purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

C **30.8** ~~30.9~~ **Use of Interface Capacity by the Network Customer:** There is no limitation upon a Network Customer's use of Big Rivers' Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of Big Rivers' total interface capacity with other transmission systems may not exceed the Network Customer's Load.

C **30.9** ~~[illegible]~~ **Network Customer Owned Transmission Facilities:** The Network Customer that owns existing transmission facilities that are integrated with Big Rivers' Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of Big Rivers, to serve its power and transmission customers. For facilities

C ~~[illegible]~~ added by the Network Customer subsequent to the ~~[illegible]~~

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effective date of ~~the~~ this Tariff, the Network Customer shall receive credit ~~where~~ for such transmission facilities added if such facilities are ~~jointly planned and installed in coordination with~~ integrated into the operations of Big Rivers' facilities; provided however, the Network Customer's transmission facilities shall be presumed to be

C

integrated if such transmission facilities, if owned by Big Rivers, would be eligible for inclusion in Big Rivers' annual transmission revenue requirement as specified in Attachment H. Calculation of ~~the credit~~ any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

~~31~~ Designation of ~~Network Load~~

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31 ~~31.1 Network Load:~~ **Network Load**

31.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf Big Rivers will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

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31.2 ~~31.2~~ **New Network Loads Connected With Big Rivers** ~~-~~**:**

The Network Customer shall provide Big Rivers with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. Big Rivers will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Federal Energy Regulatory Commission policies.

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31.3 ~~31.3 Network Load Not Physically Interconnected with Big Rivers:~~ **Network Load Not Physically Interconnected with Big Rivers:**

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with Big Rivers. To the extent that the Network Customer desires to obtain transmission service for a load outside Big Rivers' Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

C **31.4 ~~31.4~~ New Interconnection Points~~-~~:**

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between Big Rivers' Transmission System and a Network Load, the Network Customer shall provide Big Rivers with as much advance notice as reasonably practicable.

C **31.5 ~~31.5~~ Changes in Service Requests~~-~~:**

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by Big Rivers and charged to the Network Customer as reflected in the Service Agreement. However, Big Rivers must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

C **31.6 ~~31.6~~ Annual Load and Resource Information Updates~~-~~:**

The Network Customer shall provide Big Rivers with annual updates of

Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to Big Rivers' planning process in Attachment K. The Network Customer also shall provide Big Rivers with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting Big Rivers' ability to provide reliable service.

32 ~~32~~ Additional Study Procedures For Network Integration Transmission Service Requests

32.1 ~~32.1~~ Notice of Need for System Impact Study~~.~~:

After receiving a request for service, Big Rivers shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of Big Rivers' methodology for completing a System Impact Study is provided in Attachment D. If Big Rivers determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, Big Rivers shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse Big Rivers for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to Big Rivers within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

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32.2 ~~32.2~~ System Impact Study Agreement and Cost Reimbursement:

~~(i)~~

(i) The System Impact Study Agreement will clearly specify Big Rivers' estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, Big Rivers shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

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(ii) ~~(ii)~~ If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for Big Rivers to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

C (iii) ~~(iii)~~ For System Impact Studies that Big Rivers conducts on its own behalf, Big Rivers shall record the cost of the System Impact Studies pursuant to Section 8.

C **32.3 ~~32.3~~ System Impact Study Procedures~~.~~:**

Upon receipt of an executed System Impact Study Agreement, Big Rivers will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that Big Rivers is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made

C available to the Eligible Customer as soon as the System Impact Study is

C complete. Big Rivers will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. Big Rivers shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

C **32.4 ~~32.1~~ Facilities Study Procedures~~-~~:**

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, Big Rivers, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities

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Study Agreement pursuant to which the Eligible Customer shall agree to reimburse Big Rivers for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to Big Rivers within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest (calculated ~~for each calendar month or partial calendar month using the Discount Rate as published in the Money Rates section of the Wall Street Journal applicable on the first of each such~~ using the one-year United States Treasury Bill rates effective as of the first business day of each applicable calendar month ~~or partial calendar month during which the deposit was held~~). Upon receipt of an executed Facilities Study Agreement, Big Rivers will use due diligence to complete the required Facilities Study within a sixty (60) day period. If Big Rivers is unable to complete the Facilities Study in the allotted time period, Big Rivers shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study.

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C —_When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide Big Rivers with a letter of credit or other reasonable form of security acceptable to Big Rivers equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

C **33 —Load Shedding and Curtailments**

33.1 ——Procedures—:

Prior to the Service Commencement Date, Big Rivers and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and

C indirectly interconnected with Big Rivers's Transmission System. The Parties will implement such programs during any period when Big Rivers determines that a system contingency exists and such procedures are necessary to alleviate such contingency. Big Rivers will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

C **33.2 ———Transmission Constraints–:**

During any period when Big Rivers determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of Big Rivers' system, Big Rivers will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of Big Rivers' system. To the extent Big Rivers determines that the reliability of the Transmission System can be maintained by redispatching resources, Big Rivers will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and Big Rivers' own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between Big Rivers' use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

C **33.3 ———Cost Responsibility for Relieving Transmission**

C **Constraints~~.~~:**

Whenever Big Rivers implements least-cost redispatch procedures in response to a transmission constraint, Big Rivers and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

C **33.4 ~~33.4~~ Curtailments of Scheduled Deliveries~~.~~:**

If a transmission constraint on Big Rivers' Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and Big Rivers determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement~~.~~ or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

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33.5 ~~33.5~~ Allocation of Curtailments~~.~~:

Big Rivers shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by Big

C Rivers and ~~the~~ Network Customer in proportion to their respective Load Ratio Shares. Big Rivers shall not direct the Network Customer to Curtail schedules to an extent greater than Big Rivers would Curtail Big Rivers' schedules under similar circumstances.

C **33.6 ~~33.6~~ Load Shedding~~.~~:**

To the extent that a system contingency exists on Big Rivers' Transmission System and Big Rivers determines that it is necessary for Big Rivers and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

C **33.7 ~~33.7~~ System Reliability~~.~~:**

Notwithstanding any other provisions of this Tariff, Big Rivers reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on Big Rivers' part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on Big Rivers' Transmission System or on any other system(s) directly or indirectly interconnected with Big Rivers' Transmission System, Big Rivers, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. Big Rivers will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration

C Transmission Service will not be ~~not~~ unduly discriminatory relative to Big Rivers' use of the Transmission System on behalf of its Native Load

C Customers._ Big Rivers shall specify ~~in the Network Operating Agreement~~ the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

C **34 ~~34~~ Rates and Charges**

______The Network Customer shall pay Big Rivers for any Direct Assignment Facilities, Ancillary Services, and applicable study costs~~.~~ along with the following:

C **34.1 ~~34.1~~——Monthly Demand Charge~~—~~:**

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the

C Big ~~River~~—Rivers's Annual Transmission Revenue Requirement specified in Schedule H.

C **34.2 ~~34.2~~——Determination of Network Customer's Monthly Network Load~~—~~:**

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with Big Rivers under Section ~~3~~31.3) coincident with Big Rivers' ~~Transmission System~~ Monthly ~~Peak.~~

C ~~34.2 Determination of Big Rivers' Transmission System Monthly Load: Big Rivers'~~ Transmission System ~~monthly load is Big Rivers' Transmission System Monthly~~ Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load:

C Big Rivers' monthly Transmission System load is Big Rivers' Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

C **34.4 ~~34.4~~ Redispatch Charge~~.~~:**

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and Big Rivers pursuant to Section 33. To the extent that Big Rivers incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 ~~35 Operating Arrangement~~ **Stranded Cost Recovery:**

C Big Rivers may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888.

35 Operating Arrangements

35.1 ~~35.1 Operation under The Network Operating Agreement:~~

C **Operation under The Network Operating Agreement:**

The Network Customer shall plan, construct, operate~~-~~ and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

C **35.2** ~~35.2~~ **Network Operating Agreement~~-~~:**

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network

C Operating Agreement~~ with each respective Network Customer~~. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within Big Rivers' Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between Big Rivers and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside Big Rivers' Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the ~~North American~~ Electric Reliability ~~Council (NERC) and ECAR~~ Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with Big Rivers, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies ~~NERC and ECAR requirements~~ the applicable reliability guidelines of the ERO. Big Rivers shall not unreasonably refuse to accept contractual arrangements with another entity for

C Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 ~~35.3~~ Network Operating Committee~~.~~:

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE ~~1~~1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into Big Rivers' Control Area. This service can be provided only by the

C

operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and ~~Transmission~~ Dispatch Service is to be provided directly by Big Rivers ~~and the~~. The Transmission Customer must purchase this service from Big Rivers. The charges for Scheduling, System Control and ~~Transmission~~ Dispatch Service are ~~included within~~to be based on the rates ~~for point-to-point and network transmission service, and include recovery of the developmental costs of Big Rivers' OASIS. Additional user-based fees may in the future be imposed to recover variable costs of operating the OASIS.~~ set forth below:

T/N

$0.8275/kW per year

$0.0690/kW per month

$0.0159/kW per week

$0.0032/kW per day

$0.1989 per MWh.

For firm point-to-point and non-firm point-to-point transmission service, the applicable rate shall be multiplied by the Transmission Customer's Reserved Capacity.

T

For network integration transmission service, the rate per kW per month shall be multiplied by the Transmission Customer's monthly Network Load.

______Dynamic Scheduling Service also will be provided by Big Rivers to the Transmission Customer as part of this service upon request at costs to be determined. Dynamic Scheduling Service involves the arrangement for moving the electrical effects of load or generation located within one Control Area (or other larger area of coordinated dispatch operation) such that the electrical effect of the load or generation is recognized in the real-time control and dispatch of another Control Area. Under Dynamic Scheduling Service, Big Rivers agrees to assign certain customer load or generation to another Control Area, and to send the associated control signals to the respective control center of that Control Area. Dynamic Scheduling is implemented through the use of specific telemetry and control equipment, which a Transmission Customer requesting Dynamic Scheduling Service is required to provide and install at its own cost. The provisions under which Big Rivers will provide Dynamic Scheduling Service are set forth below:

______(1) The Transmission Customer may designate any amount of firm Point-to-Point Transmission Service as Dynamic Scheduling Service.

______(2)- Designation of any amount of Firm Transmission Service as Dynamic Scheduling Service shall not relieve the Transmission Customer from paying Big Rivers the transmission charges for the total amount of reserved transmission capacity.

______(3) The amount of Firm Transmission Service not designated as Dynamic Scheduling Service shall be scheduled pursuant to the terms and conditions of this Tariff.

______(4) The amount of Firm Transmission Service designated as Dynamic Scheduling Service need not be scheduled, and no scheduling charge will be levied by Big Rivers.

In addition, assignment to Third--Parties and use of Secondary Point(s) of Receipt and Delivery shall not be allowed for Firm Transmission Service designated as Dynamic Scheduling Service.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.122

SCHEDULE ~~=~~2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on Big Rivers' transmission facilities within acceptable limits, generating ~~units in Big Rivers' Control Area, the output of~~
T ~~which is sold to or owned by LEM.~~ facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power as required by Big Rivers' transmission facilities. All Transmission Customers taking service from Big Rivers under this Tariff must obtain
C Reactive Supply and Voltage Control from Generation or Other Sources Service from Big Rivers for each transaction on Big Rivers' transmission facilities. The amount of
C Reactive Supply and Voltage Control from ~~Generation~~ Generation or Other Sources Service that must be supplied with respect to ~~-~~the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain
T transmission voltages within limits that are generally accepted in ~~ECAR~~ the region and consistently adhered to by Big Rivers.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided by Big Rivers ~~which has made arrangements with LEM to provide this~~
T ~~service to Big Rivers as necessary for operation of Big Rivers' Transmission System. The~~. The Transmission Customer must purchase this service from Big Rivers. The

T

charges for such service will be based on ~~[illegible] charged to Big Rivers by LEM~~ <u>the rates set forth below:</u>

T/
N

——— $ 1.6924/kW per year

$0.1410/kW per month

$0.0325/kW per week

$0.0065/kW per day

$0.4068 per MWh.

For firm point-to-point and non-firm point-to-point transmission service, the applicable rate shall be multiplied by the Transmission Customer's Reserved Capacity. For network integration transmission service, the rate per kW per month shall be multiplied by the Transmission Customer's monthly Network Load.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.125

SCHEDULE ~~-~~3

——Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load within Big Rivers' Control Area and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation in Big Rivers' Control Area, the output of which is ~~sold to or owned by LEM, which output is~~ raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load ~~for load located within Big Rivers' Control Area. Because Big Rivers obtains this service from LEM for its own load, Big Rivers has arranged for LEM to provide this service to Big Rivers on a tariff basis for all other loads located within Big Rivers' Control Area~~. The obligation to maintain this balance between resources and load lies with Big Rivers. Big Rivers must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from Big Rivers, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of~~-~~ and charges for~~-~~

T

T

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Regulation and Frequency Response Service ~~charged by Big Rivers will reflect a pro-~~

T ~~———~~ are set forth below:

T/ ———$1.4938/kW per year

N $0.1245/kW per month

$0.0287/kW per week

$0.0057/kW per day

$0.3591 per MWh.

For firm point-to-point and non-firm point-to-point transmission service, the applicable rate shall be multiplied by the Transmission Customer's Reserved Capacity. For network integration transmission service, the rate per kW per month shall be multiplied by the Transmission Customer's monthly Network Load.

Big Rivers Electric Corporation

SCHEDULE ~~-~~<u>4</u>

~~———~~Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. Big Rivers ~~is required to arrange for the provision of~~ <u>must offer</u> this service when a Transmission Customer's requested transmission service is used to serve load within Big Rivers' Control Area. ~~Because Big Rivers no longer controls the output of the generation needed to provide this ancillary service and obtains this service from LEM for its native load, Big Rivers has arranged for LEM to provide this service to Big Rivers on a "pass-through" basis for all other load within Big Rivers' Control Area.~~ <u>The</u> Transmission Customer~~-~~ must either purchase this service from Big Rivers or make alternative comparable arrangements<u>, which may include use of non-generation resources capable of providing this service,</u> to satisfy its Energy Imbalance Service obligation. ~~The rates and charges for Energy Imbalance Service charged by Big Rivers will reflect a pass-through of the costs charged to Big Rivers by LEM.~~ <u>Big Rivers may charge a Transmission Customer a penalty for either hourly generation imbalances under Schedule 9 or hourly energy imbalances under this Schedule for the same imbalance, but not both</u>.

C Big Rivers shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

C For purposes of this Schedule, decremental cost shall represent Big Rivers' actual average hourly cost of the last 10 MW dispatched to supply Big Rivers' Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchase and interchange power costs and taxes, as applicable.

In the event that Big Rivers assesses penalties for imbalances pursuant to this Schedule 4, Big Rivers shall distribute the penalty revenues in excess of Big Rivers' incremental cost of providing imbalance service to those Transmission Customers (including Big Rivers for Third-Party Sales and Native Load Customers) under this Tariff that reserved transmission service during the month and did not incur imbalance penalties (under either this Schedule 4 or Schedule 9) in that month. In the event that a division or organization within Big Rivers incurs imbalance penalties, Big Rivers shall be disqualified from receiving a distribution of imbalance penalties, but nonetheless shall retain its incremental cost of providing imbalance energy.

C/T

Imbalance penalty revenues shall be calculated and distributed on a monthly basis, based upon the ration of the transmission service revenues from each Transmission Customer that did not incur imbalance penalties in that month to the aggregate transmission service revenues from all such Transmission Customers that did not incur imbalance penalties in that month. For purposes of distributing imbalance penalty revenues, each Transmission Customer's transmission service revenues shall be based upon its bill(s) during the service month in which the imbalance penalties are incurred, without regard to any recalculation as the result of a billing dispute or error correction. If there are no customers that do no incur imbalance penalties in a given month, any revenues shall be distributed and allocated to Transmission Customers that do not incur

C/T

an imbalance penalty, using the calculation outlined in the preceding two sentences for the month in which at least one Transmission Customer does not incur an imbalance penalty, with interest calculated using the one-year United States Treasury Bill rate effective as of the first business day of the calendar month. Distribution shall be accomplished via a credit to the Transmission Customer's bill(s) for the applicable billing month or by a separate cash payment to the Transmission Customer during the applicable billing month, except that the Big Rivers shall retain amounts allocated to itself for Third-Party Sales.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.132

SCHEDULE ~~-~~<u>5</u>

———Operating Reserve - Spinning Reserve Service

C ______Spinning Reserve Service is ~~[illegible]~~needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output~~. Because Big Rivers no longer controls the output of the generation needed to provide this service, Big Rivers has arranged for LEM to provide~~ <u>and by non-generation resources capable of providing this service. Big Rivers must offer</u> this service ~~to Big Rivers' native load and to provide this service to Big Rivers on a tariff basis for~~<u>when</u> the ~~benefit of all Transmission Customers taking~~ transmission service <u>is used</u> to serve load ~~located~~ within ~~Big Rivers'~~ <u>its</u> Control Area. The Transmission Customer must either purchase this service from Big Rivers or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of- and charges for- Spinning Reserve Service ~~[illegible]~~<u>are set forth below:</u>

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T

$0.7668 per kW per year

$0.0639/kW per month

$0.0147/kW per week

T/N $0.0029/kW per day

$0.1843 per MWh.

For firm point-to-point and non-firm point-to-point transmission service, the applicable rate shall be multiplied by the Transmission Customer's Reserved Capacity. For network integration transmission service, the rate per kW per month shall be multiplied by the Transmission Customer's monthly Network Load.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.134

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load ~~Because Big Rivers no longer controls the output of the~~ or other non-generation ~~needed to provide~~resources capable of providing this service. Big Rivers ~~has arranged for LEM to provide~~must offer this service ~~to Big Rivers' native load and to provide this service to Big Rivers on a tariff basis for~~when the ~~benefit of Transmission Customers taking~~ transmission service is used to serve load ~~located~~ within ~~Big Rivers'~~ its Control Area. The Transmission Customer must either purchase this service from Big Rivers or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service ~~will reflect a pass-through of the costs charged to Big Rivers by LEM~~ are set forth below:

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.135

~~[illegible]~~

~~[illegible]~~

~~Long-Term Firm and Short-Term Firm Point-To-Point~~

~~Transmission Service~~ $0.9372/kW per year

$0.0781/kW per month

T/N $0.0180/kW per week

$0.0036/kW per day

$0.2253 per MWh.

For firm point-to-point and non-firm point-to-point transmission service, the applicable rate shall be multiplied by the Transmission Customer's Reserved Capacity. For network integration transmission service, the rate per kW per month shall be multiplied by the Transmission Customer's monthly Network Load.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.136

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point

Transmission Service

______The Transmission Customer shall compensate Big Rivers each month for Reserved Capacity at the sum of the applicable charges set forth below:

~~1)~~——**Yearly delivery**: one-twelfth of the demand charge of

I 1) $ **11.**~~80~~**985**/KW of Reserved Capacity per year.

I 2) ~~2)~~——**Monthly delivery**: $ **0.**~~98~~**999**/KW of Reserved Capacity per month.

I 3) ~~3)~~——**Weekly delivery**: $ **0.**~~227~~**230**/KW of Reserved Capacity per week.

I 4) ~~4)~~——**Daily delivery**: $ **0.**~~045~~**046** /KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

C 5) ~~5)~~——**Discounts**: Three principal requirements apply to discounts for transmission service as follows _(1) any offer of a discount made by Big Rivers must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-_initiated requests for discounts (including

C requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Big Rivers must offer the same discounted C transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.138

SCHEDULE 8
~~Rate Schedule STNF~~

~~Short-Term~~
Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate Big Rivers for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

I 1) ~~1)~~ **Monthly delivery**: ~~up to \$~~ **\$ 0.**~~99~~**999**/KW of Reserved Capacity per month.

I 2) ~~2)~~ **Weekly delivery**: ~~up to \$~~ **\$ 0.**~~227~~**230**/KW of Reserved Capacity per week.

I 3) ~~3)~~ **Daily delivery**: ~~up to \$~~ **\$ 0.**~~045~~**046**/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

C ~~4) Discounts: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by Big Rivers must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Big Rivers~~

C

~~SCHEDULE 8~~

~~Rate Schedule HNF~~

~~Hourly Non-Firm Point-To-Point Transmission Service~~

~~The Transmission Customer shall compensate Big Rivers for Hourly Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:~~

4) ~~Basic Charge for~~ **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $ 2.~~[illegible]~~881 /MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) ~~[illegible]~~ above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) ~~[illegible]~~ above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission

C

service as follows (1) any offer of a discount made by Big Rivers must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, Big Rivers must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

C

C/
N

SCHEDULE 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in Big Rivers' Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within Big Rivers' Control Area over a single hour. Big Rivers must offer this service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from Big Rivers or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. Big Rivers may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or hourly energy imbalances under Schedule 4 for the same imbalance, but not both.

Charges for generator imbalance shall be based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

C/N

For purposes of this Schedule, decremental cost shall represent Big Rivers' actual average hourly cost of the last 10 MW dispatched to supply Big Rivers' Native Load Customers, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes as applicable.

C/N

In the event that Big Rivers assesses penalties for imbalances pursuant to this Schedule 9, Big Rivers shall distribute the penalty revenues in excess of Big Rivers' incremental cost of providing imbalance service to those Transmission Customers (including Big Rivers for Third-Party Sales and Native Load Customers) under this Tariff that reserved transmission service during the month and did not incur imbalance penalties (under either this Schedule 4 or Schedule 9) in that month. In the event that a division or organization within Big Rivers incurs imbalance penalties, Big Rivers shall be disqualified from receiving a distribution of imbalance penalties, but nonetheless shall retain its incremental cost of providing imbalance energy.

Imbalance penalty revenues shall be calculated and distributed on a monthly basis,

./N based upon the ration of the transmission service revenues from each Transmission Customer that did not incur imbalance penalties in that month to the aggregate transmission service revenues from all such Transmission Customers that did not incur imbalance penalties in that month. For purposes of distributing imbalance penalty revenues, each Transmission Customer's transmission service revenues shall be based upon its bill(s) during the service month in which the imbalance penalties are incurred, without regard to any recalculation as the result of a billing dispute or error correction. If there are no customers that do no incur imbalance penalties in a given month, any revenues shall be distributed and allocated to Transmission Customers that do not incur an imbalance penalty, using the calculation outlined in the preceding two sentences for the month in which at least one Transmission Customer does not incur an imbalance penalty, with interest calculated using the one-year United States Treasury Bill rate effective as of the first business day of the calendar month. Distribution shall be accomplished via a credit to the Transmission Customer's bill(s) for the applicable billing month or by a separate cash payment to the Transmission Customer during the applicable billing month, except that the Big Rivers shall retain amounts allocated to itself for Third-Party Sales.

Big Rivers Electric Corporation

Open Access Transmission Tariff
Original Sheet No.146

SCHEDULE 10

Real Power Loss Factor Calculation

Real Power Losses are associated with all Transmission Service and must be provided by all Transmission Customers taking service under this Tariff. In January of every year, the average loss rate for the previous calendar year shall be calculated in the following manner:

~~annual~~Annual power losses

~~average loss rate =~~

Average loss rate = ________________________________

Big Rivers' deliveries of energy

with

~~annual~~ Annual power losses = [Big Rivers' ~~receipt~~ receipt of energy ~~-~~ – Big Rivers' deliveries of energy].

Big Rivers' receipts of energy shall be determined as the sum of: (i) energy from generation in Big Rivers' control area (excluding all generating station use

~~but including scheduled energy reimbursement for losses rendered to Kentucky~~

~~Utilities in accordance with the Interconnection Agreement between Big Rivers~~

T ——————————); (ii) imports of energy for delivery within Big Rivers' control area (determined at Big Rivers' receipt points, including dynamically scheduled loads); (iii) receipts of energy for wheeling-_through transmission by others; and (iv) net inadvertent power exchanges with other control areas (i.e., inadvertent receipts minus inadvertent deliveries).

C

C _Big Rivers' deliveries of energy shall be determined as the sum of: (i) all deliveries of energy to destinations located within Big Rivers' control area (including deliveries to Henderson Municipal Power & Light); (ii) exports of energy from Big Rivers' control ~~area~~ are (measured at Big Rivers' delivery points, including dynamically scheduled exports); and (iii) deliveries of energy for wheeling through transmission by others.

C

T ~~[illegible]~~

______The three-_year average of the most currently -calculated annual loss rate and the annual loss ——rate calculated for each of the previous two years ~~[illegible]~~ shall become the effective annual loss rate as of February 1 in each year.

T

Big Rivers Electric Corporation

Open Access Transmission Tariff
Revised Sheet No.136
Replacing Original Sheet No.136

Page 1 of 4

ATTACHMENT ~~A~~ A

Form Of Service Agreement For
Firm Point-To-Point Transmission Service

~~1.0~~

1.0 This Service Agreement, dated as of ______________, is entered into, by and between Big Rivers Electric Corporation ("Big Rivers"), and ____________ ("Transmission Customer").

2.0 ~~2.0~~ The Transmission Customer has been determined by Big Rivers to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 ~~3.0~~ The Transmission Customer has provided to Big Rivers an Application deposit in ~~the amount of $__________, in~~ accordance with the provisions of Section 17.3 of the Tariff.

4.0 ~~4.0~~ Service under this agreement shall commence on the later of (l) the requested service commencement date~~_________________~~, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Kentucky Public Service Commission, to the extent applicable. Service under this agreement shall terminate on such date as mutually agreed upon by the parties ~~______________________~~.

~~5.0~~ Big Rivers agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

C 5.0

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

C

~~[illegible]~~

C Big Rivers Electric Corporation
201 Third Street, P.O. Box 24
Henderson, Kentucky 42420
Telephone No. (270) 827-2561
Vice President System Operations

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

~~Transmission Provider:~~

C

~~By:~~

Big Rivers:

By: ____

______Name ______________________________Title______________________Date

Transmission Customer:

C

~~By:~~ ____
______Name________________________________Title____________
______Date

C ——Specifications For Long-Term Firm Point-To-Point Transmission Service

C 1.0 ~~1.0~~—Term of Transaction: ______________________________

______Start Date: ______________________________

______Termination Date: ______________________________

C 2.0 ~~2.0~~—Description of capacity and energy to be transmitted by Big Rivers including the electric Control Area in which the transaction originates.

____

C 3.0 ~~3.0~~—Point(s) of Receipt:______________________________

______Delivering Party:______________________________

C 4.0 ~~4.0~~—Point(s) of Delivery:______________________________

______Receiving Party:______________________________

C 5.0 ~~5.0~~—Maximum amount of capacity and energy to be transmitted ______(Reserved Capacity):______________________________

C 6.0 ~~6.0~~—Designation of party(ies) subject to reciprocal service obligation:______________________________

____

____

C

7.0 Name(s) of any Intervening Systems providing transmission service:____

C

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

C

8.1 ~~8.1~~ Transmission Charge: ______________________________

~~8.2~~ ______________________________

8.2 System Impact and/or Facilities Study Charge(s): ______________________________

C

~~8.3~~ ______________________________

8.3 Direct Assignment Facilities Charge: ______________________________

~~8.4~~ ______________________________

8.4 Ancillary Services Charges: ______________________________

C

C

ATTACHMENT ~~A~~ A-1

C **Form Of Service Agreement For ~~Non-~~ The Resale, Reassignment Or Transfer Of Long-Term Firm Point-To-Point Transmission Service**

C 1.0 ~~1.0~~ This Service Agreement, dated as of ______________, is entered into, by and between ~~______~~ Big Rivers Electric Corporation ("Big Rivers"), and ~~______ (Transmission Customer~~ ____________ (the Assignee).

C 2.0 ~~2.0~~ The ~~Transmission Customer~~ Assignee has been determined by Big Rivers to be ~~a Transmission~~ an Eligible Customer under ~~Part II of~~ the Tariff ~~and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 17.2~~ pursuant to which the ~~~~ transmission service rights to be transferred were originally obtained.

C ~~~~ The terms and conditions for the transaction entered into under this Service Agreement shall be ~~~~ subject to the terms and conditions of Part II of the Big Rivers ~~~~

C ~~~~ Tariff, except for ~~~~

C 3.0 ~~~~ those terms and ~~~~ conditions negotiated by the Reseller, as identified below, of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee and appropriately specified in this

C

Service Agreement. Such negotiated terms and conditions include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

C

4.0 ~~4.0~~ Big Rivers shall credit or charge the Reseller, as appropriate, for any difference between the price reflected in the Assignee's Service Agreement and the Reseller's Service Agreement with Big Rivers.

Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

C 5.0

~~[illegible]~~

Big Rivers Electric Corporation
201 Third Street, P.O. Box 24
C Henderson, Kentucky 42420
Telephone No. (270) 827-2561
Vice President System Operations

Assignee:

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be
C executed by their respective authorized officials.

Big Rivers Electric Corporation:

By: ____

Name ______________________ Title ______________________ Date

Assignee:

By: ____

Name ______________________ Title ______________________ Date

C

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________________

Start Date: ____________________

Termination Date: ____________________

2.0 Description of capacity and energy to be transmitted by Big Rivers including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ____________________

Delivering Party: ____________________

4.0 Point(s) of Delivery: ____________________

Receiving Party: ____________________

5.0 Maximum amount of reassigned capacity: ____________________

6.0 Designation of party(ies) subject to reciprocal service obligation: ____________________

____

____

____

____

7.0 Name(s) of any Intervening Systems providing transmission service: ____________________

____

C

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: ____________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge: ____________________

____

8.4 Ancillary Services Charges: ____________________

____

____

____

____

____

____

9.0 Name of Reseller of the reassigned transmission capacity:

____

ATTACHMENT B

Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service

C 1.0 This Service Agreement, dated as of ______________, is entered into, by and between Big Rivers Electric Corporation ("Big Rivers"), and ____________ (Transmission Customer).

C 2.0 The Transmission Customer has been determined by Big Rivers to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

C 3.0 Service under this Agreement shall be provided by Big Rivers upon request by an authorized representative of the Transmission Customer.

C 4.0 The Transmission Customer agrees to supply information Big Rivers deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

C 5.0 Big Rivers agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

C 6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Big Rivers Electric Corporation
201 Third Street, P.O. Box 24
Henderson, Kentucky 42420
Telephone No. (270) 827-2561
Vice President System Operations

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

____

By: ____________________________________

____

_____Name Title______ ________________Date

Transmission Customer:

____

By: ____________________________________

____

C

_____Name———_____ Title———__________
_____Date

C

T

T

T

T

ATTACHMENT ~~-~~C

~~———~~Methodology ~~-~~To Assess Available ~~———~~Transfer Capability

Big Rivers will assess the capability of the Transmission System to provide the service requested using the criteria and process for this assessment as detailed in ~~[illegible]~~ the document titled *AFC/ATC Calculation Procedures*. The document is available on the Big Rivers OASIS. In determining the level of capacity available for new Transmission Service requests, Big Rivers may exclude, from capacity to be made available for new Transmission Service requests, that capacity needed to meet current and reasonably forecasted load of Native Load Customers and Network Customers, existing firm Point-~~T~~-to-Point Transmission ~~Service~~ Service customers, previously received pending Applications for firm Point-~~T~~-to-Point Transmission Service and to meet existing contractual obligations under other tariffs and rate schedules.

In subsequent updates, Big Rivers will compute the transmission transfer capability available from the Delivering Party to the Receiving Party using Good Utility Practice and the engineering and operating principles, standards, guidelines and criteria of Big Rivers, ~~ECAR~~SERC, and any entity of which Big Rivers is a member and which has been approved by the Federal Energy Regulatory Commission to promulgate or apply regional or national reliability planning standards (such as an ~~RTG~~ RTO), or any similar organization that may exist in the future of which Big Rivers is then a member. Principal items used to determine maximum transmission transfer capability available include reliability, transmission element loading, system contingency performance, voltage levels, and stability, and other criteria specified in ~~[illegible]~~ the Big Rivers OASIS posting.

ATTACHMENT ~~A~~D

Methodology for Completing a System Impact Study

Big Rivers will assess the capability of the Transmission System to provide service requested pursuant to this Agreement. Big Rivers will determine whether a proposed use of the Transmission System results in transmission interface loading such that First Contingency Total Transfer Capability (FCTTC) is not exceeded. The FCTTC shall be as defined by NERC.

"Acceptable" and "unacceptable" steady-state voltages and facility loadings are defined by criteria established by ~~ECAR~~ Big Rivers and other utility systems with which Big Rivers is interconnected according to all applicable NERC and SERC standards.

In addition to the steady-state performance criteria described above, Big ~~Rivers~~ Rivers' Transmission System is also designed taking into account dynamic stability performance to ensure any credible disturbance (short circuit or equipment disconnection) does not result in cascading tripping of transmission facilities. The criteria applied are those established by ~~ECAR~~ Big Rivers according to all applicable NERC and SERC standards.

Transmission System performance for the requested service shall include a consideration of (i) the load and projected loads of Big Rivers' native load customers, (ii) the loads of firm Point-to-Point Transmission Customers under this ~~Agreement~~ Tariff and pursuant to other agreements, rate schedules, and contracts; (iii) transmission service to be provided in response to previously pending Valid Requests for transmission service under this ~~Agreement~~ Tariff and other contracts. Transmission Service to native load customers involves consideration of local transmission facility performance, in addition to consideration of any transmission interface transfer capability. This planning is performed the same as transmission planning for Big Rivers' native load. The primary design criterion for the Transmission System is that failure of any one circuit or piece of equipment should not cause a sustained outage or unacceptably high or low voltage to customer load, nor should it cause excessive loading on Transmission System equipment. This must be satisfied at any load level, during peak load periods as well as off-peak periods.

The exceptions to this "single contingency" criterion are (i) small distribution substations which may be supplied by a single transmission line, and (ii) large groupings of substations for which double contingency system design may be employed.

ATTACHMENT E

Index Of Point-To-Point Transmission Service Customers

Customer	Date of Service Agreement
AEP Service ~~[illegible]~~ Corp.	3/27/2002

Allegheny Energy Supply	9/11/2000
Big Rivers Power Supply	10/1/1998
Cargill-Alliant LLC	2/12/2002
Cash Creek Generation, LLC	7/16/2007
Cinergy Power Mkt. & Trading	10/31/2005
Cobb Electric Membership Corp.	6/9/2003
Conectiv Energy Supply	10/21/1999
Constellation Energy Commodities Group	10/13/1998
Coral Power L.L.C.	5/25/1999
DTE Energy Trading	7/24/2000
Duke Energy Indiana	10/31/2005
Duke Energy Kentucky, Inc.	10/31/2005
Duke Energy Trading and Marketing	8/13/1998
E.ON U.S. Services, Inc.	6/1/2000
Exelon Generation, LLC	5/14/2001
Hoosier Energy Power Marketing	10/8/1998
Lehman Bothers Commodity Services Inc.	1/16/2006
LG&E Energy Marketing Inc.	9/15/1998

NRG Power Marketing	1/15/2002
Peabody Energy	7/11/2002
PG&E Energy Trading Power, L.P.	12/15/1998
Powerex Corp.	1/24/2000
PPM Energy, Inc.	7/20/1998
Rainbow Energy Marketing Corp.	7/15/1998
Sempra Energy Trading Corp.	5/11/2000
Southern Illinois Power Coop. Marketing	8/3/1998
Southern Indiana Gas & Electric	7/15/1998
The Cincinnati Gas & Electric Company	10/31/2005
The Energy Authority	7/20/2000
The Legacy Energy Group	6/12/2000
Tennessee Valley Authority	12/9/2000

ATTACHMENT F

Service Agreement For
Network Integration Transmission Service

C

I. GENERAL TERMS AND CONDITIONS

1.0 This Service Agreement, dated as of ________________, is entered into, by and between Big Rivers Electric Corporation (hereinafter Big Rivers), and ____________________ (hereinafter Transmission Customer).

C 2.0 ~~The~~ This Transmission Customer has been determined by Big Rivers to have completed satisfactorily an Application for Network Integration Transmission Service;

3.0 Service under this Agreement shall commence on the later of: (1) ____________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as agreed by the parties hereto. Service under this Agreement shall terminate on ________________;

C 4.0 Big Rivers agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Service in accordance with the provisions of the Tariff and this Service Agreement.

C 5.0 Any notice of request made to or by either party to this Agreement regarding this Service Agreement shall be made to the representative of the other party as indicated below.

Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, Kentucky 42420
Vice President System Operations

Transmission Customer

____
____
C ____________________________
____

6.0 The Big Rivers Open Access Transmission Tariff, the attached Specifications for Network Integration Transmission Service, and Network Operating Agreement are incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the parties to this Agreement have caused this Service Agreement to be executed by their respective authorized officials.

Big Rivers Electric Corporation

By:____________________________ Date:________________

C ~~Title:________________________~~

Title:________________________

Transmission Customer

C

By:____________________________ Date: ________________

Title: __________________________

SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

C

1.0 Term of Network Service:

Start Date: ______

Termination Date: ______

2.0 Description of capacity and/or energy to be transmitted by Big Rivers across Big Rivers' Transmission System (including electric control area in which the transaction originates).

C

______

______

______

3.0 Network Resources

(1) *Transmission Customer Generation Owned:*

C

Resource	Capacity	Capacity Designated as Network Resource

____

____

____

(2) Transmission Customer Generation Purchased:

<u>Source</u>	<u>Contract Description</u>	<u>Capacity</u>

C

Total Network Resources Capacity: _(1) + (2) = __________________

4.0 Network Load

(1)-___Transmission Customer Network Load:

<u>Network Load</u>	<u>Transmission Voltage Level</u>

C

____

(2) Member Systems Load Designated as Network Load:

Network Load | Transmission Voltage Level

C

5.0 Designation of party subject to ~~reciprocal~~ reciprocity service obligation:

____

6.0 Service under this Agreement may be subject to some combination of the charges below. (The appropriate charges for individual transactions will be determined in accordance with the Terms and Conditions of the Open Access Transmission Tariff).

6.1 Load Ratio Share of Annual Transmission Revenue Requirement:

6.2 Gross Up in Load Ratio Share for Average System Transmission Losses:

6.3 Facilities Study Charge:

6.4 Direct Assignment Facilities Charge:

6.5 Ancillary Services Charges:

6.6 Redispatch Charges:

C

C

ATTACHMENT G

Network Operating Agreement

C To be developed between Big Rivers and future network customers.

ATTACHMENT H

Annual Transmission Revenue Requirement
For Network Integration Transmission Service

~~1.~~

The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall

I 1. be $~~16,887,015.~~ 19,961,900.

T 2. ~~2.~~ The amount in (1) shall be effective until amended by Big Rivers or modified by the ~~applicable regulatory commission~~Kentucky Public Service Commission.

ATTACHMENT I

Index Of Network Integration Transmission Service Customers

Customer	Date of Service Agreement

None

ATTACHMENT J

Procedures for Addressing Parallel Flows

The Joint Reliability Coordination Agreement ("JRCA") entered into by the Midwest ISO, PJM Interconnection LLP, and the Tennessee Valley Authority ("TVA") provides for cooperation in the management and operation of the electric transmission grid over a large portion of the eastern United States. As a utility within the TVA Reliability Coordinator footprint, Big Rivers is party to this agreement. The JRCA provides for the sharing of critical information, comprehensive reliability management, and congestion relief. The improved coordination provided by the JRCA allows each grid operator to recognize and manage the effects of parallel flows and preemptively address concerns.

T

The Big Rivers AFC/ATC calculation process takes advantage of the coordination provided by the JRCA. The impact of both internal and external transfers is considered with limits on both internal and coordinated external flowgates observed. The Big Rivers document titled *AFC/ATC Calculation Procedures* describes the coordinated AFC and ATC calculation procedures in detail. This document is available on the Big Rivers OASIS.

T

Real-time pre and post contingency congestion resulting from parallel flows is addressed through the TLR procedures described for the Eastern Interconnection in NERC Standard IRO-006-3 as implemented according to the JRCA.

T

T

ATTACHMENT K

Transmission Planning Process

T

ATTACHMENT K

PL-GEN-2

T

TABLE OF CONTENTS

Introduction

Commitment to the Nine Planning Principles of Rule 890

T

Introduction

Order 890 requires that Transmission Providers submit a proposal for a regional planning process that complies with the nine planning principles (described in detail below) and other requirements of the Final Rule. In the alternative, a Transmission Provider may make a compliance filing describing its existing coordinated and regional planning process, including the appropriate language in its tariff, and show that this existing process is consistent with or superior to the requirements in the Final Rule.

This document describes the nine planning principles and how Big Rivers Electric Corporation's (Big Rivers') existing planning process complies with the principles.

Central Public Power Participants:

Big Rivers and its neighboring public power companies AECI, EKPC, and TVA, have formed the Central Public Power Participants group (CPPP) for the purposes of coordinating planning within the region. The CPPP also provides the framework for stakeholder participation.

Inter-regional Participation:

Big Rivers participates in interregional planning through four relationships: as a member of the SERC Reliability Corporation; through participation in activities of the Eastern Interconnection Reliability Assessment Group (ERAG) as a SERC member; as a member of the Southeastern Interregional Planning Group (via CPPP), and through a Joint Reliability Coordination Agreement (TVA, PJM and MISO).

Commitment to the Nine Planning Principles of Rule 890

Principle 1 - Coordination:

- *The transmission provider must meet with all of its transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis*
- *The transmission provider must provide early and meaningful interaction opportunities for customers and other stakeholders to provide input regarding the transmission planning process and transmission expansion plans. The transmission provider must consider these inputs in its planning process.*
- *The FERC does not prescribe specific requirements for coordination, such as number of meetings, the scope of the meetings, the notice requirements, the format, etc.*

Coordination with retail customers is achieved through periodic meetings with each distribution cooperative and the involvement of each cooperative in the expansion planning process.

As an expansion of this effort, Big Rivers together with its CPPP partners sponsored the formation of the CPPP regional stakeholder group which is open to all transmission customers including full service distribution and direct served industrial customers, neighboring utilities and RTOs, regulatory agencies, and generation owner/development companies. The stakeholder group held its first meeting on November 14, 2007.

The stakeholder group is administered by the CPPP partners. An annual cycle of stakeholder meetings is scheduled to provide stakeholders with opportunities for participation and contributions including alternative solutions.

As illustrated in Figure 1, the first meeting in the annual cycle is used to provide base data cases and review criteria and assumptions. At the second meeting assessments of potential reliability problems and preliminary solutions will be presented. At the third meeting, advanced solutions including stakeholder suggestions are reviewed. Opportunities for stakeholder input are open up to the point of final project selection.

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Access to data, assumptions, notifications and proposals regarding studies, meeting and study schedules, study results, stakeholder group processes, and minutes and similar records is provided through OASIS. Other web-based locations will be established as required. Access to some information requires execution of a mutually acceptable confidentiality agreement.

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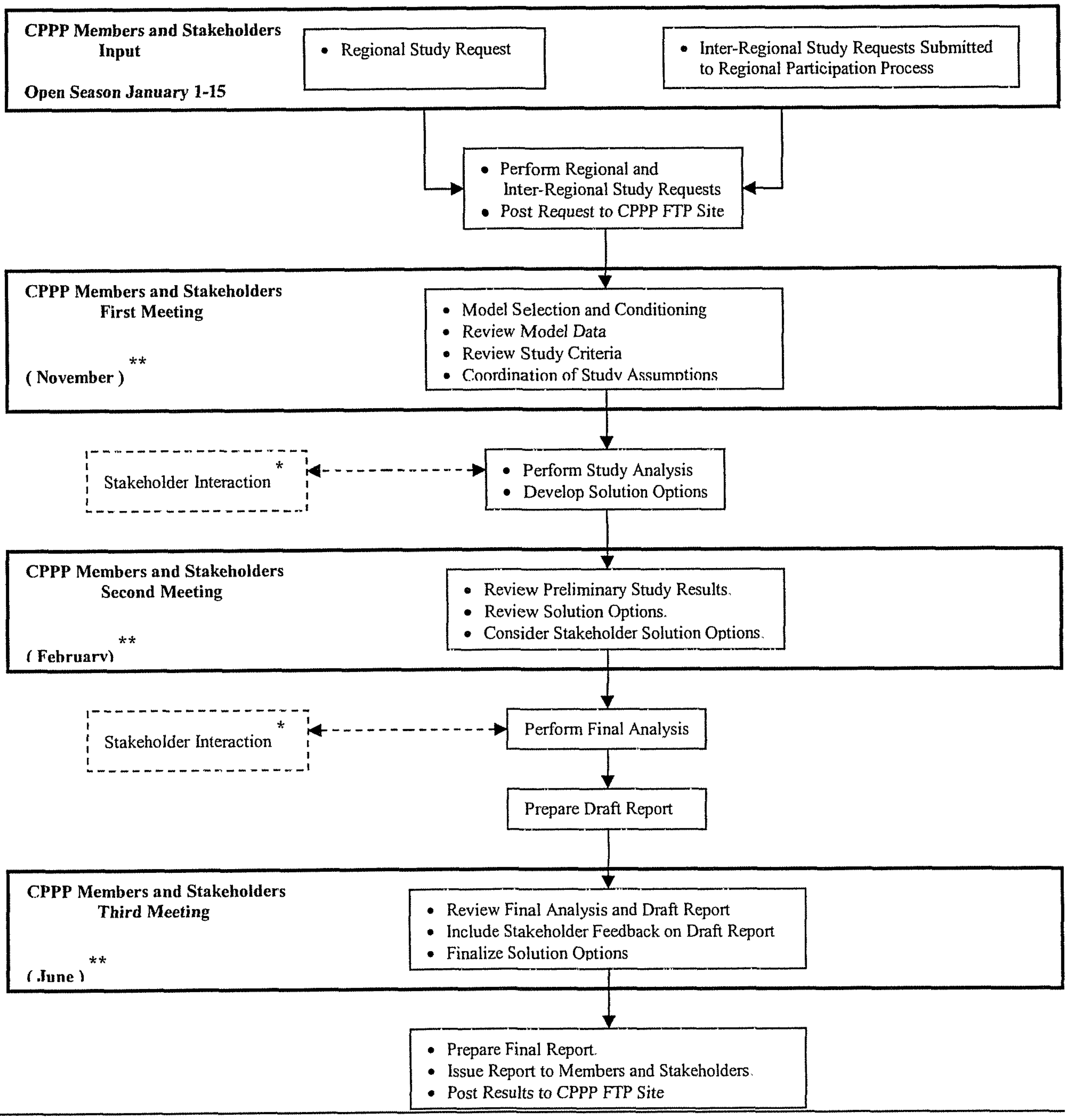

* As required by Stakeholder planner

** Date to be established in coordination with Stakeholders and other meetings

Figure 1: CPPP Regional Transmission Development Plan Participation Process Diagram

Principle 2 - Openness:

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- *The transmission provider's planning process must be open to all affected parties, including but not limited to transmission customers, interconnection customers, state commissions, and other stakeholders.*
- *The transmission provider must develop mechanisms such as confidentiality agreements and password-protected access to information to manage the release of Critical Energy Infrastructure Information (CEI) into the public domain.*

All members of the CPPP stakeholder group described above have the opportunity to access the Big Rivers transmission planning process through posted documents and stakeholder meetings.

As noted under Principle 1, information is shared through easily accessible systems subject to standard security and confidentiality measures.

Some business-related information may be considered confidential and will not be shared.

Similarly, critical infrastructure or CEI information that

1. Relates to the production, generation, transmission, or distribution of energy;
2. Could be useful to a person planning an attack on critical infrastructure;
3. Is exempt from mandatory disclosure under the Freedom of Information Act; and
4. Gives strategic information beyond the location of the critical infrastructure

Examples of CEI are details of critical contingencies and limiting facilities that would jeopardize the integrity of the bulk transmission system, specific information on protective relaying schemes, and breaker data.

It is noted that CEI data filed with the FERC as Form No. 715 can be obtained by filing a CEI request using the Commission's established procedures. For other CEI information or other commercially-sensitive information requests, Big Rivers will consider provision under a nondisclosure agreement where there is legitimate need.

Confidentiality provisions will be periodically reviewed to ensure that stakeholders have access to sufficient data to enable them to perform their own reliability and economic planning studies or replicate existing studies.

Principle 3 - Transparency:

- *The transmission provider is required to disclose data, study methodology, basic criteria, and assumptions that underlie its transmission system plans in written form.*

- *The transmission provider must make simultaneous disclosures regarding the status of transmission projects to all parties of concern.*

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Data, study methodology, basic criteria, assumptions that underlie transmission system plans, and study reports will be made available each year to stakeholders through postings supported by discussions and presentations at scheduled stakeholder meetings.

The base data cases will be those used by CPPP members for their reliability studies. Data cases are developed for the Siemens PTI Power System Simulator for Engineering (PSS/E). Conversion of data for use in other programs is the responsibility of the user.

The study methodology, basic criteria, and assumptions that underlie transmission system plans are those used by Big Rivers to ensure compliance with NERC Standards.

Principle 4 - Information Exchange:

- *Network transmission customers must submit projected load and resource information on a comparable basis as that used by transmission providers in planning for native load.*

- *Point-to-point customers are required to submit projected need for transmission service over the planning horizon*

- *The transmission provider, in consultation with customers and other stakeholders, must develop information exchange guidelines and schedules for the submittal of transmission planning information.*

- *Information must be made available at regular intervals and be identified in advance.*

Big Rivers requires network customers to provide information regarding projected loads and resources on a comparable basis to that provided on behalf of native load customers for planning purposes.

A point-to-point customer must provide information about its utilization of the transmission system including transmission capacity, duration, and receipt and delivery points. These requirements are specified in Big Rivers Open Access Transmission Tariff. Information regarding planned generator additions or upgrades including status and expected in-service date, planned retirements, and environmental restrictions are also required in accordance with generator interconnection procedures.

This information is included in Big Rivers base case models so the needs of transmission customers are addressed in the transmission expansion plan. Additional information or changes to previously submitted information can be submitted throughout the planning process and will be incorporated into the planning process wherever possible.

Principle 5 - Comparability:

- *The transmission provider must develop a transmission plan that (1) meets the specific service requirements of transmission customers and (2) treats similarly situated customers (network and retail/wholesale native load) comparably in the transmission planning process.*

- *Customer demand resources should be considered on a comparable basis to the service provided by comparable generation resources.*

Big Rivers develops transmission plans that meet the specific service requests of its transmission customers and otherwise treats similarly-situated customers comparably in transmission system planning.

Customer demand resources are considered on a comparable basis with generation resources.

Principle 6 - Dispute Resolution:

- *Transmission providers must propose a dispute resolution process. An existing dispute resolution process may be used, but the transmission provider must address how it would work in the transmission planning process.*

- *The timing of the dispute resolution process should be consistent with the transmission planning process*

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For disputes arising under Attachment K the parties will attempt to settle the dispute through informal negotiation. The dispute resolution process will progress to discussions and meeting with Big Rivers senior management.

Principle 7 - Regional Participation:

- *The transmission provider must coordinate with interconnected systems to (1) share system plans to ensure simultaneous feasibility, (2) maximize use of consistent assumptions and data, and (3) identify system enhancements that relieve congestion or integrate new resources.*

- *The Transmission Planning proposal must specify the broader region in which it proposes to conduct integrated and coordinated regional planning.*

- *The transmission provider should consider and accommodate existing institutions, physical characteristics, and historical practices in their planning process.*

Big Rivers participates in regional and interregional planning through the CPPP group as described under Principles 1 and 8.

Participation in planning between regions is achieved through four relationships: the Southeastern Interregional Planning Group (via the CPPP), a joint TVA, PJM, and MISO planning agreement, membership in SERC Reliability Corporation, and participation in the Eastern Interconnection Reliability Assessment Group (ERAG). These relationships and joint studies ensure that Big Rivers coordinates with interconnected systems.

Southeastern Interregional Planning Group:

The Southeastern Interregional Planning Group plan defines an inter-regional process among transmission owners Alabama Electric Cooperative, Dalton Utilities, Duke Energy Carolinas, Entergy Operating Companies, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, Progress Energy Carolinas, Santee Cooper, South Carolina Electric and Gas, South Mississippi Electric Power Association, Southern Company, and Tennessee Valley Authority.

The process will be used to collect data, coordinate planning assumptions and address stakeholder study requests. Data and assumptions developed at the regional level will be consolidated and used in the development of models for use in the process. In addition to performing stakeholder requested studies, the interregional planning process provides a means for the participating transmission providers and stakeholders to review the data, assumptions, and assessments being performed on an interregional basis.

Joint Planning Agreements (JRCA) with TVA PJM and MISO:

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A TVA, PJM, and MISO agreement exists for the exchange of information (including Big Rivers data) and the implementation of reliability and efficiency protocols. These agreements address the equitable and economical management of congestion on flowgates affected by flows of Big Rivers as well as TVA, PJM, and the Midwest ISO and use of the congestion management procedures by third parties on flowgates affected by the flows of any party that binds itself to the congestion management procedures of the agreements. The agreements also address arrangements for coordination of the parties systems.

The joint planning activities between TVA, PJM, and MISO are used as a basis for studies with SPP. These expanded activities are not yet fully covered by formal agreements. Initial studies include development of long term plans for the combined area for years 2018 and 2024.

Each of the entities has its own stakeholder group. The joint planning activities are being used as the basis for development of combined stakeholder participation, and for coordination of responses to stakeholder interregional study requests.

SERC Reliability Corporation:

SERC Reliability Corporation is a member of NERC and is responsibility for reliability in the southeast. Big Rivers is a member of SERC and is included in the Central Subregion of SERC. Big Rivers planning personnel participate in a number of committees, groups and task forces within SERC to ensure regional coordination in transmission planning.

The SERC planning processes and their relationship to the local planning processes of the SERC member systems are described in the SERC Reference Document "Regional Transmission Assessment Study Processes Within SERC." In general, all members including Big Rivers conduct regional reliability studies within the SERC framework of intra-regional near-term & long-term studies. Member system models are combined into a SERC reliability study model annually. SERC members couple local transmission assessment activities with regional coordinated transmission study processes. Joint study efforts involving two or more parties are used to maintain coordination among systems and along system interfaces. The processes may also involve Regional Transmission Organizations (RTOs).

Eastern Interconnection Reliability Assessment Group (ERAG).

ERAG comprises the six NERC regions composing the eastern interconnection, for the purpose of augmenting reliability of the bulk power system in the joint areas. ERAG has responsibility for the Multiregional Modeling Working Group (MMWG). A single master study base case covering the entire eastern interconnection is developed each season. Big Rivers participates in ERAG activities through its SERC membership.

ERAG study work is shared between regions under a number of study forums. SERC assigns members to conduct inter-regional studies with other RROs through the ERAG agreement. Also, SERC's designated liaison to the ERAG Multiregional Modeling Working Group (MMWG) updates the Eastern Interconnection study model.

Principle 8 - Economic Planning Studies:

- *The Transmission Provider must prepare studies identifying "significant and recurring" congestion and post such studies on their OASIS.*
- *Studies should analyze and report on (1) location and magnitude of congestion, (2) possible remedies for the elimination of congestion, (3) associated costs of congestion, (4) costs associated with relieving congestion.*
- *Such studies must include the integration of new generation resources or loads on an aggregated or regional basis.*
- *The planning process must consider both reliability and economic considerations (e.g. whether transmission upgrades or other investments can reduce the overall costs).*
- *Transmission providers should develop a means to allow the Transmission Provider and stakeholders to cluster requests for economic planning studies so that such studies can be performed in an efficient manner.*
- *Requests for economic planning studies, and responses to those requests, must be posted on OASIS. The transmission provider must coordinate with interconnected systems to (1) share system plans to ensure simultaneous feasibility, (2) maximize use of consistent assumptions and data, and (3) identify system enhancements that relieve congestion or integrate new resources.*

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Big Rivers will continue to perform planning studies to identify transmission congestion within Big Rivers and between Big Rivers and other balancing areas, with integration of new resources including options suggested by stakeholders or loads on an aggregated basis. Big Rivers will use reliability and economic studies whenever feasible to improve efficiency and lower costs. Economic benefits such as those related to transmission congestion and integration of new transmission users will be considered when addressing reliability issues.

Study reports will identify congestion in its transmission system. These study reports will be posted on OASIS.

Big Rivers presently does not use LMP as the basis for its economic analysis of congestion. Reliability studies are directed towards elimination of congestion to allow optimal economic dispatch.

Stakeholder Requested Studies.

Through the CPPP planning process, a reasonable number of economic studies will be completed. All stakeholder requests will be posted on OASIS. All economic project requests will be considered as alternatives for reliability problem solutions.

Requests for economic studies must be supported by provision of the necessary data, such as generator models and transaction patterns. Depending on confidentiality considerations, use of more generic industry data may be deemed acceptable.

Big Rivers' participation in the CPPP stakeholder process does not substitute for the official interconnection and transmission service request processes. The official interconnection process must be used for any requests to interconnect to the Big Rivers transmission system.

Principle 9 - Cost Allocation:

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- *For projects that do not fit under the cost allocation structure in the existing pro forma OATT, such as regional projects involving several transmission owners or economic projects, transmission providers are required to address the allocation of costs for new facilities in its planning process.*

- *The proposal should identify the types of new projects not covered under existing cost allocation rules.*

- *FERC is not prescribing specific cost allocation methods, but will consider (1) whether a cost allocation proposal fairly allocates costs among participants, (2) whether the cost allocation proposal provides incentives to construct new transmission, and (3) whether the proposal is supported by state authorities and participants across the region.*

Costs of transmission system upgrades are recovered through Big Rivers' rates for transmission service.

Where existing rate structures do not apply, such as to regional projects involving several transmission owners or projects identified through economic planning studies, costs will be allocated to the customers requesting the project. Where a project crosses regional boundaries, each regional transmission owner will be responsible for allocating its share of the cost.

When a project is requested that is an acceleration or modification of a project already planned for implementation, the requesting party will pay the incremental costs.

If Big Rivers elects to enhance a stakeholder requested project, the requesting party will be responsible only for the costs of the project at the level requested for that party's needs.

In applying these cost allocation principles, Big Rivers will identify benefits that a requested project may provide to Big Rivers such as deferral of other transmission projects or a reduction in energy losses. The costs assigned to the requesting party will be a net value, recognizing the value of any such benefits.

ATTACHMENT L

Creditworthiness Procedures

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1. Purpose – For the purpose of determining the ability of a Transmission Customer ("Customer") to meet its financial obligations related to service under Big Rivers Electric Corporation's ("BREC") Open Access Transmission Tariff, BREC will use the following credit review procedures.

2. Credit Review – BREC will perform a credit review of each Customer. BREC's CFO shall continuously assess each Transmission Customer's credit risk and determine their credit limit, based upon both qualitative and quantitative factors. Among other things, such factors may include the Customer's competitive position, capital structure, liquidity, financial strength, profitability and credit ratings. A credit file will be maintained for each Customer in support of such credit limit determination. BREC will treat Customer credit information confidential. The Customer shall provide the following minimum information:

    a. The most recent two fiscal years audited financial statements (including the footnotes).
    b. The most recent unaudited fiscal year, if any, and year-to-date financial statements.
    c. DUNS number.
    d. Moody's and/or S&P's long term senior unsecured debt ratings.
    e. Primary credit officer contact information, including name, title, mailing address, telephone number and facsimile number.

    Other commercially reasonable information may be requested by BREC during the credit review process. In determining credit level and collateral requirements, BREC may also use any third-party information it finds available and appropriate.

3. Credit Exposure – BREC's CFO will monitor BREC's credit exposure to each Customer. BREC will review the Customer's payment history and ensure that no payment due it is in arrears. Overdue payments will include interest at the appropriate rate.

4. Security – In the event a Customer does not meet BREC's creditworthiness standard, the Customer may substitute one or more of the following:

a. An unconditional and irrevocable letter of credit from an institution acceptable to BREC in an amount and term sufficient to support Customer's responsibilities and obligations under the Tariff.
b. A corporate guarantee acceptable to BREC.
c. Prepayment of the charge for service on terms acceptable to BREC.

Any alternative form of security proposed by the Customer and acceptable to BREC may be used.

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5. Notices – BREC will notify Customer of initial credit level and collateral requirements, and any change thereto. Customer may contest any adverse credit determination by BREC by providing supporting information, and may request an explanation of BREC's credit determination. When necessary, BREC will give Customer a reasonable opportunity to post additional collateral. All communication and notices to BREC regarding the Customer's credit shall be to the following address:

Big Rivers Electric Corporation
Attention: CFO
201 Third Street
Henderson, KY 42420
Phone: 270-827-2561
Facsimile: 270-827-2558

6. Waiver – No failure on the part of BREC to exercise any of its rights or remedies hereunder shall waive them, unless expressly stated by BREC in writing.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATION, (II) APPROVAL OF TRANSACTIONS, (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND E.ON-U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING, INC. FOR APPROVAL OF TRANSACTIONS	))))))))))))	CASE NO. 2007-00455

EXHIBIT 35

Testimony of Ralph L. Luciani

December 2007

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

DIRECT TESTIMONY OF
RALPH L. LUCIANI

ON BEHALF OF
APPLICANTS

DECEMBER 2007

DIRECT TESTIMONY OF RALPH. L. LUCIANI

INTRODUCTION AND QUALIFICATIONS

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

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

Q. Please briefly describe your business and educational background.

A. I have more than 20 years of consulting experience analyzing economic and financial issues affecting the electricity industry, including those related to costing, ratemaking, generation planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization costs and benefits. Prior to joining CRA, I was a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. I hold a B.S in Electrical Engineering and Economics from Carnegie Mellon University. I also hold an M.S. from the Graduate School of Industrial

Administration at Carnegie Mellon University. I have previously testified before the Arkansas, Maryland, Kansas, Louisiana, Maryland, Missouri, Ohio and Pennsylvania state regulatory commissions, the Federal Energy Regulatory Commission, and the Ontario Energy Board. A copy of my resume is attached as Exhibit RLL-1.

Q. **What is the purpose of your testimony?**

A. Big Rivers Electric Corporation ("Big Rivers") has asked me to develop updated rates for wholesale transmission services and ancillary services provided under its Open-Access Transmission Tariff ("OATT"). Specifically, I present new wholesale transmission rates for network and point-to-point customers under the Big Rivers OATT. I also present new ancillary services rates for Big Rivers under Schedules 1 through 6 of the OATT. I also provide testimony regarding the derivation of these new rates.

Q. **Describe Big Rivers current transmission and ancillary services rates.**

A. The current rates to wholesale transmission customers for network and point-to-point transmission service under Schedules 7, 8 and 9 in the Big Rivers OATT were developed in 1998.[1] Generation-related ancillary services under Schedules 2 through 6 of the Big Rivers OATT are currently provided to Big Rivers' wholesale transmission customers through an arrangement between Big Rivers and Western Kentucky Energy Corp. ("WKEC"), as successor to LG&E Energy Marketing ("LEM"), one of the affiliates of E.ON U.S., L.L.C. ("E.ON U.S."). Under this arrangement, the charges assessed to Big Rivers' transmission customers for these services reflect a pass-through of the costs charged to Big Rivers by WKEC. The applicable WKEC ancillary service rates were established in 1998 pursuant to an LEM filing at the Federal Energy Regulatory Commission ("FERC").[2]

Q, **Why is it necessary to change Big Rivers' ancillary services rates?**

A. After the termination of the 1998 lease agreements ("Unwind Transaction") between Big Rivers and E.ON U.S. and its affiliates (the "E.ON U.S. Parties"), Big Rivers will own and operate the generating units formerly used by WKEC to provide these ancillary services. WKEC no longer will be supplying these generation-related ancillary services. In place of purchasing these ancillary services from WKEC, Big Rivers will self-supply these services from the generation assets

1 FERC Docket No. NJ98-5-000
2 FERC Docket No. ER98-2684.

restored to its ownership and control. Because the pass through of WKEC charges reflected in the existing Big Rivers OATT schedules 2 through 6 no longer will be applicable, it is necessary for Big Rivers to develop its own rates for these unbundled ancillary services.

Q. **Why did Big Rivers also update its transmission rates in addition to these new ancillary services?**

A. In order to establish new ancillary services for Big Rivers to use on and after the date of closing of the Unwind Transaction it was necessary to examine the underlying costs associated with providing these ancillary service rates. Many of these underlying costs also underpin Big Rivers' transmission rates. Because the existing transmission rates were based on 1997-1998 vintage data and the new ancillary services rates were being developed based on 2006-2007 vintage data Big Rivers determined that it would be preferable to base all of the costs in its OATT on data of the same vintage. Accordingly, I reexamined Big Rivers' transmission revenue requirement and other cost of service issues in parallel with my development of new ancillary services rates.

Q. **Can you summarize your approach for updating the Big Rivers wholesale transmission rates?**

A. Yes. In developing the Big Rivers transmission rates, I have generally followed the method used by cooperatives in the Midwest ISO in developing their formula transmission rates under Attachment O of the Midwest ISO OATT.[3] The development of the Big Rivers rates relies primarily on data from the Big Rivers 2006 RUS Form 12 and the underlying 2006 Big Rivers accounting data. The ancillary service rates are derived by calculating the annual carrying costs of the Big Rivers generating units and applying the share of these units needed to provide each service. Because the 2006 Big Rivers data does not reflect the impact of the Unwind Transaction that will take place during 2008, I have adjusted certain data elements as noted below to reflect the projected impact of the Unwind Transaction.

Q. Can you summarize the changes to the Big Rivers wholesale transmission and ancillary services rates?

A. Yes. The transmission rates are summarized in Table 1 of Exhibit RLL-2. The proposed point-to-point transmission rates increase by 1.6% from current point-to-point rates. Currently, the charges for

[3] The cooperatives using RUS Form 12 data to develop their rates are Great River Energy, Hoosier Energy and Southern Illinois Power Cooperative. (See www.midwestiso.org at Documents, Pricing Analysis, Attachment O). Big Rivers is directly interconnected with Hoosier Energy and Southern Illinois Power Cooperative.

Schedule 1, Scheduling, System Control and Dispatch Service, are included within the Big Rivers rates for network and point-to-point transmission service, but will be assessed separately in the proposed Big Rivers OATT rates to reflect more closely FERC's Order No. 890. Including the impact of the new Schedule 1 charges, the proposed Big Rivers firm point-to-point transmission rates for annual transmission service increase by 8.6% from current rates.

The proposed ancillary service rates for Schedules 1, 2, 3, 5 and 6 are summarized in Exhibit RLL-2, Tables AS-1 through AS-5. The rates for operating reserves under Schedules 5 and 6 rates reflect the costs attributable to Big Rivers' membership in the Midwest ISO Contingency Reserve Sharing Group. The charges for Schedule 4, Energy Imbalance Service, will be assessed in the Big Rivers OATT based on the methodology contained in FERC Order 890.

Q. **What capital structure and rates assumptions did you apply in deriving the proposed rates?**

A. As shown in Table 6 of Exhibit RLL-2, for interest costs, I used the average Big Rivers long-term debt rate in 2006 derived using 2006 RUS Form 12 data. The cooperatives in the Midwest ISO in their annual Attachment O transmission rate derivation apply a 12.38% cost of equity, while LG&E in its transmission formula rate derivation applies a 10.88% cost of equity.[4] I conservatively chose to use this same 10.88% cost of equity in the derivation of the Big Rivers rates. For the debt and equity share of the Big Rivers capital structure, I used the Big Rivers projected levels of debt and equity in the Big Rivers balance sheet as of the date of the closing of the Unwind Transaction.

Q. **What other projected data did you incorporate to reflect the impact of the Unwind Transaction on Big Rivers?**

A. The 2006 Big Rivers data does not reflect certain of the production-related accounts and expenses associated with the leased generating units that will be reflected in the Big Rivers accounts subsequent to the Unwind Transaction. As such, in deriving rates, projections of the level of fuel stock, annual production O&M and annual property insurance expense subsequent to the Unwind Transaction were used. In addition, the projected annual increase in Big Rivers A&G expense after the Unwind Transaction was incorporated. No adjustments were made to the 2006 firm demand on the Big Rivers transmission system

[4] FERC Docket ER06-1183-000, LG&E Energy, LLC, et al., June 28, 2006. See also http://sppoasis.spp.org/documents/lgee/uploads/RateFormula.pdf

as a result of the Unwind Transaction, as the WKEC transmission reservation rights are being assigned to Big Rivers under the Unwind Transaction.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Ralph L. Luciani

Ralph L. Luciani

District of Columbia)
City of Washington)

Subscribed and sworn to before me by Ralph L. Luciani on this the 17th day of December, 2007.

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

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

RALPH L. LUCIANI
Vice President
CRA International

M.S. Industrial Administration, Carnegie Mellon University

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

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

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

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

PROFESSIONAL EXPERIENCE

Generation and Power Marketing

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

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

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

Nuclear Plant Sale—Mr. Luciani acted as the lead economic consultant in negotiating the sale of a utility's nuclear plant, including conducting detailed economic analyses of the various offers for the facility and assessing the complex income tax effects that would result from the sale.

Power Marketing—He prepared several affidavits in a FERC proceeding analyzing the profitability of wholesale trading activities to assess allowable cost offsets from refunds owed.

Cost-Based Wholesale Rates—Mr. Luciani filed an affidavit at FERC which developed a utility's cost-based rates for wholesale sales of capacity and energy in its control area.

Climate Change Regulation—He has assisted several utilities in analyzing the impact of potential climate change regulations on generation resource plans.

RTOs and Transmission

RTO Cost Benefit Studies—He developed the financial models used to derive the economic and rate impacts to stakeholders in four major cost-benefit studies of Regional Transmission Organizations (RTOs), and has provided related testimony in a number of state proceedings.

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

Transmission Ratemaking—Mr. Luciani presented testimony before the FERC on behalf of a group of companies seeking to join a Regional Transmission Organization regarding transmission ratemaking and calculations of earned returns for transmission activities.

Transmission Costing—He assisted a utility by providing testimony and negotiating settlement agreements in a FERC settlement process regarding the cost responsibility for the payment of through and out transmission charges.

Transmission Expansion—Mr. Luciani assisted a utility in formulating pricing alternatives for the installation of a new 500 kV transmission line to be used primarily to export power.

Financial Evaluation

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

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

Asset Valuation—Mr. Luciani performed a market valuation of the generation portfolio of a major generation company. His assessment was used as the basis for restatement of the portfolio's value on the company's balance sheet.

Mergers and Acquisitions—On several occasions, Mr. Luciani analyzed the potential acquisition of electric utilities, gauging the impact of state restructuring plans on asset value and earnings, and formulating transmission and distribution pro forma financials.

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

Distribution and Retail

Distribution Performance-Based Rates—Mr. Luciani formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan, which included distribution system and call center operating measures, to the state public utility commission.

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

Distribution Cost Allocation—Mr. Luciani filed an affidavit on behalf of a large customer in a generic distribution rate proceeding in Ontario, Canada regarding the allocation of distribution costs and the derivation of stand-by rates for load displacement generation.

Retail Market Strategy—Mr. Luciani assisted an electric utility in formulating an evaluation model to assess the profitability of new retail loads in a competitive market. Mr. Luciani also developed a financial model for a company offering a product to reduce on-peak demand in residences.

Environmental and Fuel

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

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

Expert Testimony Experience

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

Table 1
Big Rivers Electric Corporation
Transmission Rates

1	*Gross Revenue Requirement*	20,402,627	Table 3, L12
2	(Less) Rent from Transmission Property in Account 454	23,047	Table 4, L15 * TF
3	(Less) Transmission Charges for Transmission Transactions not in Divisor	417,681	Table 7, L12 * TF
4	Net Revenue Requirement	19,961,900	L1-L2-L3
	Divisor (kW)		
5	12 CP of native load service	1,134,739	Table 7, L5
6	Plus 12 CP of network load service not in above	288,138	Table 7, L9
7	Less 12 CP of Firm PTP	219,250	Table 7, L10
8	Plus Contract Demand of firm PTP	462,000	Table 7, L11
9	Total Divisor	1,665,627	L5+L6-L7+L8
	Rates:		
10	Annual Cost ($/kW/Yr)	11.985	L4/L9
11	Point to Point Rate ($/kW/Mo)	0.999	L10/12
12	Point to Point Rate ($/kW/Wk)	0.230	L10/52
13	Point to Point Rate ($/kW/Day)	0.046	L12/5
14	Point to Point Rate ($/MWh)	2.881	L13/16*1000
15	Network Integration Transmission Service Revenue Requirement	19,961,900	L4

Table 2
Big Rivers Electric Corporation
Ratebase

		RUS Form12 Reference	Company Total	Allocation		Transmission	
	Gross Plant in Service						
1	Production	12hA20e	1,506,821,571	NA	0	-	A
2	Transmission	12h11e	205,527,465	TP	0.960	197,365,517	
3	Distribution	12h16e	-	NA	0	-	
4	General & Intangible	12h1&17e	15,648,038	W/S	0.084	1,319,987	
5	Common		-			-	
6	TOTAL		1,727,997,074	GP=	0.115	198,685,504	
	Accumulated Depreciation						
7	Production	12hB1-4f	712,647,096	NA	0	-	
8	Transmission	12hB5f	92,311,240	TP	0.960	88,645,357	
9	Distribution	12hB6f	-	NA	0	-	
10	General & Intangible	12hB7f	5,868,094	W/S	0.084	495,002	
11	Common		-			-	
12	TOTAL		810,826,430			89,140,359	
	Net Plant in Service						
13	Production	L1 - L7	794,174,475			-	
14	Transmission	L2 - L8	113,216,225			108,720,159	
15	Distribution	L3 - L9	-			-	
16	General & Intangible	L4 - L10	9,779,944			824,985	
17	Common	L5 - L11	-			-	
18	TOTAL		917,170,644	NP=	0.119	109,545,145	
19	Land Held for Future Use					-	
	Working Capital						
20	Cash Working Capital				1	941,401	B
21	Materials & Supplies	12hG4d & 5d	810,996	TE	0.812	658,454	C
22	Prepayments	12aB24	8,293,993	GP	0.115	953,645	
23	TOTAL	L20+L21+L22				2,553,500	
24	Total Ratebase (before Adjustments)					112,098,645	L18+L23
	Adjustments						
25	Account No. 281 (enter negative)		-				
26	Account No 282 (enter negative)		-				
27	Account No. 283 (enter negative)		-				
28	Account No. 190		4,789,974	NA	0.000	-	D
29	Account No. 255 (enter negative)		-				
30	TOTAL		4,789,974			-	Sum L24:L29
31	Total Ratebase					112,098,645	L24+L30

A Electric plant leased to others
B 1/8 x O&M for Transmission from Table 3, line 5
C M&S inventory in Form 12 is related to transmission
D See Table 6, Note C

Table 3
Big Rivers Electric Corporation
Transmission Revenue Requirement

			Company Total	Allocation		Transmission	
	O&M						
1	Transmission Operations	RUS12aA8b	5,586,277	TE	0.812	4,535,540	A
2	Transmission Maintenance	RUS12aA16b	3,333,680	TE	0.812	2,706,640	A
3	Less Account 565	RUS12iA8a	1,321,478		1.00	1,321,478	
4	A&G	Table 5	23,869,218	See Table 5		1,610,507	
5	Total O&M		31,467,697			7,531,209	
	Depreciation Expense						
6	Transmission	12hB5c	4,785,056	TP	0.960	4,595,031	
7	General	12hB7c	391,294	W&S	0.0844	33,008	
8	Total Depreciation		5,176,350			4,628,038	
9	*Taxes Other than Income*		in above			in above	B
10	Return	Table 2,L31 * Table 6,L6				8,243,380	
11	Income Taxes	Table 2,L31 * Table 6,L10				-	
12	Total Revenue Requirement			L5+L8+L10+L11		20,402,627	

A: Includes labor overheads (pensions, benefits, payroll taxes), and functionally assigned transmission-related A&G, property taxes, and property insurance.
B: Payroll taxes and property taxes included in transmission O&M and A&G

Table 4
Big Rivers Electric Corporation
Allocators

Wages and Salaries*
Source: 2006 Accounting Data unless noted

		$		Allocation		Percent of Total	
1 Transmission (including functionally assigned A&G labor)							
560.100	OPER SUPERVISION & ENG-LINES-LABOR	333,760					
560.200	OPER SUPERVISION & ENG-STATIONS-LABOR	247,071					
561.100	LOAD DISPATCHING-LABOR	996,008					
562.100	STATION EXPENSES-LABOR	385,130					
563.100	OVERHEAD LINE EXPENSES-LABOR	184,013					
566.100	MISC TRANSMISSION EXP-LINES-LABOR	116,596					
566.200	MISC TRANSMISSION EXP-STATIONS-LABOR	112,999					
568.100	MAINT SUPERVISION & ENG-LINES-LABOR	225,857					
568.200	MAINT SUPERVISION & ENG-STATIONS-LABOR	243,521					
569.100	MAINT STRUCTURES-LABOR	394					
570.100	MAINT STATION EQUIPMENT-LABOR	882,095					
571.100	MAINT OVERHEAD LINES-LABOR	633,622					
573.100	MAINT MISC TRANSMISSION PLT-LINE-LABOR	21,960					
573.200	MAINT MISC TRANSMISSION PLT-STA-LABOR	7,123					
		4,390,148	TP	96.0%	4,215,806	8.44%	=W&S
2 Distribution		0					
3 Production		43,025,422	A		43,199,765	86.44%	B
4 Customer Assistance							
908.100	CUSTOMER ASSISTANCE EXPENSES-LABOR	454,067		1	454,067	0.91%	
5 Other Functionally Assigned A&G Labor							
A 920.101	ADMIN & GENERAL SALARIES - POWER SUPPLY	603,327		1	603,327	1.21%	
B 920.102	ADMIN & GENERAL SALARIES - CUSTOMER SERV	673,256		1	673,256	1.35%	
C 920.103	ADMIN & GENERAL SALARIES - GENERATION	830,839		1	830,839	1.66%	
6 Total Wages & Salaries		49,977,060			49,977,060	100.0%	

* Includes labor-related overhead (pensions, benefits and taxes)
A *Projected annual amount after unwind from Table AS-9, L22 total*
B 100% of production wages and salaries plus (1-TP) of transmission wages and salaries for generation step-up facilities

Transmission Plant

7 Total Transmission Plant (Table 2, L2, Company Total)	205,527,465		
8 Less Transmission plant incl. in OATT Ancillary Serv (gen step-up)	8,161,948		*Table AS9, L16, Total*
9 Included Transmission plant	197,365,517	96.0%	= *TP*

Transmission Expenses

10 Total Transmission Expense (Table 3, L1 + L2, Company Total)	8,919,957		
11 Less Trans. Expenses included in OATT Ancillary Serv (Acct. 561)	1,378,281		*RUS12iA2*
12 Net Transmission Expenses	7,541,676	84.5%	
13 Included Transmission Plant (TP)		96.0%	
14 Percentage of transmission expenses included in rates (L12*L13)		81.2%	=*TE*
15 Rent from Transmission Property in Account 454	24,000		*2006 Accounting Data*

Table 5
Big Rivers Electric Corporation
Transmission Administrative and General Expenses*

A&G Accounts -- 2006 Totals	System	Allocator		Transmission	
920.100 ADMINISTRATIVE AND GENERAL SALARIES	3,469,978	W&S	0.0844	292,709	
920.101 ADMIN & GENERAL SALARIES - POWER SUPPLY	603,327	NA	0	-	
920.102 ADMIN & GENERAL SALARIES - CUSTOMER SERV	673,256	NA	0	-	
920.103 ADMIN & GENERAL SALARIES - GENERATION	830,839	NA	0	-	
921.100 OFFICE SUPPLIES AND EXPENSES	564,373	W&S	0.0844	47,608	
921.101 OFFICE SUPPLIES & EXPENSES - POWER SUPPLY	147,991	NA	0	-	
921.102 OFFICE SUPPLIES & EXPENSES - CUSTOMER SERVICE	910,687	NA	0	-	
921.103 OFFICE SUPPLIES & EXPENSES - GENERATION	89,462	NA	0	-	
923.100 OUTSIDE SERVICES EMPLOYED	700,290	W&S	0.0844	59,073	
923.101 OUTSIDE SERVICES -- POWER SUPPLY	34,608	NA	0	-	
923.102 OUTSIDE SERVICES - CUSTOMER SERVICE	445,260	NA	0	-	
923.103 OUTSIDE SERVICES - GENERATION	2,372,347	NA	0	-	
923.104 OUTSIDE SERVICES - TRANSMISSION	145,493	TP	0.960	139,715	
924.150 PROPERTY INSURANCE-TRANSMISSION-STATIONS	-	TP	0.960	-	A
924.160 PROPERTY INSURANCE-TRANSMISSION-LINES	-	TP	0.960	-	A
924.170 PROPERTY INSURANCE-A&G	-	W&S	0.0844	-	A
925.100 INJURIES & DAMAGES-LABOR	873	W&S	0.0844	74	
925.150 INJURIES & DAMAGES-TRANSMISSION-STATIONS	-	TP	0.960	-	
925.160 INJURIES & DAMAGES-TRANSMISSION-LINES	-	TP	0.960	-	
925.170 INJURIES & DAMAGES-A&G	97,545	W&S	0.0844	8,228	
925.200 INJURIES & DAMAGES-EXPENSE	-	W&S	0.0844	-	
926.100 EMPLOYEE PENSIONS & BENEFITS-LTD-LABOR	(45,854)	W&S	0.0844	(3,868)	
926.150 EMPLOYEE PENSIONS & BENEFITS-STATIONS	-	TP	0.960	-	
926.160 EMPLOYEE PENSIONS & BENEFITS-LINES	-	TP	0.960	-	
926.170 EMPLOYEE PENSIONS & BENEFITS-A&G	-	W&S	0.0844	-	
926.200 EMPLOYEE PENSIONS & BENEFITS-EXPENSE	61,407	W&S	0.0844	5,180	
928.100 REGULATORY COMMISSION EXPENSES	427,055	W&S	0.0844	36,024	
930.100 GENERAL ADVERTISING EXPENSES-LABOR	-	W&S	0.0844	-	
930.110 GENERAL ADVERTISING EXPENSES-EXPENSE	138,330	W&S	0.0844	11,669	
930.112 GENERAL ADVERTISING EXP - EXP - CUSTOMER	65,000	W&S	0.0844	5,483	
930.200 MISCELLANEOUS GENERAL EXPENSES-LABOR	-	W&S	0.0844	-	
930.210 MISCELLANEOUS GENERAL EXPENSES-EXPENSE	684,884	W&S	0.0844	57,773	B
930.211 MISC GENRL EXPENSE - EXPENSE - POWER SUPPLY	-	NA	0	-	
930.212 MISC GENERAL EXP - EXP - CUSTOMER SERVICE	10,630	NA	0	-	
930.21 MISC GENERAL EXPENSE - EXPENSE - TRANS	-	TP	0.960	-	
931.100 RENTS-ADMINISTRATIVE & GENERAL	1,933	W&S	0.0844	163	
1 SubTotal	12,429,715			659,832	
935.100 MAINTENANCE OF GENERAL PLANT-LABOR	19,094	W&S	0.0844	1,611	
935.110 MAINTENANCE OF GENERAL PLANT-EXPENSE	85,518	W&S	0.0844	7,214	
935.111 MAINT OF GENRL PLANT - EXPENSE - POWER SUPPLY	-	NA	0	-	
935.112 MAINT OF GENRL PLANT - EXP - CUSTOMER SERVICE	169,541	NA	0	-	
2 SubTotal	274,153			8,825	
3 SubTotal 2006	12,703,869			668,656	
4 Additional Annual A&G after Unwind	11,165,349	W&S	0.0844	941,851	C
5 Total	23,869,218			1,610,507	

* Includes labor-related overhead (pensions, benefits and taxes)
A Property Insurance and property taxes have been functionally assigned under RUS standards.
B Includes general plant related property taxes
C *Table 4 W&S allocator calculated with prod labor O&M after unwind, additional A&G after unwind included for consistency*

Table 6
Big Rivers Electric Corporation
Return and Income Taxes

1	Long Term Interest	RUS12aA22b	73,344,484
2	Long Term Debt	RUS12aB45	1,206,174,608
3	Long-Term Debt Rate	L1/L2	6.08%
4	Equity Rate	A	10.88%
5	Post-Unwind Debt Share	B	73.5%
6	Rate of Return	L3*L5+L4*(1-L5)	7.35%
7	Federal Tax Rate		0.0% C
8	State Income Tax Rate		0.0% C
9	Composite Income Tax Rate	L7+L8-(L7*L8)	0.0% C
10	Income Taxes	Not Used	0.00% C

A Equity rate applied in formula transmission rates for LG&E
B As of unwind transaction date, long-term debt of $1,044.1 million and equity of $376.9 million
C Income taxes apply to non-patron activity; given NOLs, 0% tax rate applied.

Table 7
Big Rivers 2006 Coincident Peak Information
Source: Big Rivers metering data (KW)

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	12 CP Average
1 BREC Power Supply Native Load	544,978	574,477	516,391	448,369	537,101	631,255	653,237	657,251	516,611	507,067	527,047	639,085	562,739
2 CENTURY TIER 1 & 2 LOAD	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000	339,000
3 ALCAN TIER 1 & 2 LOAD	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000	233,000
4 LEM Native Load (KW)	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000	572,000
5 Total Native Load (KW)	1,116,978	1,146,477	1,088,391	1,020,369	1,109,101	1,203,255	1,225,237	1,229,251	1,088,611	1,079,067	1,099,047	1,211,085	1,134,739
6 CENTURY TIER 3 NETWORK LOAD	143,803	146,107	144,206	143,458	143,515	144,725	143,458	144,898	147,950	149,909	147,432	148,181	145,637
7 ALCAN TIER 3 NETWORK LOAD	112,341	127,245	126,294	118,691	121,672	121,931	121,888	123,616	113,507	119,339	123,702	127,202	121,452
8 WKE PLANT NETWORK LOAD	18,017	23,890	27,438	20,422	30,517	12,542	16,727	26,482	27,037	25,361	11,746	12,411	21,049
9 Other Network Load (KW)	274,161	297,242	297,938	282,571	295,704	279,198	282,073	294,996	288,494	294,609	282,880	287,794	288,138
10 FIRM PTP SCHEDULED (KW)	154,000	176,000	203,000	226,000	293,000	235,000	210,000	200,000	259,000	221,000	186,000	268,000	219,250
11 FIRM PTP RESERVED (KW)	550,000	550,000	550,000	550,000	550,000	487,000	487,000	487,000	487,000	462,000	462,000	462,000	462,000 A

A: Last 3 months used in average for line 11 as a result of change in TTC/ATC calculation and coordination by BREC to honor limits of certain flowgates outside of the BREC system

Transmission Charges for Transmission Transactions not in Divisor
Source: 2006 Accounting Data

		System	Allocation	Transmission	
456.000	OTHER ELECTRIC REVENUES	180,940	0	0	Not transmission related
456.100	OTHER ELEC REV-POWER SUPPLY	1,808,121	0	-	Big Rivers Power Supply PTP, in divisor
456.101	OTHER ELEC REV - KENERGY	2,405,450	0	-	Smelter Tier 3, in divisor
456.160	OTHER ELEC REV - SIPC	5,964	1	5,964	
456.175	OTHER ELEC REV - OGLETHORPE	0	1	-	
456.185	OTHER ELEC REV - EAST KY POWER	0	1	-	
456.190	OTHER ELEC REV - HEREC	3,252	1	3,252	
456.193	OTHER ELEC REV - WEYERHAEUSER COGEN	394,729	1	394,729	
456.195	OTHER ELEC REV - WESTERN FARMERS ELEC	0	1	-	
456.201	OTHER ELEC REV - CINERGY	0	1	-	
456.220	OTHER ELEC REV - HMP&L	27,000	1	27,000	
456.230	OTHER ELEC REV - SIGECO	1,175	1	1,175	
456.240	OTHER ELEC REV - LG&E	1,132	1	1,132	
456.245	OTHER ELEC REV - KOCH POWER SERVICES	0	1	-	
456.270	OTHER ELEC REV - LEM	5,000,000	0	-	LEM PTP (to be transferred to BRPS), in divisor
456.271	OTHER ELEC REV - LEM TIER 3	0	1	-	
456.272	OTHER ELEC REV - LEM - OTHER	1,702	1	1,702	
456.291	OTHER ELEC REV - DUKE ENERGY T & M	0	1	-	
456.299	OTHER ELEC REV - CARGILL - ALLIANT, LLC	0	1	-	
12				434,954	

Table AS-1
Big Rivers Electric Corporation
Schedule 1: Scheduling, System Control and Dispatch Service

	Account			
1	561.100	LOAD DISPATCHING-LABOR - 2006		996,008
2	561.110	LOAD DISPATCHING-EXPENSE - 2006		382,273
3			L1+L2	1,378,281
4	System Load (12 CP)		Table 1, L9	1,665,627
5	Annual Rate ($/kW-year)		L3/L4	0.8275
6	Monthly Rate ($/kW-Mo)		L5/12	0.0690
7	Weekly Rate ($/kW-Wk)		L5/52	0.0159
8	Daily Rate ($/kW-Day)		L7/5	0.0032
9	Hourly Rate ($/MWh)		L8/16 *1000	0.1989

Table AS-2
Big Rivers Electric Corporation
Schedule 2: Reactive Supply and Voltage Control

1	Total VAR Related Cost of Service	Table AS-7, L61	2,818,867
2	System Load (12 CP)	Table 1, L9	1,665,627
3	Annual Rate ($/kW-year)	L1/L2	1.6924
4	Monthly Rate ($/kW-Mo)	L3/12	0.1410
5	Weekly Rate ($/kW-Wk)	L3/52	0.0325
6	Daily Rate ($/kW-Day)	L5/5	0.0065
7	Hourly Rate ($/MWh)	L6/16 *1000	0.4068

Table AS-3
Big Rivers Electric Corporation
Schedule 3: Regulation and Frequency Response

1	Production Plant	Table AS-6, TPP	1,514,983,519
2	Fixed Charge Factor	Table AS-6, L11	16.40%
3	Total Investment Revenue Requirement	L1*L2	248,429,700
4	Capacity (MW)	Table AS-8, L1	1,663
5	Cost of Generating Capacity ($/KW-year)	(L3/L4)/1000	149.38
6	Regulation Requirement as % of Load	A	1.0%
7	System Load (12 CP)	Table 1, L9	1,666
8	Regulation Requirement (MW)	L6*L7	16.7
9	Annual Rate ($/kW-year)	L5*L8/L7	1.4938
10	Monthly Rate ($/kW-Mo)	L9/12	0.1245
11	Weekly Rate ($/kW-Wk)	L9/52	0.0287
12	Daily Rate ($/kW-Day)	L11/5	0.0057
13	Hourly Rate ($/MWh)	L12/16 *1000	0.3591

A - BREC operating standard

Table AS-4
Big Rivers Electric Corporation
Schedule 5: Spinning Reserve

1	Production Plant	Table AS-6, TPP	1,514,983,519
2	Fixed Charge Factor	Table AS-6, L11	16.40%
3	Total Investment Revenue Requirement	L1*L2	248,429,700
4	Capacity (MW)	Table AS-8, L1	1,663
5	Cost of Generating Capacity ($/KW-year)	(L3/L4)/1000	149.38
6	System Load (12 CP)	Table 1, L9	1,666
7	Spinning Reserve Requirement (MW)	A	8.6
8	Spinning Requirement as % of Load	L7/L6	0.51%
9	Annual Rate ($/kW-year)	L5*L7/L6	0.7668
10	Monthly Rate ($/kW-Mo)	L9/12	0.0639
11	Weekly Rate ($/kW-Wk)	L9/52	0.0147
12	Daily Rate ($/kW-Day)	L11/5	0.0029
13	Hourly Rate ($/MWh)	L12/16 *1000	0.1843

A - Under Midwest Contingency Reserve Sharing Group, 19 MW of reserves required of which 45% must be spinning.

Table AS-5
Big Rivers Electric Corporation
Schedule 6: Supplemental Reserve

1	Production Plant	Table AS-6, TPP	1,514,983,519
2	Fixed Charge Factor	Table AS-6, L11	16.40%
3	Total Investment Revenue Requirement	L1*L2	248,429,700
4	Capacity (MW)	Table AS-8, L1	1,663
5	Cost of Generating Capacity ($/KW-year)	(L3/L4)/1000	149.38
6	System Load (12 CP)	Table 1, L9	1,666
7	Supplemental Reserve Requirement (MW)	A	10.5
8	Supplemental Requirement as % of Load	L7/L6	0.63%
9	Annual Rate ($/kW-year)	L5*L7/L6	0.9372
10	Monthly Rate ($/kW-Mo)	L9/12	0.0781
11	Weekly Rate ($/kW-Wk)	L9/52	0.0180
12	Daily Rate ($/kW-Day)	L11/5	0.0036
13	Hourly Rate ($/MWh)	L12/16 *1000	0.2253

A - Under Midwest Contingency Reserve Sharing Group, 19 MW of reserves required of which 45% must be spinning.

Table AS-6
Big Rivers Electric Corporation
Fixed Charge Worksheet

			Fixed Charge Component	
TPP	Total Production Plant	1,514,983,519		RUS12hA20e + Table AS9, L16 Total
1	Production Fixed O&M Expense			
	A *Production Fixed O&M Expense*	96,873,218		Table AS-9: L20 + L24 + L27 (total)
	B Production Fixed O&M Expense Factor		6.3943%	L1A/TPP
2	Other Taxes Expense			
	A Production Plant Property Taxes	1,585,586		Table AS-9, L17
	B Production Other Taxes Expense Factor		0.1047%	L2A/TPP
3	A&G Expense			
	A Production Share of A&G	18,653,850		Table AS-10, L5
	B Production A&G Factor		1.2313%	L3A/TPP
4	Depreciation Expense			
	A Production Plant Sinking Fund Depreciation	2,171,572		Table AS-7: L52 + L53
	B Production Depreciation Expense Factor		0.1433%	L4A/TPP
5	Income Tax Expense		0.0000%	Not Used
6	General Plant Expense			
	A General Plant	15,648,038		RUS12hA1e & 17e
	B Production W/S Allocator	0.8810		Table 4: L3+L5C
	C Production Share of General Plant	13,786,176		6A*6B
	D Production General Plant Expense Factor		0.0692%	L6C*(L2B+L4B+L5+L8+L9)/TPP
7	*Cash Working Capital Expense*			
	Cash Working Capital Expense Factor		0.7993%	L1A*0.125/TPP
8	Accumulated Deferred Income Tax Deduction		0.0000%	Not Used
9	Rate of Return		7.3537%	Table 6, L6
10	Materials & Supplies/Prepayments			
	A Production Mat & Supplies/Prepayments	62,298,571		Table AS9: L25 and L26 (total)
	B Production Mat & Supplies/Prepayments Factor		0.3024%	L10A*(L5+L9)/TPP
11	Total		16.3982%	

Table AS-7, part 1 of 2
Big Rivers Electric Corporation
VAR-Related Revenue Requirement

			Total	Coleman	Green	Reid 1	Reid CT	Wilson 1	BREC Share HMP&L Statn 2
1	Maximum Nameplate Rating (MW)	Table AS-8,L3		480	484	66	72	440	247
2	Nameplate Power Factor (PF) (MW)	Table AS-8,L4		86.7%	90.0%	85.0%	90.0%	90.0%	90.0%
3	Exciter Rating (MW)	Table AS-8,L5		1.335	2.207	0.21	0.28	2.26	0.60
4	Gross Plant	Table AS-9, L15	1,506,124,640	136,762,863	357,240,933	21,648,152	7,860,986	896,429,856	86,181,850
5	TurboGeneration Units Account 314	Table AS-9, L5	218,151,417	28,554,251	54,913,649	4,358,405		126,020,735	4,304,377
6	Generator Exciter in A/C 314	Table AS-9, L37	32,306,058	6,791,729	8,619,023	866,507		15,930,198	98,601
7	Accessory Equipment Account 315	Table AS-9, L6	58,184,027	6,663,047	15,628,319	1,314,615		34,450,631	127,414
8	Generators Account 344	Table AS-9, L12	1,102,964				1,102,964		
9	Accessory Equipment Account 345	Table AS-9, L13	265,671				265,671		
10	Generator Step-Facilities in A/C 353	Table AS-9, L16	8,161,948	1,000,439	2,025,336	0	179,008	4,957,165	0
11	Annual Depreciation Expense	Table AS-9, L18+L19	26,937,208	2,424,446	6,377,624	381,540	188,449	15,983,028	1,582,122
12	Annual Property Tax	Table AS-9, L17	1,585,586	105,792	306,403	14,591	5,313	1,036,886	116,602
13	Fixed O&M	Tbl AS-9: L20+L24+L27	96,873,218	25,689,099	29,329,460	5,345,006	156,867	24,048,517	12,304,268
14	Fixed O&M - Labor Related	Table AS-9, L22	43,025,422	11,188,295	12,858,729	1,974,456	35,312	10,443,733	6,524,898
15	General Plant - Production Share	Table AS6,L6C*L28	13,786,176	3,584,946	4,120,185	632,654	11,315	3,346,374	2,090,703
16	General Plant Deprec - Prod Share	A	344,736	89,645	103,029	15,820	283	83,679	52,280
17	Generator Step-Facilities Depreciation	B	190,025	23,292	47,154	0	4,168	115,412	0
18	Materials and Supplies	Table AS-9, L25	55,000,000	4,994,246	13,045,568	790,538	287,064	32,735,433	3,147,151
19	Prepayments	Table AS-9, L26	7,298,571	662,743	1,731,164	104,905	38,094	4,344,034	417,631
	Allocators								
20	Reactive Allocator (1 - PF^2)	1 - L2^2	GE-VAR=	24.83%	19.00%	27.75%	19.00%	19.00%	19.00%
21	Gen-Exciter as % of Turbine Generator	Table AS-9, L45	GE-TG=	25.83%	17.67%	22.47%		16.03%	2.64%
	VAR Share of:								
22	Generator Exciter	L20	GE-VAR=	24.83%	19.00%	27.75%		19.00%	19.00%
23	Gen-Exciter as % of Total Turbine Gen	L21*L22	TG-VAR1=	6.41%	3.36%	6.24%		3.05%	0.50%
24	Balance as % of Total Turbine Gen	(1-L21)*L28	TG-VAR2=	0.21%	0.38%	0.24%		0.43%	0.24%
25	Assoc ElecEquip allocated to Gen-Exc	C	AE-GE=	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
	VAR Share of:								
26	Generator Exciter	L20	GE-VAR=	24.83%	19.00%	27.75%	19.00%	19.00%	19.00%
27	Gen-Exc as % of Tot Assoc ElecEquip	L25*L26	AE-VAR1=	3.73%	2.85%	4.16%	2.85%	2.85%	2.85%
28	Total Balance of Prod Plant	L3/L1	BP-VAR=	0.28%	0.46%	0.31%	0.39%	0.51%	0.24%
29	Balance as % of Tot Assoc ElecEquip	(1-L25)*L28	AE-VAR2=	0.24%	0.39%	0.26%	0.33%	0.44%	0.21%
30	Production Plant	L40/L4	PROD-VAR=	1.78%	1.08%	1.80%	3.10%	1.04%	0.27%
31	Share of Labor Related Prod O&M	L14/ Total of L14	PROD-LAB=	26.00%	29.89%	4.59%	0.08%	24.27%	15.17%

A L31 * RUS12hB7c * Table AS-6, L6B
B Table 3, L6 (Total) - Table 3, L6 (Transmission); allocated to plant by L10
C AEP Methodology

Table AS-7, part 2 of 2
Big Rivers Electric Corporation
VAR-Related Revenue Requirement

			Total	Coleman	Green	Reid 1	Reid CT	Wilson 1	BREC Share HMP&L Statn 2
	VAR Ratebase								
	A/C 314 - Turbine-Generator Systems		**Allocator**						
32	Associated with Gen Exciter	L5*L23	TG-VAR1	1,831,598	1,843,974	271,758		3,837,914	21,551
33	Remaining Balance	L5*L24	TG-VAR2	58,903	206,147	10,496		543,536	10,165
	A/C 315 - Accessory Equipment								
34	Associated with Gen Exciter	L7*L27	AE-VAR1	248,199	445,407	54,721		981,843	3,631
35	Remaining Balance	L7*L29	AE-VAR2	15,752	60,574	3,471		150,408	263
36	A/C 344 - Generators	L8*L26	GE-VAR				209,563		
	A/C 345 - Accessory Electric Equip								
37	Associated with Gen Exciter	L9*L27	AE-VAR1				7,572		
38	Remaining Balance	L9*L29	AE-VAR2				881		
39	Balance of Production Plant	(L4-L5-L7-L8-L9)*L28	BP-VAR	282,424	1,307,324	49,620	25,338	3,780,150	198,273
40	Total Production Plant			2,436,875	3,863,426	390,065	243,354	9,293,852	233,882
41	Transmission Plant (GSU Facilities)	L10*L26	GE-VAR	248,442	384,814	0	34,011	941,861	0
42	General Plant	L15*L30	PROD-VAR	63,877	44,558	11,399	350	34,694	5,674
43	Total Plant and Equipment			2,749,195	4,292,798	401,464	277,716	10,270,407	239,556
44	Working Capital	0.125*L13*L30	PROD-VAR	57,217	39,648	12,039	607	31,166	4,174
45	Materials and Supplies	L18*L30	PROD-VAR	88,989	141,083	14,244	8,887	339,389	8,541
46	Prepayments	L19*L30	PROD-VAR	11,809	18,722	1,890	1,179	45,037	1,133
47	Total VAR-Related Ratebase			2,907,210	4,492,252	429,637	288,389	10,685,999	253,404
	Sinking Fund Depreciation								
48	Book Depreciation Rate (SLDp)	L11/L4		1.77%	1.79%	1.76%	2.40%	1.78%	1.84%
49	Service Life (N)	1/L48		56	56	57	42	56	54
50	Rate of Return	Table 6, L6		7.35%	7.35%	7.35%	7.35%	7.35%	7.35%
51	*Sinking Fund Depreciation Rate (SFDp)*	*L50/((1+L50)^L49 -1)*		0.14%	0.14%	0.13%	0.40%	0.14%	0.16%
52	Sinking Fund Depreciation	L4*L51	2,141,665	187,110	502,919	28,922	31,593	1,255,463	135,659
53	Sinking Fund Deprec (GenStepUp)	D	29,907	3,666	7,421	0	656	18,164	0
54	Sinking Fund Deprec (General Plant)	E		16,399	18,847	2,894	52	15,307	9,564
	VAR-Related Revenue Requirement								
55	Fixed O&M	L13*L30	1,158,804	457,735	317,187	96,308	4,856	249,326	33,392
56	A&G	F	217,242	86,432	60,291	15,424	474	46,944	7,677
57	Property Taxes	L12*L30	16,693	1,885	3,314	263	164	10,750	316
58	Sinking Fund Depreciation	(L52+L53+L54)*L30	24,745	3,691	5,723	573	1,000	13,363	394
59	Income Taxes	L47*Table 6, L10	0	0	0	0	0	0	0
60	Return on Ratebase	L47*Table 6, L6	1,401,383	213,787	330,346	31,594	21,207	785,815	18,635
61	Total		2,818,867	763,530	716,861	144,163	27,702	1,106,198	60,414

D L50 / ((1+L50)^(L10/L17) -1) * L10
E *L50 / ((1+L50)^(L15/L16) -1) * L15*
F L30 *L31 *Table AS10, L5

Table AS-8
Big Rivers Electric Corporation
BREC Generating Units Technical Data
Source: BREC Plant Records

	Coleman				Green			Reid	Reid	Wilson	HMP&L Station 2		BREC
	1	**2**	**3**	**Tot**	**1**	**2**	**Tot**	**1**	**CT**	**1**	**Total**	**BREC Share**	**Total**
												69.55% B	
1 Net Capacity (MW) non-OTAG	146	146	151	443	231	223	454	65	65	419		217	1,663
2 Net Capacity (MW) OTAG	145	145	150	440	231	223	454	65	65	417		216	1,656
3 Max Turbine Nameplate Rtng (MW)	160	160	160	480	242	242	484	66	72	440	355	247 C	1,789
4 Nameplate Power Factor (%) A	85%	85%	90%	86.7%	90%	90%	90.0%	85%	90%	90%	90%	90%	
5 Exciter Rating (MW)	0.440	0.440	0.455	1.335	1.037	1.170	2.207	0.205	0.281	2.260	0.861	0.599 C	6.887

A - Total station average power factor weighted by indiviudal unit nameplate rating for Coleman and Green
B - BREC Share of HMP&L Station 2 based on 217 MW contractual share of total 312 MW
C - BREC Share of total HMP&L Station 2 applied

Table AS-9
Big Rivers Electric
Production Plant Information (12/31/2006)

			Coleman	Green	Reid	Reid CT	Wilson	BREC Share HMP&L Statn 2	Total
	Production Plant								
1	310 Land and Land Rights	A	424,665	1,110,712	83,342		2,218,858		3,837,577
2	311 Structures&Improvements	A	17,228,625	26,974,478	3,334,219		72,480,468	699,361	120,717,151
3	312 Boiler Plant Equipment	A	83,892,275	258,613,775	12,557,570		661,259,164	81,050,699	1,097,373,483
4	313 Engines&Engine Driven Gen	A							0
5	314 Turbogenerator Units	A	28,554,251	54,913,649	4,358,405		126,020,735	4,304,377	218,151,417
6	315 Accessory Electric Equipmnt	A	6,663,047	15,628,319	1,314,615		34,450,631	127,414	58,184,027
7	316 Misc Power Plant Equipmnt	A							0
8	340 Land and Land Rights	A							0
9	341 Structures &Improvements	A				154,233			154,233
10	342 Fuelholders,Producers&Acc	A				1,436,912			1,436,912
11	343 Prime Movers	A				4,901,207			4,901,207
12	344 Generators	A				1,102,964			1,102,964
13	345 Accessory Electric Equipmnt	A				265,671			265,671
14	346 Misc Power Plant Equipmnt	A							0
15	**Total Production Plant**		136,762,863	357,240,933	21,648,152	7,860,986	896,429,856	86,181,850	1,506,124,640
16	353 GenStepUp Facilities	A	1,000,439	2,025,336		179,008	4,957,165		8,161,948
17	408 Property Tax	A	105,792	306,403	14,591	5,313	1,036,886	116,602	1,585,586
18	413 Depreciation	A	2,424,446	6,377,624	381,540	188,449	15,983,028		25,355,086
19	413 Amortization	A						1,582,122	1,582,122
20	924 Property Insurance	B	331,318	865,443	52,444	19,044	2,171,669	208,782	3,648,700
21	Fixed O&M								
22	Labor-related (*)	C	11,188,295	12,858,729	1,974,456	35,312	10,443,733	6,524,898	43,025,422
23	*Non-Labor*	C	14,126,067	15,517,388	3,318,106	94,743	11,217,973	5,570,588	49,844,864
24	Total		25,314,362	28,376,117	5,292,561	130,055	21,661,706	12,095,486	92,870,286
25	Material and Supplies	D	4,994,246	13,045,568	790,538	287,064	32,735,433	3,147,151	55,000,000
26	Prepayments	E	662,743	1,731,164	104,905	38,094	4,344,034	417,631	7,298,571
27	GenStepUp O&M	F	43,419	87,900	0	7,769	215,143	0	354,231
	Account 314 Detail:								
	Individual Plant Assigned								
28	314 Generator-Exciter Direct	WP-1	6,791,729	8,619,023	866,507		15,930,198	98,601	32,306,058
29	314 Turbine Direct	WP-1	19,502,227	40,148,488	2,986,810		83,454,965	3,632,956	149,725,445
30	314 Other	WP-1	2,260,295	6,134,728	457,213		26,635,572	412,997	35,900,806
31	314 *Sub-Total*		28,554,251	54,902,239	4,310,531		126,020,735	4,144,553	217,932,309
	Jointly Allocated								
32	314 Jointly Allocated Plant	L5-L31	0	11,410	47,874		0	159,824	219,108
33	314 Joint Plant Allocation	L32/Total L32	0.0%	5.2%	21.8%		0.0%	72.9%	100.0%
34	314 Generator-Exciter Direct	G	0	0	0		0	0	0
35	314 Turbine Direct	G	0	732	3,072		0	10,257	14,062
36	314 Other	G	0	10,677	44,802		0	149,566	205,046
	Total Plant								
37	314 Generator-Exciter Direct	L28+L34	6,791,729	8,619,023	866,507		15,930,198	98,601	32,306,058
38	314 Turbine Direct	L29+L35	19,502,227	40,149,220	2,989,883		83,454,965	3,643,213	149,739,507
39	314 Other	L30+L36	2,260,295	6,145,406	502,015		26,635,572	562,564	36,105,852
40	314 Total		28,554,251	54,913,649	4,358,405		126,020,735	4,304,377	218,151,417
41	314 Generator-Exciter Direct	L37/L40	23.79%	15.70%	19.88%		12.64%	2.29%	14.81%
42	314 Turbine Direct	L38/L40	68.30%	73.11%	68.60%		66.22%	84.64%	68.64%
43	314 Other	L39/L40	7.92%	11.19%	11.52%		21.14%	13.07%	16.55%
44	314 Total		100.00%	100.00%	100.00%		100.00%	100.00%	100.00%
45	314 Generator-Exciter Direct	L37/(L37+L38)	25.83%	17.67%	22.47%		16.03%	2.64%	17.75%
46	314 Turbine Direct	L38/(L37+L38)	74.17%	82.33%	77.53%		83.97%	97.36%	82.25%
47	314 Total Direct		100.00%	100.00%	100.00%		100.00%	100.00%	100.00%

* *Includes labor-related overhead (pensions, benefits and taxes)*
A - From Big Rivers Accounting Records
B - Projected increase in annual property insurance after unwind is attributed to production plant, allocated to plants by total production plant (L15)
C - Projected Annual O&M after unwind
D - Projected level of fuel stock after unwind, allocated to individual plants by total production plant (L15)
E - Total : (Table 2, L22 * (Table 2, L1 + Table 2, L4*Table AS-6, L6B)/Table 2, L6), allocated to individual plants by total production plant (L15)
F - Total: (Table 3, L1 total+ Table 3, L2 total) * (1 - TP), allocated to individual plants by L16
G - L33 multiplied by jointly-allocated data in WP-1

Table AS-10
Big Rivers Electric Corporation
Production Administrative and General Expenses

A&G Accounts -- 2006 Totals		System	Allocator	A	Production	
920.100	ADMINISTRATIVE AND GENERAL SALARIES	3,469,978	W&S	0.8810	3,057,107	
920.101	ADMIN & GENERAL SALARIES - POWER SUPPLY	603,327	NA	0	0	
920.102	ADMIN & GENERAL SALARIES - CUSTOMER SERV	673,256	NA	0	0	
920.103	ADMIN & GENERAL SALARIES - GENERATION	830,839	PROD	1	830,839	
921.100	OFFICE SUPPLIES AND EXPENSES	564,373	W&S	0.8810	497,222	
921.101	OFFICE SUPPLIES & EXPENSES - POWER SUPPLY	147,991	NA	0	0	
921.102	OFFICE SUPPLIES & EXPENSES - CUSTOMER SERVICE	910,687	NA	0	0	
921.103	OFFICE SUPPLIES & EXPENSES - GENERATION	89,462	PROD	1	89,462	
923.100	OUTSIDE SERVICES EMPLOYED	700,290	W&S	0.8810	616,967	
923.101	OUTSIDE SERVICES -- POWER SUPPLY	34,608	NA	0	0	
923.102	OUTSIDE SERVICES - CUSTOMER SERVICE	445,260	NA	0	0	
923.103	OUTSIDE SERVICES - GENERATION	2,372,347	PROD	1	2,372,347	
923.104	OUTSIDE SERVICES - TRANSMISSION	145,493	NA	0	0	
924.150	PROPERTY INSURANCE-TRANSMISSION-STATIONS	-	NA	0	0	
924.160	PROPERTY INSURANCE-TRANSMISSION-LINES	-	NA	0	0	
924.170	PROPERTY INSURANCE-A&G	-	W&S	0.8810	0	
925.100	INJURIES & DAMAGES-LABOR	873	W&S	0.8810	769	
925.150	INJURIES & DAMAGES-TRANSMISSION-STATIONS	0	NA	0	0	
925.160	INJURIES & DAMAGES-TRANSMISSION-LINES	0	NA	0	0	
925.170	INJURIES & DAMAGES-A&G	97,545	W&S	0.8810	85,939	
925.200	INJURIES & DAMAGES-EXPENSE	0	W&S	0.8810	0	
926.100	EMPLOYEE PENSIONS & BENEFITS-LTD-LABOR	(45,854)	W&S	0.8810	(40,398)	
926.150	EMPLOYEE PENSIONS & BENEFITS-STATIONS	0	NA	0	0	
926.160	EMPLOYEE PENSIONS & BENEFITS-LINES	0	NA	0	0	
926.170	EMPLOYEE PENSIONS & BENEFITS-A&G	0	W&S	0.8810	0	
926.200	EMPLOYEE PENSIONS & BENEFITS-EXPENSE	61,407	W&S	0.8810	54,100	
928.100	REGULATORY COMMISSION EXPENSES	427,055	W&S	0.8810	376,243	
930.100	GENERAL ADVERTISING EXPENSES-LABOR	0	W&S	0.8810	0	
930.110	GENERAL ADVERTISING EXPENSES-EXPENSE	138,330	W&S	0.8810	121,871	
930.112	GENERAL ADVERTISING EXP - EXP - CUSTOMER	65,000	W&S	0.8810	57,266	
930.200	MISCELLANEOUS GENERAL EXPENSES-LABOR	0	W&S	0.8810	0	
930.210	MISCELLANEOUS GENERAL EXPENSES-EXPENSE	684,884	W&S	0.8810	603,394	
930.211	MISC GENERAL EXPENSE - EXPENSE - POWER SUPPLY	0	NA	0	0	
930.212	MISC GENERAL EXP - EXP - CUSTOMER SERVICE	10,630	NA	0	0	
930.214	MISC GENERAL EXPENSE - EXPENSE - TRANS	0	NA	0	0	
931.100	RENTS-ADMINISTRATIVE & GENERAL	1,933	W&S	0.8810	1,703	
1 SubTotal		12,429,715			8,724,831	
935.100	MAINTENANCE OF GENERAL PLANT-LABOR	19,094	W&S	0.8810	16,822	
935.110	MAINTENANCE OF GENERAL PLANT-EXPENSE	85,518	W&S	0.8810	75,343	
935.111	MAINT OF GENERAL PLANT - EXPENSE - POWER SUPPLY	0	NA	0	-	
935.112	MAINT OF GENERAL PLANT - EXP - CUSTOMER SERVICE	169,541	NA	0	-	
2 SubTotal		274,153			92,165	
3 SubTotal 2006		12,703,869			8,816,996	
4 Additional Annual A&G after Unwind		11,165,349	W&S	0.8810	9,836,854	B
5 Total		23,869,218			18,653,850	

A Table AS-6, 6B used as W/S allocator for general A&G expenses
B W&S allocator calculated using prod labor O&M after unwind, additional A&G after unwind included for consistency.