due diligence the results of which, consistent with earlier analyses, indicate that it is in the best interests of EKPC and its members that EKPC become a member transmission owner in PJM; NOW, THEREFORE, BE IT

Resolved, that the Board of Directors hereby approves (1) the delegation of authority to EKPC management to develop terms and conditions of EKPC membership in PJM with integration beginning on or after June 1, 2013, and the execution of any and all contracts, agreements or other documents necessary to accomplish such membership and integration; (2) the authorization of EKPC management to expend reasonable sums of money to train EKPC staff and to put in place processes, programs and controls meant to ensure a successful integration into PJM; and (3) the authorization of EKPC management to seek regulatory approvals of membership from the Kentucky Public Service Commission, FERC, and any other required regulatory bodies.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 22nd day of March 2012.

A. L. Rosenberger

A. L. Rosenberger, Secretary

Corporate Seal

Exhibit 2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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.	)	**CASE NO. 2012-________**

DIRECT TESTIMONY OF

DON MOSIER

EXECUTIVE VICE PRESIDENT/CHIEF OPERATING OFFICER

EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 3, 2012

I. INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is Don Mosier and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Executive Vice President and Chief Operating Officer at EKPC.

Q. How long have you been employed by EKPC?

A. I have been employed by EKPC since October 2010.

Q. Please state your education and professional experience.

A. I obtained my Bachelor of Science degree in civil engineering from the University of Virginia and my Master of Business Administration degree from the Kenan-Flagler Business School at the University of North Carolina. My professional experience includes work at Carolina Power & Light (now Progress Energy) in Raleigh, North Carolina, developing merchant generation projects and marketing activities, regulatory affairs, and nuclear power plant engineering and operations. I also was an engineering manager of U.S. Operations for Canatom Corp., a Toronto-based engineering firm that provides nuclear plant engineering and construction services. Immediately prior to joining EKPC, I was Vice President of St. Louis-based Ameren Energy Marketing ("AEM"), a subsidiary of Ameren Corp. At AEM, I managed wholesale power trading, plant dispatch, NERC and SERC compliance, transmission and congestion management activities, and customer account management for Ameren Corporation's unregulated merchant generation fleet located in the Midwest

ISO and PJM RTO.

Q. Please provide a brief description of your duties at EKPC.

A. I manage the day-to-day operations of power production and construction, power delivery, power supply, and system operations. I report directly to Mr. Campbell.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the internal deliberative process that EKPC underwent leading to its decision to seek full integration into PJM as well as to provide an overview of the operational aspects and benefits of joining PJM, and the proposed timing of fully integrating into PJM.

II. EKPC'S DECISION TO FULLY INTEGRATE INTO PJM

A. CHALLENGES FACING EKPC

Q. Let us begin with the process that EKPC went through leading up to its decision to seek full integration into PJM. First off, please describe the EKPC system as it currently exists.

A. EKPC has approximately $3.1 billion in assets and currently serves approximately 521,000 customers in 87 Kentucky counties through its 16 member distribution cooperatives. EKPC owns and/or purchases nearly 3,100 megawatts ("MW") of electric generation capacity and approximately 2,800 miles of electric transmission lines.

Q. Is EKPC currently a fully integrated member of any regional transmission organization ("RTO")?

A. No.

Q. What are some of the challenges that face EKPC as a result of not being a fully integrated member of an RTO?

A. There are three growing challenges that EKPC faces as a result of not being fully integrated into an RTO. The first is its continued ability to efficiently operate as its own dispatch control area and balancing authority. The second, which is closely related, is the increasing cost of securing firm transmission access to regional energy markets. The third challenge arises from the amount of reserves that EKPC must maintain in order to safely and reliably operate its system and the economic inefficiency that results.

Q. Explain why operating as a stand-alone dispatch control area and balancing authority is becoming increasingly challenging for EKPC.

A. EKPC currently operates as its own dispatch control area and balancing authority, so it must match generation to its load in a reliable and economic manner. Generally speaking, a larger dispatch control area and balancing authority can more easily maintain stability as individual variations in load become less significant in relation to the total system load. EKPC is somewhat of an island, however, as it is surrounded by PJM to the north and east, Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") to the west, and the Tennessee Valley Authority ("TVA") to the south. That means we have to rely only upon our own resources or those which are readily available and on a firm transmission path from our neighbors to match generation to load which is not always the most economic choice.

Transmission constraints often prevent us from being able to work with our neighbors. Operating on a stand-alone basis forces EKPC to forego some economic opportunity with respect to efficiently dispatching capacity to meet load and reduces our ability to sell available reserve capacity, especially as a winter-peaking utility.

Q. You mentioned that the second challenge facing EKPC – increasing costs of securing firm transmission access – is closely related to its operation as its own dispatch control area and balancing authority. Please explain that connection.

A. EKPC cannot sell excess energy or make economic energy purchases without having a reliable transmission path from the market to the EKPC system, and sales of EKPC's excess energy are frequently constrained because of limited transmission availability. To assure that such a path is available, EKPC purchased 400 MW of long-term, firm point-to-point transmission service to facilitate importing power to meet EKPC's reserve and economic purchase needs. The purchase was originally made from the Midwest ISO ("MISO") through EKPC's interconnection with Duke Energy Kentucky, Inc. ("Duke") in late 2010. When Duke integrated into PJM effective January 1, 2012, EKPC lost its transmission interconnection with MISO and this long-term transmission has now transferred to PJM. Maintaining this transmission path costs EKPC approximately $7 million annually.

Q. The third challenge you mentioned was meeting EKPC's current reserve requirement. How is this a challenge to EKPC?

A. EKPC currently has an internal target to maintain a 12% capacity reserve margin – which equals approximately 360 MW – on its winter peak load. In addition to this capacity reserve margin, which is used for planning purposes, EKPC must carry operating reserves during all periods of time. EKPC relies heavily on the TEE Contingency Reserve Sharing Group ("TCRSG") along with TVA, KU and LG&E to meet the North American Electric Reliability Council ("NERC") imposed contingency reserve standards. In this current reserve sharing arrangement, EKPC must hold back 94 MW of reserves it could otherwise sell on the market.

Q. Would you characterize these three challenges as being material to the efficient and economic operation of the EKPC system?

A. Yes. Both islanding and reserve sharing limit fleet-wide plant optimization, making dispatch less optimal. The ever increasing transmission constraints between EKPC and potential counterparties and more stringent regulatory requirements we foresee in the future continue to place additional economic pressure on EKPC's ability to operate independently. Moreover, our long-term transmission options are limited. Transmission paths sourcing in TVA and KU/LG&E are limited because of a lack of available long-term firm transmission with those utilities. Also, the TCRSG reserve sharing agreement could be cancelled at any time with six month's notice from any of the parties to the agreement. If that happened, we would find ourselves in a position similar to that which faced Big Rivers Electric Corporation when MISO limited access to its reserve sharing agreement to MISO members. Viewed independently, each of these challenges is significant. When you view them together, business prudence dictates that EKPC should proactively consider options to mitigate these material risks.

Q. Earlier you were asked if EKPC was a fully integrated member of any RTO, but now let me ask you if EKPC is currently a member of an RTO in any capacity?

A. EKPC became a member of PJM in 2005 for the limited purpose of being able to purchase and sell energy and to reserve transmission service. At that time, EKPC became a signatory to the PJM Operating Agreement, a Service Agreement for Firm Point-to-Point Transmission Service, a Service Agreement for Non-Firm Point-to-Point Transmission Service, a Service Agreement for Network Integration Transmission Service and other forms and disclosures. EKPC joined PJM 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. However, EKPC is not currently a signatory to either the PJM Transmission Owners Agreement or the PJM Reliability Assurance Agreement. EKPC may only become fully integrated into PJM upon the execution of the Transmission Owners Agreement and the Reliability Assurance Agreement, the transfer of functional control of certain of its transmission assets to PJM and its participation in the markets facilitated by PJM. Upon becoming signatories to these additional agreements, EKPC will also have the option to change its membership status to that of a Transmission Owner or Generation Owner.

Since 2005, EKPC has also been a Market Participant within MISO. Due to the loss of a direct interconnection with MISO following the transition of Duke from

MISO to PJM in 2012, EKPC will be terminating its membership in MISO as it fully integrates into PJM. EKPC was also a part of the MISO reserve sharing group until its discontinuation on December 31, 2009.

Q. So is it correct to say that when some of the documents and reports considered by EKPC talk about "joining" PJM, they are more precisely referring to becoming fully integrated into PJM?

A. Yes.

B. Scope of Options Considered by EKPC

Q. Did EKPC consider any other options as alternatives to becoming fully integrated into PJM?

A. Yes. EKPC gave consideration to maintaining the status quo, however, as I mentioned earlier, there are significant challenges associated with continuing to operate as an island. EKPC also gave consideration to fully integrating into MISO, however, when Duke announced it would transition from MISO to PJM, we recognized that we would be losing our only direct interconnection to MISO. Analyses conducted by our consultants confirmed that joining MISO was a less attractive option than joining PJM under the circumstances. We have also made TVA and KU/LG&E aware of our discussions with PJM, but discussions with those entities have not resulted in any specific alternatives being proposed. I would again add that a lack of available long-term firm transmission from either TVA or KU/LG&E limits the viability of these alternatives.

Q. So it became evident that becoming fully integrated into PJM was the best option against which to compare likely scenarios involving the status quo?

A. Yes.

C. THE DELIBERATIVE PROCESS UTILIZED BY EKPC IN CONSIDERING INTEGRATION INTO PJM

Q. Can you describe the actual process that EKPC employed to determine whether becoming fully integrated into PJM was preferable to maintaining the status quo?

A. Yes. Mr. Campbell will speak to the involvement of our Board of Directors in the deliberative process, but I can describe the efforts of management. Our internal deliberations consisted of two primary efforts. First, we engaged external consultants to conduct independent analysis of the prospect of becoming fully integrated into PJM. Second, we conducted our own internal analysis and held direct discussions with PJM personnel to discuss various issues.

Q. Who were your external consultants?

A. A preliminary, directional analysis of various energy and capacity market scenarios was conducted by our agent for energy marketing – ACES Power Marketing ("ACES"). We also engaged the highly-respected firm Charles River Associates ("CRA") to conduct a second review. CRA's analysis was totally independent of ACES's analysis.

Q. Did EKPC's management assist with CRA's analysis?

A. Throughout the evaluation process, EKPC's management provided whatever information was requested and necessary for CRA to formulate its analytical model as well and to assess various scenarios involving variations of the base case used for the analysis.

Q. What did CRA conclude?

A. The CRA Report, which is attached as an exhibit to Mr. Luciani's pre-filed testimony, concluded that there are numerous qualitative and quantitative benefits to joining PJM. The three key sources of benefits of EKPC joining PJM are: 1) more efficient commitment and dispatch of EKPC's generating resources leading to lower adjusted production costs for EKPC, as a result of: a) eliminating transmission charges; and b) participating in a fully integrated regional energy market; 2) advantageous peak load diversity relative to PJM as a whole, which results in significantly less planning reserves; and 3) avoided long-term, firm point-to-point transmission charges that are currently being incurred to ensure that EKPC has the ability to import and export power throughout the year. In sum, CRA determined the net expected economic benefit of joining PJM, based on a 10-year present value, to be $142 million. This benefit would serve to reduce the total power cost to EKPC's 16 member distribution cooperatives as well as help mitigate rising costs from current and proposed regulations for the United States Environmental Protection Agency ("EPA").

Q. Is CRA's conclusion consistent with the earlier analysis conducted by ACES?

A. Yes. While there are some differences in the analytical models, the overall results are similar. As I mentioned, CRA concluded that the EKPC will realize a $142 million net benefit over the first ten years of integration on a present value basis. ACES calculated that EKPC would realize an annual benefit of $12.96 million for each of the first five years of integration.

Q. **What are some of the differences in the analytical models you mentioned a moment ago?**

A. The two biggest analytical differences are the study periods and the modeling tools used by CRA and ACES. ACES performed a five year analysis covering 2012 to 2016. CRA performed a ten year analysis covering 2013 to 2022. Another significant difference was that ACES relied upon the PROMOD tool for Security Constrained Economic Dispatch ("PROMOD") while CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS"). Both are useful tools, but in this context, the GE MAPS tool has an enhanced degree of sophistication that gives us a higher level of confidence in its accuracy. Mr. Luciani describes the GE MAPS tool in more detail in his testimony.

Q. **What other things did EKPC do to evaluate the merits of becoming fully integrated into PJM?**

A. We commissioned our counsel to conduct a legal review of the various agreements that we will be required to execute as part of the integration. Without waiving any applicable privileges, I can say we are comfortable with our current understanding of the rights and obligations that we will enjoy and accept under both the Transmission Owners Agreement and the Reliability Assurance Agreement.

Q. Did you undertake any additional efforts to evaluate the merits of becoming fully integrated into PJM?

A. Yes. We have met directly with PJM managers and other personnel and have held several conference calls with them to further resolve any questions we might have had. In late February, we tendered a number of written questions to PJM, which they answered in March. All of this is in addition to the many, many internal meetings we have held to discuss our options and to evaluate the consultants' findings.

Q. How have the evaluative and deliberative efforts you have described above been communicated to EKPC's Board of Directors?

A. As Mr. Campbell's testimony explains, EKPC's Board of Directors was kept timely advised of developments as we went through the various analytical exercises I have described.

Q. Is it your opinion that EKPC has engaged in a thoughtful, comprehensive and deliberative process in evaluating whether to seek full integration into PJM and that the analysis produced by that process is objective, independent and credible?

A. Yes.

III. OPERATIONAL ASPECTS & BENEFITS OF FULL INTEGRATION INTO PJM

A. PJM's Operations

Q. EKPC is seeking to enter into a long-term commercial relationship with PJM. Please describe PJM as an entity and its major lines of business.

A. PJM is a federally regulated RTO, headquartered in Valley Forge, Pennsylvania, that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM acts independently and impartially in managing the regional transmission system and the wholesale electricity market, ensuring the reliability of the largest centrally dispatched electric grid in North America. PJM operates as a not-for-profit company and has more than 750 members, including power generators, transmission owners, electricity distributors, power marketers and large consumers. PJM has three principal lines of business. It operates the power grid as an independent system operator. It facilitates markets for energy, capacity and ancillary services. It also coordinates regional transmission planning.

Q. Please describe PJM's operation as an independent system operator.

A. PJM monitors the high-voltage electric transmission grid 24 hours a day, every day of the year. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions. PJM reports that it currently dispatches approximately 185,600 MW of generating capacity and demand response resources over 62,591 miles of transmission lines by relying upon telemetric data from approximately 74,000 points on the electric grid. More than 60.1 million people live in the PJM region.

Q. Please describe the various markets that PJM facilitates to the extent that they are relevant to EKPC's application.

A. PJM coordinates the continuous buying, selling and delivery of wholesale electricity through its Interchange Energy Market ("Energy Market"). PJM's Energy Market establishes a market price for electricity by matching supply with demand using online interfaces for members with continuous real-time data. The Energy Market is a two-settlement (Day-Ahead and Real-Time) market using hourly locational marginal prices ("LMPs") and financial transmission rights ("FTRs"). Under the PJM Operating Agreement, PJM will schedule in advance and dispatch generation on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by sellers within and into the PJM Region, continuing until sufficient generation is dispatched to serve the energy purchase requirements of such region and buyers out of such region, as well as the requirements of the PJM Region for ancillary services provided by such generation. Scheduling and dispatch is conducted in accordance with applicable schedules to the PJM Tariff and Operating Agreement. Market participants, such as EKPC, are able to follow energy market fluctuations as they occur and quickly respond to price signals bringing supply resources to the region when demand is high.

PJM also sponsors a capacity market which creates a long-term price signal for the cost of capacity needed to reliably serve load within the PJM system. The capacity market basically uses a three year planning horizon – with opportunities for adjustments in the interim – to establish pricing for capacity. This, in turn, attracts the investment that is necessary to make sure that adequate capacity exists when needed. Unlike the Energy Market which operates on a daily basis, the capacity market generally functions on a quarterly schedule.

Though they are less relevant to EKPC's decision to become fully integrated, PJM also administers various ancillary services, demand-response initiatives, financial transmission rights and reserve markets. Overall, PJM advertises that it has administered more than $103 billion in energy and energy-service trades since its markets first opened in 1997.

Q. Please describe PJM's role in coordinating regional transmission expansion planning.

A. PJM manages a sophisticated regional transmission expansion planning process ("RTEP") for transmission expansion to ensure the continued reliability of the electric system. PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations and transmission lines. PJM analyzes and forecasts the future electricity needs of the region so that its planning process ensures that the growth of the electric system takes place efficiently, in an orderly fashion, and that reliability is maintained.

Q. Do any other utilities in Kentucky participate in PJM?

A. Yes. Duke and Kentucky Power Company are both fully integrated members of PJM. In addition, Big Rivers Electric Corporation, KU and LG&E are also members of PJM according to the schedule of members attached to the PJM Operating Agreement. Finally, AEP Kentucky Transmission Company, Inc., which has filed an application for a certificate of public convenience and necessity to operate as a public utility in Kentucky, is also identified as a current member of PJM.

B. Operational Developments Upon Full Integration

Q. One of the most significant aspects of becoming fully integrated into PJM is the transfer of functional control of EKPC's transmission assets to PJM. Can you identify what transmission assets will have their functional control transferred to PJM?

A. Yes. The PJM Operating Agreement and Transmission Owners Agreement refer to PJM assuming operational control over "Transmission Facilities," which is a defined term in both Agreements. Exhibit DM-1 to my testimony provides a detailed schedule of Transmission Facilities for which functional control will be transferred to PJM. Whenever I use the term "Transmission Facilities," I am referring to these assets.

Q. Why is a transfer of functional control of EKPC's Transmission Facilities necessary to become a fully integrated member of PJM?

A. The transmission grid can be operated most reliably and efficiently when there is a centralized dispatch of generation resources and transmission capacity. To accomplish this for Generation Owners and Transmission Owners within the PJM system, the Transmission Owners Agreement and Operating Agreement grant PJM the right and authorization to use the transmission capacity of EKPC's Transmission Facilities that is required to provide service under the PJM Tariff and to resell transmission service using such capacity. PJM will compensate EKPC for the use of its transmission capacity by distributing certain revenues to EKPC as set forth in the PJM Tariff and the Transmission Owners Agreement.

Q. By transferring functional control of the Transmission Facilities to PJM, does EKPC lose any ownership interest in those assets?

A. No. The transfer of functional control is purely for operational purposes. The Transmission Facilities remain the property of EKPC and EKPC retains responsibility for their maintenance and upkeep.

Q. How will EKPC's operational and planning processes change as a result of becoming fully integrated into PJM?

A. EKPC's operational and planning processes will change in two fundamental respects. First, many of our routine, day-to-day operations, which are currently integrated, will take on more distinct and separate existences within the overall PJM framework. Second, our planning efforts will be supplemented by the inclusion of a broader regional perspective in those processes. This means that we will have the same responsibilities for meeting our existing load safely, reliably and affordably, but we will be doing so, in part, in the context of regional operational and planning processes.

Q. Please elaborate on the aspects in which EKPC's day-to-day operations will change.

A. Broadly speaking, EKPC's day-to-day activities will change as production operations, transmission operations, and load management functions will be more segregated from one another. Production operations will "bid" generation into the Day Ahead and Real Time components of the PJM Energy Market. The Transmission Facilities will be under the control and direction of the PJM system operator, and EKPC will become its own zone or sub-zone in the PJM system. This means that we will separate the functions of dispatch and transmission operations, which will be directed by PJM, from the functions of load management, which we will continue to manage, but within a broader overall context.

Q. With respect to production operations, please describe the Day Ahead and Real Time Markets.

A. The Day-Ahead Market ("DA") is a forward market in which hourly LMPs are calculated for the next operating day based upon the total generation offers, demand bids and scheduled bilateral transactions that are provided to PJM each day. The Real-Time Market ("RT") is a balancing spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions and the inevitable deviations between what was expected to occur DA and what actually occurs in RT. Weather as well as unexpected generation and transmission outages or contingencies can influence the market in RT. PJM settles transactions hourly, including any deviations which may have occurred, and issues invoices to market participants monthly.

Q. Will EKPC participate in the Day Ahead and Real Time markets?

A. Yes. Each day, EKPC will bid its estimated Member loads into the Day Ahead market. It will also bid its available generation resources into the Day Ahead market, including any interruptible loads and our Direct Load Control resources that EKPC may bid as Demand Response resources. The sum of all demand for load within the PJM system is then compared to the sum of all capacity resources bid into the Day Ahead market. Based upon a number of factors, but principally supply and demand, PJM then determines the LMP for each delivery point within PJM and uses that LMP to determine which generation resources should be dispatched on the following day – the operational day – to arrive at the most efficient and economic result. EKPC's generators will receive instructions from PJM on when and to what extent to generate electricity on the operational day. To the extent that the load forecasts may prove to be incorrect or a contingency occurs somewhere within the system, the Real Time market provides a backup for buying and selling power as needed on the operational day. Thus, by giving PJM the ability to dispatch our generation resources, we gain the ability to share in the overall economic benefit of participating in a much larger energy market. This should mean that our production costs will decrease and our purchase of economic power will increase – both of which are beneficial to our Members. EKPC will maintain the responsibility for maintenance and upkeep of our capacity resources.

Q. With respect to transmission, how will EKPC's operations change?

A. The change is very similar to the change I described for generation resources. PJM will assume responsibility for managing our electric transmission grid. In exchange we will have the ability to share in the benefits of making our grid part of a much larger grid. As we transfer functional control of the Transmission Facilities to PJM, we will also need to coordinate maintenance and any outages with PJM. EKPC will retain the responsibility for maintenance and upkeep of the Transmission Facilities.

Q. The last day-to-day operational change you mentioned was load management. How will EKPC's activities change in this respect once it joins PJM?

A. We will continue to monitor our system as we have done before. However, as part of a larger interconnection, we will also work with PJM's regional transmission managers to proactively identify imbalances quickly and to prevent any adverse impacts to EKPC or our neighbors' systems. As a fully integrated member of PJM, imbalances on the EKPC system are managed far more efficiently and more cost effectively than on a stand-alone basis by virtue of the market's overall size and diversity of resources.

Q. Will integrating into PJM impact EKPC's current interconnection agreements in any way?

A. No. The substance of these agreements will not change; however, PJM will become a signatory to the agreements.

Q. Let us go back to the other type of procedural changes you mentioned, which were changes in EKPC's existing planning processes. Please elaborate on the aspects in which EKPC's planning processes will change.

A. The biggest changes will be in the areas of capacity planning and transmission expansion planning. PJM has mature processes in place for both of these important aspects of utility management. By participating in PJM's capacity market, EKPC will add a new level of scrutiny to its existing generation resource planning efforts. Likewise, PJM's RTEP process assures that reliability and congestion issues are addressed prospectively by assuring that transmission planning happens on a suitable scale and timely, recurring basis.

Q. Describe how the PJM capacity market is structured.

A. PJM's capacity market is structured around its Reliability Pricing Model ("RPM"). Under the RPM regime, Generation Owners typically make capacity commitments three years in advance to ensure price certainty. This, in turn, creates a long-term price signal that helps to attract the investment that is needed to assure reliability throughout the entire PJM region. One important innovation in the RPM structure is the inclusion of demand response and transmission assets as resources along with traditional forms of generation capacity. In that respect, the RPM compliments and supplements the RTEP process. Under RPM, EKPC may bid its entire generation capacity into the market, but it will also have the option to self-supply its load and employ any bilateral contracts that it may choose to enter into for the procurement of power. Any remaining capacity requirements are secured through recurring capacity auctions.

In practice, it works like this: the delivery year for PJM starts on June 1st and ends on May 31st of the following calendar year. For each such delivery year, PJM holds a Base Residual Auction ("BRA") three years prior to the delivery year in question, which would be in the month of May. In May 2013, the BRA will be held for delivery year 2016/2017. PJM then holds the first of three incremental auctions for that same delivery year 16 months later in September – or 20 months before the delivery year in question begins. PJM holds the second incremental auction 10 months after that, which would be the month of July and just 10 months before the delivery year begins. The third and final incremental auction for the delivery year takes place in February – four months before the start of the delivery year in June. Thus, PJM's capacity auctions are spaced out through the calendar year, but each auction of the year is focused upon a different delivery year.

Q. You mentioned that EKPC may either bid all of its generation capacity into the PJM capacity market or it may self-supply its load requirements. What is the distinction between these two options?

A. The RPM is structured so that all of the generating resources within the PJM system are bid into a common capacity market. This allows for the greatest market efficiency and dispatching of resources and provides clear pricing signals to incentivize new generation to be built. However, the RPM also contemplates that some utilities may prefer, or be required, to hold back sufficient generation resources to be able to supply all or a significant portion of their native load. The later scenario involves what is called a Fixed Resource Requirement ("FRR") plan. To ease the integration process of a new Generation Owner such as EKPC into PJM, we must initially participate in the PJM capacity market on an FRR basis until we are able to participate in a full capacity auction cycle. Generally speaking, the RPM without the FRR is the most efficient option because it carries with it a lower reserve requirement and the greatest benefit to EKPC's Members.

Q. How will EKPC participate in the PJM capacity market?

A. EKPC will be required to submit a FRR plan for the 2013/14, 2014/15 and 2015/16 delivery years since the Base Residual Auctions for those delivery years will have already taken place prior to EKPC's integration. However, EKPC could, and intends to, participate in the RPM auction beginning in the 2016/17 delivery year, which means it would participate in the Base Residual Auction held in May 2013. During the initial FRR period, EKPC could only sell any additional capacity unneeded to meet its FRR reserve requirements in the incremental RPM auctions for each delivery year scheduled to take place over time or bilaterally to other PJM members in need of capacity. However, EKPC would be required to hold back an additional 3% of its reserve requirements during the period in which it operates on an FRR basis. This 3% holdback requirement makes an FRR plan less economic for EKPC as it would reduce EKPC's savings somewhere between \$3 million and \$9 million per year. Mr. McNalley explains in his testimony that this equates to an approximate 20% reduction in the per MWh savings our Members would otherwise expect. Participation under the traditional RPM approach will yield greater savings to EKPC due to the reduced reserve requirement and is a material consideration in our decision to seek full integration into PJM.

Q. You also mentioned that EKPC may use demand resources and transmission construction in the capacity market process. Will it likely do so?

A. EKPC is aware that the Commission has imposed conditions in the past with regard to whether customers within a utility system may participate in an RTO sponsored demand response program. As Mr. Campbell states in his testimony, EKPC is willing to accept a similar condition in this case, however, I would note that we are asking in our Application that each of our existing interruptible loads and our Direct Load Control program be included in PJM's Demand Response program as of the first day that we fully integrate into PJM. We have not made any decisions about using transmission capacity or other demand response programs, but would routinely evaluate those resources in the context of our own service needs and in the context of PJM's capacity auctions.

Q. On page 30 of its Report, CRA assumes that Cooper Unit 1 and the four Dale Units are retired in 2015. Is it EKPC's plan to retire these units?

A. No. At this time, EKPC has not made a decision to retire these units. As indicated in EKPC's 2012 Integrated Resource Plan ("IRP"), EKPC is soliciting Requests for Proposals to determine if retrofitting existing generating units, purchasing power, or constructing new facilities is the most cost-effective alternative to meet EPA rules.

The assumption for the CRA study was that the existing five coal fired generating units (4 units at Dale and Cooper Unit 1) would be replaced with a resource whose cost and operating characteristics are similar to a combined cycle facility.

Q. Please describe how RTEP works?

A. PJM's RTEP process is designed to identify transmission system upgrades and enhancements that are necessary to provide for the operational, economic and reliability requirements of the PJM system. Thus, RTEP incorporates transmission, generation and load response projects to meet all load-serving obligations. PJM applies planning and reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact and costs, culminating in one plan for the entire PJM footprint.

Q. What role will EKPC have in RTEP planning?

A. EKPC will have a limited role in RTEP planning for backbone projects. It will have a larger role in the planning of local projects of which it would be the sponsor or a beneficiary thereof.

Q. Will EKPC's involvement in the PJM Capacity Market or RTEP have any impact upon the Commission or its jurisdiction over EKPC, particularly with regard to integrated resource planning?

A. There will be no impact. Joining PJM will not affect the Commission's jurisdiction and we will continue to be subject to all of the same state requirements under which we currently operate. EKPC will continue to engage in system planning in accordance with the integrated resource planning process. Mr. Campbell speaks to the issue of the Commission's jurisdiction in his testimony and one of the conditions to which EKPC is willing to agree is that it be expressly understood that this transfer of functional control of EKPC's Transmission Facilities will not alter or affect the Commission's jurisdiction.

Q. Apart from the operational and planning changes you have already described, are there any other significant operational or planning aspects of becoming fully integrated into PJM that should be mentioned?

A. Yes. Although it is not a change from the status quo, EKPC plans to remain a member of the TCRSG. This will help assure that our integration into PJM does not have an adverse impact upon any of our current reserve sharing partners. EKPC became a member of the TCRSG in November 2009 in order to comply with NERC rules regarding reserve requirements. Although EKPC will not need to remain a member of the TCRSG following its integration into PJM, it plans to remain a member so as to avoid any disruptions to TVA, KU or LG&E. PJM has been advised of EKPC's intentions in this respect and is willing to administer EKPC's participation in the TCRSG as necessary. EKPC has been advised by TVA, KU and LG&E that each of them agrees with this arrangement.

Q. Will remaining a member of the TCRSG inhibit EKPC from realizing any of the anticipated benefits of full integration into PJM?

A. No. There is an annual administrative fee, approximately $120,000, that we will continue to pay as a member of the TCRSG. Because of the greater number of resources available as a fully integrated member of PJM, EKPC anticipates that the costs of remaining a member of the TCRSG will likely be less to meet its obligation than if it maintained the status quo.

Q. Will any of your Owner-Members notice the operational changes you have described above?

A. No. For our Members it should be a transparent development of our operations wherein they will notice no discernible change in the services we currently provide.

Q. Will any of your Owner-Members' Members notice the operational changes you have described above?

A. With the possible exception of interruptible loads, the single largest of which is Gallatin Steel ("Gallatin"), the transfer of functional control of EKPC's Transmission Facilities to PJM and resulting operational changes should again be transparent to our ultimate end users. We do not foresee any adverse impacts upon our continued ability to provide safe, reliable and affordable service throughout the EKPC system. If anything, the service we provide will be more reliable and more affordable.

Q. You alluded to the fact that there might be an impact to Gallatin and other interruptible loads. Can you elaborate upon that?

A. EKPC's analysis indicates that to fully realize the capacity value within PJM, EKPC's interruptible loads need to be enrolled in PJM's Demand Response Program.

Operating these programs outside of the PJM program diminishes the capacity value of these programs by approximately 30 percent. Under the current agreement between EKPC, Owen Electric Cooperative Corporation and Gallatin, EKPC has the ability to interrupt Gallatin's load. EKPC has six other interruptible loads which will also qualify for the Demand Response Program.

Q. Which of the current Gallatin contract provisions will need to be modified as a result of placing Gallatin's load in PJM's Limited Demand Response Program?

A. There are two portions of the Gallatin contract that will require modification. First, Provision 7 of the Gallatin contract will need to be modified to state that PJM and/or EKPC can call for a physical interruption to allow the Gallatin load to act as a capacity resource during emergency conditions in PJM. Second, as a result of joining PJM, Provision 13 of the Gallatin contract relating to regulation is no longer applicable and will need to be deleted as PJM will be providing regulation to Gallatin.

Q. Will modifications will be required to the contracts of the other six interruptible loads?

A. We anticipate that there may be some modifications that are necessary and such modifications will be filed with the Commission.

Q. What approvals are needed to allow Gallatin and the other interruptible loads to participate in the PJM Limited Demand Response Program?

A. Since each of these interruptible loads involves special contracts, we are in the process of securing the consent of the interruptible customers to make any necessary contractual modification. Moreover, it is EKPC's understanding, based on the review of the Commission's Order in Case No. 2010-00203, that Commission approval is required to participate in the PJM Demand Response Program. In addition, EKPC and Gallatin are preparing a contract amendment, which is contingent upon both the Commission's approval of EKPC fully integrating into PJM and Gallatin's participation in PJM's Limited Demand Response Program. This contract amendment will be filed with the Commission.

Q. Does the PJM Limited Demand Response Program encompass any of EKPC's other Demand Side Management programs?

A. Yes. EKPC's Direct Load Control program is eligible for inclusion in this PJM program. Sections DSM-3a and DSM-3b of EKPC's tariffs contain the details of this program. A tariff change would be required, subject to the Commission's approval, to reflect the inclusion of the Direct Load Control program into PJM's Demand Response Program.

Q. Are EKPC's energy efficiency programs eligible for inclusion in any PJM demand response program?

A. Yes. Certain energy efficiency programs are eligible to qualify as capacity resources in PJM so long as they are measurable and verifiable. As indicated in EKPC's most recently filed Integrated Resource Plan (Case No. 2012-00149), EKPC will benchmark with other utilities and do research in preparation of obtaining an evaluation, measurement, and verification (EM&V) process. Since this EM&V

process is not currently in place, EKPC does not seek Commission approval of placing energy efficiency programs in PJM's demand response programs at this time.

Q. So EKPC is asking the Commission to permit it to enroll its interruptible load and Direct Load Control load as participants in PJM's Limited Demand Response Program in order to optimize the ability of EKPC to monetize its capacity within PJM?

A. Yes. The ability to monetize this capacity will flow back to all EKPC's ratepayers and contribute to the overall net benefit of fully integrating into PJM.

C. Benefits of Fully Integrating Into PJM

Q. The changes you have described are not insignificant. In light of these changes, why are you confident that fully integrating into PJM is a good decision?

A. As CRA states at the very beginning of its report, "...EKPC joining PJM will yield significant economic benefits to EKPC. The net benefits to EKPC are relatively robust." While there will be some changes to how EKPC operates once becoming fully integrated into PJM, the benefits of this integration are clear. The cost-benefit analysis sufficiently demonstrates that this is a good decision.

Q. The CRA Report describes several benefits and costs that are likely to arise as a result of integration into PJM. Please briefly summarize the nature and extent of these benefits.

A. CRA did a good job of identifying the categories of costs and benefits that EKPC will likely realize upon becoming a fully integrated member of PJM. On the "benefits" side of the ledger, EKPC will be able to: 1) more efficiently participate in the PJM Energy Market and avoid significant production costs as a result; 2) monetize excess capacity and energy to a greater extent than it is currently able to do given existing transmission constraints and reserve requirements; and 3) avoid costs for firm point-to-point transmission service which it currently incurs to meet SERC planning reserve guidelines. On the "costs" side of the ledger, EKPC will have a modest increase in administrative expenses and governmental assessments and it will also assume an obligation to pay for certain future high-voltage transmission expansion projects within the PJM region. On a present value basis, the expected net benefit to EKPC over the first ten years of integration is $142.0 million. Moreover, CRA evaluated the relative benefits that are likely to result under various sensitivities. In other words, CRA looked at what would happen if various variables in their assumptions were changed. In each scenario that CRA examined, there were net positive benefits for EKPC when it became fully integrated into PJM. This means that while certain factors could reduce the overall net benefit over time, other factors could increase the overall net benefit. The sensitivities analysis performed by CRA gives us a high degree of confidence that the $142.0 million estimate is reasonable and appropriate.

Q. Please describe the nature and extent of the trade benefits that EKPC expects to realize following the integration.

A. Trade benefits are realized when EKPC is able to optimize its own production costs by purchasing power at a more affordable cost. CRA concluded that EKPC would be able to generate less power (thereby decreasing production costs) while at the same time increasing its economic off-system purchases. This co-optimization yields a more economic dispatch of generating resources and approximately $52.7 million in net savings over the ten year period following integration.

Q. Please describe the nature and extent of the capacity benefits that EKPC expects to realize following the integration.

A. Capacity benefits are the single largest category of benefits that accrue in the context of EKPC's full integration into PJM. Due to the fact that EKPC is a winter peaking system and PJM as a whole is summer peaking, EKPC has the unique opportunity to monetize this diversity through the reduction of its own peak reserve requirements to match those of PJM. Thus, instead of maintaining our current 12% planning reserve requirement in both the winter and summer seasons, EKPC would only be required to maintain a 2.8% installed planning reserve for EKPC's summer peak as a fully participating member of PJM's RPM. The net savings for EKPC to participate fully in PJM through the RPM equates to $147.8 million over the ten year term of the study. If, however, EKPC was only permitted to join PJM on an FRR basis, it would be required to increase its reserve requirement by an additional 3%. As I mentioned earlier and as Mr. McNalley quantifies in his testimony, this would have a materially adverse effect upon the overall benefits to be derived from becoming fully integrated into PJM.

Q. Please describe the nature and extent of the benefits arising from the

cancellation of the existing firm point-to-point transmission service agreement.

A. Becoming a signatory to the Transmission Owners Agreement and the Reliability Assurance Agreement will allow EKPC to immediately cancel the firm transmission reservation currently in effect with PJM for 400 MW of point-to-point transmission rights that is set to expire on December 31, 2016 and resulting in a savings of more than $7 million per year. If we assume that a similar agreement had to be made once the current agreement expires, then those costs will also be avoided by becoming a Transmission Owner in the PJM system. Fully integrating into PJM also limits the risks associated with being unable to secure adequate and affordable firm transmission service after the current transmission reservation expires. Thus, over the first ten years of integration, EKPC's members will save approximately $56.1 million in known and certain transmission costs for which they are currently obligated without suffering any detrimental impact to service reliability and access to the PJM market.

Q. You said earlier that there will also be new costs associated with integrating into PJM. Please describe the nature and extent of the administrative costs associated with full integration into PJM.

A. As a Transmission Owner and Generation Owner in PJM, EKPC will assume responsibility for additional administrative expenses. These costs generally arise in three contexts: 1) administrative costs imposed directly by PJM; 2) assessments charged by FERC; and 3) those which EKPC must assume internally as part of the integration and ongoing supervision of activities within PJM. CRA has concluded, and we believe it is reasonable, that EKPC will have approximately $48.3 million in new administrative costs over the first ten years following integration. This figure is arrived at by adding the following components: $35 million for PJM fees; $7.7 million in new FERC assessments; and $5.6 million for EKPC to internally complete the integration and the ongoing administration of the larger relationship with PJM.

Q. How will the $5.6 million in costs internal to EKPC be allocated?

A. Approximately $1 million will be allocated to cover the initial costs of the integration. This chiefly includes purchasing the equipment that will be necessary to provide the communications infrastructure and other hardware needed to incorporate EKPC's system parameters into PJM's models and to interface with PJM on a fully integrated basis. The remainder of the costs will generally be allocated to cover new personnel, legal and energy marketing expenses associated with operating as part of PJM. Internally, EKPC anticipates adding four full-time equivalents: one in market management, one in accounting, one in congestion management, and one in risk management.

Q. To what extent will EKPC's relationship with ACES change when it becomes fully integrated into PJM?

A. The internal cost estimate specifically includes the additional costs associated with continuing to use ACES to assist and facilitate EKPC's interactions with PJM in the energy and capacity markets and planning functions. We will be interacting with PJM more substantively and more frequently. Therefore, we will be relying upon and using ACES more frequently as well.

Q. Please describe the nature and extent of the transmission costs associated with becoming fully integrated into PJM.

A. CRA estimates that EKPC will incur costs of approximately $66.4 million over the first ten years of integration as part of PJM's RTEP program, which allocates the total cost of "backbone" transmission line projects for lines rated at 500 kV and above. EKPC will have the opportunity, however, to have the costs of any of its own transmission projects allocated to other utilities to the extent that such utilities would benefit from the addition of the new transmission infrastructure. To the extent that any additional Transmission Owners may join PJM, they would share in the RTEP expense and thereby reduce EKPC's allocation. Members that leave PJM continue to be obligated for their allocation incurred while members.

Q. Are there any additional benefits to becoming fully integrated with PJM that are not detailed in the CRA Report?

A. Yes. There are at least four other key benefits that come with joining PJM that are not included in the CRA Report. These benefits arise from: 1) an enhanced ability to provide reliable service; 2) positioning EKPC to have greater flexibility for responding to future federal regulatory requirements; 3) fundamental safeguards in the PJM marketplace that will help protect EKPC's members from needless market volatility; and 4) savings derived from discontinuing our status as a Market

Participant in MISO.

Q. Why were these four benefits not included in the CRA Report?

A. CRA performed a cost-benefit analysis. EKPC already has a very good track record of providing reliable service, so it is difficult to quantify the incremental benefits offered through participation in PJM as a result. Likewise, the federal regulatory landscape is very uncertain at this point. CRA's report focused upon known and reasonably measurable criteria and factors. EKPC will certainly be better positioned to respond to future federal requirements as a fully integrated member of PJM, but until actual rules are promulgated and finalized by the EPA or FERC, it is not possible to know exactly how much better EKPC will be positioned. The same is true of the structural protections that are in place to safeguard the integrity and stability of PJM's markets. The value is hard to quantify, but most certainly these additional aspects of full integration protect and benefit EKPC's Members and, by extension, those Members' ratepayers. As for the savings from discontinuing our membership in MISO, the decision was not made until after the benefits of joining PJM were clear – which was after CRA's report was completed.

Q. How will network reliability be improved once EKPC becomes fully integrated into PJM?

A. As I said earlier, EKPC's reliability is already very high. However, EKPC is currently constrained to manage reliability issues only with the resources at its disposal within the EKPC system. While this is workable for most reliability concerns, the increasing interconnectivity of the grid increases the likelihood that reliability issues in another area may spill over into EKPC's system unless adequate safeguards are in place. By joining PJM as a Transmission Owner, EKPC will be part of a very large grid and the ability to work around reliability issues in any particular location will be enhanced. Our Members will not necessarily notice these incremental improvements to reliability because, in the ordinary course of business, reliability is already high. However, on the very rare day when things do not go as planned, having the ability to route a greater amount of capacity and power through a larger grid allows for greater overall system stability and reliability. Thus, transferring functional control of EKPC's Transmission Facilities and participating in PJM under the Transmission Owners Agreement and Reliability Assurance Agreement will have a positive impact upon ratepayers within the EKPC system. With unconstrained access to PJM, EKPC's network reliability will not be harmed and will most certainly be improved.

Q. Can you provide a specific example of how full participation in PJM will better position EKPC to respond to developments in federal regulations?

A. Certainly. With Rule 1000, FERC is demonstrating a move towards establishing a national cost allocation methodology for transmission expansion projects. However, it remains unclear exactly when and in what form this new direction will take shape. Becoming integrated into PJM now gets EKPC into an established cost allocation methodology that has already received FERC's blessing. Therefore, we have a very high degree of confidence that EKPC will certainly be in no worse position based upon what FERC may do in the future. Participation in PJM as a Transmission Owner allows us to exchange the uncertainty of future federal cost allocation protocols for the better predictability of RTEP. Another example I would offer is in the environmental realm. EPA's new and proposed rules are causing many utilities to re-evaluate their generation portfolios. In isolation, a utility must make a significant, forty-year investment today based upon an incomplete future federal regulatory policy picture. By becoming a Generation Owner in PJM, we have the ability to hedge some of the risks associated with those types of investment decisions by having access to a very large capacity market. Full membership in PJM will allow us to respond to new environmental requirements with two very significant new tools – the freedom to purchase economic power in the short-term and the ability to participate in PJM's capacity market over the long-term. Additionally, EKPC can access other existing generation resources through joint partnership opportunities that reduce the risk of permitting, constructing and operating such resources on a stand-alone basis.

Q. Please explain how EKPC's members will benefit from the structural safeguards inherent within the PJM markets that you mentioned earlier.

A. The structure of PJM's Energy Market and RPM assure that EKPC's members will not be exposed to volatility to any extent greater than what they currently face. Moreover, PJM's operations are constantly monitored by an independent firm engaged to assure transparency and integrity in the Energy Market and PJM has imposed specific credit requirements upon its members to significantly reduce the possibility of defaults. While the benefits of these market structures are difficult to precisely quantify, they are nevertheless real and tangible safeguards which will ultimately benefit EKPC's Members.

Q. Please describe the savings that will be derived from EKPC's ability to discontinue its status as a Market Participant in MISO.

A. EKPC became a Market Participant within MISO in 2005 so that we would have the ability to buy and sell power through that market. Following the transition of Duke from MISO to PJM, we lost our only direct interconnection to MISO and our ability to transact in that market was made more complicated and costly to wheel power out of MISO. Once we become fully integrated into PJM, we will no longer have a need to access the MISO market and we will be able to discontinue our status as a Market Participant. This will save EKPC approximately $125,000 per year in membership fees alone. When internal costs are included, the savings would, of course, be even greater.

Q. The CRA Reports lists several qualitative considerations and risk factors that go along with becoming fully integrated into PJM. Have you adequately taken these into account?

A. Among the most significant of the considerations and risk factors described in the CRA Report is the difficulty associated with: 1) predicting EKPC's future costs arising from PJM's RTEP; 2) the effects of future variations in fuel costs and load growth; and 3) exit obligations. EKPC takes each of these issues seriously and has reviewed CRA's findings closely. We agree that they are legitimate risk factors, but nothing we have seen thus far causes us to believe the risks are unacceptable. To the contrary, even when these risks are taken into account under various sensitivities, full integration into PJM is still attractive.

Q. Can you summarize the relative benefits and costs of EKPC becoming fully-integrated into PJM?

A. Yes. Joining PJM is a long-term commitment and there are uncertainties regarding what amount the costs of ever disassociating with PJM may be. There is also some uncertainty with regard to what portion of future RTEP costs would be allocated to EKPC and whether future variations in fuel and load forecasts will fall within expectations. These types of risks are common to all long-term business partnerships, however, and we are convinced that these risks are well within acceptable limits. What is certain is that EKPC stands to significantly gain from capitalizing on its seasonal diversity with PJM, enjoy the benefits of favorable trading opportunities and avoiding costs that it is currently incurring both for production of power and for securing firm transmission paths. EKPC has the opportunity to lock in these real savings and also to experience other benefits which, though more difficult to ascribe a dollar value to, are nonetheless real and meaningful. The economics of joining PJM are good for EKPC, its Owner-Members and its Owner-Members' Members.

IV. TIMING OF FULL-INTEGRATION INTO PJM

Q. What is the ideal timeframe for EKPC being able to fully integrate into PJM?

A. So that we can begin to realize and maximize the benefits of membership in PJM under the Transmission Owners Agreement and the Reliability Assurance Agreement, EKPC desires to be able to participate in the Base Residual Auction for the 2016/17 delivery year, which will be held in May 2013. That would also allow us to become fully integrated into PJM on an operational level by June 1, 2013.

Q. Is there anything else that is important about integrating into PJM by June 1, 2013?

A. Yes. The sooner we integrate into PJM, the sooner we will be able to start enjoying the trade benefits that are available to EKPC and, beginning in the 2013 summer peaking season, EKPC would be able to start monetizing the value of its seasonal diversity with PJM as a whole. Finally, once we are fully integrated into PJM, the need for the existing 400 MW firm point-to-point transmission service agreement goes away and we will be able to cancel that agreement effective immediately. Thus, EKPC will be able to enjoy several types of benefits right away if we are able to integrate into PJM by June 1, 2013.

Q. In light of these considerations, when does EKPC request the Commission to issue an order in this case?

A. In order for EKPC to participate in the May 2013 Base Residual Auction for the 2016/17 delivery year and to complete the integration by June 1, 2013, PJM has told us that we would need to have approval from the Commission on or before December 31, 2012. Based upon that assurance, EKPC therefore respectfully requests that the Commission enter an Order approving EKPC's entry into PJM at least by December 31, 2012.

V. SUMMARY

Q. Would you like to summarize your testimony?

A. Yes. EKPC has undertaken a very deliberative process for evaluating whether the time is right for membership in an RTO. We have evaluated several alternatives, including maintaining the status quo. Clearly, PJM is the best fit for EKPC. The net benefits of joining PJM are well documented and the risks are acceptable. The operational changes we will be making are no different than what Duke and Kentucky Power have already done and the Commission's continued jurisdiction over EKPC will not be adversely affected in any way. Joining PJM is for a proper purpose and consistent with the public interest for all the reasons I have stated in my testimony. Accordingly, we would respectfully request the Commission to approve the Application.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is for a proper purpose?

A. Yes.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is also in the public

interest?

A. Yes.

Q. You are sponsoring one exhibit, the schedule of Transmission Facilities identified as DM-1, and incorporating it by reference into your testimony. Can you state whether this exhibit was either prepared directly by you or by someone working under your supervision and direction?

A. Yes. This schedule was prepared by someone working directly under my supervision and direction.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY

COUNTY OF CLARK

The undersigned, Don Mosier, after being duly sworn, deposes and says that he is the Executive Vice President and Chief Operating Officer of East Kentucky Power Cooperative, Inc., and that the matters set forth in the foregoing testimony are true and correct to the best of his knowledge, information and belief.

Don Mosier

Don Mosier

Subscribed and sworn to before me by Don Mosier on this 3rd day of May, 2012.

Gwyn M. Willoughby

NOTARY PUBLIC

My Commission expires: MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

Exhibit DM-1

Schedule of Transmission Facilities

Transmission Lines Transferred to PJM's Functional Control

DESIGNATION			
From (a)	To (b)	Operating (c)	Designed (d)
SPURLOCK	AVON	345	345
GALLATIN CO	KU GHENT	345	345
SMITH	NORTH CLARK	345	345
SPURLOCK DBL CIIRCUIT TAP	ZIMMER (DUKE)/STUART (DPL)	345	345
SMITH	WEST GARRARD	345	345
BEATTYVILLE	POWELL	161	161
COOPER	DENNY	161	161
COOPER	ELIHU	161	161
COOPER	MARION CO	161	161
COOPER	TYNER	161	161
COOPER	WOLFE CREEK	161	161
GREEN CO	SUMMERSHADE	161	161
LAUREL RIVER DAM DBL CIRCUIT TAP		161	161
MARION CO	GREEN CO	161	161
LAUREL CO TAP		161	161
RUSSELL CO TAP		161	161
SUMMERSHADE	BARREN COUNTY	161	161
TYNER	BEATTYVILLE	161	161
MCCREARY TAP		161	161
BULLITT CO DC TAP		161	161
BULLITT CO	SHELBY CO	161	161
PULASKI CO TAP		161	161
CASEY CO TAP		161	161
SUMMERSHADE	SUMMERSHADE TAP	138	138
SUMMERSHADE	TVA SUMMERSHADE	138	138
TYNER	FALL ROCK	161	161
ARGENTUM LOOP		138	138
AVON	FAYETTE	138	138
AVON	RENAKER	138	138
BOONE	DUKE ENERGY LONGBRANCH	138	138
CENTRAL HARDIN DBL CIRCUIT TAP		138	138
CRANSTON	ROWAN	138	138
FAWKES	FAWKES KU TIE	138	138
FAWKES	FAWKES TAP	138	138
FAWKES	WEST BEREA	138	138
FLEMINGSBURG	GODDARD	138	138
DALE	AVON	138	138
DALE	FAWKES	138	138
GHENT	BOONE	138	138
GODDARD	CRANSTON	138	138
MARION COUNTY	KU LEBANON	138	138
OWEN CO TAP		138	138
PLUMVILLE	GODDARD	138	138
RENAKER	BOONE	138	161
RODBURN	SKAGGS	138	138
SMITH	FAWKES	138	138
SMITH	LAKE REBA	138	138
SPURLOCK	BOONE	138	138
SPURLOCK	RENAKER	138	138
SPURLOCK	KENTON #1	138	138
SPURLOCK	PLUMVILLE	138	138
DALE	POWELL	138	138
SPURLOCK	FLEMINGSURG	138	138

Transmission Substations Transferred to PJM's Functional Control

STATION	VOLTAGE (kV)
COOPER	161
DALE STATION	138
SPURLOCK	345
SPURLOCK	138
ARGENTUM	138
AVON	345 &138
BAKER LANE	138
BARREN CO	161
BONNIEVILLE	138
BOONE COUNTY	138
BULLITT CO	161
CASEY CO	161
CENTRAL HARDIN	138
DENNY	161
FAYETTE	138
FALL ROCK	161
FAWKES	138
GALLATIN COUNTY	138
GODDARD	138
GREEN COUNTY	161
HEBRON	138
JK SMITH	345
JK SMITH	138
LAUREL CO	161
LAUREL DAM	161
LIBERTY JCT	161
MARION CO	161
MCCREARY CO	161
NELSON CO	138
NORTH CLARK	345
OWEN CO	138
PLUMVILLE	138
POWELL CO	161
POWELL CO	138
PULASKI CO	161
RENAKER	138
ROWAN CO	138
RUSSELL CO	161
SHELBY CO	161
SKAGGS	138
STANLEY PARKER	138
SUMMERSHADE	161
TYNER	161
WAYNE CO	161
WEBSTER ROAD	138
WEST BEREA	138
WEST GARRARD	345

Exhibit 3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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.	)))))	CASE NO. 2012-________

DIRECT TESTIMONY OF
MIKE MCNALLEY
EXECUTIVE VICE PRESIDENT/CHIEF FINANCIAL OFFICER
EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: May 3, 2012

I. INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is Mike McNalley and my business address is East Kentucky Power Cooperative ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Executive Vice President and Chief Financial Officer for EKPC.

Q. How long have you been employed by EKPC?

A. I have been employed by EKPC since July 2010.

Q. Please state your education and professional experience.

A. I obtained my undergraduate degree in economics from Reed College in Portland, Oregon and my Masters of Business Administration from Dartmouth College. Prior to joining EKPC, I held various positions with DTE Energy ("DTE"), including chief financial officer and chief operating officer of one of DTE's subsidiaries, DTE Energy Technologies. Prior to joining DTE, I worked as the corporate leader of finance or as a senior executive at various companies including Corrillian Corp., System2, Inc., and Oliver & Thompson, Inc., all located in Portland, Oregon.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for accounting, finance, performance measures, pricing and regulatory services, risk management, marketing, information technology, and supply chain at EKPC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the impact of becoming fully integrated into PJM on EKPC's financial position and rates.

II. THE FINANCIAL IMPACT OF FULLY INTEGRATING INTO PJM

Q. What is the estimated financial benefit of joining PJM?

A. EKPC should see an overall net benefit of $142 million over ten years on a present value basis according to the report prepared by Charles Rivers Associates ("CRA") and attached as an exhibit to Mr. Luciani's testimony. I have reviewed CRA's report and believe that it is credible and that its conclusion is reasonable.

Q. Other than the direct financial benefits described in the CRA Report, are there any other financial impacts that full integration into PJM will have upon EKPC?

A. Yes. Integrating into PJM will further assist us in our strategic plan to build financial strength and stability at EKPC. Specifically, participating in PJM will give us access to a broader array of options in terms of securing capacity, which will lead to greater efficiency and long-term financial benefits. Also, the credit rating agencies are very likely to view our full participation in PJM as a positive step. This, in turn, will help us maintain a good credit rating. By having a good credit rating, we will have access to private capital markets on more favorable terms than if we were unrated or did not have a good rating. Both of these financial impacts are very positive for EKPC's Members.

Q. Please explain how integrating fully into PJM will allow EKPC to be able to defer new capacity construction.

A. EKPC will be able to defer new capacity construction because of the seasonal diversity in its load. At present, and as discussed in the testimony of Mr. Mosier, EKPC plans capacity based on its winter peak load. Once integrated into PJM, the capacity needs will be based on its summer peak load, which is consistently 450 MW less than the winter peak load. To demonstrate this ability to defer new capacity construction, I would point you to the Expansion Plan Graph attached to my testimony as Exhibit MM-1. The capacity savings is represented by the difference between the summer peak (lower line that begins around the 2,500 mark in 2013) and the reserve requirement (upper line that begins around the 3,500 mark in 2013.)

Q. How will integrating into PJM be looked upon by the rating agencies?

A. Of course, I cannot speak for the ratings agencies. However, I do know that the rating agencies take a variety of factors into consideration when reviewing the credit of a generation and transmission ("G&T") cooperative such as EKPC. Among these factors are the cost recovery methodologies and cost recovery willingness of the G&T, the management of generation risks, financial strength and metrics, and competitiveness. The expression of regulatory supportiveness is also important to the rating agencies. This demonstrated degree of support reflects directly on the cooperative's ability to recover costs and therefore to service debt, so it is essential to the financial success of a regulated cooperative. Since the ability to service debt is at the core of the rating agencies' focus, they are particularly attuned to issues which can cause volatility in EKPC's cash flows. Being an "island" is inherently more risky, and, conversely, being a PJM member is less risky, as discussed in Mr. Mosier's testimony. Joining the PJM market should be viewed by the rating agencies as a measure to reduce risk for EKPC, and therefore a credit-positive for EKPC's ratings.

As described in the Application and other testimony, EKPC believes that significant financial benefits will accrue to EKPC by virtue of its full integration into PJM and participation in the PJM markets. These expected financial benefits should help facilitate a continued improvement in EKPC's financial metrics and ratios as measured by the rating agencies, enhancing the cooperative's long-term financial strength and stability. For example, the lower reserve requirement in PJM means EKPC can defer capacity additions. This deferral, of course, pushes out capital expenditures resulting in lower total assets than EKPC otherwise would need. By itself, this will boost EKPC's equity ratio faster than planned; if EKPC then considers the annual net savings from membership in PJM, I would expect faster equity ratio improvement – a key measure of financial strength for the ratings agencies. As the rating agencies measure the competitiveness of EKPC's rates against others in the region, being a member of PJM will give the rating agencies some assurance that EKPC is buying and selling its power in a competitive regional market. PJM pricing is a well-established benchmark and recognized as an industry standard. Thus, being a member of PJM demonstrates that EKPC's fleet operates competitively and that EKPC's cost to member systems is as low, and therefore competitive, as possible.

III. THE RATE IMPACT OF FULLY INTEGRATING INTO PJM

Q. Let us now focus upon how the full integration of EKPC into PJM will impact the rates of EKPC's Members. How will the $142 million in net benefits translate into EKPC's rates?

A. EKPC anticipates that, as a result of these savings, its power cost to Members will be reduced by between \$1 and \$3 per MWh. A schedule showing our calculation of the rate impact is attached to my testimony as Exhibit MM-2. The savings will benefit Members in the form of reduced fuel adjustment clause factors, base rate reductions and/or base rate case increase deferrals, increased equity and the ability to offset cost increases in other areas of our business.

Q. If EKPC is required to participate in PJM on a Fixed Resource Requirement ("FRR") basis, how will that impact the rate benefit to EKPC's members?

A. EKPC will save an additional \$3 million to \$9 million each year by participating in PJM on an RPM basis. As illustrated in Exhibit MM-2, if EKPC were to be required to participate solely on a FRR basis, however, the favorable rate impact will be reduced by approximately 20% from the projected per MWh savings to be realized under RPM. As you see then, this is not an insignificant difference and makes the nature of EKPC's participation in PJM a material consideration.

Q. How will EKPC's fuel adjustment clause factors change as a result of the integration into PJM and participation in PJM's markets?

A. By having unconstrained access to the PJM Energy Market, EKPC should be able to decrease its own production costs while offsetting the loss of power generation with less expensive power purchases. Thus, both our production costs and our increased power purchases will be more economically efficient. In terms of translating that into actual rates, the fuel adjustment clause factors will decrease as we reduce the purchased power element through more economic purchases and reduce the fuel costs element as fuel used for increased off-system sales reduces EKPC's overall jurisdictional fuel costs. The reduction in the fuel adjustment clause factor will be the first tangible benefits that our Members see once we fully integrate into PJM.

Q. You also mentioned several other types of direct benefits to Members apart from the positive adjustment in the fuel adjustment clause factors. Please elaborate.

A. There are several other ways in which participation in PJM will be financially beneficial to EKPC's members. Since a good portion of the savings realized will be in the form of avoided costs, there are several ways in which these savings could manifest themselves in EKPC's bottom line. First, we think these savings will help offset increased costs in other areas of our business, such as environmental compliance expenses. Second, we expect that EKPC will have the ability to continue to increase its equity in accordance with our strategic plan. Since our owners are also our customers, EKPC's Members will directly benefit from increased equity and the attendant benefits that are derived from increased financial strength. Third, the avoided cost savings will allow us to defer future rate increases as we are able to operate under our existing rates for a longer period of time. Fourth, along those same lines, we may be able to actually reduce rates while at the same time building equity if we are able to outperform the scenarios outlined in CRA's report and other categories of anticipated cost increases turn out to be less than expected.

Q. Has EKPC determined which of these options it will pursue once it begins to achieve these avoided cost savings?

A. No. Until we actually become integrated into PJM, it would be premature and imprudent to commit to a particular rate treatment of the net benefits anticipated to be derived from the transfer of functional control of the Transmission Facilities and participation in the PJM markets. However, as circumstances and business prudence allow, EKPC's Members will realize both short-term and long-term benefits in the form of one or more of the options I have described. Our Board of Directors and management will use the savings from PJM integration to help achieve the company's strategic goals.

Q. Will the savings associated with full integration into PJM be easy to track?

A. It depends on the nature of the savings. On the one hand, we will be able to track, with a fair degree of certainty, the value of our savings realized from economic dispatch and power purchases in the PJM Energy Market. However, as a rule, avoided costs are more difficult to track than other types of benefits – such as new revenues. The ability to specifically track the avoided cost benefits on a real-time basis is much more difficult and subjective, so likely not worthwhile.

Q. Are there any costs associated with the integration into PJM?

A. Yes. The primary sources of costs will be regional transmission expansion planning ("RTEP") and administrative expenses. The Application and Mr. Mosier's testimony outline the scope of these costs in greater detail.

Q. How does EKPC plan to recover the costs associated with integrating into PJM?

A. EKPC plans to recover the costs associated with integrating into PJM through its base rates.

Q. Will these additional costs cause EKPC to seek an increase in its base rates?

A. No. Although there will be new costs associated with integrating into PJM, they are more than offset by the expected benefits. Thus, the RTEP and administrative costs will not cause EKPC to seek an increase in its base rates sooner than what we would likely do if we were not fully integrated into PJM.

Q. Will the integration into PJM change EKPC's current rate structure to its Members?

A. The integration will not cause the current rate structure to change.

Q. Will the integration into PJM change the current rate structure of any of EKPC's Members' Members?

A. No. There should not be any changes at the retail level either as a result of integrating into PJM.

IV. Summary

Q. Would you like to summarize your testimony?

A. Yes. The financial and rate impacts of EKPC's decision to fully integrate into PJM will be positive. Financially, we will have more options to consider when seeking out the reasonable, least-cost options for future capacity investments and the credit rating agencies are very likely to view the integration into PJM as a positive sign that EKPC is taking advantage of the energy and capacity markets available to it and managing risk appropriately. From a rates perspective, our Members – and their Members – will enjoy short-term benefits in the form of lower fuel adjustment clause factors and long-term benefits in the form of increased equity, deferred rate increases, potential rate decreases and greater ability to offset increased costs in other areas of our business. On whole, our

Members will benefit significantly from the integration. Accordingly, we would respectfully request the Commission to approve the Application.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is for a proper purpose?

A. Yes.

Q. Based upon your testimony here today, is it your personal and professional opinion that EKPC becoming fully integrated into PJM is also in the public interest?

A. Yes.

Q. You are sponsoring two exhibits, the Expansion Plan Graph identified as MM-1 and the Schedule of Estimated Savings identified as MM-2, and incorporating both of those exhibits, by reference, into your testimony. Can you state whether these exhibits were prepared directly by you or by someone working under your supervision and direction?

A. Yes. Both of these scheduled were prepared by someone working directly under my supervision and direction.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY

COUNTY OF CLARK

The undersigned, Mike McNalley, after being duly sworn, deposes and says that he is the Executive Vice President and Chief Financial Officer of East Kentucky Power Cooperative, Inc., and that the matters set forth in the foregoing testimony are true and correct to the best of his knowledge, information and belief.

Mike McNalley

Subscribed and sworn to before me by Mike McNalley on this 3rd day of May, 2012.

NOTARY PUBLIC

My Commission expires: MY COMMISSION EXPIRES NOVEMBER 30, 2013 NOTARY ID #409352

Exhibit MM-1

Expansion Plan Graph

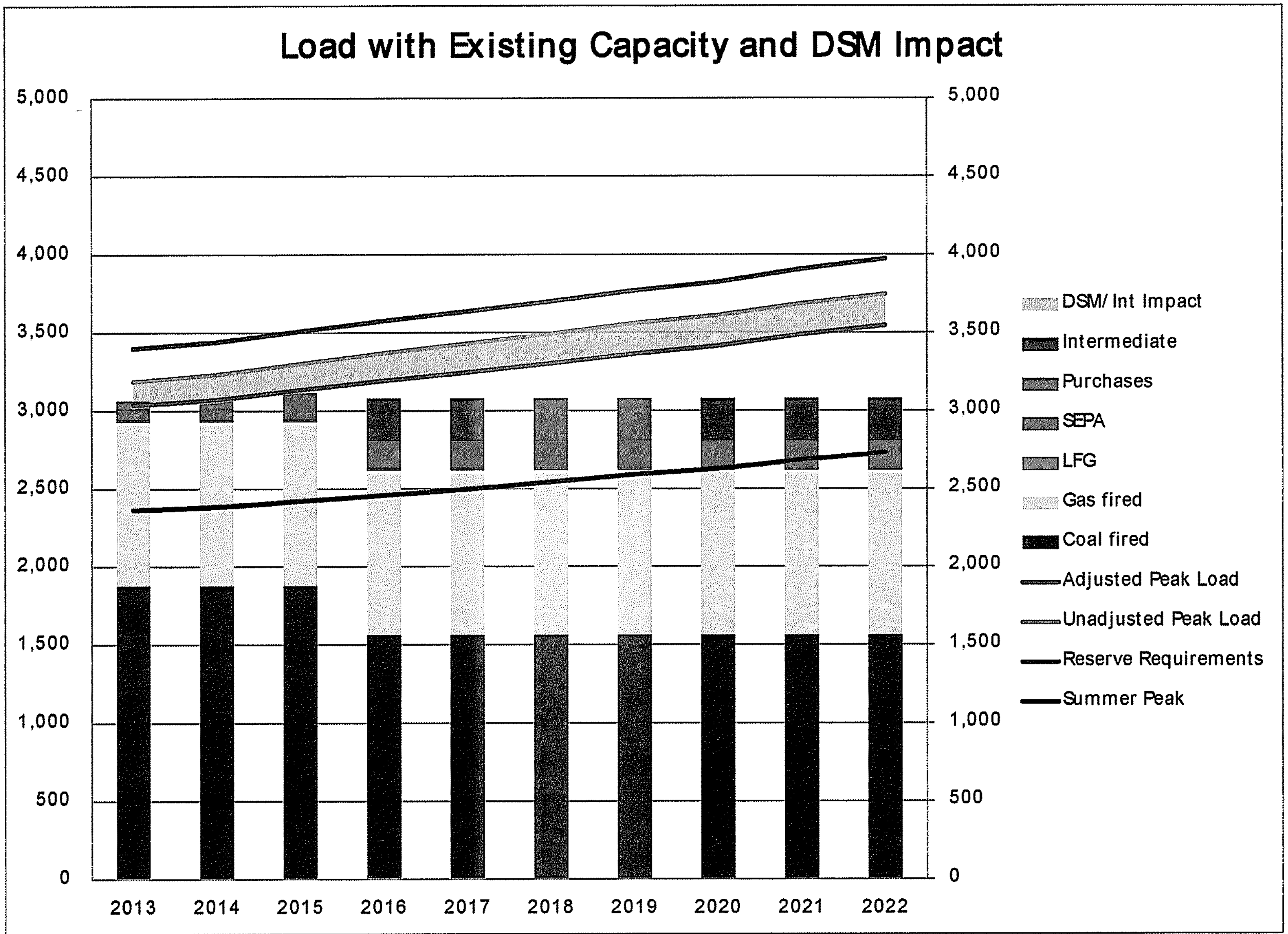
Load with Existing Capacity and DSM Impact
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
DSM/ Int Impact
Intermediate
Purchases
SEPA
LFG
Gas fired
Coal fired
Adjusted Peak Load
Unadjusted Peak Load
Reserve Requirements
Summer Peak

Exhibit MM-2

Schedule of Estimated Savings

PJM Benefit to Members

Dollars in Millions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Savings-RPM	$5.6	$14.3	$9.3	$14.8	$15.6	$17.8	$25.3	$28.5	$36.4	$42.9
Reduction in Savings FRR vs. RPM	($0.1)	($2.5)	($2.5)	($3.2)	($3.3)	($3.3)	($4.7)	($6.1)	($7.6)	($9.2)
Total Savings-FRR	$5.5	$11.8	$6.8	$11.6	$12.3	$14.5	$20.6	$22.4	$28.8	$33.7
					MWh Sales					
Member Sales	12,718,366	12,833,100	13,038,848	13,274,415	13,404,720	13,584,349	13,788,537	13,985,760	14,195,648	14,423,578
Jun-Dec	7,414,720									
					$/MWh					
Benefit to members-RPM Scenario	0.76	1.11	0.71	1.11	1.16	1.31	1.83	2.04	2.56	2.97
Benefit to members-FRR Scenario	0.74	0.92	0.52	0.87	0.92	1.07	1.49	1.60	2.03	2.34
% Difference	-1.79%	-17.48%	-26.88%	-21.62%	-21.15%	-18.54%	-18.58%	-21.40%	-20.88%	-21.45%

Exhibit 4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN APPLICATION OF EAST KENTUCKY	**)**	
POWER COOPERATIVE, INC. TO	**)**	
TRANSFER FUNCTIONAL CONTROL OF	**)**	
ITS TRANSMISSION ASSETS TO THE PJM	**)**	
INTERCONNECTION, L.L.C.	**)**	**CASE NO. 2012-________**

TESTIMONY OF
RALPH L. LUCIANI, VICE PRESIDENT
CHARLES RIVERS ASSOCIATES

Filed: May 3, 2012

I. INTRODUCTION

Q. Please state your name, title, and business address.

A. My name is Ralph L. Luciani. I am a Vice President of Charles River Associates ("CRA"). My business address is 1201 F St., NW, Washington, DC 20004.

Q. How long have you been employed by CRA?

A. Ten years.

Q. Please state your education and professional experience.

A. My education and professional experience is reflected in my *curriculum vitae* attached to this testimony as Exhibit RLL-1.

Q. Please provide a brief description of your duties at CRA.

A. I have more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation and transmission planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization ("RTO") costs and benefits. Since 2010, I have been assisting the Eastern Interconnection Planning Collaborative ("EIPC") in analyzing the transmission requirements for the Eastern Interconnection under a broad range of alternative futures. Prior to joining CRA, I was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. I hold a B.S. in Electrical Engineering and Economics from Carnegie Mellon University. I also hold an M.S. from the Graduate School of Industrial Administration at Carnegie Mellon University. I have previously testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Missouri, Ohio and Pennsylvania state regulatory commissions, the Federal Energy Regulatory Commission ("FERC"), and the Ontario Energy Board.

Q. What is the purpose of your testimony?

A. East Kentucky Power Cooperative, Inc. ("EKPC") has asked me to summarize the results of the membership assessment that CRA performed of the costs and benefits of EKPC joining the PJM Interconnection LLC ("PJM"). PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of thirteen states.

II. EXPERIENCE

Q. Have you previously been engaged on other matters involving an analysis of the costs and benefits of joining a RTO?

A. Yes, CRA has performed a number of cost-benefit studies related to RTO formation and entry into an RTO by individual utilities. I was a member of the CRA senior team that prepared the following studies:

1. The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast, prepared for the Southeastern Association of Regulatory Utility Commissioners in 2002.
2. The Benefits and Costs of Dominion Virginia Power Joining PJM performed for Dominion Virginia Power in 2004,
3. The Southwest Power Pool ("SPP") Cost-Benefit Analysis performed for the SPP Regional State Committee in 2005 (considering the costs and benefits to individual utilities of forming the SPP RTO),

4. The RTO Cost-Benefit Analysis for Aquila Missouri in 2007 (considering the costs and benefits to Aquila Missouri of joining the Midwest Independent Transmission Operator ("Midwest ISO") or SPP or being stand-alone),
5. The RTO Cost-Benefit Analysis for AmerenUE in 2007 (considering the costs and benefits to AmerenUE of remaining in the Midwest ISO, joining SPP, or being stand-alone),
6. An economic assessment in 2010 of the options available to Big Rivers Electric Cooperation for the supply of contingency reserves, including joining the Midwest ISO, and
7. A series of RTO Cost-Benefit Analyses in 2010-11 of the Entergy region joining SPP, the Midwest ISO, or remaining with the status quo.

In each of these studies, CRA has made use of its extensive knowledge of regional generation and transmission systems and electricity market structures and rules to specify a model representation of the regional electricity market. The computer simulation market model was used to project generation dispatch, production costs, inter-regional flows, and spot prices under various RTO-related scenarios. The results of the electricity modeling, supplemented with relevant RTO operating cost estimates, were then used to evaluate net benefits to individual regions and companies.

Q. Are you the primary author of the document published by CRA entitled "EKPC RTO Membership Assessment" and dated March 20, 2012 (hereinafter, the "Report"), attached as Exhibit RLL-2 to your testimony, and do you intend for

it to be incorporated into your testimony?

A. Yes.

Q. Please identify, and then briefly describe, the expertise and contributions of the other members of your CRA team who have participated in the preparation of the Report.

A. Senior CRA personnel who assisted me with the Report were Bruce Tsuchida and Pablo Ruiz, particularly in conducting the computer simulation market modeling. Mr. Tsuchida is a mechanical/electrical engineer with nearly twenty years of experience in domestic and international power generation development and the modeling of wholesale electric markets. He holds an M.S. in Technology and Policy, and in Electrical Engineering and Computer Science, from the Massachusetts Institute of Technology. Pablo Ruiz, is an electrical engineer experienced in the modeling and analysis of the electricity transmission system and wholesale electric markets. Prior to joining CRA, Dr. Ruiz was a Power Systems Engineer with AREVA T&D. Dr. Ruiz has written journal articles and has presented papers at international conferences on topics related to power flow analysis, voltage stability, operating reserve requirements, transmission expansion, unit commitment and uncertainty management. He holds a PhD in Electrical and Computer Engineering, from the University of Illinois at Urbana-Champaign.

III. SUMMARY OF COST/BENEFIT ANALYSIS

A. STUDY METHODOLOGY

Q. Please explain why you have used a ten-year period from 2013 to 2022 as the

study period in the Report?

A. CRA has often used a 10-year study horizon for assessing the costs and benefits of a utility joining an RTO, including, for example, in the recent set of RTO cost-benefit studies performed for the Entergy region. A ten-year period is able to address the major parameters that a utility faces in a decision to join an RTO, such as the impact of the need for additional capacity as load grows and the impact of known transmission expansion projects coming into service. Transmission topology and generating capacity expansion become more uncertain over time, and the out-years have a diminishing impact on the present value of costs and benefits making a ten-year horizon a common choice for study participants in these types of studies.

Q. The Report indicates that the GE MAPS modeling analysis was performed for the years 2013, 2017 and 2022 with the results of the intervening years interpolated. Why is it not necessary to perform a GE MAPS analysis for each year of the review period?

A. Each model-year in GE MAPS is time-consuming to set-up, run and post-process. As such, in the Report and in all prior CRA RTO cost-benefit studies, CRA modeled a subset of years over the study time horizon to analyze in GE MAPS when weighing the time to conduct additional model years against the value of having the increased specificity of having each individual year's results.

Q. Why is the GE MAPS analytical model the preferred choice for undertaking the nature of the analysis set forth in the Report?

A. A dispatch model that can model Day 2 RTO market flows and pricing by incorporating transmission constraints on the electrical system is essential in analyzing the impact of an entity joining a RTO. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was used by CRA in all of the prior RTO market cost-benefit studies it has performed.

Q. How long has the GE MAPS model been used as the industry standard in these types of analytical projects?

A. I have been using GE MAPS for purposes of conducting RTO cost-benefit studies since 2002, a period of 10 years. CRA also used the GE MAPS model to support the U.S. Department of Energy ("DOE") in conducting the August 2006 National Electric Transmission Congestion Study, and is using GE MAPS in the on-going DOE-sponsored work on behalf of the Eastern Interconnection Planning Collaborative in analyzing the transmission requirements for the Eastern Interconnection under a broad range of alternative futures.

Q. In using the GE MAPS model, is the most recently available source data used in building each analytical scenario?

A. Yes, as discussed in detail in the Report, the latest available source data is used along with the most recently available gas price forecast as of the time the GE MAPS modeling commences.

Q. How does the GE MAPS model account for actual and proposed changes in environmental regulations that have a significant impact upon capacity?

A. As discussed in further detail in the Report, the impact of environmental regulations on future capacity expansion and retirements are captured through CRA's North American Electricity and Environment Model ("NEEM"), and input into the GE MAPS model. NEEM is being used extensively by CRA for the on-going DOE-sponsored Eastern Interconnect Planning Collaborative work evaluating transmission expansion under various possible futures.

Q. The Report indicates that NEEM relies upon detailed analysis of coal supplies derived from mine level data on production costs and annual production capability. In recent months, several mining companies have announced that they are idling mines due to reduced demand for coal. Have these developments been taken into account as part of the analysis underlying the Report?

A. The NEEM and GE MAPS analyses conducted for the Report used available data as of the early part of 2012, and incorporated projected coal plant retirements in the demand for coal. To ensure that local conditions were reasonably captured, the coal prices used for EKPC generating plants were reviewed by EKPC generating personnel.

Q. The Report states that EKPC would be able to self-supply its ancillary services after joining PJM, and thus it would be no worse off and potentially better off if it were able to buy and sell ancillary services in PJM. Why were these ancillary benefits of joining PJM not quantified?

A. The impacts of being able to buy and sell certain ancillary services, such as regulation and operating reserves, in an RTO market tend to be small relative to other key cost-benefit measures and are difficult to capture precisely in a modeling exercise of this type without performing a separate set of analyses focused on them directly. Our modeling approach in the Report is similar to our prior RTO cost-benefit studies, including the recent set of RTO cost-benefit studies performed for the Entergy region. Again, given the option of self-supply, EKPC should be no worse off and potentially better off in PJM with respect to ancillary services.

B. SUMMARY OF ANALYSIS

Q. For the most part, the questions you will be asked will not focus upon re-characterizing the Report, however, can you begin by broadly describing how you arrived at the conclusion that EKPC will realize a net benefit of $142.0 million upon its full integration into PJM?

A. The net benefits of EKPC of joining PJM are based on an assessment of the costs or benefits to EKPC in a number of key cost and revenue categories. Joining PJM is projected to yield a decrease in EKPC adjusted production costs (fuel costs plus off-system purchased power costs net of excess energy sales revenue) of $53 million, a decrease in EKPC's net cost for procuring capacity of $148 million, and avoided firm transmission reservation costs of $56 million. These benefits are somewhat offset by an increase in administrative costs ($48 million) and transmission expansion costs ($66 million) in joining PJM. These cost and benefit impacts combine to yield a total net benefit of $142 million to EKPC over the 2013-2022 period.

1. Trade Benefits

Q. The Report concludes that EKPC is likely, on a net present value basis, to realize $52.7 million in trade benefits over ten years by joining PJM. The report further indicates that the greatest benefits are likely to occur as natural gas prices increase and load increases. Please explain the basis for your belief that natural gas prices and load will increase over the next ten years.

A. The long-term natural gas forecasts used in the GE MAPS modeling was taken from the January 2012 U.S. Energy Information Administration ("EIA") Annual Energy Outlook, and shows gas prices increasing over time from today's relatively low levels. The load forecasts in the GE MAPS modeling in the Report are taken from the FERC-714 load forecast data. For example, PJM's latest load forecast projects that energy for load will increase by about 1.4% per year over the next ten years.

2. Administrative Costs

Q. The Report mentions that EKPC's portion of the total PJM administrative charges may decline as additional entities join PJM. Given PJM's proximity to the Midwest ISO and the NY ISO, what additional utilities do you believe may become members of PJM?

A. Other than EKPC, I am not aware of any utilities with specific plans to join PJM. However, PJM is bounded to the south by non-RTO utilities and recent growth in PJM membership has come from current RTO members switching to PJM. Either could be a potential source of additional PJM members.

Q. The Report adopts PJM's estimate that EKPC will incur integration costs of $1

million or less. What expenses are included in this estimate?

A. Expenses incurred will include staff training and travel, regulatory filings, computer hardware and software upgrades, and expenditures related to setting up the processes needed for the EKPC system to interface with the PJM market. As noted in the Report, I have included a full $1 million in integration costs as a conservatively high estimate.

Q. The Report indicates that EKPC's power marketers estimated its annual internal recurring labor expense for joining PJM was $500,000. Please identify who provided this estimate and how it was derived.

A. The estimate was provided by ACES Power Marketing, and was estimated based on their experience in working with clients that are members of PJM and other RTOs, as well as their knowledge of the current staffing of EKPC. ACES estimated that 2-3 additional EKPC full-time equivalent positions would be required to handle the additional work required, along with on-going training and travel expenses. Mr. Mosier states in his testimony that EKPC currently intends to hire four full-time equivalent positions.

3. Transmission Costs

Q. The Report includes 50% of the estimated costs of the MAPP and PATH projects, beginning in 2020, as part of the total $70.2 million in transmission costs that EKPC is likely to incur over the study period. If the MAPP and PATH projects are cancelled, what effect would this have on the transmission costs EKPC is likely to be obligated to pay?

A. The estimated costs of the MAPP and PATH projects comprised $9.2 million of the $70.2 million present value of transmission costs over the 2013-2022 period incurred by EKPC in joining PJM. If cancelled, the pre-construction expenditures already incurred on these projects may be subject to recovery.

Q. What impact, if any, will the ongoing Eastern Interconnect planning process likely have on the construction of "backbone" transmission projects in PJM?

A. The ongoing Eastern Interconnection Planning Collaborative ("EIPC") work is focused on potential transmission expansion under various possible futures over the longer-term, primarily in the 2030 timeframe. Based on my work in this EIPC effort, I do not expect this process to have a material impact on PJM construction of backbone projects in the nearer-term.

Q. How would the consideration of transmission congestion between PJM and EKPC be affected by EKPC joining PJM?

A. The regional transmission planning process performed in PJM will allow full continual consideration of the impact on EKPC of transmission congestion between EKPC and current PJM members. To the extent that it is economic to implement transmission improvements on the EKPC system or on current PJM member systems to relieve congestion and improve the ability for EKPC to import and export power from the rest of PJM, this regional process would act to improve the benefits that EKPC would obtain from joining PJM.

Q. The Report estimates that EKPC's share of firm transmission revenue will likely increase from a current estimate of 0.85% once EKPC's transmission revenue

requirement is updated. Please describe the context in which EKPC will increase its transmission revenue requirement.

A. As a member of PJM, EKPC would update its transmission revenue requirement upon joining. Given increases in net transmission plant on the EKPC transmission system since the time that the EKPC transmission revenue requirement was developed in 1996, the EKPC transmission revenue requirement is likely higher today.

Q. Why is EKPC's estimated allocation of RTEP costs 1.64% while its estimated share of transmission revenues is only 0.85%?

A. Under PJM rules, the RTEP allocation is based on EKPC's share of the annual network service peak load on the PJM transmission system, while the share of transmission revenue is based on EKPC's share of the PJM transmission owners' transmission revenue requirement. Once EKPC updates its transmission revenue requirement, these two percentages will likely move closer together.

Q. The Report estimates that PJM's firm transmission revenue will escalate at the rate of inflation over the study period. Please describe whether this is a conservative assumption in comparison to how PJM's firm transmission revenue has escalated historically.

A. The PJM firm transmission revenues were $49.7 million in 2010 and $53.8 million in 2011, an increase of 8% relative to the 2.5% inflation rate assumed in the Report. The use of firm transmission to export power from PJM in the future will depend on a number of factors such as prevailing fuel prices, transmission rates, transmission improvements, etc. EKPC's share of these revenues is estimated to be $3.7 million over the 2013-2022 period. Alternatively, assuming that PJM firm transmission revenue would stay flat in nominal terms would decrease the benefit to EKPC by only $0.5 million.

Q. In the *Status Quo Case*, what alternatives to purchasing firm point to point transmission service from PJM were considered for the 2016-2022 period?

A. No other alternatives were directly considered. Not purchasing any external transmission service is an alternative, with the attendant risks of EKPC not being able to purchase energy in a situation when it needs it. Purchasing long-term transmission from external parties other than PJM, to the extent available, would require similar expense. For example, TVA's current firm point-to-point transmission rate of $1.55 kw-month is close to PJM's current rate of $1.57 kW-month.

4. Capacity Market Benefits

Q. Within the seasonal summer and winter peak periods, are EKPC's seasonal peaks aligned with PJM's seasonal peaks, or are there variations in timing of the respective peaks which afford EKPC a greater advantage to sell capacity into PJM at periods of peak demand?

A. Yes, EKPC's seasonal peak does not directly match the timing of the seasonal peak of PJM as a whole. This diversity provides, in part, the capacity benefits quantified in the Report. As noted in the Report, over the last four years EKPC's peak demand during the time of the five highest hourly peak demands on PJM has been, on average, 91.2% of EKPC's summer peak. Moreover, EKPC's winter peak is projected to be more than 30% higher than EKPC's summer peak, yielding additional load diversity between EKPC and PJM.

Q. The Report highlights EKPC's seasonal diversity as a winter-peaking system in comparison to PJM, which is summer-peaking. Over the last five years, how close has PJM's summer demand peak compared to its winter demand peak?

A. On average, PJM's winter peak demand has been about 80% of its summer peak demand over the last five years. In 2011, after normalization for weather, the PJM summer peak was nearly 24,000 MW higher than its winter peak.

Q. Does PJM forecast that the gap between its summer peak demand and its winter peak demand will grow or narrow over the study period?

A. PJM predicts that this gap will grow somewhat, as summer peak growth in PJM is projected to be slightly above that of winter peak growth over the next 10 years.

Q. Please explain why EKPC will derive a greater net benefit from participating in PJM under the Reliability Pricing Model ("RPM") as opposed to participating under the Fixed Resource Requirement ("FRR") paradigm.

A. As noted in the Report, under PJM rules EKPC would be able to transition from a FRR to RPM beginning with the 2016/17 delivery year. In an FRR, EKPC would be required to hold back (not sell capacity into or for use in the RPM) an additional 3% of its reserve requirements. EKPC, which would have capacity to sell into the RPM after taking into account EKPC's load diversity with PJM, would incur an estimated $3 to $9 million per year of additional costs under a FRR rather than under the RPM.

Q. EKPC intends to remain a member of the Reserve Sharing Group in which it currently participates along with the Tennessee Valley Authority, Kentucky

Utilities Company and Louisville Gas & Electric Company. Do you anticipate that there will be any limitations on EKPC's ability to efficiently participate in PJM's capacity and reserve markets as a result of its continued membership in the Reserve Sharing Group?

A. No. For example, Dominion Power (Virginia and North Carolina) is a member of PJM and separately continues to be a member of the VACAR reserve sharing group which includes a number of non-PJM utilities in the VACAR region of SERC.

5. Qualitative Considerations and Risks

Q. Since your report was published some utilities within the PJM region have announced that they will retire or refuel several baseload units and PJM has issued preliminary analysis which indicates this could impact reliability in the region. Are you aware of any impact that these retirements/refuelings would have on EKPC as a member of PJM?

A. Given that PJM resource adequacy remains above the target installed reserve margin in PJM, any reliability concerns of retirements or fuel-conversion outages likely will take place only on a localized basis with respect to unique locational requirements such as voltage support or black start services and is unlikely to impact the EKPC region. All else equal, additional retirements in PJM are likely to result in higher prevailing capacity prices in PJM. With EKPC having capacity to sell as a member of PJM, higher capacity prices would further benefit EKPC in joining PJM.

Q. Are the announced retirements of existing baseload units within the PJM region likely to spur the construction of new "backbone" transmission lines within

PJM?

A. No. Low gas prices likely will result in the construction of additional gas-fired capacity to the extent it is needed to meet PJM planning reserve requirements. Given the ability in most regions to locate gas-fired capacity at or near where it is needed, additional gas fired capacity and generation is unlikely to yield an increased need for backbone transmission lines to carry power long distances.

Q. The Report indicates that one of the alternatives considered was joining MISO, as opposed to PJM, but that this was deemed to not be as beneficial to EKPC. Can you quantify the approximate relative benefit of joining PJM as opposed to joining MISO?

A. Only the 2013-2017 period was examined in 2011 for the alternative of EKPC joining MISO. Noting that there is not a direct interconnection in place between EKPC and MISO, the analysis indicated that over that period the benefits of EKPC joining PJM were roughly $75 million higher.

Q. The Report suggests that participation in PJM's Day 2 Market will allow EKPC to obtain more demand response and efficiency options than if it continued under the *Status Quo Case*. How will this occur?

A. The greater transparency in the pricing of demand response and efficiency options in PJM is likely to yield a greater response from entities that believe they can profitably institute these options. That is, all else equal, the incentive to incorporate these options becomes more transparent and thus more likely to take place.

Q. The Report includes several sensitivity scenarios where the assumptions used in

the base case were altered to measure whether joining PJM would still make sense under different scenarios and, in each such scenario, EKPC realized a net benefit from joining PJM. What combination of factors would likely have to come together to form the "perfect storm" such that joining PJM would not make sense for EKPC?

A. A significant reduction in the load diversity between EKPC and PJM would be the largest risk, along with very low capacity prices. My understanding is that EKPC has been winter peaking for a number of years and is projected to remain so for the foreseeable future. Low capacity prices tend to be a function of low demand which the market responds to with generating unit retirements which act to increase the capacity prices. Over time as the market adjusts, capacity prices are unlikely to remain at very low levels. While today's low gas prices limit the upside trade benefits of joining PJM for EKPC with its predominately coal-fired generation fleet, at the same time joining PJM allows EKPC greater trading access to lower-priced gas resources thereby providing benefits to EKPC and limiting downside risk. While there are risks in joining PJM, there are a number of factors that could act to increase the benefits of joining PJM, such as higher capacity prices and higher gas prices.

IV. CONCLUSION

Q. Would you like to summarize your testimony?

A. Based on the analysis conducted as summarized in the Report, I conclude that EKPC joining PJM will yield significant economic benefits to EKPC.

Q. Based upon your experience, and in your professional judgment, will it be a

proper purpose and consistent with the public interest for EKPC and its members for EKPC to join PJM?

A. Yes.

Q. You are sponsoring two exhibits, your *curriculum vitae*, which is identified as Exhibit RLL-1, and the CRA Report dated March 20, 2012, which is identified as Exhibit RLL-2, and incorporating both of these by reference into your testimony. Can you state whether these exhibit were either prepared directly by you or by someone working under your supervision and direction?

A. Yes. Both of these Exhibits were prepared either by myself or by someone working directly under my supervision and direction.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

DISTRICT OF COLUMBIA

The undersigned, Ralph L. Luciani, after being duly sworn, deposes and says that he is a Vice President of Charles Rivers Associates, and that the matters set forth in the foregoing testimony are true and correct to the best of his knowledge, information and belief.

Ralph L. Luciani

Ralph L. Luciani

Subscribed and sworn to before me by Ralph Luciani on this 1st day of May, 2012.

NOTARY PUBLIC

My Commission expires: October 14, 2012

CHRISTINE McCAFFREY
NOTARY PUBLIC
DISTRICT OF COLUMBIA
My Commission Expires
October 14, 2012

CHRISTINE McCAFFREY • NOTARY PUBLIC • DISTRICT OF COLUMBIA

Exhibit RLL-1

Curriculum Vitae

RALPH L. LUCIANI

Vice President

M.S. Industrial Administration, Carnegie Mellon University

B.S. Electrical Engineering and Economics, Carnegie Mellon University

Mr. Luciani has more than 20 years of consulting experience analyzing economic and financial issues affecting regulated industries. He has had a special focus on the electricity industry, where he has assisted electric utilities and generating companies with business planning and restructuring, merger and acquisition analysis, resource planning, power solicitations, ratemaking, transmission planning, fuel and power supply contract negotiations, and environmental compliance strategy.

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has assisted many clients in reaching agreements in settlement processes administered by the Federal Energy Regulatory Commission (FERC). He has appeared as an expert witness in a number of regulatory proceedings.

Prior to joining CRA, Mr. Luciani was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes & Bartlett, Inc. Before that, he worked as an Edison engineer for the General Electric Company and as a financial analyst for IBM Corporation. Summarized below are a number of recent projects directed by Mr. Luciani involving the electric utility industry.

PROFESSIONAL EXPERIENCE

Generation and Power Marketing

Wind/Transmission Studies—Mr. Luciani has performed a number of wind/transmission cost-benefit studies, including leading a team analyzing the economics of installing 765 kV transmission lines to support new wind power in the Southwest Power Pool.

Power Solicitations—Mr. Luciani has assisted electric utilities in a number of solicitations for power, including formulating the RFP, conducting bidder's conferences, negotiating term sheets and definitive agreements, and obtaining regulatory approval for the final agreements.

Generation Valuation Lecturer—Over a five-year period, Mr. Luciani served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually at a large U.S. investor-owned utility.

Power Marketing—He prepared several affidavits at FERC analyzing wholesale trading activities of power marketers, developed utility cost-based rates for wholesale sales of capacity and energy, and assisted counsel in reaching an arbitration settlement regarding standby power charges.

Stranded Cost Derivation—Mr. Luciani presented testimony before four state utility commissions on the quantification of the stranded cost associated with the deregulation of generation.

Nuclear Power—Mr. Luciani assisted a utility in negotiating the sale of a nuclear plant, developed the complex financial valuation model used by credit rating agencies in a utility's application for DOE-supported financing of a new nuclear facility, and provided testimony on the benefit of CWIP financing in rates to support the financing of new nuclear plant construction

RTOs and Transmission

RTO Cost-Benefit Studies—He has directed the evaluation of the economic and rate impacts on stakeholders in a number of major cost-benefit studies of Regional Transmission Organizations (RTOs), and has provided related testimony in a number of state proceedings.

Transmission Planning—On behalf of the Eastern Interconnection Planning Collaborative (EIPC), Mr. Luciani led the economic evaluation of the potential build-out of the transmission system in the eastern U.S. needed to support future generation expansion under uncertainty with respect to climate change, renewable portfolio standards, energy efficiency, and fuel prices.

RTO Administrative Costs and Rates—Mr. Luciani worked as the lead consultant on behalf of the PJM Finance Committee in the FERC settlement process in which PJM proposed the establishment of a stated rate for the recovery of its administrative costs in place of the existing formula rate.

Transmission Ratemaking—For several utilities, Mr. Luciani has filed testimony which developed OATT transmission, ancillary service, and reactive power rates and also has presented testimony before the FERC regarding calculations of earned returns for transmission operations.

Transmission Costing—He provided testimony and negotiated settlement agreements in a FERC settlement process regarding the assignment of costs for through and out transmission charges.

Financial Evaluation

Cost of Capital—He has testified before the U.S. Bankruptcy Court and assisted counsel in a number of arbitration proceedings regarding the proper discount rate to apply in assessing termination payments for wholesale power contracts, and has assisted counsel in assessing capital structures and rates for use in FERC proceedings.

Municipalization—He assisted an electric utility in deriving the exit charges to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

Mergers and Acquisitions—On several occasions, Mr. Luciani analyzed the potential acquisition of electric utilities and formulated transmission and distribution pro forma financials.

Organizational Restructuring—Mr. Luciani acted as the lead facilitator in a 12-month project that functionally unbundled the operation of an integrated electric utility into stand-alone profit centers.

Distribution and Retail

Distribution Performance-Based Rates—Mr. Luciani formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan to the state public utility commission.

Distribution Benchmarking—He formulated a benchmarking analysis to compare the costs and rates for the distribution system of an electric utility to the systems of neighboring utilities.

Efficiency Programs—He formulated a financial and rate incentive model for an electric utility to evaluate the impact on rates and earnings of adopting energy efficiency programs.

Distribution Cost Allocation—Mr. Luciani filed an affidavit in Ontario regarding allocation of distribution costs and derivation of stand-by rates for load displacement generation.

Retail Market Strategy—Mr. Luciani formulated models to assess the profitability of new retail loads in a competitive market and a product to reduce on-peak demand in residences.

Environmental and Fuel

Environmental Regulations—He has assisted electric utilities in formulating strategies for meeting provisions of the Clean Air Act regarding SO_2, NO_x and mercury emissions, and in assessing potential climate change regulations.

Fuel Supply—Mr. Luciani assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining approval for the rate treatment.

Nuclear Spent Fuel—He assisted counsel in a litigation involving the responsibility for costs incurred in the management of nuclear spent fuel storage and disposal.

Natural Gas—He assisted counsel in obtaining state and federal approval for the merger of natural gas distribution companies, and in evaluating natural gas market manipulation in California.

Expert Testimony Experience

Mr. Luciani has testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Missouri, Ohio, and Pennsylvania public utility commissions, the Ontario Energy Board, the U.S. Bankruptcy Court, and the Federal Energy Regulatory Commission (FERC). On a number of occasions, he has also provided expert testimony on behalf of United Parcel Service (UPS) before the U.S. Postal Rate Commission.

Exhibit RLL-2

Charles Rivers Associates
March 20, 2012 Report

CRA Charles River Associates

Prepared For:

East Kentucky Power Cooperative

EKPC RTO Membership Assessment

Prepared By:

Charles River Associates

Date: March 20, 2012

Table of Contents

1. EXECUTIVE SUMMARY

On behalf of East Kentucky Power Cooperative ("EKPC"), Charles River Associates ("CRA")[1] has assessed the costs and benefits of EKPC joining the PJM Interconnection Regional Transmission Organization ("PJM").[2] Based on the analysis performed, we conclude that EKPC joining PJM will yield significant economic benefits to EKPC.

The net benefits to EKPC are relatively robust. However, the benefits are highly dependent on the allocation of PJM regional high voltage transmission expansion costs as well as PJM capacity market benefits. A number of important qualitative considerations have been identified as well, with both qualitative benefits and offsetting costs likely to be incurred by EKPC in joining PJM.

1.1. STUDY METHODOLOGY

Two different cases were analyzed over the 10-year period from 2013 to 2022:

1. EKPC continues to operate as it does today ("*Status Quo Case*"), and
2. EKPC joins PJM as of June 2013 ("*Join PJM Case*").

In the *Status Quo Case,* EKPC is assumed to continue to be a member of the TVA reserve sharing group. In the *Join PJM Case*, EKPC becomes a full member of the PJM Day 2 market.[3] CRA analyzed the impacts on EKPC using the General Electric Multi-Area Production Simulation Model ("GE MAPS") model. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology.

As a general matter, the greater level of coordination and the elimination of wheeling charges between EKPC and PJM in the *Join PJM Case* should yield system-wide production cost savings through a more efficient system commitment and dispatch. The allocation of these net savings to EKPC is assessed by estimating EKPC's Adjusted Production Costs (i.e., production cost plus economic purchase costs minus opportunity sales revenues). In turn, these savings will be offset by additional administrative and other costs incurred if EKPC joins PJM.

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1 Principal study investigators for CRA were Ralph Luciani, Bruce Tsuchida and Pablo Ruiz. The findings and conclusions contained in this study are solely those of the CRA team.

2 PJM Interconnection is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

3 A Day 2 market refers to a two-settlement (day ahead and real-time) energy market using hourly locational marginal prices and financial transmission rights ("FTRs"). Day 2 markets are currently in place in the Eastern Interconnection in PJM, the Midwest ISO, ISO New England and the New York ISO.

1.2. FINDINGS

1.2.1. Region-wide Net Benefits

The net benefits to EKPC of joining PJM are summarized in Table 1 (and more fully detailed in Appendix A). The total benefit to EKPC of joining PJM is positive in the first 19 months (June 2013 through December 2014) and over the June 2013 to December 2022 period. As shown, the net benefit over this 2013 to 2022 period is $142.0 million (2012 present value).[4]

Table 1: 2013-2022 Benefits (Costs) to EKPC of Joining PJM
(in millions of dollars; positive numbers are benefits)

	2013-14	2013-22 PrValue
1. Decrease in Adjusted Production Costs *(Trade Benefits)*	7.0	52.7
2. Administrative Costs	(10.4)	(48.3)
3. Transmission Costs	(4.0)	(66.4)
4. PJM Capacity Market Impacts	15.3	147.8
SubTotal Net Benefits (Costs)	**7.9**	**85.9**
5. Avoided Long-Term Firm PTP Transmission Charges	12.0	56.1
Net Benefits (Costs)	**19.9**	**142.0**

As listed in Table 1, the key cost/benefit measures assessed in this study are: 1. Trade Benefits, 2. Administrative Costs, 3. Transmission Costs, 4. PJM Capacity Market Impacts, and 5. Avoided Long-Term Firm Point-to-Point ("PTP") Transmission Charges. Each category is discussed in further detail below.

1. Trade Benefits are the decrease in EKPC's adjusted production costs in the *Join PJM Case* relative to the *Status Quo Case*. Adjusted production costs are the production costs for the EKPC generating units (fuel, variable O&M and emission costs) plus EKPC "off-system" purchased power costs net of excess energy sales revenue.[5] The trade benefits in the *Join PJM Case* are $52.7 million over the 2013 to 2022 period.

2. Administrative Costs are comprised of:

- RTO Administrative Charges. PJM administrative charges that would be assessed to EKPC as a PJM member are estimated to be $35.0 million over the 2013 to 2022 period.

4 A present value rate of 6.0% was applied. An underlying inflation rate of 2.5% was assumed. Benefits and costs over the 2013-2022 period cited in this report are in 2012 present value dollars unless otherwise noted. Figures in the tables throughout this report may not sum due to rounding. See Appendix A for further detail.

5 Fixed costs that do not change between cases, such as depreciation are not included in this measure. Wheeling costs and revenue impacts are included for purchases and sales.

- Other Additional Costs: Over the June 2013 to December 2022 period, EKPC would incur an estimated $5.6 million in costs for additional staffing and equipment to interface with PJM in the *Join PJM Case*. In addition, EKPC would incur $7.7 million of additional FERC charges in the *Join PJM Case*.

3. Transmission Costs are comprised of:

- PJM Transmission Expansion Allocation. PJM allocates the cost of new high-voltage (500 kV and above) lines on a pro rata basis to all member load. The allocation to EKPC in the *Join PJM Case* is estimated to be $70.2 million over the 2013 to 2022 period.
- Allocation of PJM PTP Revenue. PJM allocates firm Point-to-Point ("PTP") transmission revenue collected under its OATT to individual PJM transmission owners based on their share of the total PJM transmission owner revenue requirement. This allocation is estimated to provide EKPC $3.7 million of additional benefit in the *Join PJM Case*.

4. PJM Capacity Market Impacts are comprised of the difference between the cost of meeting required reserves by EKPC in the *Status Quo Case* and the *Join PJM Case*. EKPC is winter-peaking and must meet a 12% planning reserve requirement in both the winter and summer seasons in the *Status Quo Case*. EKPC is projected to be short of winter capacity from 2013 to 2022, but long in summer capacity for most of this period. As such, EKPC would need to purchase or construct winter capacity, or swap summer for winter capacity with a neighboring entity to meet *Status Quo Case* reserve requirements. In the *Join PJM Case*, as a result of PJM regional load diversity and the significant summer peaking nature of PJM as a whole, we project that EKPC would need to meet a much smaller reserve margin target that would apply for the summer season only. This is estimated to yield a $147.8 million benefit to EKPC in the *Join PJM Case* over the 2013 to 2022 period.

5. Avoided Long-Term Firm PTP Transmission Charges are comprised of the costs of firm transmission (currently 400 MW from PJM) that are reserved on a long-term basis by EKPC in the *Status Quo Case* that would not be needed as a member of a Day 2 market in the *Join PJM Case*. These long-term reservations are made to ensure that EKPC has the ability to import power throughout the year including in periods in which EKPC might be short of economic energy or capacity and non-firm and/or short-term firm transmission is not available. These arrangements would not be needed in the *Join PJM Case* yielding an estimated $56.1 million in benefits to EKPC in the *Join PJM Case* over the 2013 to 2022 period.

1.2.2. Qualitative Considerations and Risks

While the quantified figures show material benefits to EKPC of joining PJM, there are a number of key risks, including most importantly:

Transmission Cost Allocation. The potential high-voltage transmission expansion cost allocation to EKPC in joining PJM are significant and highly dependent on future PJM load growth, congestion, and cost allocation mechanisms, among other considerations. EKPC would have only a limited role in the approval of these high-voltage expansion plans.

Capacity Market Diversity Benefits. The significant capacity market benefits for EKPC as part of PJM are dependent on the continued diversity of EKPC's demand profile with that of PJM. To the extent that this diversity diminishes over time, EKPC benefits would decrease. However, barring a shift in regional climate, such an unexpected phenomenon would be highly dependent on changing demographics in the EKPC territory. The likelihood of such a shift is small.

Exit Costs. While the PJM RTO does not impose exit fees, an exiting member maintains an obligation to pay for its share of transmission projects approved while a member and any commitments it may have in the congestion and capacity markets. As such, the decision to join an RTO should be viewed as a long-term decision and the anticipated benefits should be material.

Other qualitative issues are discussed in the body of this report, and have the potential to positively or negatively impact EKPC if it were to join PJM. However, we believe these other risks are more limited in the potential impact they may have on any EKPC decision to join an RTO.

2. INTRODUCTION AND BACKGROUND

The CRA team pioneered some of the original RTO Cost Benefit analytical approaches and modeling tools and has applied them in a series of significant regional RTO Cost Benefit Studies, to include:

- 2002 RTO West Study of Pacific Northwest
- 2002 Southeast Regulatory Utility Commissions Conference ("SEARUC") Study of Southeast Region
- 2003 Dominion Virginia Power's PJM Study
- 2003 U.S. Department of Energy's SMD Study
- 2004 ERCOT Stakeholders Cost Benefit Study
- 2005 SPP Cost Benefit Study, led by SPP Regional State Committee
- 2007 Aquila Missouri Cost Benefit Study (Midwest ISO and SPP)
- 2007 AmerenUE Cost Benefit Study (Midwest ISO, SPP, ICT)
- 2010 Big Rivers Cost Benefit Analysis (Midwest ISO)
- 2011 Entergy Cost Benefit Analysis (SPP, Midwest ISO)

In addition, the CRA team utilized similar analytical approaches and modeling tools in the conduct of the 2006 U.S. Department of Energy Congestion Study prepared pursuant to the 2005 Energy Policy Act for the purpose of designating National Interest Electric Transmission Corridors.

CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS") to perform the energy modeling in this study. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was used by CRA in all of the prior RTO market cost benefit studies it has performed, as well as to support the U.S. Department of Energy in conducting the 2006 National Electric Transmission Congestion Study. It is also being used by CRA in the 2012 Eastern Interconnection Planning Collaborative ("EIPC") transmission expansion planning studies.

The following sections describe the study methodology, results and assumptions. In Section 3, the study methodology is described. Section 4 describes the individual cost and benefit measures assessed in this study. Section 5 summarizes the study's quantitative results, and Section 6 discusses qualitative considerations. Appendix A provides additional detail on the study results, and Appendix B provides a detailed discussion of the GE MAPS input assumptions.

3. STUDY METHODOLOGY

3.1. BASIC STUDY METHODOLOGY

Two different cases were analyzed over the nearly 10-year period from June 2013 to 2022:

1. EKPC continues to operate as it does today ("*Status Quo Case*"), and
2. EKPC joins PJM in June 2013 ("*Join PJM Case*").

In the *Status Quo Case,* EKPC is assumed to continue to be a member of the TVA reserve sharing group. In the *Join PJM Case,* EKPC becomes a full member of the PJM Day 2 market in June 2013.[6] In both cases, it is assumed that EKPC will retire the Cooper 1 and Dale generating units at the end of 2015, and construct a new combined cycle unit that would go into service at the beginning of 2016. CRA analyzed the impacts on EKPC using GE MAPS. In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. The GE MAPS analysis was performed for the calendar years 2013, 2017 and 2022, with the results for intervening years interpolated, and the results for 2013 pro-rated for a June start.[7]

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6 EKPC is not directly interconnected with the Midwest ISO now that Duke Kentucky has become a member of PJM. EKPC joining the Midwest ISO would likely entail EKPC constructing additional high-voltage transmission that would take a number of years to implement. In 2011, CRA reviewed the economics of EKPC joining the Midwest ISO without a direct interconnection in place and determined that joining PJM yielded significantly more benefits to EKPC.

7 The GE MAPS analyses are designed to optimize a full calendar year. The full calendar year 2013 results are used to interpolate the GE MAPS results for the years 2014-2016. The 2013 results are then pro-rated in both the *Status Quo* and *Join PJM* Cases to assess and compare the impact of a June entry by EKPC into PJM in 2013.

CRA used its current GE MAPS data base to perform the analysis, supplemented by input data provided by EKPC with respect to EKPC generation unit operating characteristics, and other key EKPC inputs. A full listing of the GE MAPS modeling inputs is provided in Appendix B.

In the GE MAPS modeling, there is a commitment (next-day) step and a dispatch (real-time) step. In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load in the region for the next day. GE MAPS then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs.

As a general matter, the greater level of coordination and the elimination of wheeling charges between EKPC and PJM in the *Join PJM Case* should yield system-wide production cost savings through a more efficient system commitment and dispatch. The allocation of these net savings to EKPC is assessed by estimating EKPC's Adjusted Production Costs (i.e., production cost plus economic purchase costs minus opportunity sales revenues). In turn, these savings will be offset by additional administrative and other costs incurred if EKPC joins PJM.

3.2. Seams Charges

GE MAPS was used to model different impediments to EKPC trade under the *Status Quo Case* and the *Join PJM Case*. The impediments to trade applied in this study include commitment and dispatch seams charges. Seams charges are applied by CRA in the GE MAPS model at the "seam" or border between regions (e.g., between EKPC and TVA, EKPC and LG&E). In the absence of seams charges, GE MAPS will optimize the commitment and dispatch of generation across the entire Eastern Interconnect as if it were one balancing authority with traders and operators having perfect information about all load, resources and transmission congestion, and with no transmission wheeling charges payable for regional imports and exports.

In practice, there are impediments to trade that take place on a real-time basis, including wheeling charges and imperfect knowledge regarding flows outside of the control area. For example, trade with a neighboring region is often scheduled in blocks (e.g., eight peak hours) and the price observed by traders can change by the time that transmission service is arranged. In contrast, inside of a Day 2 RTO market, generator bids are accepted in real-time relative to the actual real-time hourly price.

During the cost-benefit analysis ("CBA") stakeholder process in Missouri for the AmerenUE CBA, CRA worked with trading analysts who estimated for CRA the price differential needed across borders before they would actively pursue trades. The cross-seam price differential needed ranged from $3 to $5 per MWh plus the applicable wheeling charge, depending on the nature of the market. Purchasing from an organized Day 2 market was perceived to have lower cross-seam trading friction than a traditional bi-lateral market given the improved transparency that such a market provides, the economic-based congestion management, and the existence of cross-seam agreements. Working with study stakeholders, similar seams charges have been applied by CRA in subsequent CRA RTO cost-benefit studies and in the CRA modeling performed in 2011 on behalf of the Eastern Interconnection Planning Collaborative ("EIPC) to analyze transmission requirements for the Eastern Interconnection under a broad range of alternative futures.

The dispatch seams charges between TVA, PJM and LGE were set at applicable non-firm off-peak wheeling rates plus a dispatch friction rate of $3/MWh for purchasing from PJM (a Day 2 market), and $5/MWh for purchasing from TVA and LGE. For purchasing from EKPC, the dispatch friction rate was also set at $5/MWh, but the wheeling charge was set at $0 given that the wheeling revenues paid to the EKPC transmission provider are used directly to reduce costs assessed to EKPC load.

As shown in Table 2, in the *Join PJM Case* with EKPC as a member of PJM, there are no friction/wheeling charges between EKPC and (existing) PJM. However, the total seams charge assessed for sales to LGE and TVA from EKPC as a member of PJM increases by $1 given that the transmission charges are collected by PJM under its OATT and redistributed to transmission owners on a generic allocation basis. Outside of the EKPC region, dispatch seams charges were set at either $3 or $5 per MWh plus the applicable wheeling rate consistent with those developed in the prior CRA CBA stakeholder processes.[8]

Table 2 : Dispatch Seams Charges Applied in GE MAPS in the EKPC Region
Dispatch Friction + Wheeling Charge ($/MWh)

	Status Quo Case				Join PJM Case			
	To EKPC	To PJM	To TVA	To LGE	To EKPC	To PJM	To TVA	To LGE
From EKPC	--	5+0	5+0	5+0	--	0	3+3	3+3
From PJM	3+3	--	3+3	3+3	0	--	3+3	3+3
From TVA	5+3	5+3	--	5+3	5+3	5+3	--	5+3
From LGE	5+2	5+2	5+2	--	5+2	5+2	5+2	--

The dispatch seams charges discussed above are applied in GE MAPS to optimize the generation of all units in the modeled footprint that have been already committed to operate in the GE MAPS commitment step. In addition, in deciding which units are most economic to commit to operate, commitment seams charges are also applied in GE MAPS. Commitment seams charges reflect that a control area with responsibility for reliably committing generating units for operation the next day cannot fully rely on units outside of the control area over which the control area has no direct control.

To model the commitment process, CRA defines major "commitment pools" in GE MAPS in which units inside the pool are committed to run to ensure reliable service within the commitment pool without consideration of external non-firm resources. These major

8 See Appendix B for further detail. All GE MAPS inputs, including seams charges, are listed in real 2010 dollars.

commitment pools include, among others, PJM, the Midwest ISO, SPP, Southern Company and TVA. To the extent that the commitment process for regions within a major commitment pool is not jointly optimized, CRA applies a $10 per MWh commitment hurdle between these regions (again, as developed during CBA stakeholder processes). That is, generating units in a commitment pool will not be committed to meet load in another region within the same commitment pool unless there is a least a $10 cost advantage over units that would be available within that region.[9]

For purposes of this study, LG&E and EKPC were included in the PJM commitment pool, with TVA as a separate major commitment pool. As shown in Table 3, in the *Status Quo Case*, $10/MWh commitment seams charges were applied between PJM, LG&E and EKPC. In the *Join PJM Case*, $10 commitment seams charges were applied between LG&E and the combined PJM/EKPC regions. See Appendix B for further detail.

Table 3: Commitment Seams Charges ($/MWh) Applied in GE MAPS in the EKPC Region

	Status Quo Case			Join PJM Case		
	To EKPC	To PJM	To LGE	To EKPC	To PJM	To LGE
From EKPC	--	10	10	--	0	10
From PJM	10	--	10	0	--	10
From LGE	10	10	--	10	10	--

4. BENEFITS AND COSTS

4.1. TRADE BENEFITS

The GE MAPS cases analyzed in this study will reflect varying degrees of impediments to trade between EKPC and PJM. Reductions in the impediments to trading should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this proposal.

Increases or decreases in production cost in any particular utility area (e.g., EKPC), by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it

9 Modeling commitment pools, rather than applying commitment seams charges between all balancing regions in the Eastern Interconnect, greatly speeds up the optimization process in GE MAPS.

generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered.

Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.[10]

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For utilities in which cost-of-service rate regulation is in effect (like EKPC), utility rates reflect the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales (i.e., Adjusted Production Costs). Utility customers under cost-of-service regulation also pay for the fixed costs of owned-generating units through base rates. Thus, deriving trade benefits for these utilities requires an analysis of both the production cost of operating the generating plants and the associated trading activity (purchases and sales).

The production cost of the generating units is derived directly from the MAPS outputs for each case. A simple calculation of regional Adjusted Production Costs using LMPs will miss the economic impact of price differentials between buying and selling regions (i.e., trade benefits). As such, for purposes of deriving the impact of trading with adjoining regions, CRA applies a methodology developed in consultation with stakeholders in prior RTO cost-benefit studies. In the absence of existing FTRs/ARRs to help evaluate the value received by trading parties resulting from these price differentials, CRA captures these impacts through a split-savings methodology. Under this methodology, the net hourly GE MAPS tie-line flows into and out of EKPC are used as a proxy for purchase and sale transactions by EKPC.

In each hour, the net interchange is derived using EKPC tie-line flows to assess whether EKPC is a net importer (purchaser) or exporter (seller) of power. If a net purchaser in the

10 Consider a simple two-company example. Assume there is a $16 marginal cost to generate in Company A's control area and a $20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of $16, while Company B will generate 1 MW less at a production cost savings of $20. Thus, the total saving in production cost is $4 (i.e., $20 – $16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive $18, for a trade benefit of $2 ($18 – $16), and Company B will pay $18, for a trade benefit of $2 ($20 – $18). The total trade benefit of $4 ($2 + $2) will match the total production cost saving of $4.

hour, the net purchase amount is multiplied by the weighted average split-savings price for tie-lines with flows into EKPC. Similarly, if a net exporter (seller) in the hour, the net sale amount is multiplied by the average split-savings price for tie-lines with outgoing flows. We obtain the tie-line prices by defining a "node" in GE MAPS at each end of the tie-line. In assessing regional benefits, the impact of the wheeling costs and revenues are also tracked and incorporated into the assessment of the overall costs and benefits.

4.1.1. Trade Benefit Results

In the *Join PJM Case*, EKPC generates less power (decreasing production costs) while simultaneously increasing off-system purchases in comparison to the *Status Quo Case*. The decreased cost of EKPC generating less power more than offsets the purchase cost change, indicating that the dispatch of EKPC's generation is better optimized in PJM. This is illustrated by the GE MAPS results for calendar year 2013 as shown in Table 4 (for purposes of this table, the full calendar year of 2013 is used).

As shown, the co-optimization between PJM and EKPC in the *Join PJM Case* is yielding a more economic dispatch for EKPC. It is assumed that the wheeling costs EKPC would pay on purchases from PJM in the *Status Quo Case* are covered by EKPC's long-term firm transmission purchase from PJM discussed in Section 4.3.3. If this long-term firm transmission purchase is not in place in the *Status Quo Case*, the trade benefits of joining PJM would be higher.

Table 4: Comparison of EKPC Adjusted Production Costs - 2013
(positive $ numbers are costs)

	GWh (000)			Millions of Dollars		
	StatusQuo	Join PJM	Increase	StatusQuo	Join PJM	Increase
Generation	12.00	11.17	(0.83)	400.2	370.0	(30.2)
Purchases	1.71	2.20	0.49	72.4	87.1	14.6
Sales	(0.81)	(0.47)	0.34	(30.5)	(19.1)	11.4
Wheel Costs				0.9	1.0	0.0
Total	**12.9**	**12.9**	**0.0**	**443.1**	**438.9**	**(4.2)**

The GE MAPS results for 2017 are similar, but result in a somewhat greater decrease in EKPC adjusted production costs as load increases. By 2022, as gas prices and loads increase, the trade benefits of EKPC joining PJM increase significantly as shown in Table 5. These reductions in EKPC adjusted production costs yield total trade benefits of $52.7 million to EKPC in joining PJM over the 2013 to 2022 period.

Table 5: Comparison of EKPC Adjusted Production Costs - 2022
(positive $ numbers are costs)

	GWh (000)			Millions of Dollars		
	StatusQuo	Join PJM	Increase	StatusQuo	Join PJM	Increase
Generation	12.86	12.60	(0.26)	652.7	636.8	(15.8)
Purchases	2.62	2.74	0.12	188.1	183.8	(4.3)
Sales	(0.44)	(0.29)	0.15	(24.3)	(17.7)	6.6
Wheel Costs				2.5	2.4	(0.1)
Total	**15.0**	**15.0**	**0.0**	**818.9**	**805.4**	**(13.5)**

4.2. Administrative Costs

A number of costs must be analyzed in addition to those directly addressed in GE MAPS. These include RTO administrative costs, FERC charges and implementation costs. The specific categories of costs addressed in this study are discussed in detail below.

4.2.1. RTO Administrative Charges

PJM incurs significant capital and operating costs to operate its markets and these costs are recovered through administrative charges assessed to PJM members. PJM has a formal budget projection for these costs through 2015, with projected costs of $0.33 to $0.34 per MWh of load. We assumed these charges would increase at the rate of general inflation after 2015. Using these per MWh rates, the PJM administrative charges that would be paid by EKPC in the *Join PJM Case* are projected to be $35.0 million over the 2013 to 2022 period.[11] It should be noted, however, that PJM's membership continues to grow which may help mitigate administrative cost pressure.

These administrative charges are comprised of a number of Schedule 9 charges[12] specified in the PJM OATT, including:

- Schedule 9-1: Control Area Administration Service, funding the activities of PJM associated with preserving the reliability of the PJM region and administering transmission service.
- Schedule 9-2: Financial Transmission Rights Administration Service, funding the administration by PJM of Financial Transmission Rights (FTRs).
- Schedule 9-3: Market Support Service, funding the activities of PJM in supporting the operation of the PJM Energy Market and related functions.
- Schedule 9-4: Regulation and Frequency Response Administration Service, funding the administration by PJM of regulation and frequency response in the PJM market.

11 See Appendix A for further detail on all cost items in this Section.

12 Schedule 9-FERC charges are analyzed separately in the next section.

- Schedule 9-5: Capacity Resource and Obligation Management Service, funding the operation and oversight by PJM of the PJM capacity market.
- Schedule 9-MMU: Market Monitoring Unit funding.
- Schedule 9-OPSI. Organization of PJM States, Inc. funding.

4.2.2. FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, including that of cooperatives. As a cooperative, EKPC is currently exempt from paying these FERC charges and thus would not pay these FERC charges in the *Status Quo Case*. To estimate the amount of FERC charges EKPC would pay as a member of PJM, the current PJM FERC assessment charges of $0.0689 per MWh were escalated at inflation and applied to the annual EKPC load. This results in additional FERC fees of $7.7 million for EKPC in the *Join PJM Case* over the 2013 to 2022 period.

4.2.3. Internal Staffing and Equipment Costs

RTO market participants will incur expenditures to participate in an RTO market over and above the RTO administrative charges. This will include additional staffing, new computer equipment and other items. In the *Join PJM Case*, because PJM would be performing certain functions now performed or contracted for by EKPC, there may be offsetting savings as well. PJM estimated that based on EKPC's size and its experience with other joining entities, EKPC would likely incur initial integration charges of less than $1 million. We have conservatively included a full $1 million of these costs in 2013. Based on input from EKPC's power marketers, an additional $0.5 million per full year of EKPC labor costs were included in the *Join PJM* case starting in June 2013. Finally, an additional $0.1 million per full year of additional EKPC legal costs were included in the *Join PJM* case. This results in additional internal staffing and equipment costs of $5.6 million for EKPC in the *Join PJM Case* over the 2013 to 2022 period.

4.3. TRANSMISSION COSTS

4.3.1. Transmission Expansion Cost Allocation

Under current PJM policy, PJM allocates the cost of new "backbone" high-voltage (500 kV and above) transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process on a uniform basis to all PJM load.[13] There is no phase-in for new members for these allocated high-voltage lines. PJM provided a listing of the total cost estimate for each individual approved backbone high-voltage project that is in-service, under construction, in the engineering and planning phase, or on-hold. We assumed

13 The sharing is based on the non-coincident annual peak of each PJM transmission zone. These charges are recovered under Schedule 12 of the PJM tariff. Backbone facilities are comprised of "Regional Facilities" that operate at or above 500 kV and "Necessary Lower Voltage Facilities" that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities.

that under-construction projects would be in service by June 2013 when EKPC would join PJM, and that the projects in the engineering and planning stage would come on-line on average in June 2015 (based on the expected in-service dates of two of the largest projects in this stage).[14] For the two major on-hold projects (the MAPP and PATH projects), we included 50% of the cost of these projects starting in 2020 as it is unclear when or if these projects will be constructed or be replaced with other projects over time. EKPC does not have and does not currently plan to have 500 kV or above high-voltage lines on its system the costs of which could be shared with PJM. Based on this analysis, we estimated that EKPC's allocation of these high-voltage backbone projects in the *Join PJM Case* would be $70.2 million over the 2013 to 2022 period.

Regional lower-voltage PJM projects also could be shared with EKPC based on the projected impact the new line would have on the EKPC system. However, EKPC would only be responsible for sharing the costs of these lower-voltage projects that are approved in a RTEP after EKPC would become a member. Thus, EKPC would have a role in determining if the regional transmission expansion is cost-beneficial, and there would also be cost-sharing by other PJM members of future EKPC transmission projects under this process. As such, no additional costs were included in the *Join PJM Case* for this category of projects.

4.3.2. Transmission Revenue Allocation

In the *Join PJM Case*, EKPC, as a transmission owner, would share the PJM firm transmission revenue that is collected under the PJM OATT. The PJM firm transmission revenue was $54 million in 2011. The revenue is allocated on an annual transmission revenue requirement basis. Applying the EKPC annual transmission revenue requirement used to develop EKPC's current transmission rates, EKPC would have a 0.85% share of this annual PJM revenue. EKPC's allocation share likely will be higher at the time it updates its revenue requirement upon joining PJM. Assuming EKPC's 0.85% share would not increase and that the PJM firm transmission revenue would escalate at inflation over the study period, the total allocation to EKPC is estimated to be $3.7 million over the June 2013 to December 2022 period.[15]

4.3.3. Long-Term Firm Transmission Costs

EKPC currently makes long-term firm point-to-point transmission reservations to ensure that EKPC has the ability to import power throughout the year including in periods in which EKPC might be short of capacity or economic energy and non-firm and/or short-term firm transmission service might not be available. EKPC currently has a 400 MW reservation with

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14 Based on 2011 data for PJM and EKPC, a 1.64% EKPC allocation was applied along with an estimated carry charge rate of 19.5% on the project costs.

15 Network service revenues collected by EKPC from LG&E for LG&E load on the EKPC transmission system would be allocated directly to EKPC under the PJM tariff if EKPC were to join PJM, yielding no difference with the *Status Quo Case*.

PJM through October 2016. It is anticipated that EKPC would need similar long-term reservations throughout the 2013-2022 study period in the *Status Quo Case*.

As part of a Day 2 market in the *Join PJM Case*, EKPC would not need these long-term transmission arrangements. PJM has confirmed that if EKPC were to join PJM this existing reservation would no longer be in effect (in practice, replaced by network service under the PJM Tariff). Based on the cost of the reservations with PJM, assumed to remain constant through 2015 and thereafter increase at inflation, the savings from avoiding these costs in the *Join PJM Case* are $56.1 million.

4.4. PJM Capacity Market Impacts

In prior RTO assessments performed by CRA, the capacity benefits of joining an RTO have typically been a secondary consideration. For a small utility, the diversity benefits of joining an RTO usually will yield a lower planning reserve target. But often, the utility is already long in capacity (along with the RTO) yielding small near-term benefits. For a utility already in a large reserve sharing group (like EKPC, which is currently in the TVA reserve sharing group), the impact of any differences in the amount of operating reserves needed when joining an RTO also does not tend to yield major cost differences.

However, EKPC, as a stand-alone winter-peaking utility, is in a unique position to gain significant capacity benefits in joining an RTO. In PJM, the reserve requirements for the EKPC system would be based on the EKPC share of the total PJM peak load during the five highest PJM peak demand hours in each year. This share would be used to determine the amount of capacity EKPC would need to have or procure on a three-year look ahead basis in the PJM Reliability Pricing Model ("RPM") capacity market. Historically, and based on PJM projections, these five highest PJM peak load hours all take place during the summer season meaning that EKPC would effectively only have to plan to meet its summer peak reserve requirements as a member of PJM.

EKPC must meet a 12% planning reserve requirement in both the winter and summer seasons in the *Status Quo Case,* based on installed capacity. In contrast, for example, in PJM's RPM for the June 2014 to May 2015 delivery year, PJM targets a 15.3% installed reserve margin ("IRM") target applicable to the average of the 5 highest PJM peak load hours. Combined with a PJM-wide average equivalent forced-outage rate "(EFOR)" of 6.25% this yields an Unforced Capacity Obligation ("UCAP") requirement of 8.09%. Using annual EKPC data from 2008 to 2011, the EKPC peak during the five PJM peak hours has been only 91.2% of the actual EKPC summer peak (ranging from 89.8% to 92.5%), and the average forced-outage rate for the EKPC generating units has been 4.1%. Taking these factors into account, we estimate that the EKPC installed planning reserve target for EKPC's summer peak in 2014/15 would be 2.8% as a member of PJM. Maintaining this 2.8% EKPC installed reserve margin in the summer would yield the 8.09% UCAP requirement EKPC would need in 2014/15 as a member of PJM.[16]

In the *Status Quo Case*, EKPC is projected to be short of winter capacity from 2013 to 2022, but long in summer capacity for most of this period and would need to purchase or construct winter capacity, or swap summer for winter capacity with a neighboring entity to meet *Status Quo Case* reserve requirements.

In the *Join PJM Case*, upon entry into PJM in June 2013, EKPC would integrate into the RPM by submitting a Fixed Resource Requirement ("FRR") plan for the 2013/14, 2014/15 and 2015/16 delivery years. EKPC could then participate in the PJM RPM auction beginning in the 2016/17 delivery year. During the FRR period, EKPC could sell any additional capacity unneeded to meet its FRR reserve requirements in the RPM auctions for each delivery year scheduled to take place over time or bilaterally to other PJM members in need of capacity. However, in an FRR, EKPC would be required to hold back (not sell capacity into or for use in the RPM) an additional 3% of its reserve requirements. This 3% holdback requirement as part of an FRR makes an FRR less economic for EKPC, which would have capacity to sell, than being part of the RPM.

In the *Join PJM Case*, EKPC would participate in two RPM auctions prior to the June 2013 date in which EKPC would formally join PJM. In February 2013, EKPC would sell capacity beyond what it would need in its FRR in the third and final incremental auction for delivery year 2013/14. In May 2013, EKPC would participate in the Base Residual Auction for delivery year 2016/17.[17]

The most recent PJM RPM auction results were used as the prevailing capacity price for the EKPC region. The latest available price is for the 2014/15 delivery year, and this capacity price was assumed to remain constant through the 2018/19 delivery year. Prices thereafter were assumed to gradually rise to reach by 2022/23 the net cost of new entry ("CONE") for additional capacity estimated by PJM as part of the capacity auction process. The lower capacity prices in the PJM RPM for the 2013/14 delivery year are used for the 2013/14 period.[18]

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16 The effective summer installed planning reserve margin for EKPC as a member of PJM is similar in other delivery years, but varies slightly as PJM's estimate of IRM and pool-wide EFORs varies somewhat by delivery year.

17 After June 2013, the 2nd incremental auction for delivery year 2014/15 will take place in July 2013, and the 1st incremental auction for delivery year 2015/16 will take place in September 2013. In general, Base Residual Auctions take place in May three years and one month prior to the delivery year, 1st incremental auctions for the delivery year take place 16 months later in September, 2nd incremental auctions take place 10 months after that in July, and the 3rd and final incremental auction for the delivery year takes place 7 months after that in February just before the start of the delivery year in June.

18 Incremental capacity auctions in PJM, like those that EKPC would participate in for the 2013/14 through 2015/16 delivery years, have typically yielded capacity prices below those obtained in the Base Residual Auction. As such, capacity prices in 2013/14 through 2015/16 in EKPC were reduced from the Base Residual Auction results by the average percentage amount by which prior incremental auctions in PJM have yielded lower prices than Base Residual Auctions.

The approach used to estimate EKPC's capacity costs in the *Status Quo Case* and *Join PJM Case* is summarized as follows:

Status Quo Case: In years in which EKPC is long in summer capacity, EKPC swaps summer capacity for winter capacity with another party up to the point at which it just meets its 12% summer reserve target, and purchases the remaining winter capacity needed to meet its 12% winter reserve target at the winter season market price for capacity. Both transactions require 3 months of external transmission charges. Once EKPC becomes short of summer capacity, EKPC purchases the required amount of winter and summer capacity to meet its 12% summer and winter reserve requirement.

Join PJM Case: EKPC sells capacity into the PJM market at the annual capacity market price up to the point that it just meets its summer reserve target under PJM rules. EKPC's summer peak for reserve purposes is based on its average peak during the 5 hours (5 CPs) in which PJM as a whole peaks. No external transmission charges are required. During the FRR period (through 2015/16), an additional 3% of reserve capacity is held back and not sold.

Based on the above, the capacity market benefits to EKPC of joining PJM over the 2013 to 2022 period are $147.8 million (2012 present value). If EKPC were to remain in a FRR plan after the 2015/16 delivery year, this would yield additional costs to EKPC of $3 to $9 million per year. See Appendix A for further detail.

5. OVERALL COST-BENEFIT RESULTS

Shown in Table 6 are the overall net benefits, between the *Join PJM Case* and the *Status Quo Case*, using the components discussed above. As shown, the overall net benefit of EKPC joining PJM is $142.0 million *(2012 present value)* over the June 2013 to December 2022 period.

Table 6: 2013-2022 Benefits (Costs) to EKPC of Joining PJM
(in millions of 2012 present value dollars; positive numbers are benefits)

Trade Benefits	52.7
Administrative Costs	(48.3)
Transmission Expansion Costs, net	(66.4)
PJM Capacity Market Benefits	147.8
Avoided Long-Term Firm PTP Charges	56.1
Total Net Benefits (Costs)	**142.0**

5.1.1. Sensitivity Analyses

During 2011, CRA prepared a number of GE MAPS cases for EKPC using then prevailing input assumptions to ascertain the impact on trade and capacity benefits under various possible assumptions. Five different cases were analyzed for the 2013 to 2017 period.[19]

Case 1: *Base gas prices as of 2011, base load, no retirement of EKPC units*

Case 2: *High EKPC load growth (3% higher than Case 1 in 2013 and 8% higher in 2017), high natural gas prices (40% higher than Case 1), small (<150MW) unscrubbed coal plants (including Dale and Cooper 1) retire by 2016.*

Case 3: *Low EKPC load growth (load flat at 2011 levels), low natural gas prices (10% below Case 1).*

Case 4: *Small (<150MW) unscrubbed coal plants (including Dale and Cooper 1) retire by 2016.*

Case 5: *New EPA rules in effect by 2016 leading to coal plant retirements (including Dale and Cooper 1)*[20]

These differing case assumptions have impacts on both the EKPC trade benefits and the EKPC capacity market benefits. The change in input assumptions in these cases was applied to both the *Status Quo Case* and *Join PJM* Case. Results are summarized in Table 7.

Table 7: 2011 GE MAPS Analysis of 2013-2017 Trade and Capacity Benefits (Costs) to EKPC of Joining PJM
(in millions of 2011 present value dollars, positive numbers are benefits)

Case	Total	Change from Case 1
1: Base 2011 Gas and Load	**90.4**	
2: High Load/High Gas/2017 Coal Retire	**205.3**	*+114.9*
3: Low Load/Low Gas	**44.8**	*(45.6)*
4: 2017 Coal Retire	**120.0**	*+29.6*
5: CSAPR/MACT by 2017	**117.5**	*+27.0*

As shown, the trade and capacity benefits for EKPC are substantially positive across all cases examined in GE MAPS in 2011. The low load and low gas assumptions in Case 3 led

19 The 2018 to 2022 period was not examined, and EKPC joining PJM for the full calendar year of 2013 was assumed.

20 On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), which requires 27 states to significantly reduce SO_2 and NO_X emissions. The EPA's Maximum Achievable Control Technology ("MACT") rule requires coal and oil-fired power plants to reduce emissions of mercury, other metallic toxics, acid gases, and organic air toxics through "command and control" emission rate limits for mercury, acid gases, and particles.

to the largest reduction in trade and capacity benefits. Lower gas prices tend to decrease trade benefits as price disparities between regions tend to decrease. Low load growth tends to decrease capacity prices and thus reduces capacity benefits. Natural gas prices have decreased significantly from those used in the Case 1 analysis conducted in 2011. The results presented in the prior sections reflect the lower prevailing gas price projections as of early 2012.

6. QUALITATIVE CONSIDERATIONS

While the quantified figures show material benefits to EKPC of joining PJM, there are a number of key risks, as noted below:

1. Transmission Cost Allocation. The potential high-voltage transmission expansion cost allocation to EKPC in joining PJM are significant and highly dependent on future PJM load growth, congestion and cost allocation mechanisms, among other considerations. EKPC would have only a limited role in the approval of these high-voltage expansion plans.

2. Capacity Market Diversity Benefits. The capacity market benefits for EKPC are dependent on the continued diversity of EKPC's summer demand profile with that of PJM, as well as the continued winter peaking nature of the EKPC system. To the extent that these summer diversity or winter peaking attributes diminish over time, EKPC benefits would decrease. In addition, any increases to the long-term forced-outage rates of the EKPC generating units would decrease these benefits.

3. Exit Costs. While the PJM RTO does not impose exit fees, an exiting member maintains an obligation to pay for its share of transmission projects approved while a member and any commitments it may have in the congestion and capacity markets. As such, the decision to join an RTO should be viewed as a long-term decision and the anticipated benefits should be material.

4. Long-term Firm Transmission Needed. A significant amount of benefits of the *Join PJM Case* are associated with no longer needing long-term firm transmission to ensure EKPC's ability to import economic power when needed. To the extent that the need for these reservations (after the expiration of the current reservation with PJM in 2016) could be economically and reliably mitigated in the *Status Quo Case* through increased energy efficiency/demand response or capacity expansion, the benefits to the *Join PJM Case* would decrease.

5. Financial Transmission Rights. EKPC would be provided a set of Financial Transmission Rights ("FTRs")[21] upon joining PJM. The expectation is that the value of these along with

21 FTRs are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path FTRs provide a hedging mechanism that can be traded separately from transmission service. Market participants are able to hedge against their congestion costs by acquiring FTRs that are consistent with their energy deliveries

corresponding Auction Revenue Rights ("ARRs")[22] will equal or exceed the congestion payments that EKPC would incur as part of a Day 2 PJM market. However, the benefit or possible cost will not be known until the specific set would be issued.

6. Reliability. Upon joining PJM, EKPC would become part of the PJM reserve sharing group and the large PJM Day 2 market. As such, it is not expected that there will be any reduction in EKPC reliability even with the lower reserve margin the EKPC would be able to maintain as part of PJM.

7. Demand Response and Energy Efficiency Program. Under the Day 2 PJM market, demand side options have the ability to bid into the market to be compensated for both energy and capacity reductions. The LMP pricing in a Day 2 PJM market also provides better means to properly value and incent energy efficiency improvements. It is anticipated that these economic incentives would provide EKPC with the ability to obtain more demand side and efficiency options on its system than in the *Status Quo Case*.

8. Ancillary services. Under the Day 2 PJM market, ancillary services such as operating reserves can be purchased and sold. EKPC could continue to self-supply its ancillary services and thus should be no worse off, but could be possibly better off, under this market. This possible benefit has not been quantified.

9. Timing of Entry. EKPC would need to participate in a PJM Base Residual Auction and an Incremental Auction in the first months of 2013 prior to formally joining PJM in June 2013. It is assumed that there is enough time for EKPC to be ready to transition to the PJM market, including participation in capacity auctions in February and May 2013, from the time a decision is made by EKPC to join PJM. Annual benefits are positive in all years, indicating an even earlier entry may be beneficial.

10. Interruptible Customer. EKPC has a large industrial interruptible customer on its system that currently has the option to pay prevailing market prices for power whenever EKPC initiates an interruption. In the analysis above, it is assumed that EKPC does not procure reserves for the load of this customer. There is the potential for the customer to qualify as a PJM demand resource. The ability of this customer to continue with the current arrangement is uncertain with EKPC as a member of PJM and presumably would be the subject of negotiation with EKPC that could yield additional EKPC costs.

11. Other PJM Entries/Departures. Membership in PJM may vary over time, possibly increasing or decreasing EKPC benefits. Additional entry into PJM should be beneficial providing increased opportunity to optimize power production and procurement and greater operating economies of scale, while departures likely would produce the opposite effect.

In sum, of the above items, CRA views transmission cost allocation, capacity market diversity benefits and exit fees to be of considerable importance in evaluating the EKPC decision to

22 Auction Revenue Rights (ARRs) are entitlements allocated annually to PJM firm transmission service customers that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. EKPC would transition from directly assigned FTRs to receiving ARR entitlements within two planning years of becoming a PJM member.

join an RTO. These risks need to be weighed against the considerable benefits found for EKPC to join PJM.

7. CONCLUSIONS

Based on the analysis performed, we conclude that EKPC joining PJM will yield significant economic benefits to EKPC. The net benefits to EKPC are relatively robust. However, the benefits are highly dependent on the allocation of PJM regional high voltage transmission expansion costs, PJM capacity market benefits and avoided long-term firm transmission charges. A number of important qualitative considerations have been identified as well, with both qualitative benefits and offsetting costs likely to be incurred by EKPC in joining PJM.

APPENDIX A: FURTHER QUANTITATIVE RESULT DETAILS

The annual net benefit (cost) to EKPC is captured in Table 8.

Table 8: Net Benefit (Cost) to EKPC of Join PJM Case (millions of $)

	Jun-Dec 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2012 Present Value
Inflation	2.5%										
Present Value Rate	6.00%										
Decreased Cost to Serve EKPC Load	2.5	4.6	4.9	5.3	5.7	7.4	9.3	11.2	13.2	13.5	52.7
PJM Administrative Charges	(2.5)	(4.4)	(4.5)	(4.7)	(4.9)	(5.1)	(5.3)	(5.6)	(5.8)	(6.1)	(35.0)
FERC Charges under PJM OATT	(0.5)	(1.0)	(1.0)	(1.0)	(1.1)	(1.1)	(1.2)	(1.2)	(1.3)	(1.3)	(7.7)
Internal Staffing/Equipment Costs	(1.4)	(0.6)	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(5.6)
Subtotal Generation/Administration	(1.9)	(1.4)	(1.2)	(1.1)	(1.0)	0.5	2.0	3.7	5.4	5.4	4.4
PJM Transmission Expansion Allocation	0.0	(4.8)	(10.3)	(10.3)	(10.3)	(10.3)	(10.3)	(15.4)	(15.4)	(15.4)	(70.2)
Allocation of PJM Firm PTP Revenues	0.3	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	3.7
Subtotal Transmission Costs	0.3	(4.3)	(9.8)	(9.7)	(9.7)	(9.7)	(9.7)	(14.8)	(14.8)	(14.8)	(66.4)
PJM Capacity Market Benefits	2.9	12.4	12.7	17.9	18.4	18.9	24.7	31.1	37.1	43.4	147.8
Net Benefits	1.2	6.7	1.8	7.0	7.6	9.6	17.0	20.0	27.7	34.0	85.9
Avoided Firm PTP Charges Payable	4.4	7.6	7.6	7.7	7.9	8.1	8.3	8.5	8.8	9.0	56.1
Net Benefits	5.6	14.3	9.3	14.8	15.6	17.8	25.3	28.5	36.4	42.9	142.0

Further detail regarding the trade benefit results derived in GE MAPS is captured in Table 9.

Table 9: EKPC Trade Benefit Detail (millions of $)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Present Value
Status Quo											
Generation	400.2	439.8	481.2	524.3	569.3	585.5	602.1	619.2	636.7	652.7	
Purchases	72.4	77.6	83.0	88.5	94.4	115.1	136.9	159.7	183.5	188.1	
Sales Revenue	(30.5)	(33.5)	(36.7)	(40.0)	(43.4)	(38.9)	(34.1)	(29.0)	(23.7)	(24.3)	
Wheel Costs Net	0.9	1.0	1.1	1.2	1.2	1.5	1.8	2.1	2.5	2.5	
Total	443.1	484.9	528.6	574.1	621.6	663.3	706.7	751.9	799.0	818.9	
Join PJM											
Generation	370.0	410.3	452.3	496.2	542.0	560.9	580.4	600.5	621.3	636.8	
Purchases	87.1	91.3	95.7	100.3	105.0	122.4	140.5	159.5	179.3	183.8	
Sales Revenue	(19.1)	(22.2)	(25.4)	(28.8)	(32.4)	(28.9)	(25.2)	(21.3)	(17.2)	(17.7)	
Wheel Costs Net	1.0	1.0	1.1	1.1	1.2	1.5	1.8	2.1	2.4	2.4	
Total	438.9	480.4	523.7	568.8	615.9	655.9	697.5	740.8	785.7	805.4	
Savings in Join PJM											
Production Cost Savings	30.2	29.6	28.9	28.1	27.3	24.6	21.7	18.6	15.4	15.8	183.2
Purchase Cost Savings	(14.6)	(13.7)	(12.8)	(11.8)	(10.7)	(7.3)	(3.6)	0.2	4.2	4.3	(56.6)
Sales Revenue	(11.4)	(11.3)	(11.2)	(11.1)	(11.0)	(10.0)	(8.9)	(7.7)	(6.5)	(6.6)	(72.5)
Wheel Costs Net	(0.0)	(0.0)	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.3
Total	4.2	4.6	4.9	5.3	5.7	7.4	9.3	11.2	13.2	13.5	54.4
Total with June 2013 Start	2.5	4.6	4.9	5.3	5.7	7.4	9.3	11.2	13.2	13.5	52.7

Further detail regarding administrative and transmission costs are captured in Table 10 and Table 11.

Table 10: Administrative Cost Detail (millions of $)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Present Value
EKPC Administrative Charges in PJM												
EKPC Energy for Load (GWh) (a)		7,573	13,148	13,409	13,701	13,891	14,133	14,390	14,644	14,914	15,173	
PJM Admin Charges ($/MWh) (b)		0.334	0.333	0.337	0.345	0.354	0.362	0.371	0.381	0.390	0.400	
EKPC PJM Admin Fees (M$)		2.5	4.4	4.5	4.7	4.9	5.1	5.3	5.6	5.8	6.1	35.0
EKPC FERC Charges in PJM												
EKPC Energy for Load (GWh) (a)		7,573	13,148	13,409	13,701	13,891	14,133	14,390	14,644	14,914	15,173	
EKPC FERC Fees under PJM OATT ($/MWh) (c)		0.071	0.072	0.074	0.076	0.078	0.080	0.082	0.084	0.086	0.088	
EKPC FERC Fees in PJM (M$)		0.53	0.95	0.99	1.04	1.08	1.13	1.18	1.23	1.28	1.34	7.7
EKPC Internal PJM Interface Costs (d)		1.35	0.62	0.63	0.65	0.66	0.68	0.70	0.71	0.73	0.75	5.6
Transmission Cost Status Quo – Duke Contract												
MW Reserved (Annual Average)		400	400	400	400	400	400	400	400	400	400	
Rate (PJM Monthly PTP $/kW-Month)		1.574	1.574	1.574	1.613	1.654	1.695	1.737	1.781	1.825	1.871	(g)
Charges (M$)		4.4	7.6	7.6	7.7	7.9	8.1	8.3	8.5	8.8	9.0	56.1
EKPC Share of PJM Transmission Revenue in Join PJM												
Transmission Revenue PJM Firm PTP (M$) (f)		33.0	58.0	59.4	60.9	62.4	64.0	65.6	67.2	68.9	70.6	
EKPC Share	@ 0.85%	0.3	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	3.7
EKPC Annual Transmission Rev Requirement (M$)		30.7	0.85%									
Existing PJM Annual Trans Rev Requuirement (M$) (h)		3576.3										
Total (M$)		3607.0	100%									

(a) EKPC 2011 Load Forecast, 2013 prorated for June start
(b) PJM forecast through 2015, escalated thereafter at inflation, includes market monitoring and OPSI charges, but not FERC fees
(c) PJM Schedule 9-FERC rate of 0.0689/MWh in 2012 escalated at inflation
(d) $1M of year 1 integration costs; additional FTE cost of $0.5M per full year and legal fees of $0.1M per full year, both escalating at inflation
(f) 2011 PTP Firm PJM revenues, escalated at inflation
(g) Firm PTP Rate asssessed to EKPC under PJM OATT, held constant through 2015, escalated thereafter at inflation
(h) www.pjm.com/markets-and-operations/market-settlements/~/media/markets-ops/settlements/network-integration-trans-service-jan-2012.ashx

Table 11: EKPC Backbone RTEP Allocation (millions of $)

	RTEP Cost Estimate (M$)	EKPC Allocated Share	EKPC Cost Allocation (M$)	Levelized Carrying Charge Rate	EKPC Annual Cost (M$)
Project Status					
In-Service and Under-Construction	1,506	1.64%	24.7	19.5%	4.82
Engineering and Planning	1,701	1.64%	27.9	19.5%	5.44
On-Hold Projects	3,228	1.64%	53.0	19.5%	10.33

EKPC Annual Cost, June 2013 Entry	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Present Value
Project Status											
In-Service and Under-Construction (M$)		4.82	4.82	4.82	4.82	4.82	4.82	4.82	4.82	4.82	32.8
Engineering and Planning (M$)		-	5.44	5.44	5.44	5.44	5.44	5.44	5.44	5.44	31.9
SubTotal (M$)	0.00	4.82	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	61.0
On-Hold Projects (M$)		-	-	-	-	-	-	5.16	5.16	5.16	9.7
Total (M$)	0.00	4.82	10.26	10.26	10.26	10.26	10.26	15.42	15.42	15.42	70.2

Notes:
Revenue Requirements estimated using 19.5% annual fixed charge rate and a EKPC Network Service Peak Load (NSPL) share using 2012 Data
In-Service and Under-Construction Projects assumed fully in Schedule 12 charges by 2013
Major Engineering and Planning Projects expected to be in-service by mid-2015, recovery of work in progress would begin earlier
On-Hold Projects (MAPP and PATH), 50% probability of coming online applied, starting in 2020
2013 set at zero, as EKPC would have no PJM NCPL allocation from 2012 for the year 2013.
Assume no allocation of projects below 500 kV (would be based on future plans subsequent to EKPC joining and supporting analysis of impact on EKPC)

Further detail regarding capacity market benefits is captured in Table 12.

Table 12: EKPC Capacity Market Benefits

EKPC Planning Reserve Margin – Status Quo	12.0%	*Winter and Summer,*
EKPC 5CP Summer Peak Diversity Factor in PJM	0.912	*Four-year average, 2008-11*
Seasonal Share of Annual Capacity Value (per MISO VCM 2010-11 PY)	Summer:	74%
	Winter :	13%

For Planning Year beginning June of:		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Peak Load (net of DSM)	**W**	3,070	3,132	3,191	3,245	3,302	3,363	3,412	3,486	3,544	3,610
	S	2,263	2,285	2,322	2,361	2,402	2,447	2,496	2,534	2,591	2,638
Existing Resources	**W**	3,037	3,037	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
	S	2,831	2,831	2,831	2,770	2,770	2,770	2,770	2,770	2,770	2,770
Reserve Margin	**W**	-1%	-3%	-6%	-8%	-9%	-11%	-12%	-14%	-15%	-17%
	S	25%	24%	22%	17%	15%	13%	11%	9%	7%	5%
Capacity Prices											
Annual Installed Capacity Price ($/kW-yr)		1.9	34.1	34.2	43.3	43.3	43.3	60.0	76.7	93.4	110.1
Summer price - 3 mo. avg ($/kW-mo)		0.5	8.4	8.4	10.6	10.6	10.6	14.7	18.8	22.9	27.0
Winter price - 3 mo. avg ($/kW-mo)		0.1	1.5	1.5	1.9	1.9	1.9	2.6	3.3	4.1	4.8
Implied 1 to 1 swap price ($/kW-mo)		0.4	6.9	6.9	8.7	8.7	8.7	12.1	15.5	18.9	22.2
<u>**Status Quo Case**</u>											
Reserves Needed (MW)	**W**	401	471	574	634	698	767	821	904	969	1043
	S	-296	-272	-230	-126	-80	-29	25	67	132	185
Swap (MW)	**W<->S**	296	272	230	126	80	29	0	0	0	0
Addtl Purchase (MW)	**W**	104	199	344	509	618	737	821	904	969	1043
Addtl Purchase (MW)	**S**	0	0	0	0	0	0	25	67	132	185
Swap Transmission Cost ($/kW-mo)		1.96	1.96	1.96	2.01	2.06	2.11	2.16	2.22	2.27	2.33
+ Swap Cost/(Revenue) to EKPC M$		1.4	(4.0)	(3.4)	(2.5)	(1.6)	(0.6)	0.0	0.0	0.0	0.0
Purchase Transmission Cost ($/kW-mo)		1.96	1.96	1.96	2.01	2.06	2.11	2.16	2.22	2.27	2.33
+ Purchase Cost to EKPC (M$)		0.6	2.1	3.6	5.9	7.3	8.8	13.0	19.3	28.4	38.6
= Total Cost/(Revenue) to EKPC (M$)		2.0	(2.0)	0.1	3.4	5.7	8.3	13.0	19.3	28.4	38.6
<u>**Join PJM Case**</u>											
Summer Peak Load @ 5CPs with PJM		2,064	2,084	2,118	2,154	2,191	2,232	2,277	2,311	2,364	2,406
PJM Forecast Pool Requirement (UCAP)		1.0804	1.0809	1.0859	1.0859	1.0859	1.0859	1.0859	1.0859	1.0859	1.0859
Summer Unforced Capacity Required		2,230	2,253	2,300	2,339	2,379	2,424	2,472	2,510	2,567	2,613
Existing Summer Unforced Capacity		2,716	2,716	2,716	2,654	2,654	2,654	2,654	2,654	2,654	2,654
Addtl Unforced Capacity Needed		-486	-463	-416	-316	-275	-230	-182	-145	-88	-41
Unforced Capacity Price ($/kW-year)		2.1	36.3	36.3	46.0	46.0	46.0	63.7	81.5	99.3	117.0
<u>*Out of Time FRR Period*</u>											
Addl Unforced Capacity Needed if in FRR		67	68	69	70	71	73	74	75	77	78
+ Total Cost/(Revenue) to EKPC (M$)		(0.9)	(14.4)	(12.6)							
<u>*In RPM*</u>											
+ Total Cost/(Revenue) to EKPC					(14.5)	(12.7)	(10.6)	(11.6)	(11.8)	(8.7)	(4.8)
= Total Cost/(Revenue) to EKPC		(0.9)	(14.4)	(12.6)	(14.5)	(12.7)	(10.6)	(11.6)	(11.8)	(8.7)	(4.8)
<u>**Benefits (Lower Costs) in Join PJM Case**</u>		2.9	12.4	12.7	17.9	18.4	18.9	24.7	31.1	37.1	43.4
Additional Cost FRR vs. RPM		*0.1*	*2.5*	*2.5*	*3.2*	*3.3*	*3.3*	*4.7*	*6.1*	*7.6*	*9.2*

Further detail regarding capacity prices is captured in Table 13.

Table 13: Capacity Pricing

Actual PJM Capacity Auction RTO Area Price in terms of UCAP $/MW Day
Date listed is Auction Close

Auction	**Auction for the DY**					**Ratio to Base Price**			
Delivery Year	**Base**	**1st**	**2nd**	**3rd**		**Base**	**1st**	**2nd**	**3rd**
2008/9	111.92			10.00		1.00			0.09
	Jul-07			Jan-08					
2009/10	102.04			40.00		1.00			0.39
	Oct-07			Jan-09					
2010/11	174.29			50.00		1.00			0.29
	Jan-08			Jan-10					
2011/12	110.00	55.00		5.00		1.00	0.50		0.05
	May-08	Jun-09		Mar-11					
2012/13	16.46	16.46	13.01			1.00	1.00	0.79	
	May-09	Sep-10	Jul-11	*Mar-12*					
2013/14	27.73	20.00		EKPC->		1.00	0.72		
	May-10	Sep-11	*Jul-12*	*Mar-13*					
2014/15	125.99		EKPC -->>						
	May-11	*Sep-12*	*Jul-13*	*Feb-14*					
2015/16		EKPC -->>							
	May-12	*Sep-13*	*Jul-14*	*Feb-15*					
2016/17	EKPC -->>								
	May-13	*Sep-14*	*Jul-15*	*Feb-16*					
					Average	1.00	0.74	0.79	0.20

Capacity Prices *For DY beginning June:*	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	
UCAP Price ($/MW day)	5.64	99.58	99.58	125.99	125.99	125.99	174.65	223.31	271.97	320.63	(a)
UCAP Price ($/kW-yr)	2.06	36.35	36.35	45.99	45.99	45.99	63.75	81.51	99.27	117.03	(b)
PJM Poolwide EFORd	0.063	0.0625	0.0590	0.0590	0.0590	0.0590	0.0590	0.0590	0.0590	0.0590	(c)
ICAP Price ($/kW/yr)	1.93	34.08	34.20	43.27	43.27	43.27	59.99	76.70	93.41	110.13	(d)

(a) *2013/14 price based on 2013/14 Base Price multiplied by average ratio of 3rd incremental auction price to base price*
2014/15 price based on 2014/15 Base Price multiplied by average ratio of 2nd incremental auction to base price.
2015/16 price held constant at 2014/15 price
2016/17 price based on receiving 2014/15 Base price in 2016/17 base auction.
2017/18 and 2018/19 price held constant at 2016/2017 price
2018/19-2022/23 straight-line to reach 2015/16 auction paramters net CONE by 2022/23
(b) *UCAP Price in $/MW day * 365/1000*
(c) *From RPM parameters, 2015/16 used for out years*
(d) *UCAP Price * (1 - PJM Poolwide EFORd)*

APPENDIX B: GE MAPS MODELING ASSUMPTIONS

B.1 OVERVIEW

All financial assumptions specified in this appendix are expressed in real 2010 US dollars, unless otherwise noted.

GE MAPS is a detailed economic dispatch and production-costing model for electricity networks. It was originally developed by General Electric (GE) and is currently used by over twenty major utilities and RTOs in the U.S. CRA has worked closely with GE to ensure that the model's data structures and functionality accurately reflect the competitive market.

GE MAPS determines the least-cost security constrained dispatch of generating units to satisfy a given demand, on the assumption that the units are dispatched according to their variable costs. The major advantage of GE MAPS is its ability to simulate the hourly operation of generating units and transmission systems (e.g. transformers, lines, phase shifters, busses) in significant detail. For example, it accurately represents capacity constraints, minimum up time limitations, and thermal constraints on the transfer capability of transmission lines, line and unit contingencies and scheduling limitations of hydro plants. As such, GE MAPS provides a highly accurate, detailed simulation of the hourly operation of the individual generating units and transmission system that constitute the wholesale market.

Among the key outputs of the GE-MAPS model is a set of Locational Marginal Prices (LMPs), computed for each bus in each hour and the hourly dispatch of all generators for each relevant geographic market. The model's geographic footprint encompasses the entire Eastern Interconnection (U.S. and the Canadian provinces of Ontario, Manitoba, and Saskatchewan) with a focus on the PJM and TVA footprint and surrounding regions.

The GE MAPS simulations are run for three years (2013, 2017, and 2022). Results for years not simulated are interpolated. Each year consists of two cases, the Status Quo Case and the Join PJM Case:

Status Quo Case: EKPC continues to operate independently while participating in the current TVA reserve sharing agreement. Wheeling rates and seams charges applied between EKPC and surrounding areas, including TVA, LGE, MISO, and PJM.

Join PJM Case: EKPC joins the PJM RTO. The expanded PJM (including EKPC) will have joint unit commitment and dispatch. Wheeling rates and seams charges between the EKPC and the rest of PJM (specifically between EKPC and AEP, Dayton, Duke Ohio/Kentucky, and Virginia Power) are eliminated.

B.2 DATA SOURCES

Primary data sources for CRA's GE MAPS model include the Eastern Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG), the NERC Electricity Supply and Demand (ES&D) database, the EIA 860 filings, the Ventyx Energy Velocity Database, the NERC regions and Independent System Operators/Regional Transmission Organizations, the

FERC submissions by generation and transmission owners, and CRA analysis of plant operations and market data. Major data components are listed in the sections following.

B.3 TRANSMISSION

The CRA model utilizes the MMWG ERAG 2013 summer peak model (2008 release) power flow case. This power flow case encompasses the entire Eastern Interconnection system including lines, transformers, phase shifters, and DC ties. CRA has modified this power flow case based on transmission update reports from the various ISO/RTOs and utilities. Monitored constraints originate in the NERC Book of Flowgates.

For constraints monitored for their thermal limit violations, limits are modified with respect to the power flow to reflect transmission upgrades. For constraints enforced for stability purposes, CRA uses the limits obtained from the sources above. Furthermore, flows on all lines with a nominal rating of 345kV and above within the PJM and TVA footprint are monitored.

Flowgates specifically for the EKPC region are listed in Table B1. The limits for these flowgates shown in Table B1 are further adjusted (reduced) to account for Transmission Reliability Margin ("TRM"), as listed in Table B2.

Table B1: NERC Flowgates for the EKPC Region

Flowgate ID	Monitored Element	Contingent Element	Summer Limit (MW)	Winter Limit (MW)
1608	5WOLF -1 161 - 5RUSSCOJ 161 Ckt 1		265	265
1624	5SUMME-1 161 - 5SUMSHAT 161 Ckt 1	5SUMME-1 161 - 5SUMSHAD 161 Ckt 1	223	223
1625	5SUMME-1 161 - 5SUMSHAD 161 Ckt 1	5SUMME-1 161 - 5SUMSHAT 161 Ckt 1	327	327
1626	5WOLF -1 161 - 5RUSSCOJ 161 Ckt 1	5WOLF -1 161 - 5WAYNE-1 161 Ckt 1	327	327
1627	5WOLF -1 161 - 5RUSSCOJ 161 Ckt 1	8PHIPP-1 500 - 8POCKETN 500 Ckt 1	327	327
1628	5WOLF -1 161 - 5RUSSCOJ 161 Ckt 1	8PHIPP-1 500 - 8VOLUN-1 500 Ckt 1	327	327
1649	7AVON 345 - 4AVON 138 Ckt 1		432	434
1650	7AVON 345 - 4AVON 138 Ckt 1	05BROADF 765 - 05BAKER 765 Ckt 1	522	581
1651	4AVON 138 - 4BBORO T 138 Ckt 1	05BROADF 765 - 05BAKER 765 Ckt 1	428	428
1652	4AVON 138 - 4BBORO T 138 Ckt 1	4AVON 138 - 4AVON-R 138 Ckt 1	428	428
1654	4MARION 138 - 5MARION 161 Ckt 1	7ALCALDE 345 - 7BROWN N 345 Ckt 1	232	232
1655	7AVON 345 - 4AVON 138 Ckt 1	05CULLOD 765 - 05WYOMIN 765 Ckt 1	522	581
1662	5BEATTYV 161 - 5DELVINT 161 Ckt 1	5LR TAP 161 - 5W IRVIN 161 Ckt 1	200	204
2096	5BLUE LK 161 - 5CEDARIN 161 Ckt 1	06CLIFTY 345 - 7TRIMBLE 345 Ckt 1	284	284
2130	4SPKNTR1 138 - 4KENTON 138 Ckt 1		227	227
2245	5BLUE LK 161 - 5CEDARIN 161 Ckt 1	05BROADF 765 - 05BAKER 765 Ckt 1	284	284
2277	4AVON-R 138 - 4LOUDON 138 Ckt 1	7GHENT 345 - 7W LEXNG 345 Ckt 1	274	274
2284	5BLUE LK 161 - 5CEDARIN 161 Ckt 1		228	228
2297	5ELIHU 161 - 5COOPER 161 Ckt 1		228	228
2482	4MARION 138 - 5MARION 161 Ckt 1		192	192
2483	4AVON-R 138 - 4LOUDON 138 Ckt 1		221	221
2488	5BLUE LK 161 - 5CEDARIN 161 Ckt 1	7GHENT 345 - 7W LEXNG 345 Ckt 1	284	284
2565	5BLUE LK 161 - 5CEDARIN 161 Ckt 1	05CULLOD 765 - 05WYOMIN 765 Ckt 1	284	284

Table B2: TRM Adjustments for EKPC Flowgates

Flowgate	Required TRM (MW) For Reserve-Sharing	
	Status Quo Case	Join PJM Case
Wolf Creek - Russell Jct 161	42	42
Avon 345/138 xfmr	25	25
Avon 345/138 xfmr (FLO) Baker-Broadford 765	25	25
Avon-Boonsboro T 138 (FLO) Baker-Broadford 765	12	12
Avon-Boonsboro T 138 (FLO) Avon-Loudon 138	10	10
Avon 345/138 xfrm (flo) Culloden-Wyoming 765 kV	25	25
Boone Co-Longbranch 138 kV	31	31
Spurlock-Kenton 138	2	2
Cooper2-Elihu 161	65	65
Summer-5Summer&Summer-Sshadt	19	4
Wolf Crk-Russell Jct & Wolf Crk-WayneCo	42	42
Wolf Crk-Russell Jct & PhippsBnd-Pocket 500 KV	46	46
Wolf Crk-Russell Jct & PhippsBnd-Vol 500 KV	44	44
Marion 138/161 flo Brown N - Alcade 345	20	20
Marion 138/161 kv xfmr	14	14

B.4 LOAD INPUTS

For each load-serving entity, GE MAPS requires an annual forecast of peak load and total energy, and an hourly load profile.

For peak load and energy forecasts, CRA uses the latest FERC-714 load forecast data available for each load-serving entity where available. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. For PJM, the load forecast is derived from the 2011 PJM load forecast. If any of the forecasts do not project load through 2017, CRA uses the average growth rate by forecast area to extrapolate the peak load and energy forecast through 2017. For this study, CRA froze the load growth outside of the area of focus in years after 2013, so as to obviate the need to evaluate generation build patterns in those regions.

Hourly load profiles are drawn from hourly actual demand, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions.[23] These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape for each company for each forecast year.

The peak load and energy forecast for EKPC is shown in Table B3.

23 It is important that all hourly load profiles use the same year for all areas It is also important that the hourly load profiles and hourly wind profiles are time-synchronized, especially for high wind potential areas. This is because both load and wind are heavily correlated to weather patterns. CRA uses 2006 data for both hourly load profiles and wind profiles, as both load profiles and hourly wind profiles are available for this year.

Table B3: Peak Load and Energy Forecast for EKPC

EKPC Forecast \ Year	2013	2017	2022
Peak Load Summer (MW)	2263	2402	2638
Peak Load Winter (MW)	3034	3245	3544
Energy (MWh)	12977020	13890650	15172903

*Peak Load is before DSM, Energy is after DSM. DSM will be modeled explicitely as price responsive dispatchable demands

B.5 Thermal Unit Characteristics

GE MAPS includes a detailed model of thermal generation in order to accurately simulate operational characteristics and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology type), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.[24]

The CRA generation database reflects unit-specific data for each unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel, and size are used. Table B4 shows these generic assumptions.

24 Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include but are not limited to summer/winter capacity, full load heat rates and emissions data.

Table B4: Generic Characteristics for Thermal Units

Type	Size	Variable O & M ($ / MWh)	Fixed O & M ($ / kW-year)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Forced Outage Length (Days)	Heat Rate Shape
Combined Cycle	All	2.50	21	1.75	7.78	2	4 blocks: 50% capacity @ 113% FLHR, 67% capacity @ 75% FLHR, 83% capacity @ 86% FLHR, and 100% capacity @ 100% FLHR
Combustion Turbine *1	< 50 MW	10.00	10	2.46	4.92	1	1 block: 100% capacity @ 100% FLHR
	> 50 MW			2.49	6.66		
Steam Turbine Coal *2	< 100 MW	5.00	35	3.32	8.73	7	4 blocks: 50% capacity @ 106% FLHR, 65% capacity @ 90% FLHR, 95% capacity @ 95% FLHR, and 100% capacity @ 100% FLHR
	100 - 200 MW	4.00		3.93	8.26		
	200 - 600 MW	3.00		4.36	9.2		
	> 600 MW	2.00		4.36	9.2		
Steam Turbine Gas/Oil *3	< 100 MW	6.00	35	2.35	6.78	2	4 blocks: 25% capacity @ 118% FLHR, 50% capacity @ 90% FLHR, 80% capacity @ 95% FLHR, and 100% capacity @ 100% FLHR
	100 - 200 MW	5.00		3.14	11.96		
	200 - 600 MW	4.00		3.05	13.01		
	> 600 MW	3.00		3.03	14.97		

*1 VOM includes startup cost
*2 Supercritical units have a different heat rate shape
*3 Supercritical units have a different heat rate shape

The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. Heat rate data is drawn from prior ES&D databases where available, the Ventyx Energy Velocity Database, and other publicly available sources. For newer plants, heat rates are based on industry averages for the technology of the unit. The NERC Generation Availability Data System (GADS) database is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available. The Fixed O&M values include an estimate of $1.50/kW-yr for insurance and 10% of base Fixed O&M (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

Table B5 shows the CRA assumptions for the EKPC units. For EKPC coal units the minimum up time is assumed to be 96 hours (4 days) and minimum down time was assumed to be 24 hours (1 day). For all other coal units modeled, the assumption is 24 hours for minimum up time and 12 hours for minimum downtime. Also Cooper 2 unit is assumed to be a must-run unit for voltage stability.

Table B5: EKPC Units

Unit Name	Summer Capacity (MW)	Winter Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Unit Type	Note
Cooper 1	116	116	9920	Coal (STc)	Retires 2015
Cooper 2*	222.5	222.5	10105	Coal (STc)	Must run unit
Dale 1	23	23	11900	Coal (STc)	Retires 2015
Dale 2	23	23	11900	Coal (STc)	Retires 2015
Dale 3	74	75	11227	Coal (STc)	Retires 2015
Dale 4	75	75	11093	Coal (STc)	Retires 2015
H L Spurlock 1	300	300	10042	Coal (STc)	
H L Spurlock 2	510	510	9900	Coal (STc)	
H L Spurlock 3	268	268	9592	Coal (STc)	
H L Spurlock 4	268	268	9592	Coal (STc)	
New CC at Smith	250	275	7100	CC	COD 2016
J K Smith 1	104	142	11133	GT	
J K Smith 2	104	142	11133	GT	
J K Smith 3	104	142	11133	GT	
J K Smith GT 4	74	98	10670	GT	
J K Smith GT 5	74	81	11007	GT	
J K Smith GT 6	74	81	11007	GT	
J K Smith GT 7	74	81	11007	GT	
J K Smith GT 9	78	101	8869	GT	
J K Smith GT 10	78	101	8869	GT	
Bavarian Landfill	3.2	3.2	9000	Refuse (STr)	
Laurel Ridge Landfill	4	4	9000	Refuse (STr)	
Green Valley Landfill	3.2	3.2	9000	Refuse (STr)	
Pearl Hollow Landfill	2.4	2.4	9000	Refuse (STr)	
Pendleton County Landfill	3.2	3.2	9000	Refuse (STr)	
Mason County Landfill	1.6	1.6	9000	Refuse (STr)	

B.6 Nuclear Units

CRA assumes that nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each unit are drawn from the Energy Central database of unit outages. Nuclear plants do not contribute to quick-start or spinning reserves. The model includes refueling and maintenance outages for each nuclear plant. For the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. For this specific study, no nuclear retirements are anticipated. Watts Bar Unit 2 of TVA is assumed to be online in 2013. The Bellefonte units are not included.

B.7 Hydro Units

GE MAPS has special provisions for modeling hydro units, and requires specification of a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Plant capacity data is drawn from the NERC ES&D database. Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-

1998. CRA assumes that hydro plants are able to provide spinning reserves of up to 50% of plant capacity. The Laurel Hydro plant is modeled using hourly 2006 data, as provided by EKPC.

B.8 RENEWABLE RESOURCES

Individual wind resources are modeled as low-cost ($1/MWh) dispatchable energy resources with either a fixed annual capacity factor of 30% or a fixed wind shape taken from NREL data. All PJM wind units are assigned fixed wind shapes from the NREL sites they are mapped to on a unit-by-unit basis. All non-PJM wind units in areas surrounding PJM (MISO, TVA, NYISO) are also assigned fixed wind shapes but on a region-by-region aggregate mapping to NREL sites for the corresponding region. All non-PJM wind units in areas further from PJM (Ontario, New England, VACAR, SPP etc) are modeled with a fixed 30% capacity factor.

B.9 CAPACITY ADDITIONS AND RETIREMENTS

CRA adds new generation based on projects in development or advanced stages of permitting, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. CRA also adds generic capacity where economically justified, or as required to maintain resource adequacy per installed capacity reserve margins published by various NERC regions.

CRA tracks planned and announced retirements from power pool publications and trade press announcements and retires units accordingly with the exception of nuclear units.

For this study, Cooper 1 and Dale 1 through 4 were assumed to retire as of the end of 2015. A 250MW CC unit is assumed to come online at the Smith bus in 2016.

B.10 ENVIRONMENTAL REGULATIONS

For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NOx reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NOx or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. NOx emission rates are drawn from the CEMS data filed with the US Environmental Protection Agency.

CRA modeled NOx and SO_2 allowances based on the Cross-State Air Pollution Rule ("CSAPR") finalized July 6, 2011 and the Proposed Air Toxics Rule / Utility MACT (maximum achievable control technology) issued December 2011. CO_2 emissions based on the Regional Greenhouse Gas Initiative (RGGI) for northeastern states are also modeled.

CSAPR pollution control caps on SO_2 divide the covered states into 2 groups and annual SO2 reductions will occur in two phases, most likely in 2013 and tightened in 2014. All states will be required to reduce SO_2 emissions with Phase I in 2013. In 2014, only states in control Group 1 will be forced to reduce emission to the Phase II cap. Figure B1-1 shows state-level coverage of both groups.

Figure B1-1: States regulated under CSAPR SO2 caps

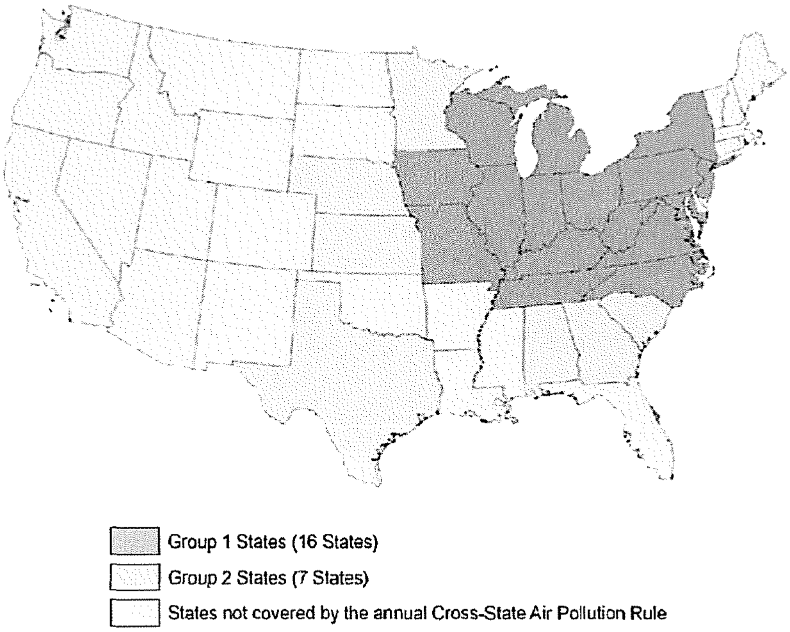

Figure B1-2 shows the coverage of the NO_X programs. States in green and blue are required to reduce emissions as part of the NO_X annual program and states in green and yellow are required to reduce emissions under the NO_X seasonal program.

Figure B1-2 CSAPR NOX Geographical Coverage

B.11 External Region Supply

CRA explicitly models the U.S. portion of the Eastern Interconnection and the Canadian provinces of Ontario, Manitoba and Saskatchewan. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as fixed flows, based on the flows in the power flow model.[25]

B.12 Dispatchable Demand (Interruptible Load)

The presence of demand response is important to energy and installed capacity prices. The value of energy to interruptible loads caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. CRA uses values for interruptible load, and demand side management reduction in peak from the NERC ES&D database. This interruptible load is spread among load areas based on their load share of the

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25 Typically CRA would model these as price sensitive supply curves derived from historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. For this study CRA freezes the flows on the DC ties to eliminate any external noise that a price sensitive supply curve may create.

total system load. The dispatchable demand is implemented as generators with a dispatch price of \$600/MWh for the first block (50% of area dispatchable demand) and \$800/MWh for the second block (the remaining 50% of area dispatchable demand).

These units rarely run, as the high prices they require indicate a supply shortfall and prompt economic new entry. Thus they play an insignificant role in the energy market, but can play an important role in the capacity market. If these loads can be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

B.13 Market Model Assumptions

B.13.1 Marginal Cost Bidding

All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel Variable O&M plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

B.13.2 Operating Reserve Requirement

Operating reserves are based on requirements instituted by each reliability region. These requirements are typically based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand, depending on the region. Operating reserves are typically split into spinning reserves and non-spinning reserves (quick starts). The reserves market affects energy prices, since units that are providing these reserves cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled.

For the TEE Contingency Reserve Sharing Group (TCRSG), which includes EKPC, TVA and LGE/KU, requirements for spinning reserves and quick start reserves are treated separately as two types of constraints that need to be met simultaneously with the requirement to balance generation and loads. GE MAPS is used to co-optimize commitment and dispatch for meeting spinning reserve requirements and quick start requirements.

The TCRSG requirements for operating reserves are 100% of the first largest contingency (largest committed unit). This requirement is allocated amongst the group members based on each member's load share ratio. For 2013 through 2022, this requirement is assumed to be 1250MW (Brown Ferry nuclear).

For the *Status Quo Case*, EKPC is assumed to carry 92 MW of the TCRSG requirement and the rest is carried by TVA and LGE based on the load ratio from the forecast load as shown in

Table B7.[26] 50% of these operating reserve requirements are carried as spinning reserves and the rest as non-spinning reserves. EKPC also carries an additional 2% of their daily peak load as spinning reserves.

Table B7: EKPC Share of Operating Reserves (Load Ratio)

Area \ Year	Load Ratio		
	2013	2017	2022
LGEE	18.5%	18.4%	18.4%
TVA	81.5%	81.6%	81.6%

In the *Join PJM Case*, these EKPC operating reserve requirements are replaced with PJM assumptions. The additional spinning reserve equal to 2% of the daily peak load is no longer carried by EKPC. TVA and LGE share the entire TCRSG requirements for operating reserve, split by the load ratio shown in Table B7. The PJM Synchronized Reserve Market currently has two Synchronized Reserve Zones, the RTO Synchronized Reserve Zone and the Southern Synchronized Reserve Zone. The RTO Synchronized Reserve Zone contains the Mid-Atlantic Sub Zone, which can be segregated from the rest of the RTO Synchronized Reserve Zone by the AP South reactive transfer interface. The RTO Synchronized Reserve Zone requirement is calculated as the larger of the RFC minimum requirement of synchronized reserves (a minimum Synchronized Reserve requirement of at least 50% of the Balancing Authority's most severe single contingency) or the largest contingency in RTO Synchronized Reserve Zone. The Mid-Atlantic sub zone requirement is equal to the largest contingency in Mid-Atlantic region. The Southern Synchronized Reserve Zone is exclusively for the Dominion Virginia Power control area, and the requirements are based on VACAR rules where reserves equal to 1.5 times the largest unit in VACAR is maintained by VACAR members.

In modeling supply for operating reserves within the area of interest, the spinning and quick start capabilities of generating units are specified on a unit-type basis. For spinning reserves, the maximum level of spinning reserve capability of a thermal unit is set to be the least of the unit's capacity above minimum block, 50% of the unit's capacity, and the unit's ramp rate (in MW/min) times 10. This is because spinning reserves are typically needed to meet the requirements within 10 minutes. Assumed ramp rates are: 10 MW/min for combine cycle units, 6 MW/min for gas and oil steam units, and 3 MW/min for coal units. For hydro plants in general, spinning reserve capability is set on a monthly basis at 50% of the difference between plant's capacity in that month and its average for that month hourly output. No spinning capability is assigned to nuclear generators.

26 The load ratio share basis uses the coincident peak load levels of all LSEs in each Party's Balancing Authority Area for the 12-month period ending on October 1 of each calendar year.

B.13.3 Transmission Losses

Transmission losses are modeled at marginal rates over the entire Eastern Interconnection. The reference bus is fixed.

B.14 Seams Charges and Wheeling Rates

Seam charges are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, seams charges are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Seams charges are considered for both commitment and dispatch of generating units; however, the charges between any two areas may be different for commitment than for dispatch. For the current analysis, commitment is done on a pool by pool basis, and dispatch is done by the system as a whole, subject to seams charges. The seams charge modeled for dispatch include both the actual wheeling rates defined in transmission tariffs, and a second value, which is referred to as friction, representing the hurdles caused by market inefficiencies. The wheeling rates are based on non-firm hourly rates.

Table B8 gives an overview of the seams charges used for dispatch between EKPC, PJM, TVA, and other neighboring control areas.

Table B8: Seams Charges ($ / MWh)

	From Commitment Pool	To Commitment Pool	Dispatch Seams Charge Wheel	Friction*	Total
	Day 2:				
1	MISO	PJM	0	2	2
	MISO	All Other	5	3	8
2	PJM	MISO	0	2	2
	PJM	All Other	3	3	6
3	SPP *	All	2	3	5
4	NE	NY	0	3	3
	NE	All but NY	7	3	10
5	NY	NE	0	3	3
	NY	HQ	2	3	5
	NY	OH	4	3	7
	NY	PJM	5	3	8
	Non-Day 2:				
6	VACAR-Duke/CPL	All	2	5	7
7	Entergy	All	3	5	8
8	FRCC	All	3	5	8
9	SOCO	All	5	5	10
10	TVA	All	3	5	8
11	OH	All	2	5	7
12	HQ	All	8	5	13
13	NB/Maritimes	All	3	5	8

Other Hurdles		Dispatch Seams Charge Wheel	Friction*	Total	Commit Hurdle
Cleco Power	*SPP*	3	5	8	10
SPP	*Cleco Power*	2	3	5	10
Cleco Power	*Entergy*	3	5	8	NA
AECI	*Entergy*	3	5	8	10
Entergy	*AECI*	3	5	8	10
AECI	*All Other*	3	5	8	NA
Intra-FRCC	*Intra-FRCC*	3	5	8	10
Duke/CPL/SCG	*Duke/CPL/SCG*	2	5	7	10
NWE	*MISO/WAPA*	4	5	9	10
WAPA	*NWE/SASK/MISO*	4	5	9	10
WAPA	*SPP*	4	5	9	NA
MISO	*NWE/WAPA/SASK*	5	3	8	10
SASK	*WAPA/MH/MISO*	6	5	11	10
MH	*MISO*	0	5	5	10
MH	*SASK*	9	5	14	10
MH	*OH*	9	5	14	NA
MISO	*MH*	0	3	3	10
Intra-Maritimes	*Intra-Maritimes*	3	5	8	10
PJM	*LG&E*	3	3	6	10
LG&E	*PJM*	2	5	7	10
LG&E	*EKPC*	2	5	7	10 **
LG&E	*Others*	2	5	7	NA
PJM	*EKPC*	3	3	6	10 **
EKPC	*LG&E*	0	5	5	10 **
EKPC	*PJM*	0	5	5	10 **
EKPC	*Others*	0	5	5	NA **

$3 dispatch friction hurdle for flows out of active managed markets
Non market areas not expected to be as efficient hence higher dispatch friction hurdle
Average of on- and off-peak non-firm hourly PTP rate used in addition to friction
PJM to/from MISO friction set at $2 given extensive seams management process
** Day 2 planned*
*** These paths/hurdles are eliminated in the Change Case, EKPC is a part of PJM*

B.15 Fuel Prices

GE-MAPS uses monthly fuel prices for each thermal unit. The fundamental assumption of behavior in competitive markets is that generators will bid their marginal cost into the energy market. The marginal cost for a plant fueled by natural gas is the opportunity cost of fuel purchased (in addition to non-fuel variable O&M and environmental adders), or the spot price of natural gas at the location closest to the plant. CRA therefore uses forecasts of spot prices at regional hubs, and refines these on the basis of historical differentials between price points and their associated hubs. For fuel oil CRA uses estimates of the price delivered to generators on a regional basis.

The remainder of this section discusses the fuel price forecast methodology. The fuel forecast for gas and oil is based on NYMEX forwards from January 23, 2012 and EIA's Annual Energy Outlook (AEO) long term forecasts from AEO 2012 Early Release Edition, issued January 23, 2012. Coal prices are derived from NEEM. A description of NEEM is included in Section B.17.

Specific oil and gas price forecasts used in this study are provided in the next sections.

B.16 Natural Gas and Fuel Oil Price Forecast

B.16.1 Natural Gas Forecast

Principal Drivers

The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast

In the near term, the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of the closing of January 23, 2012. For later years, the forecast follows the AEO long term trend. Figure B2 shows the CRA Base Scenario forecast for natural gas prices at Henry Hub.

Regional Prices

CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

Basis Differentials by Region

CRA recognizes multiple pricing points within each region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this timeframe, CRA derives monthly differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

The pricing points used and their relation to the NYMEX Clearport futures are shown in Table B9.

Table B9: Pricing Points and NYMEX Hubs

Region	States	Natural Gas Pricing Point	Weights	Deriving Source - Summer (NYMEX Clearport hubs)
Eastern New York	NY (East)	Transco Zone 6 (NYC)	1	Direct NYMEX Clearport Hub
Western New York	NY (West)	Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
		Iroquois	0.5	Regressed to Michigan and Transco Zone 6 NYC
PJM	DC, DE, MD, NJ, PA (East)	Texas Eastern Zone M-3	0.5	Direct NYMEX Clearport Hub
		Transco Zone 6 (non-NYC)	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
Appalachia	KY, OH, PA (West), WV	Columbia Gas Appalachia	0.25	Direct NYMEX Clearport Hub
		Leidy Hub	0.25	Regressed to Transco Zone 6 NYC
		Dominion (Appalachia)	0.5	Direct NYMEX Clearport Hub
Southern New England	CT, MA, RI	Algonquin City Gates	1	Regressed to Transco Zone 6 NYC
Northern New England	ME, NH, VT	Tennessee Zone 6	0.5	Regressed to Texas Eastern Zone M 3 and Transco Zone 6 NYC
		Dracut	0.5	Regressed to Dominion (Appalachia)
Iowa-Missouri-Nebraska	IA, MO, NE	Ventura	1	Direct NYMEX Clearport Hub
Florida	FL	Florida CityGate	1	Direct NYMEX Clearport Hub
Mid-Continent	KS, OK	NGPL Mid-Continent Basis	1	Direct NYMEX Clearport Hub
Midwest	IL, IN, MI, MN, ND, SD, WI	Chicago Basis	0.5	Direct NYMEX Clearport Hub
		Michigan Basis	0.5	Direct NYMEX Clearport Hub
Ontario-East	ON (East)	Niagara	1	Regressed to Dominion (Appalachia) and Michigan Basis
Ontario-West	ON (West)	Dawn, Ontario	1	Regressed to Michigan Basis
South Atlantic East Region 1	VA	Texas Eastern Zone M-3	0.8	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.2	Regressed to Transco Zone 3
South Atlantic East Region 2	NC	Texas Eastern Zone M-3	0.5	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.5	Regressed to Transco Zone 3
South Atlantic East Region 3	SC	Texas Eastern Zone M-3	0.3	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.7	Regressed to Transco Zone 3
South Atlantic East Region 4	GA	Texas Eastern Zone M-3	0.1	Direct NYMEX Clearport Hub
		Florida Gas, Mobile Bay	0.9	Regressed to Transco Zone 3
South Atlantic East Region 5	AL, MS	Transco Zone 4	0.5	Regressed to Transco Zone 3
		Florida Gas, Mobile Bay	0.5	Regressed to Transco Zone 3
South Atlantic East Region 6	AR, TN	Texas Eastern Zone M-1	0.5	Regressed to East LA Basis
		Henry Hub	0.5	Direct NYMEX Clearport Hub
South Atlantic South	LA	Henry Hub	1	Direct NYMEX Clearport Hub

Local Delivery Charges

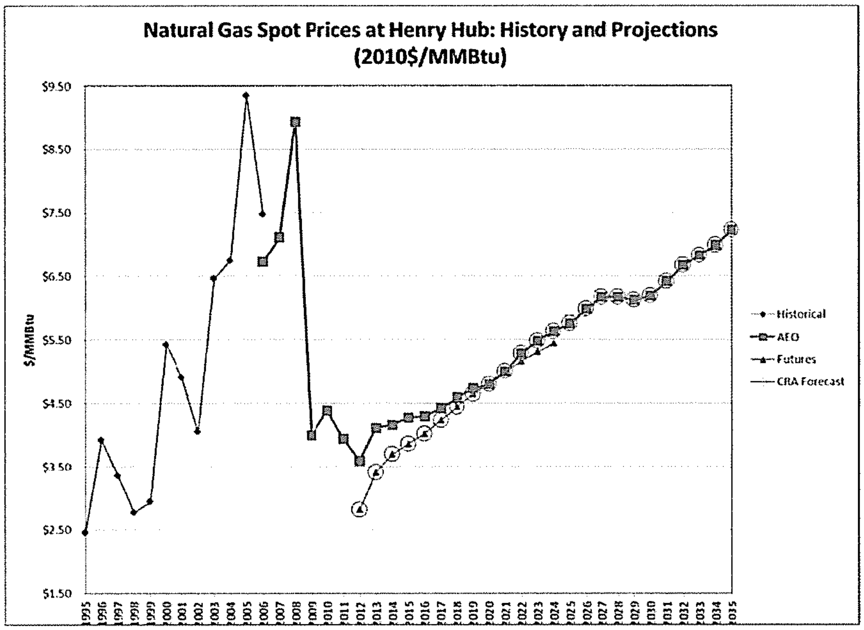
Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies (LDC). CRA estimates this local component at $0.07/MMBtu for all units. For older units, CRA estimates extra LDC charges derived from AGA statistics, generally on a state by state basis.[27]

Seasonal Pattern

Natural gas prices are varied seasonally based on NYMEX futures data in the near term. In the long term, the seasonal pattern for the last available year is repeated for each year.

Figure B2: Henry Hub Prices, History, and Forecast (in Real 2010 $/MMBtu)

27 States such as New York or Pennsylvania are split into multiple regions Pennsylvania is split into east and west for natural gas price forecasting purposes.



Gas Price Forecast Summary

Table B10 contains monthly gas price forecasts for the Base Scenario for Kentucky, Tennessee, Ohio, and Pennsylvania for the years modeled.

Table B10: Monthly Natural Gas Price Forecasts (in real $2010 / MMBtu)

Year	Month	Kentucky		Tennesee		Ohio		East-PA		West-PA	
		No LDC	With LDC	No LDC	With LDC	No LDC	With LDC	No LDC	With LDC	No LDC	With LDC
2013	Jan	$3.45	$4.12	$3.75	$4.11	$3.45	$3.97	$4.58	$4.69	$3.45	$3.56
	Feb	$3.45	$4.12	$3.65	$4.01	$3.45	$3.96	$4.56	$4.66	$3.45	$3.56
	Mar	$3.38	$4.04	$3.60	$3.96	$3.38	$3.89	$3.54	$3.65	$3.38	$3.48
	Apr	$3.39	$4.06	$3.46	$3.82	$3.39	$3.90	$3.48	$3.59	$3.39	$3.50
	May	$3.40	$4.07	$3.47	$3.83	$3.40	$3.91	$3.49	$3.60	$3.40	$3.51
	Jun	$3.43	$4.09	$3.50	$3.85	$3.43	$3.93	$3.51	$3.62	$3.43	$3.53
	Jul	$3.46	$4.12	$3.53	$3.88	$3.46	$3.97	$3.55	$3.65	$3.46	$3.57
	Aug	$3.47	$4.13	$3.54	$3.90	$3.47	$3.98	$3.56	$3.67	$3.47	$3.58
	Sep	$3.47	$4.13	$3.54	$3.89	$3.47	$3.98	$3.56	$3.66	$3.47	$3.57
	Oct	$3.50	$4.16	$3.57	$3.92	$3.50	$4.01	$3.59	$3.69	$3.50	$3.61
	Nov	$3.45	$4.11	$3.84	$4.19	$3.45	$3.96	$3.48	$3.59	$3.45	$3.56
	Dec	$3.66	$4.31	$4.02	$4.37	$3.66	$4.16	$4.25	$4.35	$3.66	$3.76
	Average	$3.46	$4.12	$3.62	$3.98	$3.46	$3.97	$3.76	$3.87	$3.46	$3.57
2017	Jan	$4.48	$5.10	$4.68	$5.02	$4.48	$4.96	$5.61	$5.71	$4.48	$4.58
	Feb	$4.44	$5.06	$4.53	$4.87	$4.44	$4.92	$5.42	$5.52	$4.44	$4.54
	Mar	$4.33	$4.95	$4.44	$4.78	$4.33	$4.81	$4.34	$4.43	$4.33	$4.43
	Apr	$4.24	$4.86	$4.24	$4.58	$4.24	$4.72	$4.22	$4.32	$4.24	$4.34
	May	$4.24	$4.86	$4.25	$4.58	$4.24	$4.72	$4.22	$4.32	$4.24	$4.34
	Jun	$4.26	$4.88	$4.26	$4.60	$4.26	$4.73	$4.24	$4.34	$4.26	$4.36
	Jul	$4.28	$4.90	$4.29	$4.62	$4.28	$4.76	$4.27	$4.36	$4.28	$4.38
	Aug	$4.30	$4.92	$4.31	$4.64	$4.30	$4.78	$4.28	$4.38	$4.30	$4.40
	Sep	$4.30	$4.92	$4.31	$4.64	$4.30	$4.78	$4.28	$4.38	$4.30	$4.40
	Oct	$4.33	$4.94	$4.33	$4.66	$4.33	$4.80	$4.31	$4.41	$4.33	$4.43
	Nov	$4.42	$5.04	$4.62	$4.95	$4.42	$4.90	$4.78	$4.87	$4.42	$4.52
	Dec	$4.63	$5.25	$4.81	$5.14	$4.63	$5.11	$5.59	$5.69	$4.63	$4.73
	Average	$4.36	$4.97	$4.42	$4.76	$4.36	$4.83	$4.63	$4.73	$4.36	$4.45
2022	Jan	$5.61	$6.18	$5.79	$6.10	$5.61	$6.05	$7.00	$7.10	$5.61	$5.70
	Feb	$5.57	$6.14	$5.61	$5.91	$5.57	$6.01	$6.77	$6.86	$5.57	$5.66
	Mar	$5.44	$6.01	$5.50	$5.81	$5.44	$5.88	$5.42	$5.52	$5.44	$5.53
	Apr	$5.26	$5.84	$5.23	$5.53	$5.26	$5.70	$5.24	$5.33	$5.26	$5.36
	May	$5.27	$5.84	$5.23	$5.54	$5.27	$5.71	$5.24	$5.33	$5.27	$5.36
	Jun	$5.28	$5.86	$5.25	$5.55	$5.28	$5.72	$5.26	$5.35	$5.28	$5.38
	Jul	$5.32	$5.88	$5.28	$5.58	$5.32	$5.75	$5.29	$5.38	$5.32	$5.41
	Aug	$5.34	$5.91	$5.31	$5.61	$5.34	$5.78	$5.32	$5.41	$5.34	$5.43
	Sep	$5.34	$5.91	$5.31	$5.61	$5.34	$5.78	$5.32	$5.41	$5.34	$5.44
	Oct	$5.38	$5.95	$5.35	$5.65	$5.38	$5.82	$5.36	$5.45	$5.38	$5.47
	Nov	$5.49	$6.06	$5.67	$5.97	$5.49	$5.93	$5.92	$6.01	$5.49	$5.58
	Dec	$5.73	$6.30	$5.88	$6.18	$5.73	$6.17	$6.91	$7.00	$5.73	$5.82
	Average	$5.42	$5.99	$5.45	$5.75	$5.42	$5.86	$5.75	$5.85	$5.42	$5.51

B.16.2 Fuel Oil Price Forecast

Principal Drivers

The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast

Through 2012, the Base Scenario forecast is derived from the NYMEX futures prices for light sweet crude oil as of the closing of January 23, 2012. For subsequent years, as the futures market becomes less liquid, the forecast follows that of the AEO long term trend.

Regional Prices

CRA forecasts prices for fuel oil #2 and #6 (1% sulfur) by US census region. This forecast is prepared in two steps. First CRA uses a regression model calibrated to historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. Second, historical basis multipliers for each of the census region are applied against the Mid-Atlantic Census region (which includes New York Harbor).

Seasonal Pattern

Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term, and based on historical monthly patterns in the longer term.

Oil Price Forecast Summary

Table B11 contains monthly oil price forecasts for the Base Scenario for Kentucky, Tennessee, Ohio, and Pennsylvania for the years to be modeled.

Table B11: Monthly Fuel Oil Price Forecasts (in real $2010 / MMBtu)

Year	Month	Kentucky		Ohio		Pennsylvania		Tennesee	
		FO2	FO6	FO2	FO6	FO2	FO6	FO2	FO6
2013	Jan	$23.33	$9.37	$23.82	$12.43	$22.58	$12.08	$23.33	$9.37
	Feb	$23.33	$9.38	$23.83	$12.44	$22.58	$12.09	$23.33	$9.38
	Mar	$22.31	$9.39	$22.79	$12.45	$21.60	$12.10	$22.31	$9.39
	Apr	$22.19	$9.39	$22.67	$12.46	$21.48	$12.10	$22.19	$9.39
	May	$21.19	$9.40	$21.65	$12.47	$20.52	$12.11	$21.19	$9.40
	Jun	$20.95	$9.41	$21.39	$12.47	$20.28	$12.12	$20.95	$9.41
	Jul	$21.00	$9.41	$21.45	$12.48	$20.33	$12.13	$21.00	$9.41
	Aug	$21.37	$9.42	$21.82	$12.49	$20.69	$12.14	$21.37	$9.42
	Sep	$21.97	$9.43	$22.44	$12.50	$21.27	$12.15	$21.97	$9.43
	Oct	$22.24	$9.43	$22.72	$12.51	$21.53	$12.15	$22.24	$9.43
	Nov	$22.49	$9.44	$22.97	$12.52	$21.77	$12.16	$22.49	$9.44
	Dec	$22.84	$9.45	$23.33	$12.53	$22.11	$12.17	$22.84	$9.45
	Average	$22.10	$9.41	$22.57	$12.48	$21.40	$12.12	$22.10	$9.41
2017	Jan	$27.88	$11.26	$28.48	$14.93	$26.99	$14.50	$27.88	$11.26
	Feb	$27.89	$11.26	$28.48	$14.94	$27.00	$14.51	$27.89	$11.26
	Mar	$26.68	$11.27	$27.24	$14.95	$25.82	$14.52	$26.68	$11.27
	Apr	$26.53	$11.28	$27.10	$14.96	$25.69	$14.53	$26.53	$11.28
	May	$25.35	$11.29	$25.89	$14.97	$24.54	$14.54	$25.35	$11.29
	Jun	$25.06	$11.29	$25.59	$14.98	$24.26	$14.55	$25.06	$11.29
	Jul	$25.12	$11.30	$25.65	$14.99	$24.32	$14.56	$25.12	$11.30
	Aug	$25.55	$11.31	$26.10	$15.00	$24.74	$14.57	$25.55	$11.31
	Sep	$26.27	$11.32	$26.83	$15.01	$25.44	$14.58	$26.27	$11.32
	Oct	$26.59	$11.32	$27.16	$15.02	$25.74	$14.59	$26.59	$11.32
	Nov	$26.88	$11.33	$27.46	$15.03	$26.03	$14.60	$26.88	$11.33
	Dec	$27.30	$11.34	$27.88	$15.04	$26.43	$14.61	$27.30	$11.34
	Average	$26.43	$11.30	$26.99	$14.98	$25.58	$14.56	$26.43	$11.30
2022	Jan	$29.37	$11.88	$30.00	$15.75	$28.43	$15.31	$29.37	$11.88
	Feb	$29.37	$11.89	$30.00	$15.76	$28.44	$15.32	$29.37	$11.89
	Mar	$28.10	$11.90	$28.70	$15.78	$27.21	$15.33	$28.10	$11.90
	Apr	$27.95	$11.90	$28.55	$15.79	$27.06	$15.34	$27.95	$11.90
	May	$26.71	$11.91	$27.28	$15.80	$25.86	$15.35	$26.71	$11.91
	Jun	$26.40	$11.92	$26.96	$15.81	$25.56	$15.36	$26.40	$11.92
	Jul	$26.46	$11.93	$27.03	$15.82	$25.62	$15.37	$26.46	$11.93
	Aug	$26.92	$11.94	$27.50	$15.83	$26.07	$15.38	$26.92	$11.94
	Sep	$27.68	$11.94	$28.27	$15.84	$26.80	$15.39	$27.68	$11.94
	Oct	$28.01	$11.95	$28.61	$15.85	$27.12	$15.40	$28.01	$11.95
	Nov	$28.32	$11.96	$28.92	$15.86	$27.42	$15.41	$28.32	$11.96
	Dec	$28.76	$11.97	$29.37	$15.87	$27.84	$15.42	$28.76	$11.97
	Average	$27.84	$11.92	$28.43	$15.81	$26.95	$15.36	$27.84	$11.92

B.16.3 Other Fuel Price Forecasts

Coal price forecasts are developed by the CRA NEEM model as described in the next section.

Coal prices will vary depending on the future policy outlook. For example, the anticipation of a policy with higher carbon prices will tend to lead to lower coal prices. Table B12 shows the forecasted coal prices for the base scenario for the EKPC coal plants.

Table B12: Annual Coal Price Forecasts (in real $2010 / MMBtu)

Unit \ Year	2013	2017	2022
Cooper 1	$ 2.78	Retired	
Cooper 2	$ 2.78	$ 2.88	$ 2.88
Dale 1	$ 2.78	Retired	
Dale 2	$ 2.78	Retired	
Dale 3	$ 2.78	Retired	
Dale 4	$ 2.78	Retired	
H L Spurlock 1	$ 2.45	$ 2.82	$ 2.82
H L Spurlock 2	$ 2.45	$ 2.82	$ 2.82
H L Spurlock 3	$ 2.25	$ 2.62	$ 2.62
H L Spurlock 4	$ 2.25	$ 2.62	$ 2.62

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Both wind and hydro plants do not have fuel prices. CRA assumes that the marginal cost is $1/MWh.

B.17 NEEM Forecast

The NEEM model is a long-term planning model that optimizes fuel and environmental compliance decisions based on the environmental scenario considered. NEEM is a linear program that minimizes total electrical system costs over a long time-horizon subject to meeting demand, reserve margin, and environmental/renewable targets. Output from CRA's North American Electricity and Environment Model (NEEM) is used to populate the MAPS model with plant-specific coal price inputs. Given that coal-fired generation is the target of many existing, pending and proposed environmental policies, the future coal selection at generating stations and the quantity of coal consumed nationally is heavily dependent upon the scenario modeled and the resultant retrofit decisions, generation levels, and new capacity additions.

NEEM contains a detailed treatment of coal supply, with 23 supply curves representing domestic production areas, imports, and different coal qualities (sulfur and Btu). These curves are built up from mine level data on production costs and annual production capability.

Coal units in the model choose coals based on the various coal options' characteristics and the plant-specific delivered price for each. The delivered prices are the sum of the mine-mouth prices and plant-specific transport costs. Each of the supply curves is divided into tranches of tonnages (typically 4 to 15 tranches). As demand rises, exhausting the annual supplies available at a given tranche, the market price for that coal rises accordingly. Mine-mouth prices for each coal type are determined by North American supply and demand. In addition, there are mine lifetime supply constraints applied to each cost tranche of each coal production area, simulating depletion. Mine depletion is of greatest relevance for the Central Appalachian production area where the total available resources are relatively small relative to annual consumption.

The individual coal supply curves have been constructed using mine level cost and available tonnage information from some 1000 mines. Costs include labor costs, permitting, and other factors.

Table B13 includes the quality parameters associated with each of the 23 coals included in the NEEM model.

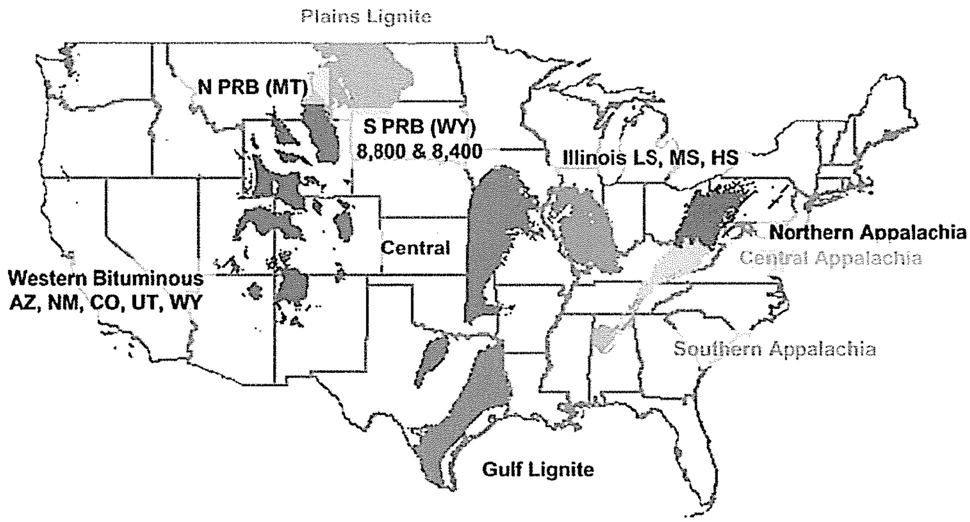
Table B13: Coal Quality Parameters

Coal	Rank	SO2 (lbs/MMBtu)	Hg (lbs/TBtu)	Btu per lb
Arizona Bituminous	Bituminous	0.93	4.2	10,915
Central Applachian, compliance	Bituminous	1.12	5.9	12,507
Central Applachian, high-sulfur	Bituminous	2.00	8.2	12,325
Central	Bituminous	4.92	12.7	12,174
Gulf Lignite	Lignite	3.37	10.8	6,840
Illinois Basin, low-sulfur	Bituminous	2.50	4.5	12,091
Illinois Basin, medium-sulfur	Bituminous	3.50	6.5	11,502
Illinois Basin, high-sulfur	Bituminous	5.00	6.3	11,665
Imports	Bituminous	1.00	5.5	12,000
Northern Appalachian, high-Btu / high-sulfur	Bituminous	4.07	12.5	12,938
Northern Appalachian, high-Btu / low-sulfur	Bituminous	2.44	12.3	12,840
Northern Appalachian, low-Btu / high-sulfur	Bituminous	3.77	20.9	11,516
Northern Appalachian, low-Btu / low-sulfur	Bituminous	1.76	16	12,098
New Mexico Bituminous	Bituminous	1.55	4.2	9,393
Plains Lignite	Lignite	2.30	10.8	6,585
PRB, Montana	Subbituminous	1.18	5.2	9,052
PRB, North	Subbituminous	0.83	7.1	8,400
PRB, South	Subbituminous	0.71	5.8	8,800
Colorado Bituminous	WesternBit	0.98	3.7	11,218
Utah Bituminous	WesternBit	1.28	4.1	11,790
Southern Appalachian	Bituminous	2.52	8.7	11,747
Wyoming Sub-bituminous	Subbituminous	1.14	3.7	9,185
Saskatchewan Lignite	Lignite	[redacted]	[redacted]	10,000

Not all plants are allowed to select from the full range of coals available in the model. Limitations on coal selection are a function of coal rank (bituminous, subbituminous, lignite) – NEEM requires a capital cost to change from bituminous to subbituminous, if a particular plant is not already able to burn subbituminous. Transportation access of various coals by each plant (e.g., rail access) also limits the selections.

Coal selection is regulated within the model through a plant-specific coal transportation cost matrix that matches plants to coals (and the cost of transport). The matrix represents the cheapest transportation option for each coal/plant pairing (rail, truck, or barge). The plant/coal-type transport cost entries are populated based on a proprietary forecast of the $/ton-mile cost of long-haul shipments and data about the types of coal burned at each plant.

Figure B4: Key Coal-Producing Regions in the United States



The relevant coal-related output from the NEEM model is a set of coal choices by the plants in the model, a plant-specific delivered coal price for each NEEM unit by year (for each coal burned), a schedule of pollution control retrofit decisions by unit, and also emissions allowance prices. Note that, to maintain consistency across coal units, NEEM-based coal prices apply to all coal units in the modeled footprint in both the *Status Quo* and *Join PJM Cases*.