Frost Brown Todd LLC
ATTORNEYS

KENTUCKY · OHIO · INDIANA · TENNESSEE · WEST VIRGINIA

Mark David Goss
(859) 244-3232
MGOSS@FBTLAW.COM

August 20, 2010

Via Hand-Delivery

RECEIVED
AUG 20 2010
PUBLIC SERVICE COMMISSION

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

Re: PSC Case No. 2010-00043
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.

Dear Mr. Derouen:

Enclosed you will please find an original and nine (9) copies of the Midwest Independent Transmission System Operator, Inc.'s Supplemental Responses to certain Commission Staff First and Second Data Requests to MISO (designated as "Part I"); and, Supplemental Responses to certain KIUC First and Second Data Requests (designated as "Part II") to MISO and BREC.

You will please note that the portion containing the Supplemental Response for each Data Request is contained in red.

Also, because of formatting issues, a detailed index referring to the particular Data Requests being supplemented and the page number upon which that Supplemental Response can be found, is provided for ease of reference.

Please file the Supplemental Responses at your earliest convenience. Should you have any questions regarding this filing, please let me know.

Sincerely yours,

Mark David Goss

Enclosures
cc: Counsel of Record

INDEX TO MIDWEST ISO'S SUPPLEMENTAL RESPONSES FILED AUGUST 20, 2010

MIDWEST ISO'S SUPPLEMENTAL
RESPONSE TO THE COMMISSION'S and KIUC'S
DATA REQUESTS
PSC CASE NO. 2010-00043
August 4, 2010

Part I

Supplemental Responses to Kentucky Public Service Commission First and Second Data Requests to BREC & MISO

Item PSC 1-2) ***Refer to the Direct Testimony of Clair J. Moeller at page 19.***

a. Will the Midwest Independent Transmission System Operator ("Midwest ISO") seek to include grandfathered agreement ("GFA") load in transmission cost allocation in the July 2010 filing with the Federal Energy Regulatory Commission ("FERC")?

b. Are there any other changes that will be proposed in the July 2010 FERC filing that will impact Big Rivers? If yes, explain and quantify the cost to Big Rivers.

Original Response:

a. No decision has been made regarding the inclusion of grandfathered agreement load in transmission cost allocation for the July 15, 2010 filing.

b. At this point, changes that will be proposed in the July 2010 FERC filing have not been finalized. However, based on the current proposed methodology there could be potential impacts to Big Rivers (assuming this is the proposal submitted to and accepted by FERC). The overarching goal is 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. For a detailed description of the methodology currently under consideration by the Midwest ISO - Injection/Withdrawal methodology - refer to the Midwest ISO's straw proposal titled "Transmission Cost Allocation Design" published on March 22, 2010. (Copy attached.)

The Midwest ISO has estimated the potential impacts for Big Rivers under the Injection/Withdrawal methodology based on our modeling of a 2014 test year taking into account future load growth, state RPS mandates, generation expansion, and new transmission facilities. The transmission facilities included for cost sharing under the Injection/Withdrawal methodology primarily represent reliability projects scheduled tentatively to go in-service through 2014 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 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.

As stated in response to Item PSC 2a, above, a final decision has not been made regarding treatment of Grandfathered Agreement (GFA) load under the Injection/Withdrawal cost allocation methodology. In estimating the potential costs to Big Rivers under Injection/Withdrawal in 2014 the Midwest ISO has performed the calculation with and without GFA load being allocated costs. As shown in Figure 1 the estimated annual total charges under Injection/Withdrawal in 2014 for Big Rivers is $8.8 million if all Big Rivers load is charged and decreasing to $3.8 million if GFA load is excluded.

Supplemental Response:

a: The new cost allocation proposal currently pending at FERC does not allocate cost to GFA load.

b: Yes. See response to PSC 2-1 for further explanation and quantification of cost.

Item PSC 1-6) ***Assuming Big Rivers becomes a member of the Midwest ISO, will Big Rivers be obligated to pay a share of any transmission projects that were approved prior to Big Rivers' membership? If yes, explain in detail the total estimated cost of the approved transmission projects and the derivation of Big Rivers' share.***

Original Response with Supplemental Response (contained as edits in red): Current Midwest ISO transmission cost allocation protocols do not require new members to pay for transmission projects, the planning of which the new member has not been party to, under the planning process of the Midwest ISO Tariff, and which are deemed eligible for sharing as Baseline Reliability Projects or Regionally Beneficial Projects or Generator Interconnection Projects. Likewise, the same type of projects that are already planned for implementation by the new member prior to joining the Midwest ISO are not eligible for sharing with other Midwest ISO members. ~~At the present time, the expectation is that the July 15, 2010 FERC filing will maintain this policy with regard to the timing of initial planning obligations.~~ The cost allocation for the new Multi-Value Project ("MVP") category, currently pending at FERC is somewhat different. With the exception of GFA load which is excluded under the filing, all Midwest ISO load will pay the regional rate for Multi Value Projects. Thus, upon becoming a member, one might be able to argue that the rate that Big Rivers would pay includes an MVP that may be approved just slightly ahead of its membership. At the present time only one MVP has been proposed for consideration for calendar year 2010. That project, in Michigan, has an estimated project cost of \$510 million which results in an annual revenue requirement of approximately \$139 million. Big Rivers, with an estimated 1.1% share of energy and exports, would have included as part of its transmission rates approximately \$0.5 million projected to begin in 2013 as the first branches of this MVP are phased in with the entire project projected to be completed and on line in 2015, at the very earliest. Whether Big Rivers and others ultimately have the costs of this project or any other MVPs included in the transmission rates depends on: (1) FERC's acceptance of the proposed Multi Value Project Cost Allocation Methodology; (2) the approval, by the Midwest ISO Board, of this project as a Multi Value Project; and any (3) local siting and/or regulatory reviews, approvals, and challenges. It is also relevant to note that the annual charge rate, and the associated obligation for the project, would decline annually to reflect depreciation.

Item PSC 1-8) ***If Big Rivers becomes a Midwest ISO member and later withdraws, explain the basis, the amount, and the derivation of any financial obligation for Big Rivers arising from:***

a. Transmission projects that were approved by the Midwest ISO prior to Big Rivers' membership;

b. Transmission projects that were approved by the Midwest ISO during the time of Big Rivers' membership; and

c. Any non-transmission capital project or expenditure.

Original Response) a. Current Midwest ISO transmission cost allocation protocols do not require new members to pay for transmission projects approved prior to their membership. Since these projects would not be allocated to Big Rivers, there would be no withdrawal obligation related to them.

b. The exiting party would maintain responsibility for its share of the allocation of projects approved during the parties' membership. The amount owed would be that defined under the tariff at the time the projects were approved. Under the current tariff the cost allocation for each project would be based on Big Rivers' load ratio share of the total load for the applicable zones for each project.

c. Any non-transmission capital project costs or expenditures that would be allocated to the exiting member would be included in the exit fee. Exit fee estimates for 2009 and 2015 were provided in previously submitted testimony.

Supplemental Response:

a) Addendum: With respect to transmission projects approved prior to Big Rivers' membership that are deemed Multi-Value Projects under the cost allocation methodology pending at FERC, there would also be no withdrawal obligation.

b) Addendum: Under the cost allocation methodology pending at FERC, Big Rivers' obligation would be based on its load ratio share in the footprint.

Item PSC 1-10) ***Page 42 of the Crockett Testimony states that firm power and transmission contracts in effect as of a certain date might be eligible to be "grandfathered." Describe the specific transmission contracts that might be eligible for this "grandfather" status.***

Original Response: Big Rivers requested GFA treatment for all of its wholesale contracts, including the two wholesale contracts with Kenergy Corp. for service for resale to the smelters. The following treatment was determined to by the Midwest ISO to be consistent with its Tariff and FERC orders.
Big Rivers is a party to two agreements that are already listed as GFAs in Attachment P of the Midwest ISO tariff. This status will not change. Those Carved-Out GFAs are:

- 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").

The Midwest ISO Attachment P filing proposes Carved-Out GFA treatment for the following agreements:

- "Agreement for Transmission and Transformation Capacity" dated April 11, 1975, between Big Rivers and the City of Henderson.
- 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").
- Contract between Big Rivers and SEPA dated June 30, 1998.
- Interconnection Agreement between Big Rivers and Louisville Gas and Electric Company dated December 21, 1973, as amended.
- Interchange Agreement between Big Rivers and Associated Electric Cooperative, Inc., dated April 16, 1993.

The Midwest ISO Attachment P filing also proposes Option A treatment for the following GFAs, consistent with Big Rivers' request:

- Wholesale Power Agreement dated October 14, 1977, between Big Rivers and Jackson Purchase Rural Electric Cooperative Corporation, as amended.
- Wholesale Power Contract dated June 11, 1962, between Big Rivers and Meade County Rural Electric Cooperative Corporation, as amended.
- "Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Green River Electric Corporation, as amended.
- "Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Henderson-Union, as amended.

Please see the response to KIUC MISO Data Request 1-8 for the explanation of why Midwest ISO determined that GFA treatment is not available for the smelter-related wholesale contracts.

Supplemental Response: FERC issued an order accepting the GFA status proposed by Midwest ISO (described in the previous answers) on May 26, 2010. FERC Letter is reproduced below:

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426
OFFICE OF ENERGY MARKET REGULATION
In Reply Refer To:
Midwest Independent Transmission
System Operator, Inc.
Docket No. ER10-1024-000
May 26, 2010

Attention: Daniel M. Malabonga
Counsel
505 Ninth Street, NW
Suite 1000
Washington, DC 20004
Reference: Revised Attachment P (List of Grandfathered Agreements)

Dear Mr. Malabonga:

On April 6, 2010, Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed revised tariff sheets proposing to classify certain Grandfathered Agreements of Big Rivers Electric Corporation's (Big Rivers) in connection with the integration of Big Rivers into Midwest ISO as a transmission-owning member. Pursuant to authority delegated to the Director, Division of Electric Power

Regulation- Central, under 18 C.F.R. 375.307, your submittal in the above referenced docket is accepted for filing, effective September 1, 2010, as requested.

Notice of the filing was published in the *Federal Register* with comments, protests, or interventions due April 27, 2010. Under 18 C.F.R. 385.210, interventions are timely if made within the time prescribed by the Secretary. Under 18 C.F.R. 385.214, the filing of a timely motion to intervene makes the movant a party to the proceeding, if no answer in opposition is filed within fifteen days. No adverse comments or protests were filed. The filing of a timely notice of intervention makes a State Commission a party to the proceeding.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. 385.713.

Sincerely,
Penny S. Murrell, Director
Division of Electric Power
Regulation – Central

Item PSC 1-19) ***When does the Midwest ISO anticipate its proposed ARC tariff to be approved by the FERC?***

Original Response: The Midwest ISO expects to have an order in the month of May 2010, prior to the effective date of the Tariff Sheets of June 1, 2010.

Supplemental Response: The Midwest ISO is still awaiting an order, which it anticipates receiving any time in the near future.

Supplemental Responses to KY PSC Second Requests to BREC & MISO

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 this proceeding.

Original 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, Bluegrass Generating (the entity whose identity was withheld due to confidentiality concerns in the response to PSC 1-1 dated April 7, 2010), and most recently with Owensboro Municipal Utilities. While no alternative solution to the Contingency Reserve problem has been identified, Big Rivers continues to explore economically advantageous 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.

Supplemental Response:

Please note that this supplemental response only covers Item 2. Items 1 and 4 were previously answered by Messrs. Crockett and Luciani.

a. The Midwest ISO did not change the current exclusion of grandfathered agreement load from transmission cost allocation in the July 15, 2010 filing to FERC.
b. Yes, there are changes to the Midwest ISO's transmission cost allocation policy filed on July 15, 2010 that are expected to have an impact on Big Rivers pending approval by the Federal Energy Regulatory Commission (FERC).

On July 15th, after taking under consideration the multiple, divergent positions and input provided by stakeholders over the previous 19 months, the Midwest ISO filed with the Federal Energy Regulatory Commission ("FERC") a cost allocation proposal designed to establish a new transmission project and cost allocation category called Multi Value Project ("MVP"). MVPs are defined as projects that enable the reliable and economic delivery of energy in support of documented energy policy mandates and address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones. Recognizing the regional nature of such projects, their costs are proposed to be allocated to all load in, and exports from, the Midwest ISO on an energy (MWh) basis via a postage-stamp rate. A project must meet at least one of the following three criteria in order to qualify for sharing as an MVP:

1) Enables the reliable delivery of energy in support of a documented public policy mandate or law;

2) Provides multiple types of economic value across multiple pricing zones; or

3) Addresses at least one reliability issue associated with a NERC or Regional Entity standard and provides economic value to multiple pricing zones.

The new MVP transmission project category, and its associated broad-based cost allocation, are designed to: (1) facilitate the integration of large amounts of location-constrained resources, including renewable generation resources; (2) support Midwest ISO member and customer compliance with evolving state and federal energy policy requirements; (3) enable the Midwest ISO to address multiple reliability needs and provide economic opportunities through regional transmission development.

To *estimate* the potential future impact to Big Rivers under the newly-filed cost allocation methodology, the Midwest ISO must use a set of *potential* transmission projects that Midwest ISO staff has developed that have the attributes of and *could* qualify as MVPs. This early effort of identifying a potential set of "starter projects" is being determined using a number of factors, including transmission corridors identified in multiple Midwest ISO studies (i.e. the Regional Generation Outlet Study (RGOS) and another study known as the "Top Congested Flowgate Study", as well as ongoing analyses as part of the expansion planning and generation interconnection queue study process), synchronizing generator interconnection queue locations with Renewable

Portfolio Standard (RPS) timing needs, and the probability of construction. It is anticipated that these starter projects, or projects like them, will likely be proposed, fully analyzed and vetted, and then may be developed within 5-10 years after the anticipated FERC approval of the MVP cost allocation methodology. Therefore, keeping in mind all of these above qualifications, the list of potential MVP starter projects are catalogued on Figure 1, below. It must be noted that this preliminary list includes transmission lines in every region of the Midwest ISO footprint and represents approximately $4.6 billion in anticipated investment over the next 10 years.

	MVP Starter Projects	Zone (State)	Voltage Class	Estimated Cost
(1)	Big Stone-Brookings	XEL (ND/MN)	345 kV	$150,000,000
(2)	Brookings-Twin Cities	XEL (MN)	345 kV	$700,000,000
(3)	Lakefield-Mitchell County	ITCM (MN/IA)	345 kV	$600,000,000
(4)	Sheldon-Webster-Blackhawk-Hazelton	MEC (IA)	345 kV	$458,000,000
(5)	Dubuque-Spring Green & Lacrosse-Spring Green-W Middleton	ATC (WI)	345 kV	$811,000,000
(6)	Sheyenne-Audubon 230 kV rebuild	OTP (MN)	230 kV	$60,000,000
(7)	Thomas Hill-Adair-Ottumwa	AMMO (MO)	345 kV	$195,000,000
(8)	Adair to Palmyra	AMIL (IL)	345 kV	$100,000,000
(9)	Palmyra-Quincy-Merdosia-Ipava & Ipava-Meredosia-Pawnee	AMIL (IL)	345 kV	$345,000,000
(10)	Pawnee-Pana	AMIL (IL)	345 kV	$76,000,000
(11)	Pana-Mt. Zion-Kansas-Sugar Creek	AMIL (IL)	345 kV	$250,000,000
(12	St. John to Hiple 2nd circuit	NIPS (IN)	345 kV	$75,000,000
(13)	Davis Besse to Beaver 2nd circuit	FE (OH)	345 kV	$71,000,000
(14)	Sidney-Rising	AMIL (IL)	345 kV	$68,000,000
(15)	Michigan Thumb Loop Expansion	ITC (MI)	345 kV	$510,000,000
(16)	Sullivan-Meadow Lake-Greentown[1]	DUK/AEP (IN)	765 kV	$171,875,000
	Total			**$4,640,875,000**

Note: 1) The estimated cost only reflects that portion eligible for cost sharing in the Midwest ISO.

Figure 1. MVP Starter Projects (in 2010 $s)

In addition to advancing the integration of renewable resources to meet public policy requirements, these anticipated projects are expected to also provide overall benefits driven by reductions in congestion and losses, such as reduced aggregate production cost of delivered energy, and maintaining or reducing the Midwest ISO Planning Reserve Margin, as well as broadly-shared reliability benefits by facilitation of upgrades needed to ensure continued satisfaction of transmission grid reliability standards. The economic benefits provided by the MVP starter projects are, likewise, expected to be broadly shared by all loads in the Midwest ISO footprint.

As part of the July 15th filing, the Midwest ISO provided an analysis that estimated and quantified the economic benefits associated with the list of MVP starter projects listed in Figure 1. This analysis showed significant savings to the Midwest ISO region in the form of reduced congestion and the provision of greater access across the footprint. The adjusted production cost savings in 2015 is estimated to be $294 million which would be broadly spread across the footprint. In addition to the reduction in production costs the MVP starter projects are expected to reduce transmission system losses which equates to a cost savings potential of about $67 million.

A rough calculation of what Big Rivers' share of these above noted production and losses cost savings can be made using their load ratio share of Midwest ISO load. Utilizing the a 1.9% load ratio share[1] for Big Rivers, which excludes First Energy load, Big Rivers' share of the cost savings as a result of the MVP starter projects is estimated to be $7 million by 2015. This annual savings would continue to accrue and grow each successive year with the savings to Big Rivers in 2025 growing to $26 million per year.

In an effort to be conservative in its estimated charges to Big Rivers for the MVP starter projects, the Midwest ISO assumed that **all** of the projects listed in Figure 1 were indeed approved and in-service by 2015. The actual charges in 2015 would obviously vary depending on what projects are finally approved and when those projects ultimately go in-service. The potential, annual charges to Big Rivers are shown on Line 3 of Figure 2. Further, the estimated charges to Big Rivers for Baseline Reliability Projects are shown on Line 4 of Figure 2.

[1] The 1.9% intentionally does not net out GFAs as benefits would flow to all load, regardless of whether or not it is being served under a GFA arrangement.

It would be incomplete; however, to reflect only the potential transmission *charges* associated with the MVP Starter Projects, without also showing corresponding potential benefits. For that more complete costs and benefits comparison the Midwest ISO has also incorporated and included the additional benefits and costs Big Rivers would incur with Midwest ISO membership as provided in the Direct Testimony of Mr. Luciani referencing his analysis done in January 2010, pages 28-29, and in Tables 2.

Nominal Dollars in Millions	2011	2012	2013	2014	2015
1) Decreased Cost to Serve Big Rivers Load	11.0	12.1	13.3	14.4	14.8
2) Estimatetd MVP Starter Project Benefits	**0.0**	**0.0**	**0.0**	**0.0**	**6.9**
3) Charges for MVP Starter Projects	**0.0**	**0.0**	**(0.39)**	**(1.03)**	**(10.9)**
4) Charges for RECB I Baseline Reliability Projects	**0.0**	**0.0**	**0.0**	**(0.12)**	**(0.24)**
5) Midwest ISO Administrative Charges	(4.6)	(4.1)	(3.9)	(3.9)	(4.1)
6) FERC Charges	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
7) Internal Staffing/Equipment Costs	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
Sub Total	4.9	6.5	7.5	7.8	4.9
8) Cost Avoided for 200 MW of New Reserves	22.0	22.6	23.1	23.7	24.3
Net Benefits	26.9	29.1	30.6	31.5	29.2

Figure 2[2]. Big Rivers Benefit and Cost Comparison to Midwest ISO Membership (assumes a 2.5% inflation rate)

The MVP starter projects include portions of the transmission expansion plans currently under consideration through the Midwest ISO RGOS process. The RGOS was established to develop a rational, regionally beneficial transmission expansion plan to recognize and facilitate the RPS objectives passed by most Midwest ISO member states. The current long term projections of the possible costs of those plans range in total cost from \$13 to \$14 billion out over the time period extending to 2025. For comparison purposes only, the very rough estimates for the previously requested snapshot year of 2014 is \$0.8 million[3], and for 2025, at the extreme end of the projections done based on the entire estimated MVP \$14 billion build-out, the similar math calculates to a Big Rivers proportionate share of approximately \$30 million. It is important to note that these are rough estimates that are highly dependent on a number of unknown variables

[2] Note that the transmission charges shown on Line 3 in Figure 2 assume First Energy is allocated a portion of the MVP Starter Projects. If First Energy is determined to have no obligations, the charges shown on Line 3 in Figure 2 could increase, but no more than 12%.

[3] See also Line 3, Column 2014 in Figure 2, above.

which could include multiple levels of review and scrutiny. The multiple tiers of review of any MVPs proposed will be subject to extensive scrutiny by multiple industry and sector stakeholder groups to ensure any project that does ultimately get approved has both merit and positive benefits. The level of comment and scrutiny is certainly proving to be the case with the first such MVP project discussed above. The know unrelated venues for public reviews include, but are not be limited to: (1) FERC's acceptance of the proposed Multi Value Project Cost Allocation Methodology; (2) the review and vetting of any proposed projects as MVPs through the applicable Midwest ISO stakeholder planning processes; (3) the approval, by the Midwest ISO Board, of all of these project as a Multi Value Projects; (4) local siting reviews; and (5) any other applicable state and local regulatory prudence or environmental reviews, approvals, and challenges.

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.

Original Response with Supplemental Response (contained as edits in red):

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.~~ Potential revenues from Multi

Value Projects (MVPs) 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 as well.

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 4 Source Service.
- Schedule 7 – Long-Term Firm and Short-Term Firm Point-To-Point Transmission 6 Service.
- Schedule 8 – Non-Firm Point-To-Point Transmission Service. 8
- Schedule 9 - Network Integration Transmission Service (NITS). 9
- 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.~~ At present, Big Rivers has not submitted any projects for consideration as part of the Midwest ISO Transmission Expansion Plan (MTEP) process. In the future, Big Rivers may have MTEP approved cost shared projects which could qualify to be recovered through Schedule 26. In addition, if the MVP Proposal (as outlined by the Midwest ISO in its Supplemental Response to PSC 2-1(b), above) prevails at FERC, future Big Rivers MTEP approved cost shared projects could also be proposed and recovered under the MVP 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.~~ 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), Schedule 26, and the proposed MVP Schedule 26-A.

Given the assumptions noted above, no Bundled Load transmission revenues would be distributed to Big Rivers.

- Other Network Load
  - ~~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 does not have a GFA will be responsible to pay Schedules 1, 2, 9, 10, 26, and the proposed 26-A. 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.~~ Other Network load taking NITS that is under a GFA will be responsible to pay Schedule 10. Given the assumptions noted above, no transmission revenues collected by the Midwest ISO would be distributed to Big Rivers. However, if ancillary services (Schedules 1 and 2) are not taken under the GFA, then Schedules 1 and 2 will be charged and the associated revenues 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-5 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."

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.***

Original 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.

Supplemental Response: The proposal filed at FERC was different than the initial Injection / Withdrawal proposal. See also the Supplemental Response to PSC 2-1, above, for estimated impacts under the Multi Value Project process which was filed and pending with FERC.

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.

Original 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.

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.

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 through the Midwest ISO regional planning process.

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

Supplemental Response: The proposal filed at FERC was different than the initial Injection / Withdrawal proposal. See also the Supplemental Response to PSC 2-1, above, for estimated impacts under the Multi Value Project process which was filed and pending with FERC.

Part II

Supplemental Responses to KIUC First and Second Data Requests

Item KIUC MISO 1-9) ***Please provide an estimate of the incremental amount, stated in dollars, that Big Rivers will be obligated to pay in each year, 2011 through 2015, based on MISO's final grandfathering decision compared to its financial obligation if all the above wholesale contracts had been grandfathered.***

Original Response: The terms grandfathering and grandfathering decision in questions 8-9 is assumed to refer to Grandfathered Agreements and Treatment of Grandfathered Agreements, under the Midwest ISO's Tariff, including section 38.8.3(A). Module A of the Tariff defines Grandfathered Agreements as An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

Based on the initial evaluation of the agreements that may qualify as GFAs under the Midwest ISO's Tariff, the Midwest ISO plans a future filing to add any appropriate agreements to Attachment P of the Tariff. Ultimately, the Treatment received will be dependent on the individual agreements and the terms of the Tariff, and must be approved by the Commission as part of an Attachment P filing.

Such Grandfathered Agreements relate to Transmission Service, and as such to the extent any wholesale contracts failed to qualify for Treatment as a GFA, individual customers would convert to standard OATT service. Any financial impact would be limited to the difference between existing service rates and OATT rates, which may not directly impact Big Rivers.

With the exception of Transmission Service rates, and exemption from allocation of RECB charges under the current Schedule 26, Transmission Service receiving Option A or C GFA treatment essentially receive charges and credits consistent with all other types of Transmission Service and associated Market Transactions. As a result, any incremental amounts would equal the difference between RECB Charges allocated to transmission customers taking service under the OATT versus RECB Charges allocated to customers taking service under GFAs. See responses to questions 2.a. and b. of the KPSC Data request for further content related to any RECB charges that may be allocated on GFAs post July 2010.

Supplemental Response: On April 6, 2010, the Midwest ISO filed with the Federal Energy Regulatory Commission proposed modifications to attachment P to its Tariff, to classify certain Grandfathered agreements of Big Rivers Electric Corporation. On May 26, 2010, the FERC approved these modifications, effective September 1, 2010. As a result of these proceedings, the previously provided responses do not require any additional modifications.

Item KIUC MISO 1-11) ***Please provide the current MTEP operating plan and budget for each of the years 2011 through 2015 with respect to expansion of transmission facilities to the Great Plains region in order to connect wind energy sources to the MISO transmission grid. In your response, please include the following:***

(a) the projected dates or range of dates for each facility expansion;

(b) the projected range of cost for each facility expansion;

(c) the current stage of the approval process for each facility expansion;

(d) a narrative discussion of competing positions among stakeholders within MISO about whether transmission expansion to accommodate wind facilities, generally, should be undertaken by MISO Transmission Owners (TOs), and about how the costs of such facilities should be allocated among stakeholders.

Original Response with Supplemental Response (contained as edits in red):

a. Certain transmission upgrades to integrate specific wind generators are currently in the Midwest ISO Transmission Expansion Plan (MTEP). These projects are identified as Generator Interconnection Projects and are identified in Appendix A of the MTEP. However, no large scale transmission projects designed to integrate wind energy resources to the grid are reflected in the current MTEP plan. The Midwest ISO is currently performing a study to determine the best transmission solution to deliver enough energy from renewable resources (predominately wind) to load in order to meet existing state renewable portfolio standards (RPS). This study is called the Regional Generator Outlet Study or RGOS. The RGOS is an open and collaborative planning effort between the Midwest ISO and our Stakeholders. Additional study details can be found on the Midwest ISO website through the link to our Renewable Energy gateway which provides an update on the progress of this study[4]. Because the RGOS study is in the transmission project design and alternative evaluation phase, there is neither a definitive plan or an implementation schedule at this time. However, the Midwest ISO expects the RGOS transmission to be built in a phased in approach over the next 5~~10~~ to 15 years beginning with transmission projects expected to provide benefit under a wide variety of energy policy outcomes.

b. Because the RGOS is still ongoing, final cost estimates are not available at this time. Currently it is estimated that 13~~5~~ to 16~~20~~ billion dollars in new transmission investment may be needed to support state RPS in the Midwest ISO footprint. These projections will change as the planning process evolves, or if there are changes in public policy driving RPS.

c. Because the projects being considered in the RGOS are still in the planning phase they are not yet in the formal approval process. Once the RGOS is completed it is expected that these portfolio of transmission projects identified would be moved into Appendix B of the MTEP. Appendix B projects are projects that are demonstrated to be a potential solution to an identified reliability, policy or other need, or to an identified cost savings or other benefit. The Midwest ISO is targeting the RGOS projects to be in Appendix B for the 2010 MTEP.

The next phase of the approval process would be to move the projects to Appendix A. Appendix A projects are projects that have been justified to be the preferred solution to an identified reliability, policy or other need, or to achieve an identified cost savings or other benefit. To reach Appendix A status, a project must be approved by the Midwest ISO Board of Directors.

d. There is general agreement among many Midwest ISO Transmission Owners and other stakeholders that transmission expansion is needed to integrate new kinds of variable resources (predominately wind) into the Midwest ISO system in order for our stakeholders to be compliant with existing state RPS, as well as maintain reliability and

[4] http://www.midwestmarket.org/page/Renewable%20Energy%20Study

reduce congestion on the system. The majority of states within the Midwest ISO currently have some kind of RPS and there is a potential for a federal RPS at some point in the future. Because of this the need for transmission expansion is well defined and accepted. There is ongoing discussion and varied opinions regarding what kind and size (DC v. AC, 345kV v. 765 kV) of transmission expansion is needed to not only meet current needs but be robust enough that it would provide benefits given the uncertainty around future needs (i.e. Federal RPS, development of nuclear technology, increased demand response resources etc.). The purpose of the RGOS is to evaluate these different options and come up with the best engineering solution(s) to the challenge of integrating large amounts of variable generation into the Midwest ISO system.

The Midwest ISO and our Stakeholders have been engaged in discussions on how the cost of transmission development should be allocated since January of 2009. Some stakeholders feel that broad cost sharing should be limited to unique policy driven projects, and that those costs should be shared equally. Other stakeholders feel that one cost sharing methodology that applies to all transmission expansion is more appropriate.

There are also varied opinions on the specific details of who should pay costs. Should all of the costs be paid directly by load or should some of the costs be carried by generators as a means to target the appropriate end use load? Should transmission revenue requirements be allocated on the basis of voltage, project flow or some combination? **Over the**~~Although opinions vary~~ **last 19 months**, the Midwest ISO **ha**~~is~~ **worked**~~ing~~ very closely with our stakeholders through our Regional Expansion Criteria and Benefits Task Force (RECBTF) and our state commissions through the Organization of Midwest ISO States Cost Allocation and Regional Planning (CARP) group to achieve a cost allocation methodology that will be broadly accepted.

On July 15th, after taking under consideration the multiple, divergent positions and input provided by stakeholders over the previous 19 months, the Midwest ISO filed with the Federal Energy Regulatory Commission ("FERC") a cost allocation proposal designed to establish a new transmission project and cost allocation category called Multi Value Project ("MVP"). MVPs are defined as projects that enable the reliable and economic delivery of energy in support of documented energy policy mandates and address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones. Recognizing the regional nature of such projects, their costs are proposed to be allocated to all load in, and exports from, the Midwest ISO on an energy (MWh) basis via a postage-stamp rate. A project must meet at least one of the following three criteria in order to qualify for sharing as an MVP:

1) Enables the reliable delivery of energy in support of a documented public policy mandate or law;

2) Provides multiple types of economic value across multiple pricing zones; or

3) Addresses at least one reliability issue associated with a NERC or Regional Entity standard and provides economic value to multiple pricing zones.

The new MVP transmission project category, and its associated broad-based cost allocation, are designed to: (1) facilitate the integration of large amounts of location-constrained resources, including renewable generation resources; (2) support Midwest ISO member and customer compliance with evolving state and federal energy policy requirements; (3) enable the Midwest ISO to address multiple reliability needs and provide economic opportunities through regional transmission development.

Item KIUC MISO 1-12) ***Please refer to lines 9-10 of page 9 of your direct testimony. Please provide evidence, including Documents and Studies, that serve as a foundation for the statement "We (MISO) have operated for more than a year under this model with excellent performance." In your answer, please identify criteria by which performance is assessed, and explain how performance is gauged, given predefined measurement criteria.***

Original Response with Supplemental Response (contained as edits in red):
The criteria used to determine that Midwest ISO Balancing Authority (BA) operation has achieved excellent performance are the NERC Control Performance Standards. Since the launch of the Midwest ISO ASM market on January 6, 2009, the Midwest ISO has been the Balancing Authority for its entire market footprint. The Midwest ISO has been participating under the NERC Balancing Authority ACE Limit (BAAL) Proof-of-Concept Field Trial for the same period which replaces Control Performance Standard 2 (CPS 2) performance criterion.

From January 6, 2009 to date, Midwest ISO BA has been fully compliant with Control Performance Standard 1 (CPS 1), BAAL and Disturbance Control Standard (DCS) as evidenced in NERC auditable reports to the Regional Entities and NERC.
To date the Midwest ISO has been over 100% Compliant with CPS 1 for every month of BA Operation and currently has a rolling 12 month Average CPS 1 compliance of ~~134.9~~131.1%. NERC requires each Balancing Authority to achieve, as a minimum, CPS 1 compliance of 100%.
Also to date, as the BA Operator, the Midwest ISO participated in the Midwest Contingency Reserve Sharing Group (CRSG) from Jan 6, 2009 through Dec 31, 2009 and is currently coordinating with Manitoba Hydro under a separate Reserve Sharing Agreement that began Jan 1, 2010. Under the previous Midwest CRSG and the current arrangement with Manitoba Hydro, the Midwest ISO has participated in ~~9~~11 DCS level events and has been 100% Compliant with DCS for all events.

Finally, the Midwest ISO has been 100% Compliant with BAAL under the Proof-of-Concept Field Trial noted above.

Item KIUC MISO 1-18) ***Refer to lines 16-21 of page 18, and lines 1-2 of page 19 of your direct testimony. Please provide Documents and Studies, including workpapers, used by MISO for the determination of the Cost of New Entry (CONE).***

Response) The Midwest ISO works closely with the Independent Market Monitor ("IMM") in developing estimates of CONE. The IMM uses these estimates of CONE in his annual 'State of the Market' report that he files with the Midwest ISO Board and FERC to assess the odds that certain resource types participating in the Midwest ISO Markets can achieve enough revenues to cover expected costs. CONE estimates are used as a value of new investment in generation resources. These estimates of CONE have been filed and justified with the FERC: see the below excerpt from the Midwest ISO Compliance Filing in FERC Docket No. ER08-394-003 filed on November 19, 2008 (pages 5-10) as one such example.

"In response to the Commission's directive, the Midwest ISO has reviewed the methodology used in other RTOs/ISOs, as well as, consulted with the IMM regarding the CONE value. The current CONE value of $80,000/MW-year was estimated by the Midwest ISO's IMM for use in their 2007 State of the Market Report. This CONE value is based on the overnight capital costs with a five percent contingency factor and the fixed operating and maintenance costs for a conventional combustion turbine built in the Midwest ISO Region developed by the Energy Information Administration for the 2008 Annual Energy Outlook."

"These values were stated in 2006 dollars so the IMM inflated the costs by 6.5 percent to report them in 2008 dollars. To include additional factors that were not included in the overnight capital costs, the IMM included an additional 7.5 percent to reflect financing costs and the carrying cost of working capital. Taken together, the IMM assumed capital costs of $555 per kW and fixed operating and maintenance of $12.55 per kW-year."

"In order to produce the annualized CONE from these cost numbers, the IMM assumed a 50/50 debt to equity ratio, 15 year depreciation, 20 year project life and loan term, 7 percent loan interest rate, 3 percent escalation factor, 2.5 percent GDP deflator, 43 percent combined federal and state tax rate, and 12 percent return on equity. These assumptions are comparable to the assumptions used by other RTOs in the development of CONE estimates and produce a levelized CONE value of $80,000/MW-year."

Supplemental Response: While the CONE estimate in use today under the Midwest ISO tariff is $80,000/MW-year, FERC requires the Midwest ISO to file updates to these estimates each year on 1 August. The Midwest ISO will make this compliance filing on 1 August 2010 as required by FERC, and indicate that the revised estimated value for CONE for the 2011/2012 planning year is $95,000/MW-year. The IMM is in full support of this revised estimate, and the methodology for estimating this value of CONE remains as described in the original response.

Part II

Supplemental Responses to KIUC Data Requests to BREC

Item KIUC 1-23) ***Has Big Rivers, MISO, or any other party estimated Big Rivers' exit fees for any year after 2015? If so, please provide all Documents, Studies and work papers supporting the estimate of such exit fees.***

Original Response: Neither Big Rivers nor any party working on behalf of Big Rivers in this matter has estimated the exit fees from the Midwest ISO for any year beyond 2015. Representatives of the Midwest ISO have informed Big Rivers that the Midwest ISO has not performed such calculations. However, the exit fees as calculated by the Midwest ISO for yearend 2009 and year end 2015 show a decline in magnitude which would presumably continue for years beyond 2015.

Supplemental Response: Yes, Midwest ISO has calculated exit fees beyond 2015 which includes an exit fee as of December 31, 2020. This estimated exit fee calculation is included as part of the Supplemental Response in to KIUC 2-4, below, as well as PSC 2-4, above.

Item KIUC 2-4) ***Please refer to KNJC 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 20 5 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 MIS0 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.

Original 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 IS0 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 IS0 Transmission Owners.

Rig 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 Rig 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 IS0 exit fees is the October 15, 2009 email from Midwest ISO.\

c. The 20 15 exit fee model has been attached (RREC 12.3 1 15 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 Rig Rivers out ten years to 2020. By extrapolation and comparison of the estimated 201 *S* projection, the most relevant factors and sections of the Midwest IS0 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 Rig Rivers would follow suit and decline from $3.3M in 201 *5* to $2.9M in 2020. The attachment is titled ("BREC 123120 Exit Fee Calc DRAFT.pdf')

Supplemental Response: No. The forecasted exit fees of $6 million in 2009 and $3.5 million at the end of 2015 do not include cost responsibility for transmission projects approved during the MTEP process assuming Big Rivers is 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 is from the Midwest ISO Transmission Owners. If Big Rivers would exit in 2015 they would only be obligated to pay for the projects approved during the time they were a Midwest ISO member. Big Rivers' potential cost responsibility for transmission projects that are approved through 2015 would be highly dependent on the transmission cost allocation methodology in effect during that time period and the cost of the transmission projects approved during that time. As described in the response to PSC 2-1b the Midwest ISO filed with the Federal Energy Regulatory Commission a new cost allocation methodology for a new project type called Multi Value Projects. In addition to Multi Value Projects Big Rivers could be allocated portions of other project types eligible for cost sharing such as Baseline Reliability Projects.

The estimated Big Rivers obligation for approved transmission projects provided below are based on the average annual revenue requirements over the 40-year book-life of the approved transmission projects for the *estimated* portion of transmission costs allocated to Big Rivers over this period. The actual methodology utilized in the event Big Rivers would choose to exit in 2015 may differ depending on the agreement that would need to be reached with the Midwest ISO Transmission Owners at the time of exit. The Midwest ISO has estimated the potential obligation if Big Rivers would exit in 2015 for two types of cost shared projects, Baseline Reliability Projects and Multi-Value Projects.

The estimated Big Rivers obligation if they would choose to exit in 2015 for Baseline Reliability Projects is based on the types and costs of projects approved in the past assuming that this level of investment continues in the future with Big Rivers as a member. Utilizing the methodology generally described above, the estimated average annual obligation for Big Rivers over a 40-year book-life period for Baseline Reliability Projects would calculate to be approximately $0.38 million per year, in 2010 dollars.

Since Multi Value Projects are a new project-type that are proposed to *be* eligible for cost sharing, pending FERC approval, the Midwest ISO has made a rough estimate of the hypothetical obligation. This estimate necessarily presumes that: (1) FERC accepts the pending MVP proposal; (2) MV Projects get proposed and approved under the multiple tiers of review and scrutiny as noted in the Supplemental Response to Item PSC 2-1, above; (3) the projects go forward and actually get built; and (4) the project gets energized and placed into service by an exit decision by Big Rivers in 2015. With these factors in mind, an estimate using $1 billion in Multi Value Project(s) costs purely as an illustrative amount would translate into an amount to Big Rivers under a 2015 exit scenario of $1.7 million, in 2010 dollars, per year over the 40-year book-life period for such projects.

It must be noted that the estimates provided do not reflect or capture any amounts that would, likewise, be contributed toward and paid by the other transmission owners for transmission upgrades that Big Rivers proposes and are included in the MTEP/MVP processes; nor do these rough calculations capture any corresponding benefits that would also be realized by Big Rivers (and other transmission owners) that are the direct result of such future transmission upgrades and expansions.

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

a. Please provide all computer models with cells intact, 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 intact, 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 thee cost estimate0 for the scenario, either (i) or (ii), that is not implicit in your original response.

Original 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 IS0 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 IS0 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 IS0 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 IS0 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 IS0 website[5]. 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 KIIJC 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 123.

See the file titled "BREC Response to KITJC 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 123.

b. Using the proxy annual charges to Big Rivers' load under the proposed I/W proposed cost allocation methodology[6] in the 2014 and 2024 studied test year the following graph (see Figure 1 , below), is a reasonable estimate of the intervening years of 201 1 through 20 13 and 20 15 through 2023 based on linear interpolation. 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. 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.

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

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[5] Link to document titled - "Cost Allocation Proposal Comparisons"
ittp://www.midwestiiiarltet.or~/~ublisli/Document/ff6b1b2 80201754d -7e3aOa48324a?rev=2

[6] 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.

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

Supplemental Response:

b. The cost allocation methodology filed by the Midwest ISO on July 15th is different than the methodology used in the initial response. See response to PSC 2-1 for an updated quantification of the costs to BREC under the filed cost allocation methodology.

Item KIUC 2-12) ***Please refer to Big Rivers' response to PSC 1-20. At what point in time will MIS0 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?***

Original Response: The Midwest IS0 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.

Supplemental Response: FERC issued an order accepting the GFA status proposed my Midwest ISO (described in the previous answers) on May 26, 2010. FERC Letter is reproduced below:

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426
OFFICE OF ENERGY MARKET REGULATION
In Reply Refer To:
Midwest Independent Transmission
System Operator, Inc.
Docket No. ER10-1024-000
May 26, 2010

Attention: Daniel M. Malabonga
Counsel
505 Ninth Street, NW
Suite 1000
Washington, DC 20004
Reference: Revised Attachment P (List of Grandfathered Agreements)

Dear Mr. Malabonga:

On April 6, 2010, Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed revised tariff sheets proposing to classify certain Grandfathered Agreements of Big Rivers Electric Corporation's (Big Rivers) in connection with the integration of Big Rivers into Midwest ISO as a transmission-owning member. Pursuant to authority delegated to the Director, Division of Electric Power Regulation- Central, under 18 C.F.R. 375.307, your submittal in the above referenced docket is accepted for filing, effective September 1, 2010, as requested.

Notice of the filing was published in the *Federal Register* with comments, protests, or interventions due April 27, 2010. Under 18 C.F.R. 385.210, interventions are timely if made within the time prescribed by the Secretary. Under 18 C.F.R. 385.214, the filing of a timely motion to intervene makes the movant a party to the proceeding, if no answer in opposition is filed within fifteen days. No adverse comments or protests were filed. The filing of a timely notice of intervention makes a State Commission a party to the proceeding.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. 385.713.

Sincerely,
Penny S. Murrell, Director
Division of Electric Power
Regulation – Central

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 MIS0 for reserve sharing. This is a continuing request.***

Original Response with Supplemental Response (contained as edits in red): Big Rivers has requested and received contingency reserve supply from Midwest IS0 on 36 occasions thus far in 2010 ~~2010six occasions in each of the first three months of 2010 for a total of I8occasions~~. The individual event summaries are provided monthly in the attached documents.

Att RR BREC
Updated 08172010.x

LEXLibrary LR09470 . 0573666 431430v1

Recipient	Start Time (EST)	Stop Time (EST)	MW	Reason
BREC	01/02/2010 19:52	01/02/2010 20:30	140	lost two mills at Wilson
BREC	01/04/2010 09:16	01/04/2010 10:00	120	loss of Henderson 1
BREC	01/07/2010 22:57	01/07/2010 23:30	90	N/A
BREC	01/26/2010 07:24	01/26/2010 08:00	120	loss of Henderson 1
BREC	01/26/2010 13:22	01/26/2010 14:00	100	loss of Green Unit 1
BREC	01/29/2010 00:24	01/29/2010 01:00	70	N/A
BREC	02/04/2010 00:38	02/04/2010 01:15	80	Lost a mill @ Wilson
BREC	02/09/2010 03:30	02/09/2010 04:00	130	REID 4 TRIP
BREC	02/15/2010 21:53	02/15/2010 22:10	110	Loss of Henderson 2
BREC	02/15/2010 22:10	02/15/2010 22:30	20	Loss of Henderson 2
BREC	02/20/2010 19:53	02/20/2010 20:08	60	Lost a mill @ Wilson
BREC	02/24/2010 17:31	02/24/2010 18:00	95	Lost a mill @ Wilson
BREC	02/24/2010 18:41	02/24/2010 19:00	70	Lost a mill @ Wilson
BREC	03/02/2010 11:54	03/02/2010 12:57	130	Loss of Coleman 1
BREC	03/05/2010 05:20	03/05/2010 05:42	160	Loss of Henderson 2
BREC	03/18/2010 20:16	03/18/2010 21:00	50	Issues w/ Wilson
BREC	03/24/2010 18:33	03/24/2010 19:00	35	Loss of Mill at Coleman
BREC	03/30/2010 06:03	03/30/2010 06:15	65	Loss of Mill at Coleman
BREC	03/30/2010 19:38	03/30/2010 20:00	110	loss of Henderson 1
BREC	04/01/2010 12:57	04/01/2010 14:00	230	Loss of Wilson 1
BREC	04/05/2010 22:38	04/05/2010 23:00	240	Loss of Wilson 1
BREC	04/08/2010 19:04	04/08/2010 20:00	50	Loss of Wilson 1 in startup
BREC	04/08/2010 20:00	04/08/2010 20:16	20	Reduction in orginal event above
BREC	04/14/2010 09:55	04/14/2010 10:30	125	Loss of Coleman 1
BREC	04/23/2010 10:03	04/23/2010 10:12	105	Loss of mill at Wilson
BREC	04/23/2010 10:12	04/23/2010 10:16	185	Increase in event above, Wilson still losing MW
BREC	04/23/2010 10:16	04/23/2010 10:30	415	Increase in event above, Lost Wilson
BREC	04/23/2010 10:30	04/23/2010 11:00	315	Reduction in event above
BREC	04/23/2010 11:00	04/23/2010 11:04	125	Reduction in event above
BREC	04/23/2010 11:04	04/23/2010 11:30	25	Reduction in event above
BREC	04/23/2010 14:10	04/23/2010 14:15	110	Loss of Wilson in startup
BREC	04/23/2010 14:15	04/23/2010 15:00	70	Reduction in event above
BREC	05/03/2010 06:27	05/03/2010 07:00	80	Loss of sched/mill trouble Coleman
BREC	05/06/2010 20:02	05/06/2010 21:15	125	Loss of Coleman 2
BREC	05/07/2010 12:17	05/07/2010 13:00	130	Loss of Hemphill 2
BREC	06/07/2010 12:42	06/07/2010 13:00	70	N/A
BREC	06/13/2010 13:10	06/13/2010 13:18	65	Loss of mil on their Wilson unit.
BREC	06/13/2010 13:18	06/13/2010 13:33	95	Loss of mil on their Wilson unit
BREC	06/13/2010 13:33	06/13/2010 14:00	295	Loss of their Wilson unit.
BREC	06/16/2010 12:03	06/16/2010 13:00	115	Loss of Henderson 2
BREC	06/22/2010 14:46	06/22/2010 15:00	35	Loss of mill at Henderson
BREC	07/15/2010 19:18	07/15/2010 20:00	30	Loss of Henderson unit II
BREC	07/21/2010 10:13	07/21/2010 10:35	85	Reduction of the Wilson unit
BREC	07/29/2010 20:07	07/29/2010 21:00	420	Loss of Wilson
BREC	07/29/2010 21:00	07/29/2010 21:15	120	Loss of Wilson
BREC	08/10/2010 17:10	08/10/2010 17:30	130	Loss of mill at Wilson

BREC	08/10/2010 17:30	08/10/2010 17:35	20	Reduction in original event above
BREC	08/11/2010 17:22	08/11/2010 18:00	40	Loss of Reid 6 CT