SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

April 30, 2010

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PUBLIC SERVICE COMMISSION

Hand Delivered

Mr. Jeff DeRouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Case No. 2010-00043

Dear Mr. Derouen:

Enclosed for filing on behalf of Big Rivers Electric Company ("Big Rivers") are an original and nine (9) copies of Big Rivers' responses to the Supplemental Data Requests of Commission Staff and to the Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. ("KIUC"). An attachment to the response to Item 3 of KIUC's second set of data requests is being filed under seal pursuant to a petition for confidential treatment. The petition for confidential treatment is enclosed and is attached to the responses to the Commission Staff's supplemental data requests. A sheet noting that the attachment has been redacted is included with each of the copies of the responses to KIUC's second set of data requests.

Sincerely,

TAK

Tyson Kamuf

Cc: Attached Service List
David G. Crockett
Albert M. Yockey

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Service List
Case No. 2010-00043

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VERIFICATION

I, C. William Blackburn, Senior Vice President of Financial and Energy Services and Chief Financial Officer of Big Rivers Electric Corporation, verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

C William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 27th day of April, 2010.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-13

VERIFICATION

I, David G. Crockett, Vice President – System Operations of Big Rivers Electric Corporation, verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

David G. Crockett
David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David G. Crockett on this the 27th day of April, 2010.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-13

VERIFICATION

I, Ralph Luciani, Vice President, Charles River Associates, verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Ralph Luciani

DISTRICT OF COLUMBIA)

SUBSCRIBED AND SWORN TO before me by Ralph Luciani on this the 27th day of April, 2010.

Notary Public, District of Columbia
My Commission Expires October 14, 2012

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

VERIFICATION

I, Richard Doying, Vice-President of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this Verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Richard Doying

STATE OF INDIANA)
COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Richard Doying on this 28th day of April, 2010.

Dorothy M. Shute

Dorothy Shute
Notary Public
My Commission Expires 5-8-17

DOROTHY M. SHUTE
Notary Public, State of Indiana
My County of Residence: Hendricks
My Commission Expires May 8, 2017

VERIFICATION

I, Clair J. Moeller, Vice-President of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this Verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Clair J. Moeller

STATE OF INDIANA)
COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Clair J. Moeller on this 28th day of April, 2010.

Dorothy M. Shute

Dorothy Shute
Notary Public
My Commission Expires 5-8-17

DOROTHY M. SHUTE
Notary Public, State of Indiana
My County of Residence: Hendricks
My Commission Expires May 8, 2017

Item PSC 2-1) ***Refer to the responses to Items 1, 2, and 4 of the First Data Request of Commission Staff ("Staff's First Request"). Provide updates, as applicable, and describe any changes from the initial responses. Consider this a continuing request; provide updates with descriptions of any changes or new developments, as they become known, for the remainder of the proceeding.***

Response) As an update to Item 1 of the Staff's First Request, Big Rivers has continued discussion of power purchase options with Southern Illinois Power Cooperative, Paducah Power System, and most recently with Owensboro Municipal Utilities. Bluegrass Generating Company, LLC (the entity whose identity was withheld due to confidentiality concerns (that have since been addressed) in the response to PSC 1-1 dated April 7, 2010), is another entity with which Big Rivers is evaluating alternative arrangements and structures that might result in a way for Big Rivers to satisfy its Contingency Reserve requirements without joining the Midwest ISO. While no alternative solution to the Contingency Reserve problem has been identified, Big Rivers continues to explore alternatives to Midwest ISO membership.

As an update to Item 2 of the Staff's First Request, Midwest ISO has provided a revised status in data request KIUC 2-12.

Big Rivers' response to Item 4 of the Staff's First Request has not changed.

Witness) David G. Crockett with respect to Item 1 of the Staff's First Request
Clair J. Moeller, Midwest ISO with respect to Item 2 of the Staff's First Request
Ralph L. Luciani with respect to Item 4 of the Staff's First Request

Item PSC 2-2) *Refer to page 18 of 18 of Attachment 1 of the response to Item 2 of Staff's First Request.*

a. Identify where in the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") "Transmission Owners' Agreement" the transmission revenue distribution provisions are located.

b. This section of the attachment refers to "the regional and local zones' revenues" that the Midwest ISO will collect and distribute to transmission owners. Explain whether these constitute all types of transmission revenues that will potentially be distributed to Big Rivers. If there are other types of transmission revenues that might apply to Big Rivers, identify them and how they are to be distributed/allocated.

Response) a. Transmission revenue distribution provisions can be found in Appendix C.III. parts A and B of the Midwest ISO Transmission Owners Agreement. The Transmission Owners Agreement can be found on the Midwest ISO website at the following location:
("http://www.midwestmarket.org/publish/Document/469a41_10a26fa6c1e_-6d790a48324a?rev=15")

b. Potential Injection/Withdrawal revenues do not constitute all types of transmission revenues that will potentially be distributed to Big Rivers. Other types of transmission revenues may be distributed to Big Rivers.

Definitions - the following list of definitions has been provided to assist with understanding of Midwest ISO terminology utilized in this response:

- Border Transmission Owner - A Midwest ISO Transmission Owner (TO) whose transmission facilities are interconnected with those of a non-Midwest ISO transmission owner.
- Bundled Load - The aggregate usage by customers who purchase electric services as a single service or customers who purchase electric services under a retail tariff rate schedule that includes power, energy and delivery components, as distinguished from customers who purchase transmission service as a separate service.
- Drive-in Point-to-Point transmission service - the generation source is outside the Midwest ISO and the load is located within the Midwest ISO.
- Drive-out Point-to-Point transmission service - the generation source is located within the Midwest ISO and the load is located outside of the Midwest ISO.
- Drive-through Point-to-Point transmission service - both the generation source and the load are located outside of the Midwest ISO.
- Drive-within Point-to-Point transmission service - both the generation source and the load are located within the Midwest ISO.
- Schedule 1 – Scheduling, System Control, and Dispatch Service.
- Schedule 2 – Reactive Supply and Voltage Control From Generation or Other Source Service.
- Schedule 7 – Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service.
- Schedule 8 – Non-Firm Point-To-Point Transmission Service.
- Schedule 9 - Network Integration Transmission Service (NITS).
- Schedule 10 – The Midwest ISO cost recovery adder. Schedule 10 consists of three separate charges: demand, energy, and FERC. These rates are intended to recover Midwest ISO costs and none of the Schedule 10 revenue collected by the Midwest ISO is distributed to TOs.
- Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan.

- Zone(s) - The transmission pricing zone(s) identified in the transmission Tariff as (they) may be changed pursuant to Appendix C of the Transmission Owners Agreement.

Assumptions: In order to respond to this question, the following assumptions have been made:

- Big Rivers will be a separate Zone within the Midwest ISO footprint.
- In addition to Bundled Load, Big Rivers may have other network load taking Network Integration Transmission Service (NITS).
- Big Rivers currently has no Midwest ISO Transmission Expansion Plan (MTEP) approved cost shared projects the cost of which would be recovered through Schedule 26. In the future Big Rivers may have MTEP approved cost shared projects. For purposes of this response, it has been assumed that the Injection/Withdrawal Straw Proposal (previously provided by the Midwest ISO as Attachment 1) prevails and any future Big Rivers MTEP approved cost shared projects would be recovered under the Injection/Withdrawal methodology.
- Big Rivers has no qualified generators that provide reactive power and voltage control. In order to receive revenue for the provision of reactive power and voltage control generators within the Midwest ISO must have a FERC approved revenue requirement. This requirement is applicable to FERC jurisdictional and non-jurisdictional entities (such as Big Rivers).
- There are no qualified generators located in Big Rivers' Zone that are not owned by Big Rivers. If there were, then load, excluding Grandfathered Agreement (GFA) load, would be charged the appropriate Big Rivers zonal Schedule 2 rate and the Schedule 2 revenue collected by the Midwest ISO would be distributed to the applicable non-Big Rivers owned generators.

Distribution of Revenues Related to Network Integration Transmission Service (NITS)

- Bundled Load
  - Per the Transmission Owner's Agreement (TOA), Appendix C.II.A.3.a (Second Revised Sheet No 121a), TOs taking NITS to serve their Bundled Load do not have to pay transmission charges pursuant to Schedules 1, 2 and 9. If Big Rivers opts to apply this exemption to their Bundled Load, Big Rivers would not pay Schedules 1, 2 or 9. However, the Bundled Load would be responsible to pay Schedule 23 (rates are the same as Schedule 10). Given the assumptions noted above, no Bundled Load transmission revenues would be distributed to Big Rivers.
  - Other Network Load
  - Other Network load taking NITS that does not have a GFA will be responsible to pay Schedules 1, 2, 9, and 10. Given the assumptions noted above, the transmission revenues collected by the Midwest ISO for Schedules 1 and 9 would be distributed to Big Rivers.
  - Other Network load taking NITS that is under a GFA will be responsible to pay Schedule 10. If ancillary services (Schedules 1 and 2) are not taken under the GFA, then Schedules 1 and 2 will be charged. Given the assumptions noted above, no transmission revenues collected by the Midwest ISO would be distributed to Big Rivers.

Distribution of Revenue for Point-to-Point Transmission Service

- In accordance with the TOA (Appendix C.III.A.3, 5, and 6) the following point-to-point transmission service revenues (Schedules 7, 8, and 1) collected by the Midwest ISO would be distributed 100% to Big Rivers:
  - Revenues collected by the Midwest ISO for transmission services associated with power transactions where the generation source(s) and load(s) are physically located within the Big Rivers Zone shall be fully distributed to Big Rivers whether the generation source is controlled by Big Rivers or another entity.

- Revenues collected by the Midwest ISO for Point-to-Point transmission service for delivery directly to a wholesale requirements customer or a former wholesale requirements customer of Big Rivers shall be distributed to Big Rivers.
- Revenues collected by the Midwest ISO for Drive-in Point-to-Point transmission service shall be fully distributed to Big Rivers if Big Rivers is a Border TO that purchases power from outside the Midwest ISO for delivery to its Zone and pays the Midwest ISO for such transmission service to effectuate that purchase.
- Please note: Except by mutual agreement of the parties to a GFA, the Midwest ISO shall not collect or distribute any revenues for transmission service related to such agreements.

Distribution of Revenue for Out and Through Transmission Service

- Big Rivers would receive a share of Midwest ISO revenues collected for drive-out, drive-through, and certain drive-within point-to-point transmission service. In accordance with the TOA (Appendix C.III.A.7), this revenue is distributed among TOs using the following methodology:
    - "(i) fifty percent (50%) of such revenues shall be distributed in proportion to transmission investment (calculated each month based on the relative proportion of transmission investment reflected in the then applicable rates determined by the formula in Attachment O to the Transmission Tariff); and (ii) fifty percent (50%) of such revenues shall be shared based upon power flows. Such power flows shall be calculated using load flow analysis techniques to develop transaction participation factors. The methodology for developing transaction participation factors is described in Appendix C-1. Participation factors less than three percent (3%) shall be ignored."

Witness) Clair J. Moeller, Midwest ISO

Item PSC 2-3) *Refer to the responses to Item 3.a of Staff's First Request and Item 2 of the First Data Request of Kentucky Industrial Utility Customers, Inc. ("KIUC") to the Midwest ISO ("KIUC MISO Request 1"). The response to part 3.a. of Staff's First Request states that a discount rate of 5.83 percent was used to determine the net present value of the cost decrease to serve the Big Rivers load over the five-year period from 2011 through 2015. The assumptions shown in the attachments to the response to KIUC MISO Request 1, Item 2, include a discount rate of 9.5 percent.*

a. The response to part 3.a. of Staff's First Request refers to footnote 8 on page 4 of Mr. Luciani's testimony. The footnote on page 4 of the testimony is footnote 1, which refers to an Exhibit to Mr. Crockett's testimony. Confirm whether the footnote reference should be to footnote 8 on page 25 of Mr. Luciani's testimony.

b. Explain the rationale for the 9.5-percent discount rate included in the Midwest ISO assumptions in the attachments to KIUC MISO Request 1, Item 2.

c. Are there any instances where discount rates other than 5.83 or 9.5 percent were used for purposes of this application? If yes, identify where in the application they were used, how they were calculated, and the rationale for their use.

Response) a. Confirmed. The footnote reference should be to footnote 8 on page 25 of my testimony.

b. The Midwest ISO used a weighted average cost of capital (WACC) based on a typical rate for utilities located in the Midwest. The WACC was reviewed by Midwest ISO stakeholders on multiple occasions during the development of the Value Proposition.

c. (i) No other discount rates were used. With respect to the CRA testimony and exhibits provided in this application, only the 5.83% discount rate was applied. (ii) The only discount rate used for the Midwest ISO Value Proposition was 9.5%.

Witness) Ralph L. Luciani for parts a and c(i)
Clair J. Moeller, Midwest ISO for parts b and c(ii)

Item PSC 2-4) ***Refer to the response to Item 8.c. of Staffs First Request. Identify the non-transmission projects that are contemplated through 2015 and the approximate amount, based on current conditions, which would be allocated to Big Rivers in each year from 2011 through 2015.***

Response) The basis for the exit fee calculation is the net financial obligation and allocation of that obligation to transmission owners through the weighted average of their load ratio share. In order to forecast the future net financial obligations, assumptions were made regarding future capital expenditures and debt financing. These assumptions were high level in nature and not based on a specific list of projects.

Witness) Clair J. Moeller, Midwest ISO

Item PSC 2-5) *Refer to the responses to Items 18 and 21 of Staffs First Request, which address issues related to the Midwest ISO's proposal to allow Aggregators of Retail Customers ("ARC") to sell demand response directly into the Midwest ISO market.*

a. The first and third paragraphs of the response to Item 18 include statements such as "The KPSC has the ability to decide when and if ARCS can sell demand response directly into Midwest ISO markets . . . ." and "The KPSC can decide on the appropriate value for the MFRR [Marginal Foregone Retail Rate]." Explain whether the Commission's ability to decide these matters comes from the general authority conferred on it by the provisions of Kentucky Revised Statutes ("KRS") Chapter 278 or if it comes from some other authority such as provisions in the Midwest ISO's tariff or specific orders of the Federal Energy Regulatory Commission ("FERC").

b. The second paragraph of the response to Item 21 states, among other things, that Big Rivers' customers will be able to participate in the ARC tariff unless expressly prohibited by the Commission. Explain whether the Commission's authority to prohibit such participation stems from its general authority under KRS Chapter 278 or from a different source of authority.

Response) a. The authority for the KPSC deciding on the appropriate value of the MFRR is based on filed tariff language made by the Midwest ISO before the FERC [Section 38.6(2) b&c, filed on 2 October 2009]. The ability for the KPSC to decide when and if ARCs can sell directly into Midwest ISO markets is based on FERC Orders 719 and 719-A. [see FERC 719-A, Docket No. RM07-19-001: FERC order regarding ARC participation begins at paragraph 41, the most relevant paragraph is #60]

b. The response to the second paragraph of Staff Item 21 was based on the language contained in FERC Orders 719 and 719-A; and the understanding and belief that Big Rivers is a utility that distributed more than 4 million MWh in the previous fiscal year. If Big Rivers does not fall under this FERC definition, other conditions apply, as explained in response to question 11 below. We do not offer an opinion on applicability of KRS Chapter 278 to this situation and defer to and respectfully submit that this latter issue is best addressed by the Commission if it is presented with that issue.

Witness) Richard Doying, Midwest ISO

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF
APRIL 19, 2010 SECOND DATA REQUEST
PSC CASE NO. 2010-00043
April 30, 2010

Item PSC 2-6) ***Refer to the response to Item 19 of Staffs First Request. Consider this a continuing request. Upon its issuance, provide the FERC order on the Midwest ISO's proposed ARC tariff.***

Response) At the current time, Midwest ISO's response is unchanged from its initial one.

Witness) Richard Doying, Midwest ISO

Item PSC 2-7) *Refer to the response to Item 26 of KIUC's First Data Request to Big Rivers and page 27 of Mr. Luciani's testimony. The last entry on the attachment, which contains Mr. Crockett's notes from a conference call with Dairyland Power regarding its integration process with the Midwest ISO, is "Total employees involved – 8 full time." In the study referenced by Mr. Luciani, Western Farmers Electric estimated that interfacing with the SPP RTO would require four employees. Mr. Luciani included that number of employees in his analysis of Big Rivers' operations as a member of the Midwest ISO. Explain why four, rather than eight, employees are projected to be sufficient to perform the required tasks for Big Rivers. What causes Big Rivers to be more like Western Farmers Electric and less like Dairyland Power?*

Response) Big Rivers is not necessarily more like Western Farmers Electric than Dairyland Power. The reference in the Dairyland Power conference call notes identified the number of Dairyland Power employees performing tasks involved in the integration process into Midwest ISO not the number of employees expected to be required after Dairyland would be fully integrated. The Western Farmers Electric number identified by Mr. Luciani is the count of additional employees expected to be required following full integration into the Southwest Power Pool. Big Rivers included four employees following full integration into the Midwest MISO.

Witness) David G. Crockett

Item PSC 2-8) ***Refer to Big Rivers' response to Staffs First Request, Item 1, page 2. If no firm transmission capacity is available from Midwest ISO to accommodate Big Rivers' purchase of contingency reserves from a third party, explain how that capacity will be available to Big Rivers as a member of Midwest ISO.***

Response) When Big Rivers is incorporated into the Midwest ISO's Market and Reliability Footprint there are several processes, operating in different time horizons, that will contribute to the sufficiency and deliverability of energy and operating reserves available to the Big Rivers area. These processes are: the Reserve Zone Methodology, Day-Ahead and Real-Time Energy & Operating Reserve Markets, and RTCA or Operating Guides.

The Midwest ISO determines the Reserve Zone configuration on a quarterly basis, by identifying transmission constraints that occur through Resource redispatch, and grouping sets of Resources, Load and/or Interface Elemental Pricing Nodes with similar impact on these transmission constraints. Reserve Zone Requirements are then determined daily by separately simulating the loss of each individual Resource inside each Reserve Zone, and attempting to replace the lost resource starting with transfers from Resources with the highest impact on the transmission constraints identified in the Reserve Zone configuration study. The largest amount of any single Resource that cannot be replaced by transfers from the most impactful Resources outside the Zone, without reaching a constraint limit, is the Reserve Zone Requirement. Big Rivers' Resources and transmission will be modeled and included in the Reserve Zone Configuration, and Reserve Zone Requirement studies, once Big Rivers is a member of the MISO Market. Ancillary Service products are then cleared in the Day-Ahead, and Real-Time Energy and Operating Reserve Markets in quantities and dispersed locations consistent with the Reserve Zone Requirements.

In real-time operation, contingency reserve deliverability is preserved either through use of Real-time Contingency Analysis ("RTCA") or Operating Guides, as follows. RTCA will simulate the loss of each generator above 100 MW every 5 minutes and search for equipment or voltage limit violations from each contingency. If a limit violation occurs in the RTCA study, the Reliability Coordinator will initiate the binding constraint process, which uses a combination of market redispatch and TLR to unload the transmission system before an event occurs that might require the transfer of contingency reserves. This results in sufficient unloading of the system such that contingency reserve activation and the transmission of reserves in the form of energy will not violate the equipment or voltage limits. In some cases, Operating Guides are used to ensure deliverability of contingency reserves. In these cases, the Operating Guide sets an operating limit to prevent an insecure state of the transmission grid for a variety of conditions, including generator contingencies. The Operating Guide operating limit is reduced to provide sufficient capacity for reserve deliverability. In real-time, if this limit is surpassed, the binding constraint process is initiated to reduce the load to the Operating Guide limit.

Witness) Richard Doying, Midwest ISO

Item PSC 2-9) ***Refer to Big Rivers' response to Staff's First Request, Item 2, page 2. Do the estimated costs in 2014 shown for Big Rivers under "Injection/Withdrawal" reflect the recent decision of First Energy to withdraw as a member of Midwest ISO? Explain the impact of First Energy's withdrawal on the estimated costs to Big Rivers in 2014 and in subsequent years.***

Response) The estimated costs in 2014 shown for Big Rivers under "Injection/Withdrawal" in Item PSC 1-2b of the first data request do not reflect the decision of First Energy to withdrawal as a member of the Midwest ISO. Based on the same proposed "Injection-Withdrawal" methodology used for the original Big Rivers estimate excluding First Energy would increase the total annual charges in 2014 to $9.0 million based on all load in the Big Rivers Pricing Zone, and if GFA load is not included the estimated annual charges would be $3.9 million. It is likewise important to remember that the membership in the Midwest ISO continues to evolve and change. While it is true that First Energy has chosen to leave the Midwest ISO, others like Mid American Energy and Dairyland Power Cooperative have recently decided to join. Accordingly, it is extremely difficult to predict what these changes will be in subsequent years beyond 2014.

	Injection/Withdrawal charges applied to all Load in Big Rivers Pricing Zone	Injection/Withdrawal charges applied to Non-GFA Load in Big Rivers Pricing Zone
[1]	[2]	[3]
Total Annual Charges (in Millions)	9.0	3.9
Total Annual Charges on $/MWh Basis	0.81	0.60

Figure 1. 2014 Estimated Total Annual Charges under Injection/Withdrawal for Big Rivers with First Energy Excluded as a Midwest ISO Member (in 2009 Dollars)

Witness) Clair J. Moeller, Midwest ISO

Item PSC 2-10) *Refer to Big Rivers' response to Staff's First Request, Item 18.*

a. Does the term "LSE," as used in the response, refer only to Big Rivers, only to its three member distribution cooperatives, or to all of those entities?

b. Explain the statement, at page 3, lines 4-5, that, but for the demand reduction, "the LSE would have purchased the MW from the wholesale spot market." Also explain how this statement is true for Big Rivers.

c. For purposes of preparing an Integrated Resources Plan, is Big Rivers able to reduce its future need for generating capacity by the amount of demand reduction available for sale into the Midwest ISO market? If yes, explain how Big Rivers can be sure that the demand reduction will actually occur at the time that Big Rivers is approaching or experiencing a peak on its own system.

Response) a. The answer depends on which of the named entities registers with the Midwest ISO as the market participant responsible for the customers' load, i.e., the LSE. Big Rivers could act on behalf of its member cooperatives and register as the LSE; alternatively, it is possible under the Midwest ISO constructs that each of the coops could register separately if they and Big Rivers so desire. The Midwest ISO provides choice and flexibility in how potential market participants can register their load and resource assets.

b. (i) If Big Rivers is the registered LSE, this statement would apply. The use of the word 'purchased' may be imprecise. If Big Rivers acts as the LSE, to provide the necessary transparency of the market and to reliably operate the grid, Big Rivers' load is required to clear through the Midwest ISO markets. LSEs can secure long term energy contracts or self supply to meet their load obligations, or purchase from the Midwest ISO spot markets. Regardless, all of the LSE's load is cleared and settled through the Midwest ISO markets. If the demand reduction posed in the question hypothetical had not occurred and Big Rivers is the designated LSE, then the load obligations of Big Rivers would be incrementally higher by the amount of load reduction that would not have otherwise occurred under the hypothetical. (ii) All of Big Rivers' generation and most of the energy to serve its load will settle through the Midwest ISO market.

c. (i) Presuming that this hypothetical assumes that Big Rivers is the LSE, and that the amount of demand reduction registered by the ARC, measured from a capacity perspective (i.e. in MWs), is coincident with the LSE's peak load obligation such that it is being used by Big Rivers to meet its resource adequacy requirements under Module E of the Midwest ISO tariff; then, yes, Big Rivers can reduce its need for generation capacity commensurate with the MW amount of load reduction. Under the Midwest ISO Module E construct and proposed ARC tariff modifications, Big Rivers will be assured that the demand reduction occurs when it needs it by the contractual arrangements it would have with the ARC. (ii) As a result of load control equipment on items such as air conditioners and hot water heaters, Big Rivers could be sure that demand reduction would occur.

Witness) Richard Doying, Midwest ISO, for parts a, b(i), and c(i)
C. William Blackburn for parts b(ii) and c(ii)

Item PSC 2-11) ***Refer to Big Rivers' response to Staff's First Request, Item 21. Since Big Rivers has no retail customers, and two of its three member distribution cooperatives distribute substantially less than 4 million MWh annually, provide citations to the specific provisions in FERC Order 719-A that authorize the retail aggregation of customers of the two member distribution cooperatives with sales of less than 4 million MWh annually.***

Response) See ¶ 60 in Docket No. RM07-19-001; Order No. 719-A, Wholesale Competition in Regions with Organized Electric Markets (Issued July 16, 2009), which reads in part: "RTOs and ISOs may not accept bids from ARCs that aggregate the demand response of: (1) the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an ARC, or (2) the customers of utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an ARC."

Witness) Richard Doying, Midwest ISO

Item PSC 2-12) *Refer to Big Rivers' response to Staffs First Request, Item 2, page 2, lines 7-1 3, and Item 6, lines 1 1-1 3. On April 13, 201 0, the Midwest ISO presented "Modeling Results of Midwest ISO Straw Proposal" to the Cost Allocation and Regional Planning group of the Organization of MISO States. Assume that the allocation methodology upon which those results were based is submitted to, and accepted by, FERC and that, after that approval, Big Rivers becomes a member of the Midwest ISO in the third quarter of 2010.*

a. Provide a calculation of the costs that would be allocated to Big Rivers in years 2014 and 2024 under that proposed methodology. In providing the costs, present them as "Injection/WithdrawaI Charges Applied to All Load in Big Rivers Pricing Zone" and as "Injection/WithdrawaI Charges Applied to Non-GFA Load in Big Rivers Pricing Zone" as was done in Big Rivers' response to Staffs First Data Request, Item no. 2.

b. Provide a calculation of the costs that would be allocated to Big Rivers in years 2014 and 2024 under the current Midwest ISO cost allocation methodology.

Response) a. See estimates provided in response to Item PSC 2-9, above for 2014. In addition to the 2014 test year the Midwest ISO also has estimated the potential impacts to Big Rivers under the proposed Injection/Withdrawal methodology as of March 22, 2010 using a 2024 test year taking into account future load growth, state RPS mandates, generation expansion, and new transmission facilities. In 2024 the majority of the new transmission facilities are estimated to be driven by the results of the Midwest ISO's Regional Generation Outlet Study (RGOS) that is currently under development and additional refinements as the various drivers, primarily renewable energy mandates, continue to evolve. The 2024 estimates provided assume that all of the transmission identified in the RGOS, with an estimated total cost of approximately $16 billion,1 is in-service and subject to cost recovery under the proposed Injection/Withdrawal methodology. These results that attempt to predict and project out over a fifteen (15) year time horizon and merely indicative of a general direction and can not and do not take in to account all of the potential intervening variables that could both completely change as well as mitigate the perceived impacts. Therefore, the 2024 results shown below are, at best, indicative estimates and likely to change depending on, but not limited to, actual transmission investment, changes to evolving cost allocation methodologies, load shifts and growth, and future RPS mandates.

In estimating the potential effects of this on Big Rivers' decision to join the Midwest ISO the following represent the application of (1) the proposed Injection/Withdrawal methodology, (2) utilizing the projected 2024 RGOS estimates, (3) calculated with and without GFA load being allocated costs. As shown in Figure 2, below, the estimated annual potential total charges under Injection/Withdrawal in 2024 for Big Rivers is $52.9 million if all Big Rivers load part of the calculation which then decreases to $29.1 million if GFA load is excluded from the computation.

	Injection/Withdrawal charges applied to all Load in Big Rivers Pricing Zone	Injection/Withdrawal charges applied to Non-GFA Load in Big Rivers Pricing Zone
[1]	[2]	[3]
Total Annual Charges (in Millions)	52.9	29.1
Total Annual Charges on $/MWh Basis	4.75	4.42

Figure 2. 2024 Estimated Total Annual Charges under Injection/Withdrawal for Big Rivers with First Energy Excluded as a Midwest ISO Member (in 2009 Dollars)

[1] The Regional Generation Outlet Study is continually refining the transmission plans with the cost estimates provided here based on indicative plans as of April 2010.

Note that the 2024 cost estimates for Big Rivers' do not reflect or capture amounts that would, likewise, be contributed by other transmission owners toward transmission upgrades that Big Rivers proposes are included for cost sharing under the same methodology.

b. The transmission facilities included for years 2014 and 2024 primarily represent reliability projects scheduled tentatively to go in-service through 2014 or 2024 but which have not yet been approved. Note that since Big Rivers has not been a part of the Midwest ISO planning process all of the projects included in the 2014 or 2024 test year are located outside of the Big Rivers Pricing Zone. Also, note that under current Midwest ISO policy that relieves new entrants of the responsibility to pay for projects planned prior to their entry year, some of the modeled costs may ultimately be excluded from the transmission cost allocated to Big Rivers. The cost allocation methodology applied to calculate the 2014 and 2024 cost estimates is based on the currently effective Tariff described in my direct testimony starting on Page 18 Line 15.

In estimating the potential costs to Big Rivers under the current cost allocation methodology in 2014 and 2024 the Midwest ISO has performed the calculation with and without GFA load being allocated costs. As shown in Figure 3 the estimated annual total charges in 2014 for Big Rivers is $1.0 million if all Big Rivers load is charged and decreasing to $0.20 million if GFA load is excluded.

	Charges applied to all Load in Big Rivers Pricing Zone	Charges applied to Non-GFA Load in Big Rivers Pricing Zone
[1]	[2]	[3]
Total Annual Charges (in Millions)	1 0	0 2
Total Annual Charges on $/MWh Basis	0.09	0 03

Figure 3. 2014 Estimated Total Annual Charges under the Current Cost Allocation Methodology for Big Rivers (in 2009 Dollars)

In 2024 the estimated annual total charges for Big Rivers applying the current cost allocation methodology is $1.5 million and decreasing to $0.35 million if GFA load is excluded, see Figure 4. Note that the 2024 estimate under the current cost allocation methodology excludes the transmission costs associated with the Regional Generation Outlet Study that are included in the cost estimates provided in Item PSC 2-9 under the proposed Injection/Withdrawal cost allocation methodology. Under the current cost allocation methodology transmission identified through the Regional Generation Outlet Study likely would not qualify for cost sharing treatment. The 2024 cost estimate is based on currently available information and subject to change as projects are identified and reviewed throughout the Midwest ISO regional planning process.

	Charges applied to all Load in Big Rivers Pricing Zone	Charges applied to Non-GFA Load in Big Rivers Pricing Zone
[1]	[2]	[3]
Total Annual Charges (in Millions)	1.5	0.35
Total Annual Charges on $/MWh Basis	0.13	0.05

Figure 4. 2024 Estimated Total Annual Charges under the Current Cost Allocation Methodology for Big Rivers (in 2009 Dollars)

Note that both the 2014 and 2024 cost estimates for Big Rivers' do not reflect or capture amounts that would, likewise, be contributed by other transmission owners toward transmission upgrades that Big Rivers proposes and are included for cost sharing under the same methodology

Witness) Clair J. Moeller, Midwest ISO

Item PSC 2-13) ***Refer to Big Rivers' response to Staff's First Request, Item 8, lines 18-22. Would the obligation be limited to the one-year cost for the year of the exit, or would the obligation be the annual allocation until completion of cost recovery, per the cost allocation protocols, of the cost of all project(s) approved during the party's membership?***

Response) The obligation would be for the equivalent of the annual allocation until completion of cost recovery, per the cost allocation protocols, of the cost of all project(s) approved during the party's membership. Note that this obligation could take the form of a lump sum payment equivalent to the value of an annual charge until the completion of recovery rather than an ongoing charge of the annual allocation amount.

Witness) Clair J. Moeller, Midwest ISO

RECEIVED
APR 30 2010
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL TO TRANSFER FUNCTIONAL CONTROL OF ITS TRANSMISSION SYSTEM TO MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)	CASE NO. 2010-00043

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL PROTECTION

1. Big Rivers Electric Corporation ("Big Rivers") hereby petitions the Kentucky Public Service Commission ("Commission"), pursuant to 807 KAR 5:001 Section 7 and KRS 61.878(1)(c), to grant confidential protection to the attachment to Item 3 of its responses to the second data requests of Kentucky Industrial Utility Customers, Inc. ("KIUC"). The attachment that Big Rivers seeks to protect (the "Confidential Information") contains historical and future budgets with respect to Big Rivers' off-system sales and revenues and margins from those sales.

2. Big Rivers seeks to protect as confidential the entirety of the attachment. One (1) sealed copy of the attachment printed on yellow paper is filed with this petition, and a copy of a sheet noting the entire attachment has been redacted is contained in each of the 10 copies of the responses to KIUC's second data requests filed with this petition. 807 KAR 5:001 Sections 7(2)(a)(2), 7(2)(b).

3. A copy of this petition and a copy of the sheet noting that the attachment has been redacted have been served on all parties. 807 KAR 5:001 Section 7(2)(c).

4. If and to the extent that the Confidential Information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will

notify the Commission and have its confidential status removed. 807 KAR 5:001 Section 7(9)(a).

5. The Confidential Information is not publicly available, is not known outside of Big Rivers, and is not disseminated within Big Rivers except to those employees and professionals with a legitimate business need to know and act upon the information.

6. In this petition, Big Rivers is seeking confidential treatment of its historical and future budget projections of off-system sales and revenues and margins from off-system sales. Such information falls within a category of commercial information "generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to competitors" of Big Rivers. *See* KRS 61.878(1)(c)(1); 807 KAR 5:001 Section 7(2)(a)(1).

7. The Confidential Information is precisely the sort of information meant to be protected by KRS 61.878(1)(c)(1), and the Commission and Kentucky courts have often found that confidential financial information about a company is generally recognized as confidential and proprietary. *See, e.g., Hoy v. Kentucky Indus. Revitalization Authority*, 907 S.W.2d 766, 768 (Ky. 1995) ("It does not take a degree in finance to recognize that such information concerning the inner workings of a corporation is 'generally recognized as confidential or proprietary'"); *Marina Management Service, Inc. v. Com. Of Ky., Cabinet for Tourism*, 906 S.W.2d 318, 319 (Ky. 1995) (finding that a marina's financial records, including information on asset values, notes payable, rental amounts on houseboats, related party transactions, profit margins, net earnings, and capital income, were entitled to confidential protection); Order dated April 3, 2006, in *In the Matter of: The Joint Application of Nuon Global Solutions USA, BV, Nuon Global Solutions USA, Inc., AIG Highstar Capital II, LP, Hydro Star, LLC, Utilities, Inc. and Water*

Service Corporation of Kentucky for Approval of an Indirect Change in Control of a Certain Kentucky Utility Pursuant to the Provisions of KRS 278.020(5) and (6) and 807 KAR 5:001, Section 8, PSC Case No. 2005-00433 (finding that certain terms contained in a Stock Purchase Agreement were confidential and proprietary and that disclosure could result in competitive harm).

8. Big Rivers competes in the wholesale power market to sell energy excess to its Members' needs. Public disclosure of the Confidential Information would give Big Rivers' competitors in that market an unfair competitive advantage by allowing them to use information about Big Rivers' projected sales, costs, and margins to Big Rivers' disadvantage when competing for sales in the wholesale power market. Even Big Rivers' historical budget figures would give competitors insight into future costs. Suppliers of wholesale power to Big Rivers could also use Big Rivers' cost projections (both the future and the historical budget projections) to manipulate their offers to Big Rivers to Big Rivers' competitive disadvantage, preventing Big Rivers from obtaining the lowest cost. Likewise, purchasers of power from Big Rivers in the wholesale power market could use the future and historical budget projections of sales, costs, and margins to Big Rivers' disadvantage hurting Big Rivers' ability to obtain the highest price possible for its off-system sales. As is well-documented in multiple proceedings before this Commission, Big Rivers' margins are derived almost exclusively from its off-system sales.

9. Based on the foregoing, the Confidential Information should be given confidential protection. If the Commission disagrees that Big Rivers is entitled to confidential protection, due process requires the Commission to hold an evidentiary hearing. *Utility Regulatory Com'n v. Kentucky Water Service Co., Inc.*, 642 S.W.2d 591 (Ky. App. 1982).

WHEREFORE, Big Rivers respectfully requests that the Commission classify and protect as confidential the Confidential Information filed with this petition.

On this the 29th day of April, 2010.

BKP
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COUNSEL FOR BIG RIVERS
ELECTRIC CORPORATION

Item KIUC 2-1) *Please refer to Big Rivers' response to KIUC item 1-1, the December 17, 2009 Preliminary Economic Assessment of CRA.*

a. Did the Big Rivers Board of Directors ever get a final CRA Economic Assessment? If yes, please provide.

b. Please explain why Big Rivers entered into the Memorandum of Understanding with MISO on December 11, 2010 [sic] when its Board did not have the CRA Preliminary Assessment at that time?

c. Please provide all workpapers, computer models with cells in tact, assumptions and other documents used in the Preliminary Assessment.

d. Please refer to page 13 of the Preliminary Assessment. Please calculate the "trade benefit" to Big Rivers of the Change Case (Big Rivers joins MISO) versus the Base Case (Big Rivers not in MISO) for the period 2011 through 2014 using the GE MAPS analysis. Please provide all back up documents, computer models and assumptions for this calculation. If the "trade benefit" for 2011 is different than the $2.4 million "decreased cost to serve Big Rivers load" provided in response to KIUC item 2 please explain any differences.

e. Please identify all differences between the December 17, 2009 CRA Preliminary Assessment and the February 1, 2010 CRA economic analysis presented in the testimony of Mr. Luciani. In particular, please explain why: 1) transmission expansion costs (MTEP) were included in the Preliminary Assessment but not the KPSC testimony; and 2) the Preliminary Assessment compared the Base Case (Big Rivers not in MISO) versus the Change Case (Big Rivers joins MISO) whereas the KPSC testimony compared the Change Case (Big Rivers joins MISO) versus the Stand Alone Case (200 mw of Smelter uninterruptible capacity, 65 mw Reid CT, and 152 mw coal stand by).

f. On page 12 CRA identifies the wheeling charge from BREC into MISO at $2.88/MWh. Was this the same charged used in Mr. Luciani's testimony? If not, what was used in the testimony and explain any differences.

g. On page 12 CRA, identifies the MISO wheeling charge into BREC as $6.32/MWh on-peak and $3.00/MWh off-peak. Were these the same charges used in Mr. Luciani's testimony? If not, what was used in the testimony and explain any differences.

Response) a. The December 17, 2009 CRA Preliminary Assessment is the final and was provided to Big Rivers' Board of Directors. It was called "preliminary" because it was Phase I of CRA's work. Phase II was the subsequent GE MAPS analysis which was used in the testimony of Ralph Luciani filed with the Commission on February 2, 2010. Since that time, a Phase II study of the GE MAPS analysis from Mr. Luciani's testimony was prepared by CRA dated March 22, 2010 by CRA and is provided on the attached CD.

b. Big Rivers' management sought and received Board approval for authority to sign the MISO MOU during its regularly-scheduled November 20, 2009 meeting. Big Rivers' management was given authority to negotiate and enter into the MOU if the terms as determined by the president & CEO, in his judgment, were consistent with the best interests of the corporation and its members. At that time, Big Rivers' management was mindful that the MISO Board would have to approve Big Rivers' membership application, but it was unclear at the time of the November Big Rivers' Board meeting whether the MISO Board would be willing to move their normally-scheduled December 3rd meeting date and/or would be willing to call a special MISO Board meeting to act on Big Rivers' MISO application request until after the Big Rivers' Board's next regularly scheduled meeting on December 18, 2009. Given this concern, Big Rivers' management asked for Big Rivers' Board approval during the November meeting to execute the MISO MOU if necessary to give the MISO Board the opportunity to act on Big Rivers' application request so that reserve sharing service could be provided to Big Rivers on January 1, 2010 after the Midwest Contingency Reserve Sharing Group (MCRSG) dissolved at the end of 2009.

This recommendation was made to the Board and accepted based on the following:

- Big Rivers management had been providing the Board updates on the reserve sharing situation during each monthly Board meeting since May 2009 so the Board was aware of the work that had been done to identify alternatives (and their relative costs) and what the situation facing the company would be when the Midwest Contingency Reserve Sharing Group (MCRSG) dissolved at the end of 2009.
- Big Rivers' had run out of other economically viable alternatives by that time.
    - By the end of September when it became apparent Big Rivers' would be unable to participate in the new reserve sharing group involving TVA, E.On and East Kentucky Power Cooperative (due to TVA concerns about the "fence"), it had become clear that the only viable options for Big Rivers to deal with the reserve issue was either to join MISO or work out an interruptible arrangement with the smelters.
        - Joining PJM was not viable because Big Rivers was not electrically interconnected to one of its member systems and we could not obtain firm transmission service of sufficient quantity to a PJM member or to SPP to participate in either of those reserve sharing groups.
            - TVA had performed a study of what would need to be done on their transmission system to allow sufficient power to flow to Big Rivers from SPP.
                - The work was estimated to cost ~ $4.9 million and could not be completed until mid 2012.
                - TVA also indicated similar studies would need to be completed on other surrounding transmission systems to Big Rivers. In addition to lack of time to complete those studies (due to the impending MCRSG dissolution at the end of 2009), we had no idea how long any needed improvements might take or how much they would cost.
        - Our neighbors, SIPC, Vectren, and Hoosier were participating in other reserve sharing groups and were not interested in severing those relationships to form a new reserve sharing group with Big Rivers.

- The smelters had not yet committed to a self-serve solution under which they would interrupt load to assist.
  - That commitment didn't come until December 1st. Given that timeframe, there was insufficient time in Big Rivers management's opinion to negotiate an agreement with the smelters for that service and also obtain PSC approval of that agreement by January 1st.
  - The conversations with the smelters at that time involved 200 MW of interruptible load which was not enough to permit Big Rivers to restore its Area Control Error (ACE) within the NERC-mandated 15 minute window without off-system quick-start CT capacity or firm callable replacement power support.
  - Big Rivers had been unable at that time to identify adequate quick-start CT capability or callable replacement power support on other systems nor could it find sufficient firm long-term off-system transmission capacity to move the power to Big Rivers' system to permit Big Rivers to restore ACE and/or return contingency reserves to the pre-operating event contingency levels within the NERC-mandated 105 minutes following the event.
  - It was not until early March 2010 that the smelters indicated an interest in interrupting up to 300-plus MW of load.
    - That decision negated the need to obtain off-system quick start capacity, but obtaining long term off-system firm transmission capacity to transmit replacement reserve power to Big Rivers is still a stumbling block.
- Based upon Big Rivers' best knowledge at that time based on input provided by MISO, the cost of joining MISO would be approximately $4.7 million annually.
  - This would have an estimated on-going rate impact of approximately 47 cents/MWh ($4,700,000 / 10,000,000 MWh per year internal load or 0.047 cents per kwh).
  - These costs were of the magnitude of other operational-type misfortunes that Big Rivers' might encounter at any time as an operating generating and transmission company.
    - If it absolutely had to, Big Rivers could meet that financial challenge like any other event of that magnitude it might face; by finding as many cost offsets and/or additional revenue making opportunities to cover the incremental costs until such time as those expenses could be recovered through rate relief.
    - If cash flow became a concern, we could possibly utilize our lines of credit.

    - The MISO cost paled in comparison to the lost opportunity cost of holding Big Rivers' generation back at sufficient levels to meet the worst case operational reserve scenario (loss of Wilson's 417 MW capacity).
        - Hold-back of that amount of generation was estimated to be in the $30 million per year range under a conservative estimate (400 MW x 85 % capacity factor x 8,760 hours per year x $10/MWh margin = $29.8 million)
        - Book-end estimates of this option placed it out of range of the MISO alternative:
            - 300 MW x 75 % capacity factor x 8,760 hours per year x $5/MWh = $9.9 million per year
            - 350 MW x 80% capacity factor x 8,760 hours per year x $20/MWh = $49.1 million/year
    - Even if Big Rivers had decided to hold back generation to sufficiently meet a worst case contingency situation, Big Rivers' units were physically incapable of ramping generation levels up quickly enough to restore ACE in the required 15 minute time frame.
    - The decision to sign the MISO MOU was reversible if the PSC did not permit Big Rivers' to join MISO which would likely be the case should a better alternative later emerge.
        - Should that happen, Big Rivers would have been obligated to pay MISO's costs to the point in time when that decision was made.
        - It was estimated MISO's total cost of integrating Big Rivers would be $1.5 million so that was a worst case scenario, but the possibility of incurring that much expense was unlikely in Big Rivers management's opinion because it was believed if an alternative would emerge, it would happen relatively soon after the first of the year.
- Failure to do anything by January 1, 2010 was not a viable option for several reasons:
    - In Big Rivers management's opinion, it would be just a matter of time before an event would occur where Big Rivers would be unable to import sufficient capacity to meet a reserve contingency.
    - That could result in at least some customer outages, and in a worst case scenario, loss of the entire Big Rivers' system with possible cascading outages to neighboring systems.
        - If a lengthy outage involved smelter load and one or more of their pot-lines froze, it would be very costly for them at a minimum, possibly result in a permanent shutdown with

attendant loss of jobs and local and state tax revenue along with law suits and adverse publicity for both Big Rivers and Kenergy, which might impact Big Rivers' credit rating resulting in its inability to borrow funds in the capital market and increase fees and interest rates.
        - The same situation could apply to other customers served by Big Rivers' Members.
    - At a minimum, should Big Rivers not meet NERC-mandated ACE and generating reserve requirements, it would almost certainly result in a SERC/NERC investigation that could lead to fines up to $1 million per day per occurrence.
        - Such an occurrence would quickly bring Big Rivers to its "financial" knees not to mention the impact on Big Rivers' reputation.
  - Big Rivers received a November 30th preliminary reserve analysis report from Mr. Luciani of CRA. That report indicated joining MISO could have an economic impact on Big Rivers in a range from a positive benefit of approximately $1.6 million a year to an expense as high as approximately $29.1 million a year (dependent on how the Member and smelter contracts were treated, along with the actually adopted MISO Transmission Expansion Plan (MTEP), and how those transmission expansion costs were allocated among the MISO members).
    - Mr. Luciani's best estimate at that time was that the mid range annual financial impact (after applying revenue benefits) to Big Rivers was on the order of approximately $6.8 million which was in the range of the estimates that had been provided to the Big Rivers' Board since July 2009.
- Given these reasons along with the financial impact estimate that became available from Mr. Luciani in late November, Mr. Bailey made the decision to sign the MISO MOU on December 4, 2009 (after it was learned that the MISO Board was willing to hold a specially-called Board meeting later in December to consider the application). MISO's Board subsequently approved the application on December 14th.

c. Supporting material is provided in the attached CD-ROM. The dispatch model used to derive the preliminary trade benefits contains CRA commercially sensitive material and has not been provided to Big Rivers.

d. A GE MAPS analysis was used to calculate the 2011 trade benefit of Big Rivers being in the Midwest ISO ("Midwest ISO Case") in comparison to being a hypothetical member of the terminated MCRSG ("Hypothetical MCRSG Case"). The results of this GE MAPS analysis were provided in the response to KIUC 1-2, and showed a trade benefit of $2.4 million in 2011 for the Midwest ISO Case in comparison to the Hypothetical MCRSG Case. See the response to KIUC 2-9a for supporting material. Big Rivers has not asked CRA to perform a GE MAPS analysis of trade benefits of the Hypothetical MCRSG Case for subsequent years.

e. The transmission cost allocation on page 9 was included in the December 17 Preliminary Assessment to frame a possible range of Big Rivers' allocated costs under various Midwest ISO transmission high-voltage transmission investment scenarios. This same allocation methodology is described in footnote 10 on page 30 of my direct testimony. Given uncertainties in how much transmission will be built on the Midwest ISO system, how much it will cost, how the costs will be allocated, the GFA status of the Big Rivers load, and the resulting offsetting benefits from increased access to wind power, I have not quantified the net impact of this issue.

As noted on page 18 of the Preliminary Assessment: "The analysis of trade benefits is highly preliminary … a GE MAPS analysis would be required to better access the trade benefits taking into account generation dispatch in both Big Rivers and the Midwest ISO, and applicable transmission constraints." The simplified modeling approach in the Preliminary Assessment used 2008 historical data as the basis for measuring changes. In 2008, Big Rivers operated as a member of the now-terminated MCRSG. Thus the simplicity of the modeling approach dictated measuring the Midwest ISO Case in comparison to being a member of the MCRSG. The own-system standalone option was discussed in the Preliminary Assessment but not directly quantified (see page 3, "Own-system options could potentially meet the Big Rives reserve needs but the cost may be prohibitive given the smelter pricing incentive required and the additional cost incurred in operating coal units at minimum load.") The Stand-alone Case was analyzed directly in the GE MAPS analysis for the years 2011-2014 prepared for my testimony in order to directly compare the two available non-hypothetical alternatives.

The general methodology used in assessing the Midwest ISO costs in the Preliminary Assessment and my Direct Testimony is similar. There were updates made to the Midwest ISO cost estimates and the figures were provided for 2011-2014, instead of 2010.

f. Yes. The GE MAPS model requires an integer value as an input, and, as such, the $2.88 rate was rounded to $3/MWh for the GE MAPS analysis.

g. Yes. The GE MAPS model applies the same wheeling rate on- and off-peak, and, as such, the $6.32/MWh on-peak and $3.00/MWh off-peak rates were averaged to $4.66/MWh and then rounded to $5/MWh in the GE MAPS analysis.

Witness) David G. Crockett for parts a-b
Ralph L. Luciani for parts c-g.

Item KIUC 2-2) ***Please provide all computer models with cells in tact, workpapers and all other documents that support your response to KIUC item 2-1.***

Response) CRA responsive documents, models and workpapers are provided in the CD-ROM attached to the response to KIUC 2-1c.

Witness) Ralph L. Luciani

Item KIUC 2-3) *Please refer to your response to KIUC item 1-5. Crockett states that the annual costs of self-supply in terms of lost opportunity margins at the time the decision to join MISO was $29.8 million (400 MW times 8,760 times 85% capacity factor times $10/MWh projected margins).*

a. For each month since the Unwind closed, please provide: 1) the dollar amount of the net margin on off-system sales realized by Big Rivers; 2) the MWh volume of off-system sales net of transmission losses; 3) the net price per MWh received by Big Rivers for its off-system sales.

b. Please compare the items referenced in item a. above with Big Rivers' budget projections.

c. What is Big Rivers' currently budgeted amounts for the items referenced in item a. above (1) assuming it does not join MISO and (2) assuming it does join MISO. This request seeks information for as long a forward period as the currently approved budget exists.

d. Given the capacity factors used by CRA in its analysis, does [Big] Rivers believe that the assumed 85% capacity factor of the coal units that would be idled is realistic? If Big Rivers did idle any coal generation for a stand alone scenario, which units would be idled in descending order and how many MW would be idled for each unit?

e. Does Big Rivers agree that the maximum capacity (MW) of coal units that would have to be idled under a stand alone scenario with no Smelter interruptible capacity is 352 MW (417 MW minus the 65 MW Reid CT) not 400 MW?

f. Please confirm that Big Rivers is required to maintain approximately 32 MW of reserves in the MISO case, which is the same amount of reserves as it maintained in the MCRSG arrangement.

g. Has Big Rivers calculated the cost of a stand alone scenario for a short-term period (for example September 1, 2010 through December 31, 2011) using current information including margins from off-system sales? If not, please explain why not.

Response) a. The analysis referred to was a "back of the envelope" analysis done to provide a relative order of magnitude of this option versus the others being considered. Pages 1 and 2 of the attached 5 page schedule provide the actual information for each of the months August 2009 through February 2010. It is important to note that actual off-system sales include the impact of Century having a potline down.

b. Pages 1 and 2 of the attached 5 page schedule provide the board-approved 2009 Post-Unwind Budget and the 2010 Budget information for each of the months August 2009 through February 2010, in comparable format to a. above. Also, the difference between actual and budget is shown. It is important to note that budgeted off-system sales do not reflect Century having a potline down.

c. Pages 2 through 5 of the attached 5 pages schedule provide the board-approved 2010 Budget and 2011-2013 Financial Plan information for each of the months March 2010 through December 2013, assuming Big Rivers does not join the Midwest ISO, in comparable format to a. and b. above. The board-approved 2010 Budget and the 2011-2013 Financial Plan do not include the impact of joining the Midwest ISO. It is important to note that budgeted off-system sales do not reflect Century having a potline down.

d. The question misconstrues the analyses that were performed. The term capacity factor in the CRA study is the same as used by utilities in reference to individual generating units. The capacity factor is the equivalent percentage of time that a generating unit generates to its capacity for a defined amount of time. In the response to KIUC 1-5, the "back of the envelope" analysis used an 85% capacity factor to represent the percentage of time that a capacity of 400 MW could be sold. The "back of the envelope" analysis was arrived at simply by multiplying 400 MW times 8760 hours times $10/MWh times a .85 factor ("capacity factor of the amount for sale" or "sales factor" or "market clearing factor"). The CRA study calculates generation capacity factors for each individual unit.

In the Stand-alone Case, the idling of the coal generation units would be done based upon several cost factors that enter into the operation of each unit. Some of those cost factors change slowly and others become very volatile at times and change quickly. Some factors change due merely to the physical location of the generating unit itself and the mode of delivery of its consumables. Therefore, if Big Rivers did idle any coal generation for a stand-alone scenario the number of MWs idled at each unit and the "stacking order" of the idling of the units would change quite often in order to take advantage of the economies that exist at the time.

e. Big Rivers agrees that the actual unused capacity set aside to meet the contingency reserve obligation in the Stand-alone Case with no smelter interruptible capacity is 352 MW and not the 400 MW value used in the calculation which was intended to produce a representative lost off-system sales opportunity cost. Even at 352 MW the number is still $26.2 million, which is several times the administrative costs of the Midwest ISO.

f. Big Rivers approved the usage of 32 MW of contingency reserve by CRA in the Midwest ISO Case as a reasonably representative amount of reserve required under the Midwest ISO Ancillary Services Market operation. The assumption made by Big Rivers was that the required total Midwest ISO reserve quantity and the Big Rivers' load ratio share would be the same as that under the MCRSG.

g. No. The referenced time period is not relevant to any analyses Big Rivers is performing. For each of the first three months during 2010, average margins on Big Rivers' off-system sales were in excess of $10/MWh.

Witness) a-d. C. William Blackburn
e-f. David G. Crockett
g. C. William Blackburn

ATTACHMENT TO KIUC 2-3

REDACTED

(FILED UNDER PETITION FOR CONFIDENTIAL TREATMENT)

Item KIUC 2-4) *Please refer to KIUC items 1-22 and 1-23.*

a. Do the forecasted exits fees of $6 million in 2009 and $3.5 million at the end of 2015 include Big Rivers' cost responsibility for transmission projects approved while it was a member? If not, please recalculate the exit fees to include such amounts.

b. Please confirm that the only document in the possession of Big Rivers that attempts to calculate MISO exit fees is the October 15, 2009 email from MISO.

c. Please provide all documents, workpapers and computer models which support these exit fee calculations.

d. Please provide the same exit fee calculations for 2020.

Response) a. No. The estimated, forecasted exit fees of $6 million in 2009 and $3.5 million at the end of in 2015 do not include cost responsibility for transmission projects approved under the MTEP process under the scenario that Big Rivers is assumed to be a member. The Midwest ISO handles the cost responsibility for transmission projects under a separate calculation because, unlike forecasted exit fees, the source of these costs are from the Midwest ISO Transmission Owners.

Big Rivers' potential cost responsibility for transmission that is approved through 2015 would be highly dependent on the transmission cost allocation methodology in effect during that time period. At the time of this response the proposed cost allocation method is continuing to evolve, which would impact the forecasted exit fee transmission component. The estimated value provided below is based on transmission projects that presumably approved after July 15, 2010 and placed in-service before the end of 2014, allocated using the currently effective Tariff structure. Additional projects approved during this time period but not in-service as of 2014 would not be included in the estimate provided. The present value of the annual revenue requirements for the estimated, projected portion of transmission costs allocated to BREC over this period, assuming an 8% discount rate and 40-year book life for any such projects, is $2.2 million in comparable 2009 dollars. It must be noted that this estimate does not reflect or capture amounts that would, likewise, be contributed by the other transmission owners toward transmission upgrades that Big Rivers proposes and are included in the same process. The forecasted exit fees do not include the cost responsibility for transmission projects approved while it was a member.

b. The only document that attempts to calculate Midwest ISO exit fees is the October 15, 2009 email from Midwest ISO.

c. The 2015 exit fee model has been attached (BREC 123115 Exit Fee Calc FINAL)

d. The following exit fee numbers are the best estimates, based upon the facts and circumstances known at this time projected for Big Rivers out ten years to 2020. By extrapolation and comparison of the estimated 2015 projection, the most relevant factors and sections of the Midwest ISO financial obligations that make up what would be the basis of the exit fee calculation are and continue to decrease (except for: accrued liabilities, which normally remain consistent; and operating leases). Accordingly, the estimated exit fee projection for Big Rivers would follow suit and decline from $3.3M in 2015 to $2.9M in 2020. The attachment is titled ("BREC 123120 Exit Fee Calc DRAFT.pdf")

Witness) David G. Crockett for part b.
Richard Doying, Midwest ISO for parts a, c, and d.

Estimated Exit Fee Calculation ($Millions)

Big Rivers Electric Cooperative (BREC)

December 31, 2015 Projected Balance Sheet

	Total	Schedule 10	Schedule 16	Schedule 17	Allocations Sch. 10	Sch. 16	Sch.17
Accrued Liabilities							
Subtotal	$ 60.65	$ 30.52	$ 3.43	$ 26.69	50.3%	5.7%	44.0%
Capitalized Leases							
Subtotal	$ 6.96	$ 3.50	$ 0.39	$ 3.06	50.3%	5.7%	44.0%
Deferred Revenue							
Subtotal	$ 15.17	$ 6.82	$ 1.52	$ 6.82	45.0%	10.0%	45.0%
Notes Payable							
Subtotal	$ 108.75	$ 48.94	$ 9.88	$ 48.94	45.0%	9.1%	45.0%
Interest Expense							
Accrued Interest	$ 3.26	$ 1.47	$ 1.30	$ 1.47	45.0%	9.1%	45.0%
Remaining Interest	$ 21.15	$ 9.61	$ 2.04	$ 9.50	45.0%	9.1%	45.0%
Subtotal	$ 24.41	$ 11.08	$ 3.34	$ 10.97			
Operating Leases	$ 5.55	$ 2.99	$ 1.29	$ 2.28	53.8%	23.2%	41.0%
Total Liabilities	$ 221.49	$ 103.85	$ 17.84	$ 98.76			
Less: Cash [5]	$ 27.59	$ 12.42	$ 3.51	$ 12.42	45.0%	9.1%	45.0%
Total Financial Obligation	$ 193.90	$ 91.43	$ 14.33	$ 86.34			

($Millions)		Schedule 10 [3]	Schedule 16	Schedule 17 [4]
Billing Determinants - excludes non-Tos				
Big Rivers Power Cooperative (BREC)		13.31	-	-
Midwest ISO Transmission Owners - Total (+ MidAm - FE + BREC)		779.39	-	-
Company Percentage	1.707%	1.707%	N/A	N/A

	Total Exit Fee	Schedule 10	Schedule 16	Schedule 17
Net Exit Fee Obligation ($Millions)	$ 3.31	N/A	N/A	N/A

Notes:

1 Deferred Revenue liability related to ComEd & LGE Withdrawal Obligation offset by cash received that is reflected in the Cash Balance.
2 Accrued Interest liability offset by cash received to pay accrued interest that is included in the Cash balance.
3 Sch. 10 BREC and Midwest ISO Billing Determinants are sourced from the Midwest ISO Load Forecasting Team (ICCP data). 7/08 through 6/09 actual results were used.
4 Actual Sch 16 & 17 Billing Determinants unavailable for BREC
5 Cash does not include MP restricted deposits
6 Midwest ISO Total Sch. 10 Billing Determinants include MEC & MPW, since they will be joining Midwest ISO prior to 12/31/09; and removes FE & related parties.
7 Total Exit Fee Obligation based on Sch. 10 Load Ratio Share (since Sch. 16 & Sch. 17 Billing Determinants for BREC are unavailable).
8 Includes $45M in Debt for new Data Center (Issued 2/1/2010 - 20 yr term).
9 Includes two $50M Debt issues (7/1/2012 & 7/1/2014 - 5 yr term)

Estimated Exit Fee Calculation **Big Rivers Electric Cooperative (BREC)**
($Millions)

December 31, 2020 Projected Balance Sheet

	Total	Schedule 10	Schedule 16	Schedule 17	Sch. 10 (*Allocations*)	Sch. 16 (*Allocations*)	Sch.17 (*Allocations*)
Accrued Liabilities							
Subtotal	$ 60.65	$ 30.52	$ 3.43	$ 26.69	50.3%	5.7%	44.0%
Capitalized Leases							
Subtotal	$ 0.28	$ 0.14	$ 0.02	$ 0.12	50.3%	5.7%	44.0%
Deferred Revenue							
Subtotal	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	45.0%	10.0%	45.0%
Notes Payable							
Subtotal	$ 97.50	$ 43.88	$ 9.75	$ 43.88	45.0%	10.0%	45.0%
Interest Expense							
Accrued Interest	$ 2.80	$ 0.26	$ 0.28	$ 1.26	45.0%	10.0%	45.0%
Remaining Interest	$ 11.19	$ 5.04	$ 0.12	$ 5.04	45.0%	10.0%	45.0%
Subtotal	$ 13.99	$ 5.30	$ 0.40	$ 6.30			
Operating Leases	$ 5.55	$ 2.99	$ 0.29	$ 2.28	53.8%	5.1%	41.0%
Total Liabilities	$ 177.97	$ 82.82	$ 14.88	$ 79.26			
Less: Cash [5]	$ 9.52	$ 4.28	$ 0.95	$ 4.28	45.0%	10.0%	45.0%
Total Financial Obligation	$ 168.45	$ 78.54	$ 13.93	$ 74.98			

($Millions)		Schedule 10 [3]	Schedule 16	Schedule 17 [4]
Billing Determinants - excludes non-Tos				
Big Rivers Power Cooperative (BREC)		13.31	-	-
Midwest ISO Transmission Owners - Total (+ MidAm - FE + BREC)		779.39	-	-
Company Percentage	1.707%	1.707%	N/A	N/A

	Total Exit Fee	Schedule 10	Schedule 16	Schedule 17
Net Exit Fee Obligation ($Millions)	$ 2.88	N/A	N/A	N/A

Notes:

1 Deferred Revenue liability related to ComEd & LGE Withdrawal Obligation offset by cash received that is reflected in the Cash Balance.
2 Accrued Interest liability offset by cash received to pay accrued interest that is included in the Cash balance.
3 Sch. 10 BREC and Midwest ISO Billing Determinants are sourced from the Midwest ISO Load Forecasting Team (ICCP data). 7/08 through 6/09 actual results were used.
4 Actual Sch 16 & 17 Billing Determinants unavailable for BREC
5 Cash does not include MP restricted deposits
6 Midwest ISO Total Sch. 10 Billing Determinants include MEC & MPW, since they will be joining Midwest ISO prior to 12/31/09; and removes FE & related parties.
7 Total Exit Fee Obligation based on Sch. 10 Load Ratio Share (since Sch. 16 & Sch. 17 Billing Determinants for BREC are unavailable).
8 Includes $45M in Debt for new Data Center (Issued 2/1/2010 - 20 yr term).
9 Includes two $50M Debt issues (7/1/2012 & 7/1/2014 - 5 yr term) and one $75M isssued 7/2016 - 5 year term

4/28/2010

Item KIUC 2-5) ***Please refer to your response to KIUC item 1-24.***

a. ***Assuming that FERC approves Option A grandfather status for Big Rivers' non-Smelter load, what is the revenue impact expected to be for each year from 2011-2014? Please provide all computer models, workpapers and other documents which support your answer.***

Response) Under Option A, Big Rivers would participate in all Midwest ISO markets, and must nominate and hold Financial Transmission Rights. Big Rivers was assumed to participate in all Midwest ISO markets in the Midwest ISO Case analyzed in my Direct Testimony, see Table 2 on page 28 of my Direct Testimony for the impacts. As noted in my testimony on page 32, "Big Rivers will nominate and hold Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) as a member of the Midwest ISO that will be expected to cover its internal congestion costs (the difference in location prices between Big Rivers' load withdrawal and power supply injections). However, in practice, the value of the FTRs and ARRs may be more or less than actual congestion costs." While I did not incorporate any costs for transmission expansion in my analyses, under currently existing Midwest ISO rules, any load for which Option A grandfather status applies would be exempt from such charges.

Witness) Ralph L. Luciani

Item KIUC 2-6) ***Please refer to PSC Item 1-1. Please update this response.***

Response) Big Rivers has continued discussion of power purchase options with Southern Illinois Power Cooperative, Paducah Power System and most recently with Owensboro Municipal Utilities. Bluegrass Generating Company, LLC (the entity whose identity was withheld due to confidentiality concerns, which have since been addressed, in the response to PSC 1-1 dated April 7, 2010) is another entity with which Big Rivers is evaluating alternative arrangements and structures that might result in a way for Big Rivers to satisfy its Contingency Reserve requirements without joining the Midwest ISO. While no alternative solution to the Contingency Reserve problem has been identified, Big Rivers continues to explore alternatives to Midwest ISO membership.

Witness) David G. Crockett

Item KIUC 2-7) *Please refer to PSC item 1-2.*

a. ***Please provide all computer models with cells in tact, workpapers and other documents which support the $8.8 million and $3.8 million calculations.***

b. ***Please provide the same information requested in PSC item 1-2 for each year from 2011 through 2020. Please include all computer models with cells in tact, workpapers and other documents which support this calculation.***

c. ***Does the $3.8 million cost, if GFA load is excluded, assume that (i) none of Big Rivers' wholesale power contracts have GFA status or (ii) only the wholesale power contracts with the Distribution Cooperatives have GFA status?***

d. ***With reference to item (c) above, please provide the cost estimate for the scenario, either (i) or (ii), that is not implicit in your original response.***

Response) The estimates provided previously in response to PSC Item 1-2 as well as the refinements provided below in subparts (a) through (d), inclusive, are based on a number of assumptions under the March 22, 2010 Midwest ISO proposed straw proposal known as Injection-Withdrawal methodology ("I/W"). There have been numerous Organization of MISO States - Cost Allocation, Regional Planning ("OMS-CARP") and stakeholder meetings that led up to the I/W as well as other proposed methodologies still under discussion since March 22, 2010. The focus of these numerous OMS-CARP and stakeholder meetings over the last fifteen months has been a concerted effort to address the complex issue of establishing a fair allocation of costs to enable transmission system development to support reliability and economic goals, renewable resource integration, and other public policy objectives, while maintaining the Midwest ISO Value Proposition. There has been and continues to be a considerable amount of OMS-CARP and stakeholder feedback, input, and direction provided to the Midwest ISO to assist it with the important determination of what methodology should be selected and presented to FERC in the Midwest ISO's July 15, 2010 filing. Accordingly, the proposed cost allocation modifications that the Midwest ISO will ultimately make in its July 2010 FERC filing continues to evolve and change, even since the March 22, 2010 Injection-Withdrawal straw proposal. Cost estimates for Big Rivers excluding their GFA load based on the proposals currently under consideration is available on the Midwest ISO website.1 It must further be noted that these estimates do not reflect or capture amounts that would, likewise, be contributed and paid by the other transmission owners toward transmission upgrades that Big Rivers proposes and are included in the same process.

a. See the file titled "BREC Response to KIUC Question 2-7a Model based on All BREC Load .xlsm" on the attached CD for the supporting calculation of the $8.8 million estimate of total charges to Big Rivers load in the 2014 test year. The $8.8 million estimate is located on the tab named "Retail and State Impact" in cell I23.

See the file titled "BREC Response to KIUC Question 2-7a Model based on Non-GFA Load .xlsm" on the attached CD for the supporting calculation of the $3.8 million estimate of total charges to Big Rivers load in the 2014 test year. The $3.8 million estimate is located on the tab named "Retail and State Impact" in cell I23.

b. Using the proxy annual charges to Big Rivers' load under the proposed I/W proposed cost allocation methodology2 in the 2014 and 2024 studied test year the following graph (see Figure 1, below), is a reasonable estimate of the intervening years of 2011 through 2013 and 2015 through 2023 based on linear interpolation. Linear interpolation is a simplistic approach that is the only reasonable way to timely provide the

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[1] Link to document titled – "Cost Allocation Proposal Comparisons"
http://www.midwestmarket.org/publish/Document/ff6bb_1280201754d_-7e3a0a48324a?rev=2

[2] See preliminary qualifications set forth at the beginning of this response regarding the cost estimates that are based on Injection/Withdrawal Proposal of March 22, 2010.

annual estimates requested in this data request. There has not been, nor is there time and resources to do an depth methodological study or analysis for each of the years identified in the data request. It must be further noted that this interpolation estimate graph does not reflect or capture amounts that would, likewise, be contributed by the other transmission owners toward transmission upgrades that Big Rivers proposes and are included in the same process, which would only tend to drive the cost estimates down.

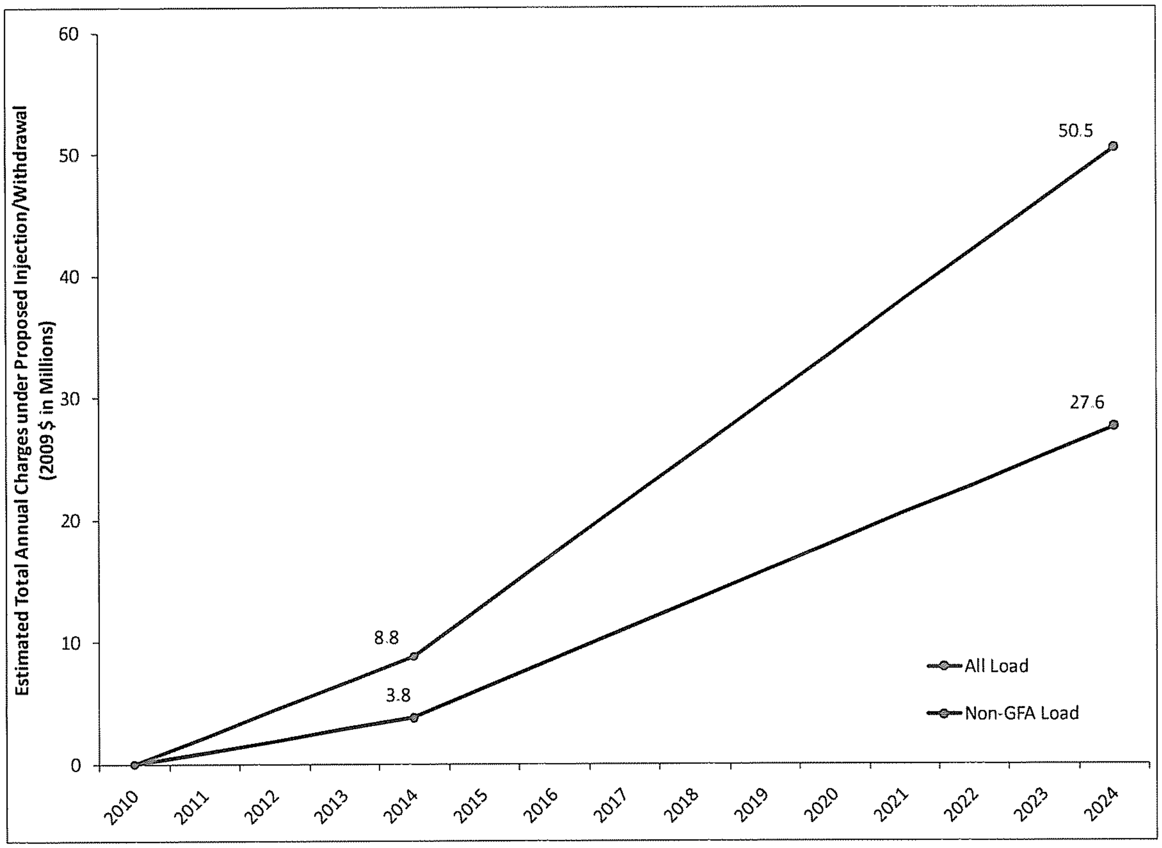

Figure 1. Interpolated 2010 to 2024 Estimated Annual Charges to Big Rivers' based on I/W Proposal (March 22, 2010)

c. The $3.8 million estimate is based on only the wholesale power contracts with the Distribution Cooperatives having GFA status.

d. The $8.8 million estimate provided represents scenario (i) where none of Big Rivers' wholesale power contracts have GFA status.

Witness) Clair J. Moeller, Midwest ISO

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO KIUC'S
APRIL 19, 2010 SECOND DATA REQUEST
PSC CASE NO. 2010-00043
April 30, 2010

Item KIUC 2-8) ***Please refer to PSC item 1-7.***

a. Please provide all computer models with cells in tact, workpapers and other documents which support the $736,981 and $147,396 calculations.

b. Please provide the same information requested in PSC item 1-7 for each year from 2011 through 2020. Please include all computer models with cells in tact, workpapers and other documents with support this calculation.

c. MISO estimates that Big Rivers' share of the 2009 MTEP costs, if Big Rivers had been a member of MISO in 2009, would have been $736,981 with an annual revenue requirement of $147,396 assuming 700 MW of load had GFA status. Please provide the same information assuming none of Big Rivers' load had GFA status.

Response) a. See the file titled "BREC Response to Question 2-8a and c.xlsx" on the attached CD.

b. An estimate of Big Rivers' annual charges assuming the cost allocation methodology in effect during 2009 has been made using studied projects for 2014 and 2024. The transmission facilities included in the analysis performed for years 2014 and 2024 primarily represent reliability projects scheduled tentatively to go in-service through 2014 or 2024 but which have not yet been approved through the regional Midwest ISO planning process. Note that since Big Rivers has not yet been a part of the Midwest ISO planning process the projects included in the previously performed 2014 or 2024 analysis are located outside of the Big Rivers Pricing Zone. Also, note that under current Midwest ISO policy that relieves new entrants of the responsibility to pay for projects planned prior to their entry year, some of the modeled costs may, and probably would, ultimately be excluded from the transmission cost allocated to Big Rivers, thereby driving the estimated numbers shown below down. The cost allocation methodology applied to calculate the 2014 and 2024 cost estimates is based on the currently effective

Tariff as further described in the direct testimony of Witness Clair Moeller, starting on Page 18 Line 15.

In estimating the potential costs to Big Rivers under the current cost allocation methodology in 2014 and 2024 the Midwest ISO has performed the calculation with and without GFA load being allocated costs. Using the annual charges to Big Rivers' load under the current effective cost allocation methodology in the 2014 and 2024 test year an estimate of the intervening years of 2011 through 2013 and 2015 through 2023 based on linear interpolation, see Figure 2. Linear interpolation is a simplistic approach that is the only reasonable way to timely provide the annual estimates requested in this data request. There has not been, nor is there time and resources to do an in-depth methodological study or analysis for each of the years identified in the data request.

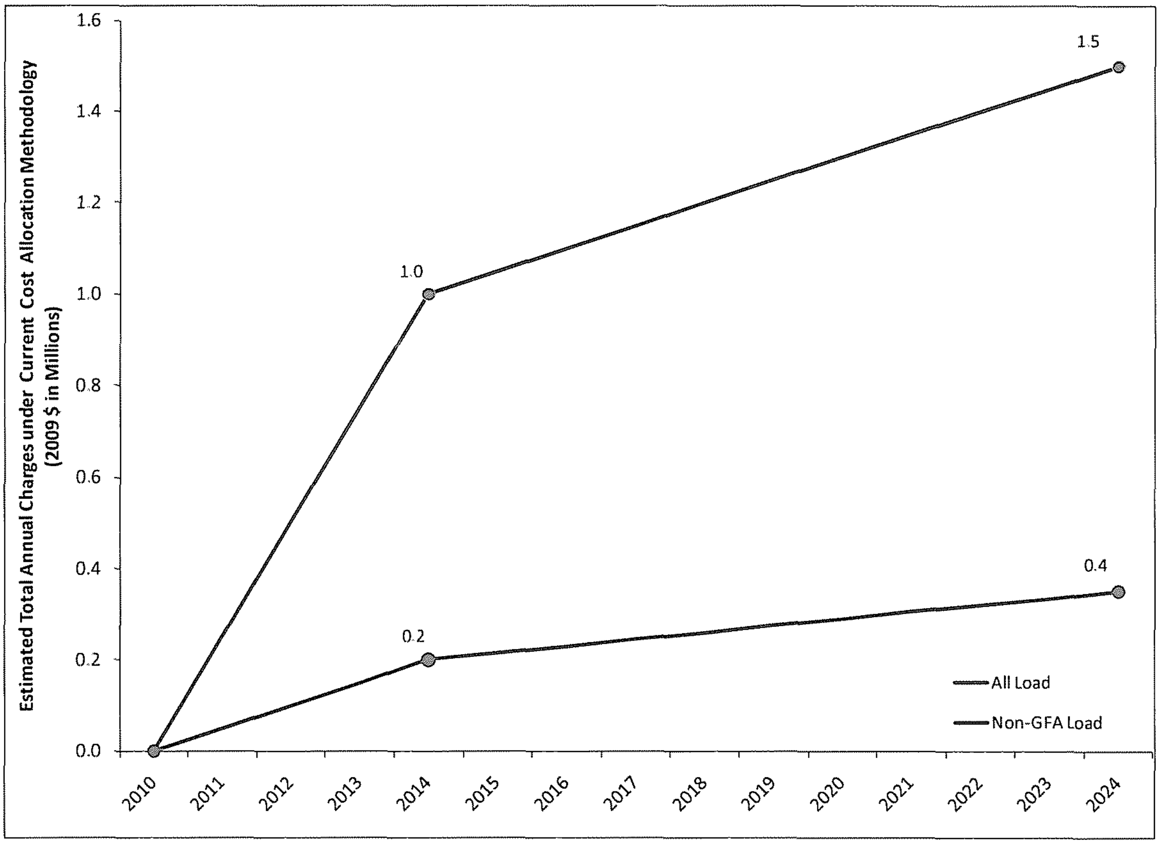

Figure 2. Interpolated 2010 to 2024 Estimated Annual Charges to Big Rivers' under the 2009 Cost Allocation Methodology

c. Assuming none of Big Rivers' load had GFA status the estimate of Big Rivers allocation of MTEP 09 project costs would be $907,898 (see Figure 3). Assuming a 20% Annual Charge Rate the Annual Revenue Requirement would be $181,580.

	Pricing Zone Allocation of Total Project Cost			
Pricing Zone	Baseline Reliability Project in METC (P1828)	Baseline Reliability Project in IPL (P2053)	Baseline Reliability Project in AMIL (P2472)	Regionally Beneficial Project in AMIL (P2829)
[1]	[2]	[3]	[4]	[5]
Ameren Illinois (AMIL)	176,719	788,839	55,531,438	623,059
Ameren Missouri (AMMO)	177,049		916,641	624,223
ATC System (ATC)	278,904		1,443,979	375,421
Big Rivers Electric Corporation (BREC)	**38,328**	**536,000**	**198,437**	**135,133**
City of Columbia, Missouri (CWLD)	5,903		30,559	20,811
City Water, Light & Power (Springfield, IL) (CWLP)	8,815		118,334	31,081
Cinergy Services (including IMPA & WVPA) (DUK)	251,260	6,950,797	1,300,857	885,870
American Trans. Sys. Inc. (FE)	275,180		1,424,698	737,003
Great River Energy (GRE)	24,840		128,606	33,436
Hoosier Energy (HE)	-	-	-	-
Indianapolis Power & Light (IPL)	64,008	3,755,970	331,389	225,673
International Transmission Company (ITC)	224,525		1,162,442	601,336
ITC Midwest/ ALTW (ITCM)	75,369		390,210	101,451
Montana-Dakota Utilities Co (MDU)	15,439		79,935	20,782
Michigan Joint Zone (METC,MPPA,Wolverine) (METC)	8,877,140		896,405	463,714
Michigan Joint Zone Subzone - GFA (MI13AG)			63,919	33,066
Michigan Joint Zone Subzone - Non-GFA (MI13ANG)	3,232		16,735	8,657
Minnesota Power (MP)	44,990		232,930	60,560
Northern Indiana Public Service Company (NIPS)	71,669		371,055	191,948
NSP Companies (NSP)	214,144		1,108,697	288,251
Otter Tail Power (OTP)	19,094		98,858	25,702
Southern Illinois Power Cooperative (SIPC)	-		-	-
Southern Minnesota Municipal Power Agency (SMMPA)	6,378		33,023	8,586
Vectren Energy (VECT)	27,013	1,368,394	139,854	95,239
Total Project Costs (2009$)	10,880,000	13,400,000	66,019,000	5,591,000

Figure 3. Estimate of Big Rivers' Allocation of MTEP 09 Projects assuming all of Big Rivers' Load is included for Cost Sharing

Witness) Clair J. Moeller, Midwest ISO

Item KIUC 2-9) *Please refer to PSC item 1-15.*

a. Please provide all computer models with cells in tact, workpapers and other documents which support the calculations in your response.

b. Please provide all computer models with cells in tact, workpapers and other documents which support Tables 3-1, 3-2, 3-3 and 3-4 to Mr. Luciani's testimony, which served the basis for this response.

c. Please confirm that the analysis performed in response to PSC item 1-15 and Tables 3-1, 3-2, 3-3 and 3-4 only considers production costs, and does not consider capital or other operation and maintenance costs that would be required to run the Big Rivers generating units at the much higher capacity factors assumed in the MISO case versus the Stand Alone case. Has Big Rivers attempted to calculate the additional capital and operating and maintenance costs necessary to run its generation at the higher capacity factors assumed for the MISO case? If yes, please provide that information. Does Big Rivers' management believe that it can operate its units at the capacity factors identified on Table 3-4 for the first five years of MISO membership without increased capital or operating and maintenance costs?

d. Please provide the off-systems sales margin information requested by Staff comparing the MISO case versus the Base Case from the December 17, 2009 Preliminary Assessment, not the Stand Alone Case offered in testimony.

Response) a. Supporting material is provided in the attached CD-ROM. The GE MAPS model used by CRA for Big Rivers is available for license from GE. The detailed output data for the GE MAPS runs performed by CRA for Big Rivers contains CRA commercially sensitive material and has not been provided to Big Rivers.

b. See response to part a.

c. The analysis described in my testimony and summarized in PSC 1-15 considers production costs, including variable O&M costs, that would be required to operate Big Rivers units at varying capacity factors. Fixed O&M and capital expenditures were not assumed to change over the operating range of the generating units in this analysis. Note that the Big Rivers generating units are more often operating at less than maximum load in the Stand-alone Case, and thus the capacity factor of the units in the Stand-alone Case will tend to decrease more than the plant operating hours. My understanding based on discussions with Big Rivers' production department is that capital and fixed operating and maintenance costs would be largely unchanged under this scenario.

d. The purchase and sales revenue of Big Rivers as a hypothetical member of the terminated MCRSG ("Hypothetical MCRSG Case") was analyzed for 2011 as summarized in the response to KIUC 1-2. The Hypothetical MCRSG Case reflects the total generation, purchase costs and sales revenue that Big Rivers would expect as a market participant in the Midwest ISO market as a member of the Hypothetical MCRSG, but not as a Midwest ISO member. See the table below for the purchase and sale data for 2011 for the Hypothetical MCRSG Case in comparison to the Midwest ISO Case. As shown, Big Rivers would make 324 GWh of total off-system sales for $13.7 million as a Midwest ISO member, and 253 GWh for $10.9 million as a Hypothetical MSCRG Midwest ISO participant. Similarly, Big Rivers would make 1,075 GWh of off-system purchases for $29.9 million as a Midwest ISO member, and 971 GWh for $27.5 million as a Hypothetical MCRSG Midwest ISO participant. Overall, Big Rivers being a member of the Midwest ISO would yield total costs to serve Big Rivers' load (in terms of fuel cost plus purchased power net of sales revenue) that are $2.4 million less than those it would incur as a Hypothetical MCRSG Midwest ISO participant. As discussed on page 23 of my Direct Testimony, the estimate of Big Rivers sales and purchases uses the hourly tie-line flows into and out of Big Rivers from the GE

MAPS modeling, with the net interchange across those tie lines aggregated on an hourly basis to determine if Big Rivers is a net purchaser or seller in that hour. As such, an analysis of Big Rivers sales and purchases solely in the Midwest ISO market was not separately derived.

Sources and Costs to Serve Big Rivers Load

Hypothetical MCRSG Case vs. Midwest ISO Case

	Hypothetical MCRSG 2011	Midwest ISO 2011	Increase 2011
GWh			
+ Generation	11,498	11,464	(33.1)
+ Purchases	971	1,075	104.1
- Sales	253	324	70.9
= Total	12,215	12,215	0.0
M$			
+ Generation Costs	$372.9	$371.0	($1.9)
+ Purchase Costs	$27.5	$29.9	$2.3)
- Sales Revenue	$10.9	$13.7	$2.9
= Total	$389.6	$387.2	($2.4)
$/MWh			
Generation	32.4	32.4	(0.1)
Purchases	28.4	27.8	(0.6)
Sales	43.0	42.4	(0.6)
Total	31.9	31.7	(0.2)

Witness) Ralph L. Luciani

Item KIUC 2-10) ***Please provide the purchase power information requested in PSC item 1-16 comparing the MISO case versus the Base Case from the December 17, 2009 Preliminary Assessment, not the Stand Alone Case offered in testimony.***

Response) See the response to KIUC 2-9(d).

Witness) Ralph L. Luciani

Item KIUC 2-11) ***Please refer to PSC item 1-22. Does Big Rivers agree with Mr. Doying of MISO that "ARC participation, if allowed by the KPSC, can only enhance the positive financial impacts to Big Rivers"? Please explain your answer.***

Response) I agree with Mr. Doying that, in concept and if properly implemented, the Midwest ISO's proposal to permit Aggregators of Retail Customers ("ARC") to sell demand response directly into the wholesale market should provide benefits to Big Rivers. However, the tariff changes to implement the Midwest ISO's proposal have not yet been approved by FERC, and several parties have filed comments at FERC with questions and concerns regarding the details of implementing the proposal. In its response at FERC, the Midwest ISO clarified a number of points and indicated its willingness to make certain requested compliance modifications to its tariff, if ordered to do so by FERC. FERC has not acted on the filing, so the Midwest ISO has not yet made any of those additional changes. Moreover, as noted by the Midwest ISO in its response to PSC 1-18, implementation of the ARC program in Kentucky requires approval from the Kentucky Public Service Commission. The Commission will have to approve the participation of ARCs in Kentucky and other implementing details. The Commission must also establish the Marginal Foregone Retail Rate used to set the compensation level for ARCs and load serving entities.

Witness) David G. Crockett

Item KIUC 2-12) ***Please refer to Big Rivers' response to PSC 1-10. At what point in time will MISO seek FERC approval of its recommendation as to GFA status of certain of Big Rivers' wholesale contracts? What is MISO's best judgment as to when FERC will act on the recommendation? Will it be prior to or subsequent to the KPSC hearing and Order in this proceeding?***

Response) The Midwest ISO submitted a section 205 filing on April 7, 2010 (Docket No. ER10-1024-000) to the Federal Energy Regulatory Commission ("FERC") to revise the Midwest ISO's Attachment P (list of Grandfathered Agreements) proposing to include Big Rivers' GFA agreements. See attached document.

Witness) Clair J. Moeller, Midwest ISO

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April 6, 2010

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**Re: Midwest Independent Transmission System Operator, Inc.
Section 205 Filing to Revise Attachment P (List of Grandfathered Agreements) of Open Access Transmission, Energy and Operating Reserve Markets Tariff to List Big Rivers Electric Corporation's Grandfathered Agreements
Docket No. ER10-1024-000**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq*., the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") respectfully seeks Commission acceptance and approval of the proposed classifications for certain Grandfathered Agreements ("GFAs") of Big Rivers Electric Corporation ("Big Rivers") in connection with the integration of Big Rivers into the Midwest ISO as a new transmission-owning member.

Big Rivers plans to be integrated into the Midwest ISO on September 1, 2010. Although such an integration date is several months away, the Midwest ISO requests expedited resolution of this filing on or before June 1, 2010, in order to enable the Midwest ISO to include the GFAs of Big Rivers in the next Commercial and Network Models in preparation for the integration, and to enable Big Rivers to participate in a partial-year allocation of Financial Transmission Rights ("FTRs") between September 1, 2010 and the June 1, 2011 start of the next annual period for allocating Auction Revenue Rights ("ARRs").

Because the Kentucky Public Service Commission ("PSC") must first approve Big Rivers' transfer of functional control of its transmission facilities to the Midwest ISO, it may be necessary for the Midwest ISO to make a later filing to remove the proffered tariff sheets submitted today, if that approval is not forthcoming. The purpose of this filing is to obtain an order from this Commission to establish the basis for modeling Big Rivers' GFAs on the Midwest ISO's system, and for Big Rivers' participation in the partial-year allocation of FTRs, pending the Kentucky PSC's order approving the integration of Big Rivers into the Midwest ISO.

I. INTRODUCTION

On December 8, 2009, Big Rivers submitted an application to join the Midwest ISO as a Transmission Owner. The present filing to amend Attachment P of the Tariff is the first in a series of filings designed to integrate Big Rivers as a Transmission Owner.[1] As discussed below, the Midwest ISO proposes to include Big Rivers' existing transmission agreements in Attachment P as either Carved-Out or Option A GFAs.

The Midwest ISO is a Commission-approved RTO that provides transmission service pursuant to rates, terms and conditions of its Tariff on file with the Commission.[2] The Midwest ISO commenced commercial operations on December 15, 2001, and began providing Point-to-Point Transmission Service and Network Integration Transmission Service ("NITS") under its Tariff on February 1, 2002. The Midwest ISO ensures reliable operation of, and equal access to, 93,600 miles of interconnected, high-voltage lines in 15 states and the Canadian province of Manitoba. The Midwest ISO also manages one of the world's largest energy markets, clearing approximately $3 billion in energy transactions monthly. The Midwest ISO is a non-profit Section 501(c)(4) organization governed by an independent board of directors. The Midwest ISO is headquartered in Carmel, Indiana, with operations centers therein and in St. Paul, Minnesota.

Big Rivers is a generation and transmission electric cooperative organized as a corporation under Kentucky law for the principal purpose of providing the wholesale electricity requirements of its three distribution corporation member-owners: Kenergy Corporation ("Kenergy") (successor -in-interest of Henderson-Union Rural Electric Cooperative Corporation ("Henderson-Union") and Green River Electric Corporation ("Green River")); Meade County Rural Electric Cooperative Corporation ("Meade County"); and Jackson Purchase Energy Corporation ("Jackson Purchase") (collectively, the "Members"). These members provide retail electric service to approximately 111,000 consumers located in 22 Western Kentucky counties.[3]

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1 These include a filing under Section 205 of the FPA to amend the ASM Tariff to incorporate references to the Big Rivers zone within the Midwest ISO; and a filing on the assignment of transmission service arrangements from Big Rivers to the Midwest ISO's Tariff.

2 *Midwest Indep. Trans. System Operator, Inc.*, 97 FERC ¶ 61,268 (2001).

3 The 22 Kentucky counties served by Big Rivers' members are: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union and Webster.

In addition, Big Rivers has shared transmission or interconnection arrangements with several municipal utilities or cooperatives, including Louisville Gas & Electric ("LG&E") and Associated Electric. Big Rivers owns more than 1,459 megawatts of generating capacity and has contract rights to an additional 395 megawatts. Big Rivers' historic peak load is 1565 megawatts. Big Rivers is not a "public utility" within the contemplation of the FPA, but owns or operates 1,262 miles of transmission facilities. At several points, the transmission facilities owned or operated by Big Rivers are interconnected with transmission facilities over which the Midwest ISO exercises functional control. Big Rivers' rates for service to its members are regulated by the Kentucky Public Service Commission.

II. BIG RIVERS' GFAs

Big Rivers is a party to several agreements under which it provides or receives interconnection, interchange or transmission services. All of these agreements were executed prior to September 16, 1998, and thus are potentially eligible for consideration as GFAs.[4] This request to classify Big Rivers' GFAs is submitted in accordance with the procedural approach established by the Commission,[5] and followed in earlier revisions to Attachment P.[6]

Pursuant to the amendment to Section 38.8.3(A) of the Tariff that was accepted by the Commission's December 15, 2009 Order in Docket No. ER10-73-000,[7] the agreements of Big Rivers with its three member-cooperatives are not eligible to be classified as Carved-Out GFAs, but they can qualify for Option A or C treatment. On the other hand, Big Rivers' agreements with non-member wholesale customers are eligible to be carved out based on the non-jurisdictional status of Big Rivers.

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4 Transmission-related agreements originally executed before September 16, 1998 can generally be classified as Grandfathered Agreements ("GFAs"). Section 1.276 of Midwest ISO's Tariff.

5 *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 at P 422 (2005).

6 *E.g., Midwest Independent Transmission System Operator, Inc.*, 128 FERC ¶ 61,046 (2009) (order conditionally accepting, among other things, integration of MidAmerican's GFAs); Letter Order dated February 14, 2006 in Docket No. ER06-350-000 (accepting Attachment P revisions to reflect Wolverine's GFAs when it became a Midwest ISO Transmission-Owner).

7 *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,221 at P 39-43 (2009).

Big Rivers has held extensive discussions with its counterparties to the GFAs listed below. Where possible, Big Rivers has reached agreement with the counterparty concerning the proposed GFA treatment. In the aggregate, the total load to be carved out comprises 96 MW, or approximately 7 percent of the total Big Rivers load. This low carve-out percentage is consistent with the previous GFA orders, in which the Commission allowed carve-outs only to the extent they constitute a small and gradually diminishing proportion of the Midwest ISO's total load.[8] For GFAs that are not eligible to be carved out, Big Rivers has chosen Option A treatment. In the aggregate, the total load eligible for Option A comprises 651 MW.

Based on the above criteria, the Midwest ISO proposes to amend Attachment P to the Tariff to indicate the GFA status and treatment of certain Big Rivers contracts, as follows:

(1) Indicate that Big Rivers is also a Transmission Owner-party to the following two existing Carved-Out GFAs:

- GFA No. 332 (Tariff Sheet No. 2833): "Transmission Line Agreement" dated February 1, 1981, between Big Rivers and SIPC.

- GFA No. 341 (Tariff Sheet No. 2835): "Interconnection Agreement" dated April 1, 1968, among Indiana Statewide Rural Electric Cooperative, Inc. acting through its Hoosier Energy Division, Southern Illinois Power Cooperatives ("SIPC"), Big Rivers, and City of Henderson, Kentucky, acting through its Utility Commission ("the City of Henderson").

(2) Add the following new Carved-Out GFAs:

- "Agreement for Transmission and Transformation Capacity" dated April 11, 1975, between Big Rivers and the City of Henderson. (GFA No.510 , Tariff Sheet No. 2882)

- Letter Agreement between Big Rivers and the City of Henderson, dated July 30, 1984, regarding the City of Henderson's contract with the Southeastern Power Administration ("SEPA"). (GFA No. 511, Tariff Sheet No. 2882)

- Contract between Big Rivers and SEPA dated June 30, 1998 (GFA No. 512, Tariff Sheet No. 2882)

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8 *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 at P 143 (2004) ("September 16, 2004 Order"), *order on reh'g*, 111 FERC P 61,042 (2005); *Midwest Independent Transmission System Operator, Inc.*, 121 FERC ¶ 61,166 at 70, 45, 48 (2007).

- Interconnection Agreement between Big Rivers and Louisville Gas and Electric Company dated December 21, 1973, as amended. (GFA No. 513, Tariff Sheet No. 2882)

- Interchange Agreement between Big Rivers and Associated Electric Cooperative, Inc., dated April 16, 1993. (GFA No. 514, Tariff Sheet No. 2883)

(3) Add the following Option A GFAs:

- Wholesale Power Agreement dated October 14, 1977, between Big Rivers and Jackson Purchase Rural Electric Cooperative Corporation, as amended. (GFA No. 515, Tariff Sheet No. 2883)

- Wholesale Power Contract dated June 11, 1962, between Big Rivers and Meade County Rural Electric Cooperative Corporation, as amended. (GFA No. 516, Tariff Sheet No. 2883)

- "Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Green River Electric Corporation, as amended (GFA No. 517, Tariff Sheet No. 2883)

- "Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Henderson-Union, as amended (GFA No. 518, Tariff Sheet No. 2884)

III. DOCUMENTS SUBMITTED IN THIS FILING

In addition to this transmittal letter, the documents being submitted in this filing are as follows:

Tab A – Redlined Tariff sheets

Tab B – Clean Tariff sheets

IV. PROPOSED EFFECTIVE DATE AND REQUEST FOR WAIVERS

The Midwest ISO respectfully requests an effective date of September 1, 2010, which is the planned date of Big Rivers' integration into the Midwest ISO. However, the Midwest ISO requests an expedited resolution of the present filing on or before June 1, 2010, due to the need to include Big Rivers' GFAs in the Midwest ISO's Commercial Model and Network Model in advance of the September 1, 2010 integration date, to pave the way for the participation of Big Rivers in the partial-year allocation of FTRs between September 1, 2010 and the next Annual ARR Allocation period. For this purpose, which constitutes good cause shown, the Midwest ISO respectfully requests waiver of the customary 120-day maximum notice requirement, 18 C.F.R. § 35.3 (2009).[9]

V. NOTICE AND SERVICE

A. Notice

Please place the following persons on the official service list in this proceeding:

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Counsel for Midwest Independent
Transmission System Operator, Inc.

* Persons designated to receive official service.

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9 *Cal. Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,271 at P 406 (2008) (finding good cause to waive 120-day maximum notice requirement "to allow the IBAA [Integrated Balancing Authority Area] proposal to be incorporated into the MRTU market systems and fully tested in time for the start of MRTU, which will take several months"), *order on reh'g*, 128 FERC ¶ 61,103 at P 327 (2009); *ISO New England, Inc., et al.*, 123 FERC ¶ 61,190 at P 46 in relation to P 6 (2008) (finding good cause "to delay implementation of the Reservation Flexibility Changes to provide ISO-NE's Internal Market Monitoring Unit with time to develop a process to ensure that market participants with external transactions submit competitively priced energy offers in support of a capacity obligation").

B. Service

The Midwest ISO hereby respectfully requests waiver of the requirements set forth in 18 C.F.R. § 385.2010. The Midwest ISO has served a copy of this filing electronically, with attachments, upon all Tariff Customers under the ASM Tariff, Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, and all state commissions within the Region, as well as the counterparties to the GFAs discussed herein. In addition, the filing has been posted electronically on the Midwest ISO's website at www.midwestmarket.org under the heading "Filings to FERC" for other interested parties in this matter.

Good cause exists for granting this waiver due to the number of interested parties in this matter, the limited resources available to make service, and the financial burden to the Midwest ISO in copying and mailing copies of this filing. Many parties, in fact, prefer receiving their copy in electronic format or via the Midwest ISO's website. In addition, paper copies will be made available to any person upon request by contacting counsel of record for the Midwest ISO.

VI. CONCLUSION

For all of the foregoing reasons, the Midwest ISO respectfully requests the Commission to accept for filing the proposed revisions to Attachment P of the Midwest ISO's Tariff, effective September 1, 2010; and to expedite the resolution of this filing on or before June 1, 2010, to enable the Midwest ISO to model the GFAs of Big Rivers in preparation for its participation in the partial-year allocation of FTRs. The Midwest ISO further requests that the Commission waive any regulations it may deem applicable in this instance, including any not specifically identified herein.

Respectfully submitted,

Daniel M. Malabonga
Duane Morris LLP

Gregory A. Troxell
Assistant General Counsel
Midwest Independent Transmission System
Operator, Inc.

Counsel for the Midwest Independent Transmission
System Operator, Inc.

/Attachments

cc: Big Rivers Electric Corporation
Jeffrey Hitchings, FERC
Patrick Clarey, FERC
Christopher Miller, FERC
Penny Murrell, FERC
Melissa Lord, FERC
Michael Donnini, FERC
Natalie Tingle-Stewart, FERC

CONTRACT NO.	**339**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative
CONTRACT PARTY (IES)	Illinois Power Company
CONTRACT TITLE	Interconnection Agreement and as amended thereto
DATED	March 1, 1983
RATE SCHEDULE NO.	N/A
GFA TREATMENT	EXCLUDED FROM GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**340**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative / Ameren Services Company
CONTRACT PARTY (IES)	Central Illinois Public Service Company
CONTRACT TITLE	Interconnection Agreement
DATED	May 2, 1972
RATE SCHEDULE NO.	N/A
GFA TREATMENT	EXCLUDED FROM GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**341**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative / Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Indiana Statewide Rural Electric, Inc.~~,~~ ~~Big Rivers Rural Electric Cooperative Corporation,~~ and City of Henderson, Kentucky
CONTRACT TITLE	Interconnection Agreement and as amended thereto
DATED	April 1, 1968
RATE SCHEDULE NO.	N/A
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**510**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	City of Henderson, Kentucky
CONTRACT TITLE	Agreement for Transmission and Transformation Capacity
DATED	April 11, 1975
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**511**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	City of Henderson, Kentucky
CONTRACT TITLE	Letter Agreement
DATED	July 30, 1984
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**512**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Southeastern Power Administration
CONTRACT TITLE	
DATED	June 30, 1998
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**513**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Louisville Gas and Electric Company
CONTRACT TITLE	Interconnection Agreement
DATED	December 21, 1973
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**514**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Associated Electric Cooperative
CONTRACT TITLE	Interchange Agreement
DATED	April 16, 1993
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**515**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Jackson Purchase Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Agreement
DATED	October 14, 1977
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

CONTRACT NO.	**516**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Meade County Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

CONTRACT NO.	**517**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Kenergy Corporation, as successor-in-interest of Green River Electric Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	GFA 517 also covers Kenergy's requirements under agreements to which Big Rivers has concurred through letters dated April 4, 2001, May 31, 2002, March 10, 2008, August 2, 2004, and May 11, 2009.

CONTRACT NO.	**518**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Kenergy Corporation, as successor-in-interest of Henderson-Union Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	GFA No. 518 also covers Kenergy's requirements under agreements to which Big Rivers has concurred through letters dated March 3, 2008 and March 10, 2008.

[SHEET NOS. 288~~2~~5 THROUGH 2890 RESERVED FOR FUTURE USE]

CONTRACT NO.	**332**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative / Big Rivers Electric Corporation
CONTRACT PARTY (IES)	
CONTRACT TITLE	1981 Transmission Line Agreement and as amended thereto
DATED	February 1, 1981
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**333**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative
CONTRACT PARTY (IES)	Southeastern Illinois Electric Cooperative
CONTRACT TITLE	Wholesale Power Contract
DATED	December 8, 1959
RATE SCHEDULE NO.	Schedule "A"
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**334**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative
CONTRACT PARTY (IES)	Egyptian Electric Cooperative Association
CONTRACT TITLE	Wholesale Power Contract and as amended thereto
DATED	December 8, 1959
RATE SCHEDULE NO.	Schedule "A"
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**339**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative
CONTRACT PARTY (IES)	Illinois Power Company
CONTRACT TITLE	Interconnection Agreement and as amended thereto
DATED	March 1, 1983
RATE SCHEDULE NO.	N/A
GFA TREATMENT	EXCLUDED FROM GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**340**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative / Ameren Services Company
CONTRACT PARTY (IES)	Central Illinois Public Service Company
CONTRACT TITLE	Interconnection Agreement
DATED	May 2, 1972
RATE SCHEDULE NO.	N/A
GFA TREATMENT	EXCLUDED FROM GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**341**
TRANSMISSION OWNER(S)	Southern Illinois Power Cooperative / Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Indiana Statewide Rural Electric, Inc. and City of Henderson, Kentucky
CONTRACT TITLE	Interconnection Agreement and as amended thereto
DATED	April 1, 1968
RATE SCHEDULE NO.	N/A
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**510**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	City of Henderson, Kentucky
CONTRACT TITLE	Agreement for Transmission and Transformation Capacity
DATED	April 11, 1975
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**511**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	City of Henderson, Kentucky
CONTRACT TITLE	Letter Agreement
DATED	July 30, 1984
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**512**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Southeastern Power Administration
CONTRACT TITLE	
DATED	June 30, 1998
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**513**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Louisville Gas and Electric Company
CONTRACT TITLE	Interconnection Agreement
DATED	December 21, 1973
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**514**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Associated Electric Cooperative
CONTRACT TITLE	Interchange Agreement
DATED	April 16, 1993
RATE SCHEDULE NO.	
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**515**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Jackson Purchase Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Agreement
DATED	October 14, 1977
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

CONTRACT NO.	**516**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Meade County Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

CONTRACT NO.	**517**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Kenergy Corporation, as successor-in-interest of Green River Electric Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	GFA 517 also covers Kenergy's requirements under agreements to which Big Rivers has concurred through letters dated April 4, 2001, May 31, 2002, March 10, 2008, August 2, 2004, and May 11, 2009.

CONTRACT NO.	**518**
TRANSMISSION OWNER(S)	Big Rivers Electric Corporation
CONTRACT PARTY (IES)	Kenergy Corporation, as successor-in-interest of Henderson-Union Rural Electric Cooperative Corporation
CONTRACT TITLE	Wholesale Power Contract
DATED	June 11, 1962
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	GFA No. 518 also covers Kenergy's requirements under agreements to which Big Rivers has concurred through letters dated March 3, 2008 and March 10, 2008.

[SHEET NOS. 2885 THROUGH 2890 RESERVED FOR FUTURE USE]

Item KIUC 2-13) ***Please refer to Big Rivers' Response to PSC 1-17.***

a. With respect to lines 14-16, please describe the specific areas of the 2011 budget that will or can be reduced to allow Big Rivers to absorb the additional MISO costs and still maintain the target margin in 2011?

b. With respect to lines 16-19, please explain the basis for your testimony that MISO costs under Schedules 10, 16 and 17 can be recovered under Big Rivers Non-FAC PPA tariff and the balance will be deferred using the deferral accounting for Non-smelter purchase power.

Response) (a) Big Rivers would realize savings in the 2011 budget from labor and labor overhead due to all positions not being fully staffed. Also, specific non-labor O&M projects budgeted to take place in 2011 would be identified during the year based on then current operational needs and requirements. Additionally, should power markets recover in 2011, increased revenue from sales could cover the increased costs.

(b) Midwest ISO Schedules 10, 16 and 17 are for transmission and purchased power related costs, which would be expensed to Accounts 555 and 565, that are specifically allowed to be recovered under Section C(2)(a) of the Non-FAC purchased Power Adjustment Factor.

Witness) C. William Blackburn

Item KIUC 2-14) ***Please refer to KIUC 1-9. This request was intended for Big Rivers' management as to whether it believes MISO membership will result in an annual benefit of $20 million to $26 million. A response is requested from Big Rivers' management rather than from Mr. Luciani.***

Response) Big Rivers believes that Midwest ISO membership offers significantly greater benefits to Big Rivers than the self-supply option that was available in late 2009. Big Rivers has not performed a detailed analysis and instead hired CRA to perform a non-biased evaluation of the potential cost/benefit of Midwest ISO membership in comparison to any other alternative solution including the Stand-alone option other than by performing an economic assessment similar to that performed by CRA. Therefore, Big Rivers accepts the results of that economic assessment which are represented by CRA to be an annual benefit of $20 million to $26 million.

Witness) David G. Crockett

Item KIUC 2-15) ***Please refer to KIUC 1-2, lines 27-28. For clarification, does the phrase "relative to being a member of the MCRSG" mean "compared to being a member of the MCRSG?"***

Response) Yes. More clearly, the phrase means "as compared to the hypothetical alternative of remaining a member of the terminated MCRSG."

Witness) Ralph L. Luciani

Item KIUC 2-16) ***Please refer to Big Rivers' response to KIUC 1-11 and 12. Is it not true that if Big Rivers found in a given year the approved MTEP costs to be unbearable and exited MISO, that it would still be required to pay its share of those costs as a non-member?***

Response) Please see the response provided by Midwest ISO witness Clair J. Moeller to Item 8(b) of the Commission Staff's initial data requests.

Witness) David G. Crockett

Item KIUC 2-17) ***Please refer to BigRivers' response to KIUC 1-14. Please provide all Documents relating to or reflecting Mr. Crockett's knowledge of the reserve sharing issue prior to April or May 2009 at which time Mr. Bailey was advised.***

Response) I had knowledge of the potential termination of the MCRSG Agreement prior to April or May, 2009. There was no reserve sharing issue prior to that timeframe. Therefore, there are no documents with respect to that issue prior to April or May, 2009.

Witness) David G. Crockett

Item KIUC 2-18) ***Please refer to Big Rivers' response to KIUC 1-16, lines 17-18. Please explain how Big Rivers believed it could structure a solution with TVA in order to address TVA's concerns.***

Response) Big Rivers proposed to provide its load ratio share of contingency reserve capacity to the group to meet the NERC standards as a reserve sharing group. Big Rivers proposed to supply contingency reserve to any of the other three members during their contingency events. Big Rivers proposed to receive contingency reserve from only E.ON and East Kentucky to meet its contingency events in order to honor the TVA concerns. However, this proposal was rejected by TVA indicating that it did not satisfy all of their concerns with respect to the benefits that Big Rivers would receive from the TVA generating assets. Big Rivers was informed by TVA on September 15, 2009, that TVA considered participation by Big Rivers in a reserve-sharing group to be prohibited by the TVA "fence" rules.

Witness) David G. Crockett

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO KIUC'S
APRIL 19, 2010 SECOND DATA REQUEST
PSC CASE NO. 2010-00043
April 30, 2010

Item KIUC 2-19) ***Please refer to Big Rivers' response to KIUC 1-26. Please provide the information received from Hoosier Energy concerning its experiences with the market settlements area of MISO.***

Response) A member of Mr. Blackburn's staff has had informal telephone conversations with Hoosier that have mainly involved setting up a date to visit Hoosier Energy to discuss their Midwest ISO experiences in more detail. Hoosier Energy has not provided any information to this staff member relevant to Hoosier's experiences with Midwest ISO.

On April 21, the staff member arranged to visit Hoosier Energy on April 28, 2010. Big Rivers will supplement this response as appropriate after that meeting.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO KIUC'S
APRIL 19, 2010 SECOND DATA REQUEST
PSC CASE NO. 2010-00043
April 30, 2010

Item KIUC 2-20) ***For each month during 2010 please provide the number, duration, amount in MW and cause of each event when Big Rivers was required to call on MISO for reserve sharing. This is a continuing request.***

Response) Big Rivers has requested and received contingency reserve supply from Midwest ISO on six occasions in each of the first three months of 2010 for a total of 18 occasions. The individual event summaries are provided monthly in the attached documents.

Witness) David G. Crockett

MISO CONTINGENCY RESERVE EVENTS						
January						
Date	Event	Reserve Requested	Start Time (CPT)	Stop Time (CPT)	Duration	
1/2/2010	Wilson two mill outages	140 MW	1852	1930	38 minutes	
1/4/2010	Henderson #1 outage	120 MW	0816	0900	44 minutes	
1/7/2010	Wilson mill outage	90 MW	2157	2230	33 minutes	
1/26/2010	Henderson #1 outage	120 MW	0624	0700	36 minutes	
1/26/2010	Green #1 FD fan outage	100 MW	1222	1300	38 minutes	
1/28/2010	Wilson mill outage	70 MW	2324	2400	36 minutes	

MISO CONTINGENCY RESERVE EVENTS

Date	Event	Reserve Requested	Start Time (CPT)	Stop Time (CPT)	Duration
February					
2/3/2010	Wilson mill outage	80 MW	2338	0015	37 minutes
2/9/2010	Henderson #1 outage	130 MW	0230	0300	30 minutes
2/15/2010	Henderson #2 outage	110/20 MW	2053/2110	2110/2130	37 minutes
2/20/2010	Wilson mill outage	60 MW	1853	1908	15 minutes
2/24/2010	Wilson mill outage	95 MW	1631	1700	29 minutes
2/24/2010	Wilson mill outage	70 MW	1741	1800	19 minutes

MISO CONTINGENCY RESERVE EVENTS

March						
Date	Event	Reserve Requested	Start Time (CPT)	Stop Time (CPT)	Duration	
3/2/2010	Coleman #1 outage	130 MW	1054	1157	63 minutes	
3/5/2010	Henderson #2 outage	160 MW	0420	0442	22 minutes	
3/18/2010	Wilson mill outage	50 MW	2016	2100	44 minutes	
3/24/2010	Coleman #3 mill outage	35 MW	1833	1900	27 minutes	
3/30/2010	Coleman #1 feeder outage	65 MW	0603	0615	12 minutes	
3/30/2010	Henderson #1 outage	110 MW	1938	2000	22 minutes	