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April 6, 2010

RECEIVED
APR 07 2010
PUBLIC SERVICE
COMMISSION

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

Re: *Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator*, P.S.C. Case No. 2010-00043

Dear Mr. Derouen:

Enclosed are an original and nine copies of the responses of Big Rivers Electric Corporation ("Big Rivers") to the first data requests propounded to Big Rivers by Public Service Commission ("Commission") staff and Kentucky Industrial Utility Customers, Inc. ("KIUC"). The verifications of the witnesses who prepared those responses are attached to this cover letter.

Big Rivers also files with these responses a petition for confidential treatment of one of the attachments to its response to KIUC Item 7. We enclose an original and ten copies of the petition, ten copies of a sheet representing the redacted material for which confidential treatment is sought and one copy on yellow paper of the material for which confidential treatment is sought.

I certify that a copy of this letter and attachments have been served on each person shown on the attached service list. Please feel free to contact me with any questions you may have.

Sincerely yours,

James M. Miller

James M. Miller
Counsel for Big Rivers Electric Corporation

cc: David G. Crockett
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VERIFICATION

I, Mark A. Bailey, President and Chief Executive 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.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 6th day of April, 2010.

BKC

Notary Public, Ky. State at Large
My Commission Expires 2/22/2014

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 6th day of April, 2010.

TSM

Notary Public, Ky. State at Large
My Commission Expires 2/22/2014

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.

Dan G Crockett
David G. Crockett

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David G. Crockett on this the 6th day of April, 2010.

R/e
Notary Public, Ky. State at Large
My Commission Expires 2/22/2014

VERIFICATION

I, Ralph L. 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 L. Luciani

Ralph L. Luciani

DISTRICT OF COLUMBIA)

SUBSCRIBED AND SWORN TO before me by Ralph L. Luciani on this the 31st day of March, 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

CHRISTINE McCAFFREY NOTARY PUBLIC DISTRICT OF COLUMBIA

Item PSC 1-1) *Refer to the Direct Testimony of Mark A. Bailey at page 13.*

a. Has Big Rivers found any new options to satisfy its Contingency Reserve Obligations on a long term basis since the original filing?

b. If so, identify and describe those options.

Response) a. Since the filing of the application in this matter, Big Rivers has not identified any new option that will satisfy its Contingency Reserve obligations on a long term basis. As I have stated in my testimony, Big Rivers will continue to explore economically advantageous alternatives to Midwest ISO membership to satisfy its Contingency Reserve obligations. We understand that our board of directors, our members and the Commission expect no less.

Big Rivers and the smelters are continuing work on a variation of the "smelter curtailment option" referred to in Mr. Crockett's Direct Testimony, Exhibit 2, at page 27. Big Rivers continues to explore both contingency reserve and replacement purchase power options with Southern Illinois Power Cooperative. In addition, Big Rivers is engaged in discussions with the Paducah Power System for contingency reserve and replacement purchase power options, and with another party (the identity of which is protected by a confidentiality agreement) for replacement purchase power only. APM has identified additional replacement purchase power options with Ameren and Southern Company. All of the off-system purchase options are faced with the major problem of available firm transmission capacity. Big Rivers has requested firm transmission service from E.ON for the potential transaction with the unidentified party, and that request is now being studied due to a lack of available firm transmission capacity. Big Rivers' request for redirecting its 100 MWs of firm transmission across TVA to import power from the Southern Company interface with TVA was denied in late 2009. Big Rivers and Southern Illinois Power are continuing discussions concerning usage of their grandfathered transmission agreement to/from Big Rivers due to the lack of firm transmission capacity out of MISO into Big Rivers.

Big Rivers' discussions with Paducah Power System will of necessity require firm transmission capacity across either E.ON or TVA into Big Rivers. Big Rivers would require firm transmission capacity across either TVA, E.ON, or the Midwest ISO relative to the Ameren purchase option.

Our efforts to date have not revealed the availability of any firm transmission capacity into Big Rivers to support these contingency reserve or replacement power options.

b. Please see response to 1a, above.

Witness) Mark A. Bailey

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.

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 the answer to 2a. 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.

	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)	8.8	3.8
Total Annual Charges on $/MWh Basis	0.79	0.58

Figure 1. 2014 Estimated Charges under Injection/Withdrawal for Big Rivers (in 2009 Dollars)

Witness) Clair J. Moeller, Midwest ISO

TRANSMISSION COST ALLOCATION DESIGN

Midwest ISO Straw Proposal

Draft, March 22, 2010

Midwest ISO
Energizing the Heartland

Contents

EXECUTIVE SUMMARY

The overarching goal of the Midwest ISO cost allocation design is 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. The Midwest ISO "Straw Proposal" proposes to use an Injection/Withdrawal methodology for transmission facility cost allocation on a going forward basis. Note that although the name is the same, the Injection / Withdrawal methodology in this proposal is different in some key aspects from what has previously been discussed as the Injection/Withdrawal method. These changes reflect stakeholder feedback as well as consideration of the feedback from LECG about potential market efficiency impacts.

Scope of the Cost Allocation Method

A. All transmission projects that are approved for inclusion in Appendix A of the Midwest ISO Transmission Expansion Plan (MTEP) after July 15, 2010 will be evaluated to determine cost sharing eligibility under the Injection/Withdrawal methodology.

  i. Existing transmission facilities, facilities under construction, and facilities approved in Appendix A of prior MTEP reports that have not yet started construction will continue to have costs shared under the methodology in place at the time of the facility approval by the Midwest ISO Board of Directors.

  ii. The Injection/Withdrawal cost allocation methodology will replace the existing transmission facility cost allocation processes, including RECB I- Baseline Reliability and Generator Interconnection Projects and RECB II – Regionally Beneficial Projects on a going forward basis.

B. Approved exclusion criterion (e.g. projects less than $5 million dollars, below 100 kV, and listed on the Transmission Owner exclude list, etc.) will be applied to each transmission project to evaluate whether the project qualifies to have its cost shared using the Injection/Withdrawal methodology, or whether otherwise excluded costs must be recovered through some other means by the sponsoring parties. The exclusion criteria are listed in Section 3 of this Straw Proposal.

i. The exclusion criteria do not include a benefit/cost ratio test. The benefit case for transmission projects will be evaluated as part of the MTEP process which determines whether a transmission project is qualified for inclusion in Appendix A.

Cost Allocation Design

A. The Injection/Withdrawal cost allocation methodology will use a two (2) layer design, regional and local, to allocate eligible transmission project costs. (see Figure 1) The Injection/Withdrawal cost allocation methodology does not propose to change the existing pricing zones.

B. A Transmission Usage Study will be performed to determine the regional and local revenue requirement allocation factors applicable to each Transmission Owner's revenue requirements. The regional and local revenue requirement allocation factors will be determined by the parent by Planning Region (West, Central, and East) of the Transmission Owner for Voltage Classes 1 and 2 and on a Midwest-ISO wide basis for Voltage Class 3, where the voltage classes are described as follows: .

i. The three (3) AC voltage classes will consist of: greater than or equal to 100 kV but less than 300 kV (Voltage Class 1); greater than or equal to 300 kV but less than 400 kV (Voltage Class 2); and greater than or equal to 400 kV (Voltage Class 3).

ii. The DC voltage class will not have its allocation percentage determined by the Transmission Usage Study; instead it will be allocated 100% to the regional layer.

iii. This Transmission Usage Study will be performed annually and will be on a five year rolling look ahead basis (i.e., in 2010 the regional and local allocation percentages will be set for 2015, in 2011 the allocation percentages will be set for 2016 and so on).

C. Each Midwest ISO Transmission Owner will report their annual revenue requirements in the three (3) AC voltage classes and one (1) DC voltage class described above for transmission projects that qualified for the Injection/Withdrawal cost allocation methodology.

D. The annual revenue requirements for transmission projects in Voltage Class 1 and 2 will then be allocated based on the prevailing Local and Regional allocation factors in the Pricing Zone's Planning Region. For Voltage Class 3 a single local and regional allocation factor will be applied to the annual revenue requirements for those facilities. The revenue requirements associated with DC facilities that are eligible for cost sharing will be assigned 100% to the regional layer.

E. All Generator Interconnection Project (GIP) Network Upgrade costs determined through the Interconnection Study Process will be allocated between Local and Regional based on the Transmission Usage Study percentages. For the portion of the upgrade costs allocated to the Pricing Zone, the new generator will be charged the "higher-of" one of the following access rates: 1) new local access rate that includes the interconnecting generator's upgrades; 2) access rate based only on the interconnecting generator's upgrades; or 3) access rate that includes the new generator's upgrade costs and the upgrade costs of other generators who are currently paying the "higher-of" rate that the new generator is benefiting from.

Cost Allocation Rates

A. All loads in a pricing zone are subject to a Local Access Charge (MW) on a monthly basis and an hourly Regional Usage Charge (MWh).
B. New and existing generators interconnected to the Midwest ISO Transmission System are subject to a Local Access Charge (MW) on a monthly basis.
    i. For new generators that cost is either the Local Access Charge or the Higher-of rate described above
C. All schedules out of Midwest ISO will be charged a Regional Usage Charge (MWh).

Cost Allocation Revenue Distribution

A. All transmission revenue collected under the Injection/Withdrawal cost allocation methodology will be distributed in accordance with revenue distribution provisions included in the Transmission Owners Agreement.

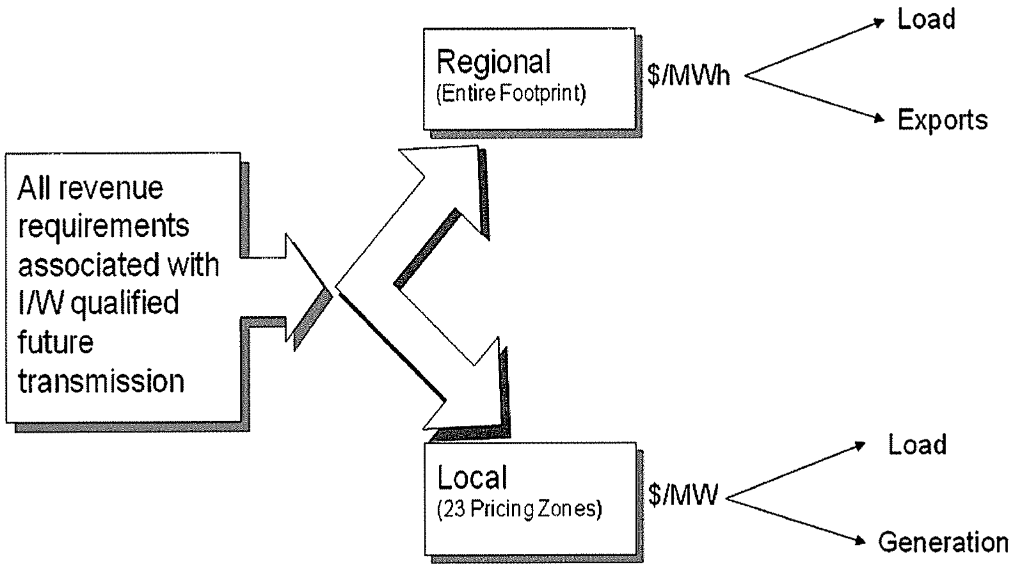

Figure 1. Overview of Cost Allocation Design

1. TRANSMISSION COST ALLOCATION DESIGN CRITERIA

On July 9, 2009, as supplemented on September 17, 2009, and on September 18, 2009, pursuant to Section 205 of the Federal Power Act (FPA), the Midwest ISO and the Midwest ISO Transmission Owners (collectively, "Filing Parties") filed proposed amendments to the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") to revise the method for allocating the cost of network upgrades for generation interconnection projects meeting the Midwest ISO's regional expansion criteria and benefits("RECB") standards ("July 9 Filing").

In the July 9 Filing, the Filing Parties proposed an interim solution to the unintended consequences of the current generator interconnection cost allocation rules, under which: (1) the cost of generation interconnection-related Network Upgrades of transmission facilities rated at 345 kV or above would be allocated 90 percent to interconnecting generators, and 10 percent regionally on a postage stamp basis; and (2) the cost of interconnection-related Network Upgrades of facilities rated lower than 345 kV would be allocated 100 percent to the interconnecting generators. The Filing Parties requested an effective date of July 10, 2009, and stated their intention to file a long-term cost allocation proposal by July 15, 2010.

On October 23, 2009, the Commission conditionally accepted the July 9 Filing and directed the Filing parties to make a FERC 205 filing (1) to fulfill their commitment to file superseding Tariff revisions regarding the proposed Phase II cost allocation methodology (including a new category of cost sharing for transmission projects necessary to integrate large quantities of remote generation resources) on or before July 15, 2010; and (2) to reflect certain conforming changes to the Tariff.

The advent of significantly increased renewable energy project development in the Midwest ISO footprint in particular, and the development of transmission projects premised on a broader range of benefits than simply reducing market congestion or increasing reliability more generally, has highlighted a gap in the current cost sharing approach. The objective of the Regional Expansion Criteria and Benefits (RECB) project is to develop a fair cost allocation mechanism that enables transmission development to support reliability and economic goals, renewable energy integration, and other public policy goals, while maintaining the Midwest ISO Value Proposition. Below are the guiding principles for the development of a cost allocation design that meets these goals:

- Eliminate / Minimize Free Riders: The transmission cost allocation methodology should allocate the costs of "lumpy" transmission upgrades to all present and future beneficiaries from those upgrades.

- Ensure the "Right" Loads Pay: The cost of transmission upgrades should be borne by the loads benefiting from those investments even if they are remote from the transmission investment and/or affected generation.

- Reflect Changing System Usage Over Time: The cost allocation should be able to change over time to reflect changes in system usage over time in those who benefit from the investments.

- Balance Attributes of System Use: The cost allocation should strike a balance among alternative methods for assigning costs, including cost allocation attributed to:

    - The direct causer of a transmission project vs. all beneficiaries;

    - Local vs. regional beneficiaries of the transmission project; and

    - Transmission project development to meet reliability needs vs. to reduce the cost of energy or to meet environmental goals.

2. INJECTION / WITHDRAWAL COST ALLOCATION METHODOLOGY

There are three major components to the injection/withdrawal cost allocation methodology:

1. Determine which transmission projects are eligible
2. Allocate the transmission revenue requirements based on the application of a Transmission Usage Study described below, to two layers:
    - Local
    - Regional
3. Allocate the transmission revenue requirements in a two layer rate design:
    - Local access charges (MW charge)
    - Regional usage rate (MWh charge)

3. SCOPE AND ELIGIBILITY

The Injection/Withdrawal methodology for allocating transmission costs will be applied to:

- Transmission projects that meet the "build" criteria in Appendix A, of the Midwest ISO Transmission Expansion Plan (MTEP), commencing with transmission projects that are approved in Appendix A of MTEP after July 15, 2010. Any benefit /cost test that may be required will be based on the "build" decision process implemented through the transmission planning process; no independent benefit/cost test will be used as a prerequisite for application of the Injection/Withdrawal methodology;

- Transmission projects that do not meet the "exclude" criterion described below

Exclusion Criteria

- Projects costing less than $5 million or costing less than 5% of net plant
- Projects rated below 100 kV
- Projects included in a Transmission Owner exclude list such as those created during the RECB I transition or any time a new Transmission Owning Member joins the Midwest ISO
- Projects necessary to address NERC category C3 that can be resolved by redispatch or load shed under the guidelines defined in the Midwest ISO Transmission Planning Business Practice Manual
- Miscellaneous system improvements that would not cause adverse impacts to overall transmission system reliability that are driven by local benefits including, but not necessarily limited to, 1) Operational flexibility improvements, 2) Safety enhancements, 3) Service reliability improvements (e.g., reliability indices), 4) Compliance with local reliability standards more restrictive than NERC TPL standards, 5)Reduction in operating and maintenance expenditures and 6) Other similar types of projects in lieu of being driven by NERC TPL compliance or generation economic benefits.
- Local system improvements for specific transmission customers including, but not necessarily limited to, 1) redundant supply facilities, 2) improved operational flexibility 3) improved service availability and/or power quality and 4) economic benefits
- Non Network Upgrades (i.e. Interconnection Facilities, direct radial lines to load)

- Any portion of a project not owned by a Midwest ISO current or future Transmission Owner
- Temporary transmission projects responding to emergency events or special operating conditions
- Incremental cost of underground or underwater transmission facilities above the cost of the estimated overhead option when implemented for aesthetics
- Projects necessary to address a Transmission Service Request (Attachment N) [Note: The specific provisions of this exclusion criterion have not yet been finalized]
- Like for like replacements of facilities already excluded due to aging, failure, relocation requirements, or any other reason, unless the replacement results in an increase in branch capacity, in which case it will not be excluded even if the resulting increased capacity is not required.
- A DC line that solely transfer energy for a specific transaction or set of transactions
- A DC line for a specific set of generators to a specific set of loads
- A DC line for which the Midwest ISO does not have the authority to dispatch and control the flow in real time

4. ALLOCATE TRANSMISSION REVENUE REQUIREMENTS

A Transmission Usage Study will be performed annually and will be performed using a five year rolling look ahead basis (i.e., in 2010 the regional and local allocation percentages will be set for 2011 to 2015, in 2011 the allocation percentages will be set for 2016, and so on). The Transmission Usage analysis will be a prospective analysis to reflect transmission investments expected to go into service within the next five (5) years based on their current status in MTEP. The allocation percentages, once set for any given year, will not change. This will allow Market Participants time to anticipate and prepare for changes in their transmission related charges.

The three (3) AC voltage classes, will consist of: greater than or equal to 100 kV but less than 300 kV (Voltage Class 1), greater than or equal to 300 kV but less than 400 kV (Voltage Class 2), and greater than or equal to 400 kV (Voltage Class 3). This will result in Local and Regional allocation factors for each of the three (3) AC voltage classes. The Local and Regional allocation factors for Voltage Class 1 and 2 will vary by Planning Region. For Voltage Class 3, the same Local and Regional allocation factors will apply to all pricing zones.

The Transmission Usage Study will be performed using an hourly production cost model. The branch flows will be analyzed for a subset of hours in the study year. The Transmission Usage analysis first calculates the regional and local flow on each line, and then determines a regional and local percent usage for each branch. A simple average is taken over the hours included in the sample to determine the regional and local percent usage for each branch. Next, each branch is categorized into one of the three (3) AC voltage classes described previously, and one of the three (3) Planning Regions. The average mileage weighted regional and local percentages for each branch are then summed based on their voltage class and Planning Region categorization.

5. INJECTION/WITHDRAWAL RATE DESIGN

Each Midwest ISO Transmission Owner will report its annual revenue requirements in the three (3) AC voltage classes and one (1) DC voltage class described above for transmission projects that qualify for the Injection/Withdrawal cost allocation methodology. The annual revenue requirements for transmission facilities in Voltage Class 1 and 2 will then be allocated to the appropriate pricing zone and regional annual revenue requirements based on the prevailing Local and Regional allocation factors in the pricing zone's planning region. For Voltage Class 3, the Midwest ISO-wide local and regional allocation factors will be applied to the annual revenue requirements of such facilities to allocate them to the appropriate pricing zone and regional annual revenue requirements. DC facilities eligible for cost sharing will be allocated 100% regionally. Based on the local or regional allocation of the annual revenue requirements by voltage class a pricing zone specific local access rate ($/MW) and Midwest ISO-wide Regional Usage rate ($/MWh) is calculated.

The Injection/Withdrawal cost allocation methodology does not propose to change the existing pricing zones.

The Injection/Withdrawal annual revenue requirements are recovered through two (2) rates; a Local Access Rate and a Regional Usage Rate. The Local Access annual revenue requirements will be included in the revenue requirements used to determine the existing system-wide rate applicable to point-to point transmission service. The Regional Usage Rate will be updated on January 1 and June 1 of each year, unless all Transmission Owners elect the historic accounting treatment, in which case the Regional Usage Rate will be updated only on June 1, or all Transmission Owners elect forward looking accounting treatment, in which case the Regional Usage Rate will be updated only on January 1.

If a Transmission Owner is eligible for forward looking treatment, the rates are effective on January 1st and will be based on projected costs for the coming year subject to the annual true-up. If a Transmission Owners selects historic treatment, the rates are effective on June 1st and are based on transmission costs incurred during the previous year. If there is a mixture of forward looking and historic treatments among

Transmission Owners, then regional rates would be updated on January 1st and June 1st of each year.

Regional Rate Design

The Regional Usage Rate is determined by dividing the Injection/Withdrawal regional revenue requirements by the sum of total energy (MWh) withdrawn plus the energy scheduled out of Midwest ISO.

Local Rate Design

The Local Access Rate for a specific pricing zone will be updated on January 1 of each year if the host Transmission Owner s utilizes forward looking accounting treatment or June 1 of each year if the host Transmission Owner utilizes historic accounting treatment. The Local Access Rate for each pricing zone is determined by dividing each pricing zone's Injection/Withdrawal local annual revenue requirements by the sum of the 12 CP Demand within the pricing zone plus the sum of the generation capacity within the pricing zone.

For a transmission project that qualifies for cost recovery under the Local Access Rate that was directly attributable to a Midwest ISO Generator Interconnection project, up to three rates shall be calculated on the portion of the GIP costs allocated to the local Pricing Zone using the allocation factors determined by the Transmission Usage Study. (see Figure 2) The rates calculated determine if the new generator is charged the "higher-of" rate or the Local Access Rate reflecting the additional GIP revenue requirements and generation capacity.

To address potential "free rider" concerns, where generators benefit with reduced GIP costs due to the investment made by earlier generators, a "test" will be performed to determine if the new generator is benefiting from upgrades made by previous generators. If it is determined that the new generator is benefiting from upgrades made by another generator who is being charged the "higher-of" rate, a new rate will be calculated based on the upgrade cost of both generators. If the "higher-of" rate with the two generators is higher than the recalculated Local Access Rate with the upgrade costs and generation capacity of both generators included then both generators will pay the "higher-of" rate.

If the new generator isn't benefiting from another generator's upgrades then a "higher-of" rate based on their GIP costs allocated to the Pricing Zone and generation capacity will be calculated. If the "higher-of" rate calculated is greater than the pricing zone's Local Access Rate reflecting the generator's GIP revenue requirements and generation capacity then the generator is charged the "higher-of" rate and if is less than the generator is charged the new Local Access Rate. The generator will pay the "higher-of" rate until it is less than or equal to the pricing zone's Local Access Rate.

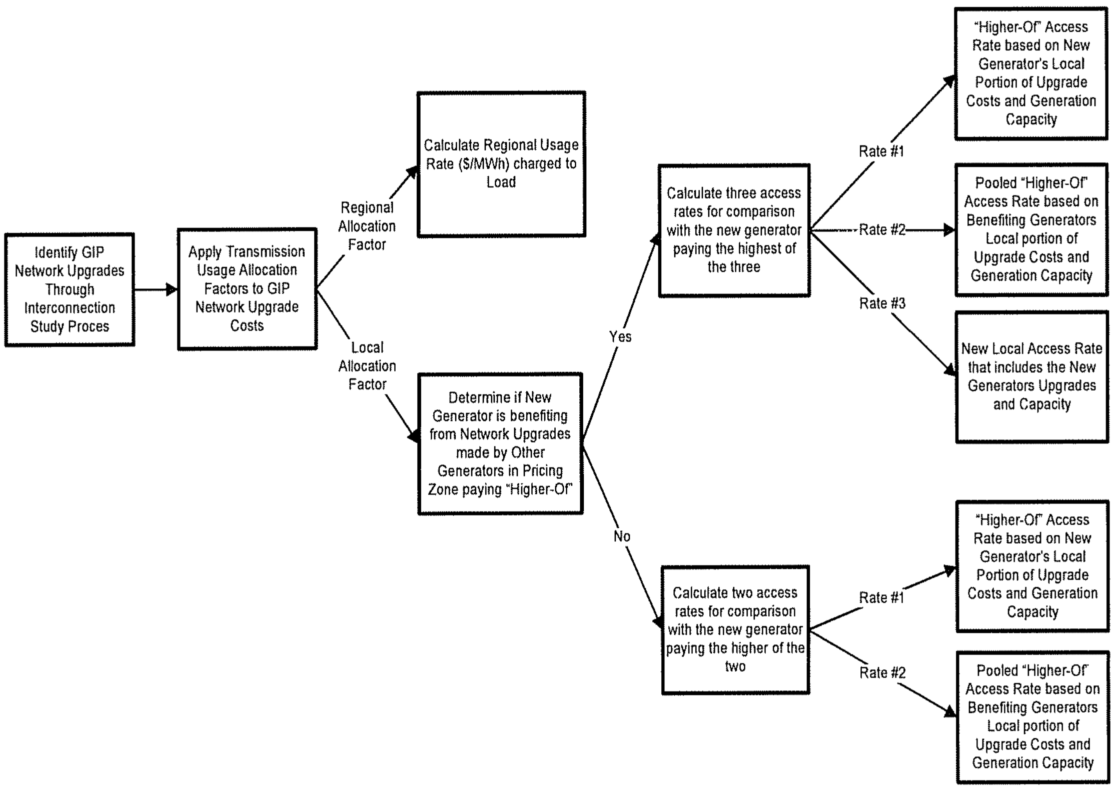

Figure 2. Steps to Determine Access Rate for New Generators

6. INJECTION/WITHDRAWAL RATE APPLICATION

All loads in a pricing zone are subject to a Local Access Charge (MW), calculated on a monthly basis, and an hourly Regional Usage Charge (MWh). New and existing generators interconnected to the Midwest ISO Transmission System are subject to a Local Access Charge (MW), calculated on a monthly basis.

Regional Charge

Charges to the Generator

Generators are not charged a Regional Usage Charge under Injection/Withdrawal.

Charges to the Load

Load will be charged a Regional Usage Charge under Injection/Withdrawal, determined as the product of the Regional Usage Rate and the total MWh consumption by the load. For pumped storage hydro facilities, the Regional Usage Rate will be applied only to the net daily withdrawal of energy. For Stored Energy Resources, the Regional Usage rate will be applied only to the net hourly withdrawal of energy. Station power will not be subject to a Regional Usage Charge.

Drive-in, Drive-out, Drive within, and Wheel-through Charges

A Regional Usage Charge will be applied to all exports and wheel-through schedules, and will be determined as the product of the Regional Usage Rate and the total MWh scheduled.

Local Charge

Charges to the Generator

Each generator interconnected to the Midwest ISO Transmission System will be charged a monthly access charge based on its generation capacity and will be determined as the product of the Local Access Charge and the generation capacity. The exact basis for the generation capacity is still under consideration. The Local Access Charge will apply to all Generation Resources physically located within or pseudo-tied into a pricing zone. The Local Access Charge will also apply to any capacity supplied by a Generation Resource located external to the Midwest ISO to a Load Serving Entity located within a pricing zone for the purpose of meeting Module E resource adequacy requirements. Demand Response Resources will not be subject to a Local Access Charge.

Charges to the Load

Load will be charged a monthly access charge that will be determined as the product of the Local Access Charge and the monthly demand of the Load coincident with the monthly peak demand of the pricing zone where the load is located.

Point-to-Point Transmission Charges

A Local Access charge will not be directly applied to point-to-point transmission service, but the Local Access revenue requirements will be included in the system-wide rate calculation.

7. TRANSMISSION REVENUE DISTRIBUTION

The Midwest ISO will collect the regional and local zones revenues and distribute these revenues to the relevant Transmission Owners in accordance with the transmission revenue distribution provisions in the Transmission Owners' Agreement of the Midwest ISO.

Item PSC 1-3) *Refer to the Direct Testimony of Ralph L. Luciani ("Luciani Testimony") at page 5.*

a. What discount rate was utilized to determine the net present values (net benefits) in the benefit analyses?

b. Explain how the discount rate was computed.

Response) a. A discount rate of 5.83% was used (see footnote 8 on page 4 of my Direct Testimony).

b. Mr. Blackburn informs me that the discount rate is the interest rate on Big Rivers' RUS long-term debt.

Witness) Ralph L. Luciani

Item PSC 1-4) ***Refer to the Luciani Testimony at page 30.***

a. Since the original filing, have any of the uncertainties mentioned in the testimony been quantified?

b. If yes, provide the financial implications for Big Rivers, including the cost of exit fees.

Response) a. No.

b. Not applicable.

Witness) Ralph L. Luciani

Item PSC 1-5) ***A March 15, 2010 article in Electric Utility Week, p.35, states that FERC released an initial decision that, if affirmed by the full commission, could help clear the path for 60 municipal systems to join Midwest ISO. If all municipal systems join Midwest ISO, what operational and financial impacts would this have on Big Rivers?***

Response) The municipals in question are electrically isolated from the Big Rivers zone, and the Midwest ISO does not anticipate any operational impact on Big Rivers should these municipals transmission owners choose to join the Midwest ISO. With regard to financial impacts, the only one that can be estimated with some accuracy would be the beneficial impact of adding the municipal load to the denominator in calculating the administrative charges paid by all members under Schedule 10. Big Rivers share of those costs would decline. Other impacts, such as transmission expansion costs, that might be allocated to Big Rivers would be entirely speculative, as would the expansion cost impact to the municipals, related to Big Rivers joining the Midwest ISO. Other questions in these Data Requests deal with the potential for wind integration on transmission expansion costs. It should be noted that with or without the municipal transmission owners as new members, the principal driver for integrating wind is the need to support state (and possibly federal) RPS requirements, not local transmission expansion by customers in the Western areas of the footprint.

Witness) Clair J. Moeller, Midwest ISO

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.***

Response) 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. Likewise, 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.

Witness) Clair J. Moeller, Midwest ISO

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF
MARCH 26, 2010 FIRST DATA REQUEST
PSC CASE NO. 2010-00043
April 7, 2010

Item PSC 1-7) ***Provide an estimate of the amount that Big Rivers would have been obligated to pay for any transmission projects approved by the Midwest IS0 in 2009 if Big Rivers had been a member for all of 2009. Include an explanation of how this estimate was calculated.***

Response) In 2009 the Midwest ISO approved 22 projects that were eligible for cost sharing with a total cost of $255 million. If Big Rivers had been a member in 2009 it would have been obligated to share some portion of the $95.9 million cost of four of the 22 projects. Three of those four projects represent larger ongoing reliability and market efficiency upgrades that include a portion shared equally by all load. The fourth project identified is for a smaller upgrade located in Southern Indiana electrical proximity to Big Rivers. An estimate was made on the portion of this project that would have been allocated to Big River if it had been included in the load flow study.

The estimates of the project cost allocations to Big Rivers provided in Table XX below are based on the load in Big Rivers that is not exempt grandfathered agreement load. Of the approximately 1,500 MW of load in Big Rivers 700 MW is served pursuant to a grandfathered agreement and is not required to share in the transmission expansion costs under Schedule 26 of the Midwest ISO Tariff. As shown in the table the portion of the project costs allocated to Big Rivers from the four projects approved in 2009 totals $736,981. Assuming a 20% Annual Charge Rate the Annual Revenue Requirement would be $147,396.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF
MARCH 26, 2010 FIRST DATA REQUEST
PSC CASE NO. 2010-00043
April 7, 2010

Pricing Zone Allocation of Total Project Cost

Pricing Zone	Baseline Reliability Project in METC (P1828)	Baseline Reliability Project in IPL	Baseline Reliability Project in AMIL	Regionally Beneficial Project in AMIL
[1]	[2]	[3]	[4]	[5]
Ameren Illinois (AMIL)	178,183	788,839	55,538,977	636,835
Ameren Missouri (AMMO)	178,516		924,195	638,025
ATC System (ATC)	281,215		1,455,879	376,595
Big River Electric Corporation (BREC)	**20,611**	**536,000**	**106,705**	**73,665**
City of Columbia, Missouri (CWLD)	5,951		30,811	21,271
City Water, Light & Power (Springfield, IL) (CWLP)	8,888		118,710	31,768
Cinergy Services (including IMPA & WVPA) (DUK)	253,342	6,950,797	1,311,577	905,457
American Trans. Sys. Inc. (FE)	277,461		1,436,439	738,161
Great River Energy (GRE)	25,046		129,665	33,541
Hoosier Energy (HE)	-	-	-	-
Indianapolis Power & Light (IPL)	64,538	3,755,970	334,120	230,662
International Transmission Company (ITC)	226,386		1,172,022	602,282
ITC Midwest/ ALTW (ITCM)	75,994		393,426	101,768
Montana-Dakota Utilities Co (MDU)	15,567		80,594	20,847
Michigan Joint Zone (METC,MPPA,Wolverine) (METC)	8,878,575		903,792	464,443
Michigan Joint Zone Subzone - GFA (MI13AG)			64,446	33,118
Michigan Joint Zone Subzone - Non-GFA (MI13ANG)	3,259		16,873	8,671
Minnesota Power (MP)	45,363		234,850	60,749
Northern Indiana Public Service Company (NIPS)	72,263		374,112	192,250
NSP Companies (NSP)	215,919		1,117,834	289,152
Otter Tail Power (OTP)	19,253		99,673	25,782
Southern Illinois Power Cooperative (SIPC)	-		-	-
Southern Minnesota Municipal Power Agency (SMMPA)	6,431		33,295	8,612
Vectren Energy (VECT)	27,237	1,368,394	141,006	97,345
Total Project Costs (2009$)	10,880,000	13,400,000	66,019,000	5,591,000

Witness) Clair J. Moeller, Midwest ISO

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.

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.

Witness) Clair J. Moeller, Midwest ISO

Item PSC 1-9) *Refer to pages 37-38 of the Direct Testimony of David G. Crockett ("Crockett Testimony"). Provide the cost of the Reserves Agreement under which Big Rivers will satisfy its contingency reserve obligation during the period January 1, 2010 to September 1, 2010.*

Response) The Reserves Agreement, Attachment RR-1 and associated tariff and procedure, specifies that Big Rivers will pay for Spinning Reserves (the Midwest ISO tariff Schedule 5) and Supplemental Reserves (the MISO tariff Schedule 6) based on Big Rivers metered load, net of transmission losses. Schedule 5 and 6 rates vary each hour. At this time, Big Rivers has submitted meter load data for January and February 2010 in accordance with the Midwest ISO procedure but has not yet been invoiced for these charges. Therefore the charge for these services during the period January 1, 2010 to September 1, 2010 was estimated to be approximately $443,000. The calculation of the estimated charge is attached.

Witness) David G. Crockett
C. William Blackburn

	MWh	Spinning Reserve Sch 5 Rate $/MWh	Supplemental Reserve Sch 6 Rate $/MWh	Total Cost
Jan	See Jan Tab for calculation of Estimated Cost			$ 82,610.62
Feb	868,646	$ 0.0522	$ 0.0048	$ 49,512.81
Mar	902,402	$ 0.0522	$ 0.0048	$ 51,436.93
Apr	842,105	$ 0.0522	$ 0.0048	$ 47,999.97
May	876,387	$ 0.0522	$ 0.0048	$ 49,954.03
Jun	902,567	$ 0.0522	$ 0.0048	$ 51,446.33
Jul	942,761	$ 0.0522	$ 0.0048	$ 53,737.40
Aug	956,487	$ 0.0522	$ 0.0048	$ 54,519.73
9/1/2010	29,339	$ 0.0522	$ 0.0048	$ 1,672.34
Total				$ 442,890.16

Actual Data
Estimated/Forecasted Input

Estimated Balancing Area Load - MWh					
Month	Native	Domtar Gen	Smelter	HMP&L	Total
31 Mar	273,862	37,200	544,608	46,732	902,402
30 Apr	236,258	36,000	527,040	42,807	842,105
31 May	249,158	37,200	544,608	45,421	876,387
30 Jun	285,176	36,000	527,040	54,351	902,567
31 Jul	307,510	37,200	544,608	53,443	942,761
31 Aug	318,419	37,200	544,608	56,260	956,487
30 Sep	267,560	36,000	527,040	49,580	880,180

Zonal data provided by ACES Settlements
Sch 5 Average Rate Jan 09 thru Jan 10
$ 0.0522
Sch 6 Average Rate Jan 09 thru Jan 10
$ 0.0048

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.***

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.

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 the Midwest ISO determined that GFA treatment is not available for the smelter-related wholesale contracts.

Witness) Clair J. Moeller, Midwest ISO

Item PSC 1-11) ***Provide a detailed explanation of the process for obtaining approval by FERC of grandfathered transmission contracts. Include a description of the criteria used to determine the eligibility for being grandfathered and state whether or not each of the Big Rivers contracts is likely to be grandfathered.***

Response) Grandfathered status is determined by FERC in response to proposed changes to the Midwest ISO tariff's Attachment P. Big Rivers worked with the Midwest ISO to maximize the number of its wholesale and transmission contracts and the amount of its wholesale load that would be eligible for grandfathered status, and succeeded in getting the Midwest ISO to agree to treat a portion of Big Rivers' wholesale load as grandfathered. The specific Big Rivers contracts and the related load that is proposed to be treated as grandfathered is set forth in the Midwest ISO Attachment P filing made at FERC in April 2010. Big Rivers sought to include (1) the "Wholesale Electric Service Agreement (Century)" dated July 1, 2009, between Big Rivers Electric Corporation and Kenergy Corp., which relates to the July 1, 2009, retail agreement between Kenergy and Century Aluminum of Kentucky General Partnership and (2) the "Wholesale Electric Service Agreement (Alcan)" dated July 1, 2009, between Big Rivers Electric Corporation and Kenergy Corp., which relates to the July 1, 2009, retail agreement between Kenergy and Alcan Primary Products Corporation as grandfathered agreements, but the Midwest ISO concluded that they did not qualify for grandfathered status because they were executed after 1998. Interested parties will have the opportunity to intervene and comment on the Midwest ISO's Attachment P filing upon issuance by FERC of a notice of filing.

Under the Midwest ISO tariff, contracts eligible for grandfathering fall into three possible categories ("Carved Out," "Option A," or "Option C"). (There is an "Option B," but it is no longer available for newly designated contracts.) In each case, in order for the contract to qualify, it must have been executed or committed to prior to (and not substantively amended after) September 16, 1998. Carved Out Status is not available for agreements between a membership cooperative and its members. For grandfathered contracts that do not qualify for carved out status, the contract parties may elect Option A or Option C status. Option A grandfathered agreements are allocated auction revenue rights ("ARRs"), which may be used to offset the costs of congestion. Option C agreements are not allocated ARRs. Big Rivers has elected Option A status for all eligible contracts, in order to take advantage of the opportunity to hedge any associated costs of congestion.

Witness) David G. Crockett

Item PSC 1-12) ***If an existing transmission contract is grandfathered, will it continue in that status indefinitely? If no, explain the time limit on such status.***

Response) Grandfathered status is available for the life of the relevant contract, unless the parties to the contract elect to put the agreement under the Midwest ISO tariff, the parties make a material substantive amendment to the terms of the agreement, or FERC orders a change to the applicable provisions of the Midwest ISO tariff.

Witness) David G. Crockett

Item PSC 1-13) ***If the existing transmission contracts are not grandfathered, explain the operational and financial implications to Big Rivers and to the other parties to the contracts.***

Response) Load served under contracts that are not grandfathered will be served pursuant to transmission service that Big Rivers must take under the Midwest ISO tariff. Such load will also be subject to all scheduling and market and operational rules of the Midwest ISO. Big Rivers cannot at this time determine the specific financial or operational impacts of compliance with such Midwest ISO requirements on specific contracts or parties.

Witness) David G. Crockett

Item PSC 1-14) ***Explain the amount and derivation of any application fees or entry fees that Big Rivers will be obligated to pay as a condition of joining the Midwest ISO.***

Response) In my Direct Testimony (page 36), I made reference to a $15,000 non-refundable membership fee paid by Big Rivers with its membership application. That membership fee is required pursuant to Article Six of the "Agreement of Transmission Facilities Owners to Organize the Midwest Independent System Operator, Inc." which was provided as Exhibit 10 to the Big Rivers filing. Article Six further states that an annual $1,000 payment is required to retain membership in Midwest ISO.

Witness) David G. Crockett

Item PSC 1-15) ***Provide an estimate of the relative net revenues that Big Rivers could expect to receive in 2011 from selling its surplus energy into the Midwest ISO day ahead energy market as a Midwest ISO member. Provide the same information if Big Rivers is a market participant but not a Midwest ISO member. If the revenues would be the same or essentially the same under either scenario, explain the reasons why.***

Response) In 2011, Big Rivers estimates that joining the Midwest ISO will result in cost savings of $11 million as compared to the Stand-alone Case where Big Rivers would be a market participant in, but not a member of, the Midwest ISO. Big Rivers would have less surplus energy to sell in the market in the Stand-alone Case because of the need to self-supply its contingency reserve requirement.

See Table 1 on page 24 in my Direct Testimony for the total estimated generation costs, purchase costs and sales revenue that Big Rivers would expect in 2011 as a Midwest ISO member. The Stand-alone Case reflects the total generation, purchase costs and sales revenue that Big Rivers would expect as a market participant in the Midwest ISO market, but not as a Midwest ISO member. For example, as a market participant, the Midwest ISO through-and-out charge would be incurred for purchases from the Midwest ISO. As shown in Table 1 for 2011, Big Rivers would make 324 GWH of annual off-system sales for $14 million as a Midwest ISO member, and 184 GWH for $7 million as a Midwest ISO participant. Similarly, Big Rivers would make 1,075 GWH of off-system purchases for $30 million as a Midwest ISO member, and 1,670 GWH for $58 million as a 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 $11 million less than those it would incur as a 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.

Witness) Ralph L. Luciani

Item PSC 1-16) ***In the event that Big Rivers purchases energy in the Midwest ISO day ahead market, provide an estimate, with supporting calculations and explanation, of the cost to Big Rivers as a Midwest ISO member. Provide the same information if Big Rivers is a market participant but not a Midwest ISO member. If the costs would be the same or essentially the same under either scenario, explain the reasons why.***

Response) See the response to PSC 1-15.

Witness) Ralph L. Luciani

Item PSC 1-17) *Refer to pages 7 – 9 of the Direct Testimony of C. William Blackburn concerning the costs Big Rivers is estimated to incur due to becoming a member of the Midwest ISO and the impact those costs will have on its financial condition.*

a. The answer at lines 9 – 12 on page 9 of the testimony reflects Mr. Blackburn's belief that the estimated additional costs Big Rivers will incur as a member of the Midwest ISO will not prevent it from meeting the "[t]ests required under its credit agreements" and will not necessitate an immediate rate adjustment for Big Rivers. Explain whether this belief is based exclusively on the estimates provided by Mr. Ralph L. Luciani in his testimony and exhibits submitted as Exhibit 4 of Big Rivers' application.

b. Provide any quantitative or economic analysis relied upon by Mr. Blackburn, if any, other than that provided by Mr. Luciani in forming his belief as stated at lines 9 – 12 on page 9 of his testimony.

c. At page 15 of its application in Case No. 2009-00441[1] currently pending before the Commission, Big Rivers states that it currently projects margins of $6.20 million for 2010, and $4.79 million for 2011. Explain whether these projected margins are based on Big Rivers becoming a member of the Midwest ISO effective September 1, 2010. If they are not so based, provide the projected margins that are based on such membership.

d. Big Rivers application in Case No. 2009-00441 also states that its Indenture to U.S. National Bank Association, Trustee, First Mortgage Obligations, provides that Big Rivers must maintain a "margins for interest ratio of 1.10." Explain whether this has the same meaning as a 1.10 Times Interest Earned Ratio.

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[1] Case No. 2009-00441, Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness, filed November 13, 2009.

Response) a. Yes, I based my assumptions about quantifiable costs on the estimates provided by Mr. Luciani.

b. None.

c. During the time period when the projected margins of $6.20 million for 2010, and $4.79 million for 2011 were being developed, Big Rivers had not determined if it would be joining the Midwest ISO. Big Rivers made the decision to develop its budgets without any projected revenues or expenses related to the possibility that it would become a member of the Midwest ISO. This exclusion was noted on its budget presentation to the Board of Directors, the CEOs for the member Distribution Systems and the Coordination Committee.

The first full year for Big Rivers to participate in the Midwest ISO will be 2011. While the projected cost for the FERC fee and internal administrative cost are significant, Big Rivers will find a budgeted expense off-set to allow it to absorb these expenses. The expenses assessed under the Midwest ISO OATT Schedules 10, 16, and 17 will be recovered in part under Big Rivers' Non-FAC PPA tariff and the balance will be deferred utilizing the regulatory deferral accounting for Non-Smelter purchase power.

d. The calculation of Times Interest Earned Ratio and Margins for Interest Ratio are different in that accruals for federal and state income taxes are only included in the calculation of the Margins for Interest Ratio. The formula for Times Interest Earned Ratio is the sum of Net Margins plus Interest Expense on Long-Term Debt divided by Interest Expense on Long-Term Debt. The formula for Margins for Interest Ratio, is the sum of Net Margins plus Interest Expense on Long-Term Debt plus accruals for federal and state income taxes and other taxes imposed on income divided by Interest Expense on Long-Term Debt.

Witness) C. William Blackburn

Item PSC 1-18) ***Explain in detail the Midwest ISO's proposed tariff to allow Aggregators of Retail Customers ("ARC") to sell demand response directly into the Midwest ISO market without first offering that demand response to the customers' Load Serving Entity ("LSE"). Include with this explanation a discussion of the amount and basis for the compensation to be paid to an ARC, as well as the compensation or cost to the LSE.***

Response) The KPSC has the ability to decide when and if ARCs can sell demand response directly into Midwest ISO markets without offering that response to the customers' LSE first. See our explanation to question 21 below.

Each ARC that reduces load in a given hour in connection with an energy-related offer, as verified and quantified by the applicable Measurement &Verification ("M&V") methodology, will be paid the average hourly LMP (Locational Marginal Price) at the Commercial Pricing Node ("CPNode") where the associated energy reduction occurred over that hour. The M&V methodology is the method employed to measure the amount of load drop provided by the ARC, comparing actual metered load to the customer baseline, which is the amount of customer load that would have occurred without the load drop. The M&V methodology utilizes NAESB approved standards, which have also been supported and proposed by FERC in a rulemaking proceeding.

The Marginal Foregone Retail Rate ("MFRR") is a proxy for the price that the retail customers would have paid under their current retail tariff for the energy they did not consume and for which the ARC received compensation from the Midwest ISO. The KPSC can decide on the appropriate value for the MFRR.

At settlement, the Midwest ISO shall deduct from the LMP payment to the ARC the relevant MFRR, i.e., the costs that the retail customers avoided by not paying their utilities/LSEs for the energy the ARC sold at wholesale by offering demand response into the Midwest ISO's energy market. The net payments the ARC will receive, therefore, is the relevant LMP, minus the relevant MFRR, for each MWh it sold into the real-time energy market.

It is appropriate, and just and reasonable, to pay ARCs the LMP, net of MFRR. In order to treat demand response comparably with a power producer the Midwest ISO must pay both of them the same price for each MWh of energy that the resource "injects" into the transmission system. That is why the Midwest ISO pays the LMP to both generation and demand response resources, including ARCs. The MFRR also is subtracted from LMP to achieve comparability. When a power producer injects energy into the Transmission System, it owns that Energy because it either produced the Energy with its own Generator or purchased it from another source. In contrast, when an ARC injects energy into the Transmission System, it is not actually delivering additional energy, but rather reallocating Energy that is already present in the system, or reducing the need for an incremental amount of MW to support the energy balance. What the ARC is actually selling is the right of a retail customer to consume that Energy at a price set by the customer's retail tariff. Since the retail customer's meter does not record Energy that the customer does not consume, the customer avoids paying for the Energy it has made available for sale by the ARC. Consequently, the ARC should pay for that Energy in order to sell it to someone else. That is why the Midwest ISO will charge the ARC for the Energy at the MFRR, which is a proxy for the weighted average price of the Energy if it were purchased under the retail tariffs of the customers who made the energy available to the ARC for sale, i.e., to be offered into the Midwest ISO's markets.

The LSE will be credited with the MFRR.

The net compensation paid to an ARC (LMP minus the MFRR) will be directly charged to the utility/LSE whose retail customers produced the demand reductions. This will be done through the Midwest ISO's Market Settlements process. Demand reduction sold by the ARC is energy that the LSE would have delivered to the retail customer, if not for the

ARC sale. If the demand reduction had not occurred, the LSE would have purchased the MW from the wholesale spot market. However, since the demand reduction was sold into that market, the amount sold was not recorded as energy consumed by the LSE, and the LSE was not charged for it. Billing the LSE the LMP minus the MFRR for this sold demand reduction is consistent with the LSE's obligation to serve.

Witness) Richard Doying, Midwest ISO

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

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.

Witness) Richard Doying, Midwest ISO

Item PSC 1-20) ***Explain the extent to which the recent FERC decision to initiate an investigation of issues relating to demand response indicates that Midwest ISO's proposed methodology for compensating ARCs will not be approved as proposed.***

Response) The Midwest ISO's preliminary assessment of the FERC Notice of Proposed Rulemaking on demand resource compensation is that the Midwest ISO's proposed methodology is consistent with the FERC proposal.

Witness) Richard Doying, Midwest ISO

Item PSC 1-21) ***Will any of Big Rivers' customers, including but not limited to the two aluminum smelters, be eligible to participate in the ARC tariff as proposed by Midwest ISO? If no, explain which customers will not be eligible to participate and the reasons for their non-eligibility. If yes, explain the approvals, if any, that an ARC must receive from either Big Rivers or this Commission to participate under the Midwest ISO demand response tariff as proposed.***

Response) In compliance with the requirements of FERC Order No. 719, as modified by FERC Order No. 719-A, the proposed ARC provisions distinguish between the retail customers of large and small utilities for purposes of determining the eligibility of retail customers to be aggregated. In particular, where the relevant utility distributed 4 million MWh or less in the previous fiscal year, their retail customers will not be deemed eligible to be aggregated unless the relevant electric retail regulatory authority permits their demand to be offered by an ARC into an organized market.

However, since Big Rivers is a utility that distributed more than 4 million MWh in the previous fiscal year, in compliance with the requirements for FERC Order No. 719-A, Big Rivers' customers will be eligible to participate in Midwest ISO markets unless expressly prohibited by the KPSC. The Midwest ISO notes that, even with respect to such larger utilities, the Relevant Electric Retail Rate Authority ("RERRA") may have made a specific determination about the ability of an ARC to participate in organized markets. In that event, the ARC may also provide such information, including any determination of the MFRR, as part of the registration process.

The above-described revisions also constitute the Midwest ISO's compliance with FERC Order No. 719-A's requirement to distinguish between smaller and larger utilities in determining ARC eligibility.

Witness) Richard Doying, Midwest ISO

Item PSC 1-22) ***Explain in detail the operational and financial impacts to Big Rivers if retail customers on its system elect to participate as ARCs. The explanation should include a discussion of all relevant factors, including participation by customers with a low level of consumption, participation by customers with a high level of consumption, participation by customers at times that do not coincide with Big Rivers' peak load, and participation by customers at times that do coincide with Big Rivers' peak load.***

Response) The proposed market design treats customers who may participate no differently whether they are low level, high level, coincident with Big Rivers' peak load or non-coincident. The response to PSC 1-18 above provides more detail on the compensation mechanism.

Further, ARC participation, if allowed by the KPSC, can only enhance the positive financial impacts to Big Rivers. Aggregating end use customers into demand resources increases the supply of resources available to the market, increases competition, can help reduce prices to consumers and enhances reliability. These design elements can increase demand responsiveness in the region and can encourage development of demand response.

Witness) Richard Doying, Midwest ISO