

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

**APPLICATION OF BIG RIVERS
ELECTRIC CORPORATION FOR A
GENERAL ADJUSTMENT IN RATES**

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Case No. 2011-00036

DIRECT TESTIMONY

OF

**WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC**

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: March 1, 2011

**Case No. 2011-00036
Exhibit 57
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**DIRECT TESTIMONY
OF
WILLIAM STEVEN SEELYE**

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DIRECT TESTIMONY
OF
WILLIAM STEVEN SEELYE

1 **I. INTRODUCTION**

2

3 **Q. Please state your name and business address.**

4 A. My name is William Steven Seelye and my business address is The Prime Group, LLC,
5 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

6 **Q. By whom are you employed?**

7 A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in
8 Crestwood, Kentucky, providing consulting and educational services in the areas of
9 utility marketing, regulatory analysis, cost of service, rate design and depreciation
10 studies.

11 **Q. On whose behalf are your testifying?**

12 A. I am testifying on behalf of Big Rive-rs Electric Corporation (“Big Rivers”).

13 **Q. Please describe your educational background and prior work experience.**

14 A. I received a Bachelor of Science degree in Mathematics from the University of
15 Louisville in 1979. I have also completed 54 hours of graduate level course work in
16 Industrial Engineering and Physics. From May 1979 until July 1996, I was employed
17 by Louisville Gas and Electric Company. From May 1979 until December 1990, I held
18 various positions within the Rate Department of Louisville Gas and Electric Company.
19 In December 1990, I became Manager of Rates and Regulatory Analysis. In May
20 1994, I was given additional responsibilities in the marketing area and was promoted to
21 Manager of Market Management and Rates. I left Louisville Gas and Electric

1 Company in July 1996 to form The Prime Group, LLC, with another former employee
2 of the Company. Since then, we have performed cost of service studies, developed
3 revenue requirements and designed rates for well over 100 investor-owned, cooperative
4 and municipal utilities across North America. A more detailed description of my
5 qualifications is included in Exhibit Seelye-1.

6 **Q. Have you ever testified before any state or federal regulatory commissions?**

7 A. Yes. I have testified in over 60 regulatory proceedings in 12 different jurisdictions,
8 including the Federal Energy Regulatory Commission ("FERC"), regarding revenue
9 requirements, cost of service or rate design. A listing of my testimony in other
10 proceedings is included in Exhibit Seelye-1.

11 **Q. Have you developed rates for electric cooperatives?**

12 A. Yes. I have developed rates for a number of generation and transmission cooperatives
13 ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power
14 Association, Big Rivers Electric Corporation, Southern Illinois Power Cooperative,
15 Corn Belt Power Cooperative, Brazos Electric, and East Kentucky Power Cooperative,
16 Inc. I have also supervised the preparation of cost of service studies and the
17 development of rates for over 100 electric distribution cooperatives.

18

19 **II. PURPOSE OF TESTIMONY**

20

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

22 A. The purpose of my testimony is to (i) support the cost of service study; (ii) describe the
23 proposed allocation of the revenue increase to the rate classes; (iii) describe the rate

1 design, new rates, and percentage increase by rate class; (iv) describe the proposed pro
2 forma adjustment to the Smelter TIER Adjustment Charges; (v) support proposed
3 changes to the Member Rate Stability Mechanism and Rural Economic Reserve; (vi)
4 support the Non-Smelter Non-FAC PPA; (vii) support the Midwest Independent
5 Transmission System Operator Inc. ("Midwest ISO") Attachment O; (viii) sponsor the
6 temperature normalization adjustment; and (ix) support certain Filing Requirements
7 from 807 KAR 5:001.

8 **Q. Please summarize your testimony.**

9 A. Big Rivers' proposed rates are designed to increase base rate revenues by \$39,953,965,
10 which is necessary to provide Big Rivers with sufficient margins to meet the financial
11 requirements set forth in its debt agreements and to continue to provide reliable service
12 to its customers. This increase in base rates is necessary so that Big Rivers can meet its
13 Margins for Interest Ratio ("MFIR") requirement and maintain investment grade credit
14 ratings, both as required by its debt covenants.

15 Big Rivers conducted a fully allocated embedded cost of service study to
16 develop rates in this proceeding. Big Rivers has three major rate classifications –
17 Rural Delivery Service ("Rurals"), Large Industrial Customer Rate ("Large
18 Industrials"), and two aluminum smelters ("Smelters") served under special retail and
19 wholesale contracts ("Smelter Agreements"). The cost of service study indicates that
20 the rate of return for the Rurals is lower than the Large Industrials and the Smelters.
21 Big Rivers is proposing to take steps in this proceeding to move the rates of return for
22 the Rurals and Large Industrials closer together. Because the rates for the Smelters are
23 contractually tied to the rate for the Large Industrials, any movement toward mitigating

1 the differential in the rates of return must be accomplished through the apportionment
2 of the revenue increase between the Rurals and Large Industrials. Therefore, Big
3 Rivers is proposing rates that will eliminate some of the differential in the rate of return
4 between the Rurals and the Large Industrials. Because the rates for the Smelters are
5 tied to the rate for the Large Industrials, Big Rivers' proposal will also close the gap
6 between the Rurals and the Smelters.

7 Big Rivers is also proposing a rate design change to the Rurals' rates.
8 Particularly, Big Rivers is proposing to bill the Rurals on the basis of coincident peak
9 demands rather than non-coincident peak demand. A demand charge billed on the basis
10 of coincident peak demand will send a more accurate price signal to the Rurals. Under
11 Big Rivers' proposed rates, the Large Industrials will continue to be billed on the basis
12 of non-coincident peak demands.

13 Big Rivers is proposing to adjust the base purchased power cost used in the
14 Non-FAC PPA. Specifically, Big Rivers is proposing to reduce the Non-FAC PPA
15 from \$0.00175 per kWh to \$0.000874 per kWh. This revenue neutral "roll in" will
16 result in a corresponding reduction in the energy charges for the three rate
17 classifications. Also, Big Rivers is proposing a new rate mechanism (which will be
18 called the "Non-Smelter Non-FAC PPA") that will allow it to amortize any balances in
19 the Non-FAC PPA Regulatory Account for the Rurals and Large Industrials every 12
20 months rather than waiting until the next general rate case to amortize the balances.

21 The revenue adjustment sought by Big Rivers will eliminate 50 percent of the
22 TIER Adjustment Charges billed to the Smelters on a pro forma basis, which is
23 equivalent to moving the Smelters' TIER Adjustment Charge to the middle of the

1 bandwidth. Positioning the Smelters in the middle of the bandwidth restores the
2 purpose of the TIER Adjustment, which is to allow Big Rivers to draw extra revenue
3 from the smelters if adverse conditions threaten Big Rivers' ability to achieve a 1.24
4 TIER between rate cases. This allows the contracts with the Smelters to function as
5 envisioned when they were negotiated.

6 Additionally, Big Rivers is proposing to modify the Member Rate
7 Stability Mechanism ("MRSM") and the Rural Economic Reserve ("RER") so that the
8 two mechanisms operate more seamlessly. The MRSM was implemented for the
9 purpose of distributing a \$157 million Economic Reserve to the Rurals and the Large
10 Industrials to offset any net billing impacts related to the FAC and Environmental
11 Surcharge. The RER was ordered to be recorded as a regulatory liability of \$60.9
12 million and used only as a credit against the rates of the Rurals once the Economic
13 Reserve is depleted. Big Rivers is proposing modifications to these mechanisms so that
14 there will not be any discontinuities in billings to the Rurals as a result of transitioning
15 from the Economic Reserve to the RER.

16 Big Rivers is also proposing a temperature normalization adjustment. Big
17 Rivers' adjustment meets the criteria that the Commission has established in prior
18 Orders for approval of temperature normalization.

19 Big Rivers is also requesting authorization to implement Midwest ISO
20 Attachment O transmission formula rate as set forth in Midwest ISO's Open Access
21 Transmission, Energy and Operating Reserve Markets Tariff ("Midwest ISO Tariff")
22 for service to wholesale customers under the Midwest ISO Tariff.
23

1 **Q. Do you have any exhibits to your testimony?**

2 A. Yes. I have prepared or supervised the preparation of the following exhibits to my
3 prepared testimony:

4 • Exhibit Seelye-1 – Qualifications of William Steven Seelye

5 • Exhibit Seelye-2 – Cost of Service Study - Functional Assignment and
6 Classification

7 • Exhibit Seelye-3 – Cost of Service Study - Allocation

8 • Exhibit Seelye-4 – Reconciliation of Billing Determinants

9 • Exhibit Seelye-5 – Analysis of Non-FAC PPA

10 • Exhibit Seelye-6 – Summary of Revenue Increase

11 • Exhibit Seelye-7 – Non-Smelter Non-FAC PPA

12 • Exhibit Seelye-8 – Updated Midwest ISO Attachment O

13 • Exhibit Seelye-9 – FERC Order in Docket No. ER11-15-000

14 • Exhibit Seelye-10 – Temperature Normalization Adjustment

15

16 **III. FILING REQUIREMENTS**

17

18 **Q. Have you reviewed the answers provided in Exhibits 1-47, which address Big**
19 **Rivers' compliance with the historical period filing requirements under 807 KAR**
20 **5:001 and its various subsections?**

21 A. Yes. I hereby incorporate and adopt those portions of Exhibits 1-47 for which I am
22 identified as the sponsoring witness as part of this Direct Testimony.

23

1 **IV. CLASSES OF SERVICE**

2

3 **Q. Please describe the customer classes served by Big Rivers?**

4 A. Big Rivers has three major rate classifications – (i) Rural Delivery Service, (ii) Large
5 Industrial Customer Rate, and (iii) the Smelters. Rural Delivery Service is the rate
6 schedule under which Big Rivers sells power to its three distribution cooperative
7 member systems for resale to their own rural members. Therefore, Big Rivers sells
8 power at wholesale under Rural Delivery Service to its three member systems –
9 Jackson Purchase Energy Corporation ("Jackson Purchase"), Kenergy Corp.
10 ("Kenergy"), and Meade County Rural Electric Cooperative Corp. ("Meade County") –
11 who in turn sell the power at retail to their members. The vast majority of the power
12 delivered under Rural Delivery Service is distributed to residential customers. The
13 Large Industrial Customer Rate is used to provide power to 20 large industrial
14 customers – 19 of which are served by Kenergy and one of which is served by Jackson
15 Purchase.

16 The customers served under the Large Industrial Customer Rate range in size
17 from 0.1 MW to 36.9 MW. Big Rivers also provides service to two large aluminum
18 smelters under special contracts which were approved by the Commission in its Order
19 dated March 6, 2009, in Case No. 2007-00455. The Smelter Agreements are with
20 Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky
21 General Partnership ("Century"). The base demand for Alcan is 368 MW and the base
22 demand for Century is 482 MW. The Base Rate under the Smelter Agreements is
23 determined by applying the Large Industrial Customer Rate to a load with a 98 percent
24 load factor, plus a \$0.25 per MWh adder. Thus, contractually, any base rate increase to

1 the Smelters in this proceeding will be determined by the demand and energy charges
2 established for the Large Industrial Customer Rate.

3 Except to the extent that any rate increase in the Large Industrial Customer Rate
4 affects the Base Rate in the Smelter Agreements, the other contractual provisions of the
5 Smelter Agreements will be unaffected by the proposed rates in this proceeding. The
6 Smelter Agreements, approved by the Commission in connection with the Unwind
7 Proceeding, were carefully negotiated among the parties and fully recognize the risks
8 and benefits associated with Big Rivers continuing to provide service to the Smelters
9 and the risks and benefits of the Smelters continuing to receive service from Big
10 Rivers.

11 **Q. What is the kWh sales composition of the three classes of service?**

12 A. During the test year, 68 percent of Big Rivers' total requirement sales were delivered to
13 the Smelters, 23 percent of total requirement sales were delivered to the Rurals, and 9
14 percent of total requirement sales were delivered to the Large Industrials. Thus, the
15 class comprising the two Smelters is the largest customer class served by Big Rivers.

16
17 **V. COST OF SERVICE STUDY**
18

19 **Q. Did you prepare a cost of service study for Big Rivers based on financial and
20 operating results for the test year?**

21 A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study
22 based on pro forma operating results for the 12 months ended October 31, 2010. The
23 cost of service study corresponds to the pro forma financial exhibits included in Exhibit
24 Wolfram-2. The objective in performing the cost of service study is to determine the
25 rate of return on rate base that Big Rivers is earning from each rate class, which

1 provides an indication as to whether Big Rivers' service rates reflect the cost of
2 providing service.

3 **Q. Did you develop the model used to perform the cost of service study?**

4 A. Yes. I developed the spreadsheet model used to perform the cost of service study
5 submitted in this proceeding.

6 **Q. What procedure was used in performing the cost of service study?**

7 A. The three traditional steps of an embedded cost of service study – functional
8 assignment, classification, and allocation – were utilized. The cost of service study was
9 therefore prepared using the following procedure: (1) costs were functionally assigned
10 (*functionalized*) to the major functional groups; (2) costs were then *classified* as
11 commodity-related or demand-related; and then (3) costs were *allocated* to the rate
12 classes.

13 **Q. Is this a standard approach used in the electric utility industry?**

14 A. Yes.

15 **Q. What functional groups were used in the cost of service study?**

16 A. The functional groups identified in the cost of service study are Production and
17 Transmission costs.

18 **Q. How were costs classified as energy related or demand related in the cost of
19 service study?**

20 A. Classification provides a method of identifying the appropriate cost driver for each
21 functionally assigned cost so that the service characteristics that give rise to the cost can
22 serve as a basis for allocation. Costs classified as *energy related* tend to vary with the
23 amount of kilowatt hours consumed. Fuel and purchased power expenses are examples

1 of costs typically classified as energy costs. Costs classified as *demand related* tend to
2 vary with the capacity needs of customers, such as the amount of generation or
3 transmission equipment necessary to meet customers' needs.

4 Production plant costs are classified as demand-related in the cost of service
5 study. Production operation and maintenance expenses are classified using the FERC
6 Predominance Methodology. Under the *FERC Predominance Methodology*,
7 production operation and maintenance accounts that are predominately fixed, i.e.
8 expenses that the FERC has determined to be predominately incurred independently of
9 kilowatt hour levels of output, are classified as demand-related. Production operation
10 and maintenance accounts that are predominately variable, i.e., expenses that the FERC
11 has determined to vary predominately with output (kWh), are considered to be energy
12 related. The predominance methodology has been accepted in FERC proceedings for
13 over 25 years and is a standard methodology for classifying production operation and
14 maintenance expenses. For example, see *Public Service Company of New Mexico*, 10
15 FERC ¶ 63,020 (1980), *Illinois Power Company*, 11 FERC ¶ 63,040 (1980), *Delmarva*
16 *Power & Light Company*, 17 FERC ¶ 63,044 (1981), and *Ohio Edison Company*, 24
17 FERC ¶ 63,068 (1983). The Predominance Methodology has also been used in the cost
18 of service studies submitted by Kentucky Utilities and Louisville Gas and Electric
19 Company in Case Nos. 2003-00433, 2003-00434, 2008-000251, 2008-00252, 2009-
20 00548, and 2009-00549 and by East Kentucky Electric Power Cooperative in Case No.
21 2008-00409.

22 Transmission plant costs and transmission operation and maintenance expenses
23 are classified as demand-related in the cost of service study. This is the same

1 methodology used to classify these costs in the Midwest ISO's FERC-approved
2 Midwest ISO Tariff under which transmission service by Big Rivers is provided.

3 **Q. Have you prepared an exhibit showing the results of the functional assignment
4 and classification steps of the cost of service study?**

5 A. Yes. Exhibit Seelye-2 shows the results of the first two steps of the cost of service
6 study – functional assignment and classification.

7 **Q. In your cost of service model, once costs are functionally assigned and classified,
8 how are these costs allocated to the customer classes?**

9 A. In the cost of service model used in this study, Big Rivers' test-year costs are
10 functionally assigned and classified using what are referred to in the model as
11 “functional vectors”. These vectors are multiplied (using *scalar multiplication*) by the
12 various accounts in order to simultaneously assign costs to the functional groups and
13 cost classifications (demand and energy). Therefore, in the portion of the model
14 included in Exhibit Seelye-2, Big Rivers' accounting costs are functionally assigned
15 and classified using the explicitly determined functional vectors identified in the
16 analysis and using internally generated functional vectors. The explicitly determined
17 functional vectors, which are primarily used to direct where costs are functionally
18 assigned and classified, are shown on page 14.

19 Internally generated functional vectors are utilized throughout the study to
20 functionally assign costs either on the basis of similar costs or on the basis of internal
21 cost drivers. The internally generated functional vectors are also shown on page 14 of
22 Exhibit Seelye-2. An example of this process is the use of total operation and
23 maintenance expenses less purchased power (“OMLPP”) to allocate cash working

1 capital included in rate base. Because cash working capital is determined on the basis
2 of 12.5% of operation and maintenance expenses, exclusive of purchased power
3 expenses, it is appropriate to functionally assign and classify these costs on the same
4 basis. (See Exhibit Seelye-2, page 2 for the functional assignment of cash working
5 capital on the basis of OMLPP shown on page 14.) The functional vector used to
6 allocate a specific cost is identified by the column in the model labeled “Functional
7 Vector” and refers to a vector identified elsewhere in the analysis by the column
8 labeled “Name”.

9 Once costs for all of the major accounts are functionally assigned and classified,
10 the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base,
11 Operation and Maintenance Expenses) is then transposed and allocated to the customer
12 classes using “allocation vectors” or “allocation factors”.

13 The results of the class allocation step of the cost of service study are included
14 in Exhibit Seelye-3. The costs shown in the column labeled “Total System” in Exhibit
15 Seelye-3 were carried forward *from* the functionally assigned and classified costs
16 shown in Exhibit Seelye-2. The column labeled “Ref” in Exhibit Seelye-3 provides a
17 reference to the results included in Exhibit Seelye-2.

18 **Q. What rate classes are identified in the cost of service study?**

19 A. In the cost of service study, all costs and revenues are fully allocated to the following
20 three rate classes – Rurals, Large Industrials, and Smelters.

21 **Q. Please describe the allocation factors used in the cost of service study.**

22 A. Production and transmission demand-related costs are allocated using a 12CP
23 methodology. With the 12CP methodology, all demand-related costs are allocated on

1 the basis of the average demand for each rate class at the time of Big Rivers' system
2 peak. For purposes of identifying the hour during which Big Rivers' system peak
3 occurs, Big Rivers' adjusted net local load was determined in the following manner: (i)
4 the *actual demand* for the Smelters and for a customer with cogeneration capability
5 ("Cogen Customer") was subtracted from Big Rivers' total net local load; and then (ii)
6 the Smelters' Base Demand *and* the lesser of (a) the Cogen Customer's actual demand
7 or (b) the Cogen Customer's requirement load, as set forth in the contract with the
8 customer, was added back. The Rural's and Industrial Customer's demand at the time
9 of the Big Rivers maximum monthly adjusted net local load was used to calculate the
10 12CP allocation factor. Again, the demand for the Cogen Customer, which is included
11 in the Large Industrial class, was determined as the lesser of the Cogen Customer's
12 actual demand or the Cogen Customer's requirement load. The Smelters' Base Demand
13 was used to determine the 12CP demands for the Smelters.

14 Energy-related costs are allocated on the basis of annual kWh sales to each
15 customer class. Because energy is delivered to each rate class at transmission voltages,
16 it was not necessary to adjust kWh sales for losses.

17 **Q. How were the margins from off-system sales allocated in the cost of service study?**

18 A. Section 4.13.1 of the Smelter Agreements provides that the Smelters receive billing
19 credits reflecting the net proceeds from certain off-system sales. During the test year,
20 the Smelters received \$28,015,863 in billing credits pursuant to Section 4.13.1 of the
21 Smelter Agreements. In the cost of service study, these off-system sales are directly
22 assigned to the Smelters pursuant to Section 4.13.1 and exactly match the credits that

1 the Smelters receive. The margins on all other off-system sales are allocated to the
2 Rurals and Large Industrials on the basis of the 12CP allocator.

3 **Q. Please summarize the results of the cost of service study.**

4 A. The following table summarizes the rates of return for each customer class from the
5 cost of service study. The Actual Adjusted Rate of Return was calculated by dividing
6 the adjusted net operating income by the adjusted net cost rate base for each customer
7 class. The adjusted net operating income and rate base reflect the pro forma
8 adjustments described in Mr. Wolfram's testimony.

9

Class Rates of Return	
Customer Class	Actual Adjusted Rate of Return
Rurals	-1.43%
Large Industrials	1.69%
Smelters	3.19%
Total System	1.64%

10

11 Determination of the actual adjusted rates of return is detailed in Exhibit Seelye-3, page
12 11.

13 It should be emphasized that the adjusted rates of return shown in the above
14 table reflect all pro forma revenue and expense adjustments proposed by Big Rivers in

1 its Application in this proceeding. Consequently, the rates of return reflect adjustments
2 in revenues and expenses to eliminate the effect of the fuel adjustment clause,
3 environmental surcharge, and the Non-FAC PPA, which are addressed by separate
4 stand-alone rate mechanisms. In addition, as will be discussed later in my testimony,
5 the above rates of return also reflect an adjustment to eliminate 50 percent of the TIER
6 Adjustment Charge revenues billed to the Smelters during the test year.

7 **Q. Since the Smelter Base Rate is tied contractually to the Large Industrial base**
8 **rates, why is the rate of return for the Smelters higher than the rate of return for**
9 **the Large Industrials?**

10 A. Under the Smelter Agreements, the Smelters agree to pay a number of charges that are
11 not paid by the Large Industrials or Rurals. Particularly, the Smelters agree to pay
12 TIER Adjustment Charges (Section 4.7.1), Surcharges (Section 4.11), and a Base Rate
13 Adder of \$0.25 per MWh (Section 1.1.20). These charges were the result of arms-
14 length negotiations between the parties and were developed in recognition of the risks
15 and benefits associated with Big Rivers providing service to the Smelters and the risks
16 and benefits of the Smelters receiving service from Big Rivers. Big Rivers and the
17 Smelters have agreed that they would not seek any change in the rate formula in the
18 Smelter Agreements. In the cost of service study, the revenues associated with these
19 charges were fully attributed to the Smelters, thus resulting in a higher rate of return for
20 the Smelters.

1 VI. ALLOCATION OF THE INCREASE

2

3 **Q. Please summarize how Big Rivers proposes to allocate the revenue increase to the**
4 **classes of service?**

5 A. Big Rivers relied on the results of the cost of service study to determine the allocation
6 of the proposed revenue increase to the classes of service. Specifically, Big Rivers is
7 proposing to allocate the revenue increase in a manner that is designed to narrow the
8 gap between the rate of return shown in the cost of service study for the Rurals and the
9 rate of return for the Large Industrials. Because the Base Rates for the Smelters are
10 linked by contract to the Large Industrial Customer Rate, no explicit consideration was
11 given to the rate of return shown in the cost of service study for the Smelters. Except
12 for the effect of the TIER Adjustment Charges proposed for the Smelters, which will be
13 discussed later in my testimony, the Smelters' Base Rates cannot be adjusted
14 independently from the Large Industrial rates. Thus, other than the effect of modifying
15 the level of TIER Adjustment Charges in test-year revenues, the only other "levers" or
16 "variables" that can be used to collect additional base rate revenues are (i) to increase
17 the base rates for the Rurals and (ii) to increase the base rates for Large Industrials.
18 Any base rate increase to the Smelters is essentially a by-product of increasing the base
19 rates to the Large Industrials.

20 **Q. How is Big Rivers allocating the revenue increase in a manner that narrows the**
21 **rates of return between the Rurals and the Large Industrials?**

22 A. The proposed increase is designed to reduce the difference between the revenues
23 collected from the Rurals and the cost of providing service to the Rurals. According to
24 the cost of service study, there is currently a difference of approximately \$11.1 million
25 between the revenues collected from the Rurals and the actual cost of providing service

1 to the Rurals. Under the proposed rates, there will be a difference of approximately
2 \$9.2 million between the revenues to be collected from the Rurals and the actual cost of
3 providing service. Consequently, Big Rivers is proposing to move the rates for the
4 Rurals \$1.9 million closer to the actual cost of providing service.

5 **Q. Is this approach to allocating the increase to the Rurals and the Large Industrials**
6 **consistent with the principle of gradualism?**

7 A. Yes. Although Big Rivers believes that it is appropriate to take steps toward
8 equalizing the rates of return between the Rurals and Large Industrials, Big Rivers must
9 also consider the impact that taking overly aggressive steps toward leveling the rates of
10 return would have on residential customers, which is the predominant type of customer
11 served under the Rurals' cost of service classifications.

12 **Q. What is the proposed base rate revenue increase for each rate class?**

13 A. Big Rivers is proposing the following base rate revenue increases: an increase of
14 \$14,172,003 to the Rurals; an increase of \$3,328,566 to the Large Industrials; and an
15 increase of \$22,553,396 to the Smelters. As will be demonstrated later, the Large
16 Industrials and Smelters will experience a significantly lower percentage increase than
17 the Rurals.

18 **Q. What are the class rates of return adjusted to reflect the proposed revenue**
19 **increases?**

20 A. The following table shows the rates of return from the cost of service study on an
21 adjusted basis with and without the proposed revenue increases:
22
23
24
25

Class Rates of Return		
Customer Class	Actual Adjusted Rate of Return	Rate of Return with the Proposed Revenue Increases
Rurals	-1.43%	2.51%
Large Industrials	1.69%	4.95%
Smelters	3.19%	6.36%
Total System	1.64%	5.05%

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13

This table illustrates how the gap in the rate of return between the Rurals and the Large Industrials has been narrowed with Big Rivers' proposed allocation of the increase. Under Big Rivers' current rates, there is a 3.1 percentage point gap between the rate of return for the Rurals and the rate of return for the Large Industrials ($|-1.43 - 1.69| = 3.12$ percentage points). After adjusting the rates of return to reflect the proposed revenue increase, the gap in the rates of return for the Rurals and Large Industrials is decreased to 2.44 percentage points ($|2.51 - 4.95| = 2.44$ percentage points). Therefore, Big Rivers' proposed allocation of the revenue increase will have reduced the rate of return gap between these two rate classes by approximately 22 percent.

1 **VII. RATE DESIGN & IMPACT OF NEW RATES**
2

3 **Q. Have you prepared an exhibit showing the reconstruction of Big Rivers' test-year**
4 **billing determinants?**

5 A. Yes. The reconstruction of Big Rivers' billing determinants (revenue proof) is shown
6 on Exhibit Seelye-4. As shown on this exhibit, when Big Rivers' current rates are
7 applied to test-year actual billing determinants the resultant calculated revenues
8 precisely match actual revenues during the test year.

9 **Q. Is Big Rivers proposing any rate design changes to the Rurals' rates?**

10 A. Yes. Big Rivers is proposing to bill the demand charge on the basis of Coincident Peak
11 ("CP") demands rather than Non-Coincident Peak ("NCP") demands. Because
12 production and transmission facilities are design to meet maximum aggregated loads on
13 system, a CP rate design more accurately reflects cost causation on the Big Rivers
14 system. The Rurals are currently billed on an NCP basis. Under Big Rivers' current
15 NCP rate design, billing demands for the Rurals are determined on the basis of member
16 demands measured at the time of each distribution member's maximum load during the
17 month. Under the proposed CP rate design, billing demands for the Rurals will be
18 determined on the basis of the distribution member's load measured at the time of Big
19 Rivers' maximum adjusted net local load during the month, determined on a 30-minute
20 clock-hour basis. In establishing the 30-minute interval during which the maximum
21 load occurs, Big Rivers' adjusted net local load will be determined in the following
22 manner: (i) the *actual demand* for the Smelters and for the Cogen Customer will be
23 subtracted from Big Rivers' total net local load; and then (ii) the Smelters' Base
24 Demand *and* the lesser of (a) the Cogen Customer's actual demand or (b) the Cogen

1 Customer's requirement load, as set forth in the contract with the customer, will be
2 added back. This is the same procedure that was used to determine the CP demands in
3 the cost of service study.

4 **Q. What are the proposed charges for the Rurals?**

5 A. Big Rivers is proposing to increase the demand charge from \$7.370 per kW per month
6 (billed on the basis of NCP demand) to \$10.1890 per kW per month (billed on the basis
7 of CP demand). Except for the roll-in of the Non-FAC PPA, which will be discussed
8 below, Big Rivers is not proposing to modify the energy charge, which is currently
9 \$0.02040 per kWh. The cost of service study indicates that a cost-based energy charge
10 would be \$0.015761 per kWh. Lowering the energy charge to \$0.015761 per kWh to
11 correspond to the energy cost derived from the cost of service study would require an
12 even larger increase in the demand charge than what is being proposed by Big Rivers.
13 Decreasing the energy charge and increasing the demand charge by a larger amount
14 would result in a larger percentage increase to the member system with the lowest
15 average load factor and the highest concentration of residential load.

16 **Q. Is Big Rivers proposing any rate design changes to the Large Industrial rates?**

17 A. No. The Large Industrials are currently billed on an NCP basis. Big Rivers is not
18 proposing to adopt a CP rate design for the Large Industrials. The individual contracts
19 with the Large Industrial customers include minimum contract demands which were
20 determined on the basis of NCP demands. Adopting a CP demand charge would likely
21 require the development of new contracts with the Large Industrial customers and
22 would also result in a larger increase to the Smelters, which cannot be supported
23 considering the higher rate of return for the Smelters as indicated by the cost of service

1 study. Although Big Rivers is not proposing any changes in the basic structure of the
2 base rates, it should be noted that Big Rivers is proposing modifications to the MRSM

3 **Q. What are the proposed charges for the Large Industrials?**

4 A. Big Rivers is proposing to increase the demand charge from \$10.1500 per kW per
5 month to \$10.8975 per kW per month and to increase the energy charge from
6 \$0.013715 per kWh to \$0.015761 per kWh. As mentioned earlier, the cost of service
7 study indicates that a cost-based energy charge would be \$0.015761 per kWh.

8 **Q. How were the Base Rates for the Smelters determined?**

9 A. As described earlier, the Base Rate rates for the Smelters are derived by applying the
10 Large Industrial Rate to a load with a 98 percent load factor, plus a \$0.25 per MWh
11 adder. At a 98 percent load factor, the demand component the Large Industrial Rate
12 stated as an energy charge is equal to \$0.015233 per kWh, which is determined by
13 dividing the proposed Large Industrial demand charge (\$10.8975 per kW) by 715.4
14 hours (730 hrs x 98 percent = 715.4 hours) ($\$10.8975/\text{kW} \div 715.4 \text{ hours} =$
15 $\$0.015233/\text{kWh}$). The energy charge from the proposed Large Industrial rate
16 ($\$0.015761$ per kWh) and the \$0.25 per MWh adder ($\0.000250 per kWh) is then
17 added to the demand component ($\$0.015233$ per kWh) to obtain the proposed Base
18 Energy Charge for the Smelters of $\$0.031244$ per kWh ($\$0.015761/\text{kWh} +$
19 $\$0.000250/\text{kWh} + \$0.015233/\text{kWh} = \$0.031244/\text{kWh}$). After reflecting the proposed
20 reduction in the Purchase Power Base for the Non-FAC PPA (as discussed below), the
21 proposed Base Energy Charge for the Smelters is $\$0.030368$ per kWh ($\$0.031244/\text{kWh}$
22 $- \$0.000876/\text{kWh} = \$0.030368/\text{kWh}$).

1 **Q. Have any other adjustments been made that affect pro forma revenue for the**
2 **Smelters?**

3 A. Yes. Big Rivers is proposing to reduce the TIER Adjustment Charges billed under
4 Section 4.7.1 of the Smelter Agreements by 50 percent. During the test year, Big
5 Rivers billed the maximum amount allowed under Section 4.7.1 of the Smelter
6 Agreements. The TIER Adjustment Charges to the Smelters were \$14,229,306 during
7 the test year. Big Rivers is proposing a pro forma adjustment to reduce the TIER
8 Adjustment Charges billed to the Smelters to \$7,114,653. Reducing the TIER
9 Adjustment Charges by 50 percent would restore \$7.1 million to the TIER Adjustment
10 bandwidth which would then be available, as contemplated in the Smelter Agreements,
11 to meet any differences that could arise between pro forma operating results developed
12 in this proceeding and actual operating results that occur once the rates go into effect.
13 If the actual operating results turn out exactly like the pro forma operating results
14 developed for the test-year in this proceeding, then Big Rivers would bill \$7.1 million
15 in TIER Adjustment Charges to the Smelters. However, if Big Rivers' expenses are
16 higher or revenues are lower than what was developed in the test year, but with
17 everything else equal, then Big Rivers would be able to charge the Smelters up to an
18 additional \$7.1 million in TIER Adjustment Charges. On the other hand, if Big Rivers'
19 expenses are lower or revenues are higher than what was developed in the test year, but
20 again with everything else equal, then Big Rivers would lower the \$7.1 million TIER
21 Adjustment Charges billed to the Smelters.

22 **Q. Why isn't Big Rivers proposing to eliminate all of the TIER Adjustment Charges**
23 **during the test year?**

1 A. Setting the TIER Adjustment Charge at the middle of the bandwidth (from \$0 to \$14.2
2 million) strikes an equitable balance in capping the additional exposure to the Smelters,
3 for purposes of this Application, at \$7.1 million (i.e., \$14.2 million total exposure less
4 \$7.1 million pro forma exposure = \$7.1 million additional exposure). Furthermore,
5 setting the TIER Adjustment Charge at the middle of the bandwidth also strikes a
6 reasonable balance between lower TIER Adjustment Charges and higher base rates.
7 Lowering the TIER Adjustment Charges to \$0 would increase base rates to all
8 customers, including the Smelters by an additional \$7.1 million above what is being
9 proposed by Big Rivers. Reducing the TIER Adjustment Charges by 50 percent thus
10 represents a balanced proposal.

11 **Q. Is setting the TIER Adjustment Charge within the bandwidth consistent with the**
12 **financial projections filed with the Commission in Unwind proceeding and**
13 **provided to the financial rating agencies?**

14 A. Yes. The TIER Adjustment Charges were generally projected to be within the
15 bandwidth in the financial forecasts submitted in the Unwind Proceeding, Case No.
16 2007-00455, and in the financial projections provided to Standard and Poor's, Fitch,
17 and Moody's in December 2008 and in March 2009 to obtain credit ratings in
18 connection with the Unwind. In Exhibit No. 79 submitted by Big Rivers in Case No.
19 2007-00455, Big Rivers provided a financial forecast going out to 2023. Beginning in
20 2011, the Smelters were shown to be between the top and the bottom of the bandwidth
21 in all but two years. As a percentage of the maximum level, the lowest TIER
22 Adjustment Charge was in 2017, which was a year that incorporated the full effect of a
23 rate increase occurring in 2016. In 2017, the TIER Adjustment Charge was shown to

1 be \$0.54 per MWh, whereas the maximum TIER Adjustment Charge is \$3.55 per
2 MWh. Thus, during 2017 the TIER Adjustment Charge is only 13 percent of the
3 maximum level, suggesting that the TIER Adjustment Charge assumed in the general
4 rate case was somewhere in the middle or toward the bottom of the bandwidth.

5 **Q. Has a pro forma adjustment been made to reduce the TIER Adjustment Charges**
6 **by \$7,114,653?**

7 A. Yes. In Reference Schedule 2.22 of Exhibit Wolfram-2, an adjustment is made to
8 reduce test-year revenues to \$7,114,653.

9 **Q. Is Big Rivers proposing to modify the Purchased Power Base that is used in the**
10 **Non-FAC PPA?**

11 A. Yes. In its Order in Case No. 2007-00455 dated March 6, 2009, the Commission
12 approved the Non-FAC PPA provision of the Smelter Agreements, which provides for
13 a monthly calculation of a Non-FAC PPA factor that is charged or credited monthly in
14 the Smelter bills. The Commission also approved the establishment of a Regulatory
15 Account Charge, through which the Non-FAC PPA charges and credits applicable to
16 non-Smelter customers will be recorded and then be amortized over a period of time
17 after review in a general rate case. Big Rivers is proposing to lower the Purchased
18 Power Base used in the Non-FAC PPA to reflect a more representative level of
19 purchased power expenses on a going forward basis. Unlike the Fuel Adjustment
20 Clause, there is not a two-year review process wherein changes to the base are
21 considered; therefore, Big Rivers is proposing to change the base in this proceeding.
22 However, it should be pointed out that changing the base represents a revenue neutral
23 change and thus will not change the level of costs ultimately to be billed to customers.

1 The Non-FAC PPA factor ("PPA") is determined by subtracting the Purchased
2 Power Base (PP(b)/S(b)) (currently \$0.00175 per kWh) from the quotient of the
3 monthly purchased power expenses PP(m) and the monthly sales S(m), as follows:

$$4 \qquad \qquad \qquad 5 \qquad \qquad \qquad \text{PPA} = \text{PP(m)/S(m)} - \$0.00175.$$

6
7 Big Rivers is proposing to lower the Purchased Power Base from \$0.00175 per kWh to
8 \$0.000874 per kWh. The proposed Purchased Power Base reflects the average
9 purchased power costs PP(m)/S(m) for June 2010. Exhibit Seelye-5 shows the average
10 purchased power costs for the test year. The reason that Big Rivers is proposing to use
11 the average cost for June to re-establish a new Purchased Power Base is that the cost for
12 June 2010 of \$0.000874 per kWh is reasonably close to the average cost of \$0.00082
13 per kWh for the test year, which can be seen in Exhibit Seelye-5. Determining the Base
14 on the basis of the cost for a single month is consistent with the Commission's normal
15 practice of determining the FAC Base on the basis of fuel costs for a particular month.

16 **Q. What rate adjustments are made to reflect the new Purchased Power Base?**

17 A. As already mentioned, the Purchased Power Base in the Non-FAC PPA will be
18 decreased from \$0.001750 per kWh to \$0.000874 per kWh, which corresponds to a
19 reduction of \$0.000876 per kWh. In order to effectuate this change, a corresponding
20 reduction must also be made to the otherwise applicable energy charges for the Rurals,
21 Large Industrials and Smelters. Reducing the energy charges established in each of the
22 three rate schedules will fully offset the billing effect of the corresponding reduction in
23 the Purchased Power Base in the Non-FAC PPA.

1 **Q. Will the Rurals and Large Industrials experience an immediate reduction in**
2 **billings as a result of lower the Purchased Power Base in the Non-FAC PPA?**

3 A. Yes. Unlike the Non-FAC PPA for the Smelters, the charges and credits under the
4 Non-FAC PPA for the Rurals and Large Industrials ("Non-Smelters") are captured in a
5 Regulatory Account which is amortized at a later date. As a result of lowering the
6 Purchased Power Base, the Rurals and Large Industrials will see an immediate
7 reduction in the energy charges of their rates. However, the off-setting effect that
8 lowering the Purchased Power Base will have on the amounts charged or credited to the
9 Regulatory Account will not be reflected in the bills to the Non-Smelters until one year
10 later, when the Regulatory Account will be amortized under Big Rivers' proposed Non-
11 Smelter Non-FAC PPA. As will be discussed in greater detail below, Big Rivers is
12 proposing to amortize the Non-FAC PPA Regulatory Account for the Non-Smelters
13 over a 12-month period beginning after charges or credits have been accumulated in the
14 Regulatory Account up through June of each year. Because the Regulatory Account
15 will not be amortized until one year after changing the Purchased Power Base reflected
16 in base rates, the Rurals and Large Industrials will experience an immediate reduction
17 in their bills as a result of lowering the Purchased Power Base, but will not experience
18 the offsetting effect on the Regulatory Account until one year later. While changing
19 the Purchased Power Base *is revenue neutral in the long run*, the impact of lowering
20 the Purchased Power Base will be seen by the Rurals and Large Industrials as a rate
21 reduction during the first year. *However, it should be emphasized that the effect is*
22 *purely short term and should not be considered permanent.*

1 **Q. Will the Smelters experience an immediate reduction in billings as a result of**
2 **lowering the Purchased Power Base in the Non-FAC PPA?**

3 A. Yes. Because there will be a one-month delay between the implementation of new
4 Base Rates for the Smelters in this proceeding and the effect on the Non-FAC PPA
5 factor as a result of changing the Purchase Power Base, the Smelters will realize a one-
6 month billing reduction as a result of lowering the Purchased Power Base.

7 **Q. Have you prepared an exhibit showing the impact of the proposed rates on pro**
8 **forma revenue?**

9 A. Yes. Exhibit Seelye-6 shows the increase in revenue by rate class from applying Big
10 Rivers' proposed rates to pro forma billing determinants. In this analysis, the billing
11 determinants and revenue reflect the following pro forma adjustments: (i) the
12 adjustment to reflect current industrial customers, (ii) the adjustment to reflect normal
13 temperatures, and (iii) reduction of 50 percent of the TIER adjustment charges to the
14 Smelters. The adjustment to reflect current industrial customers and the adjustment to
15 reflect normal temperatures are discussed in Mr. Wolfram's testimony. The adjustment
16 to reflect 50 percent of the TIER adjustment charges has already been discussed. The
17 increases are summarized on page 1 of Exhibit Seelye-6, with the detailed calculations
18 shown on pages 2 and 3. The detailed calculations provided on pages 2 and 3 show the
19 proposed rates both with and without the proposed adjustment to the Purchased Power
20 Base in the Non-FAC PPA. The increases in base rates and the percentage increases
21 are the same in either scenario. By adjusting the Purchased Power Base, base rate
22 revenues are decreased and Non-FAC PPA revenues (for the Smelters) or accruals (for
23 the non-Smelters) are decreased.

1 Amortizing the Non-FAC PPA Regulatory Account will result in an estimated
 2 annual reduction to the Non-Smelters of \$3,236,077 through the application of the
 3 proposed Non-Smelter Non-FAC PPA, which will be discussed below. The following
 4 table summarizes the percentage increase by rate class, considering only the impact of
 5 the increase in base rates, elimination of 50 percent of the TIER Adjustment Charges,
 6 and the estimated annual reduction due to the amortization of the Non-FAC PPA
 7 Regulatory Account:
 8

Impact of Proposed Revenue Increase Including Base Rate Increase, Elimination of TIER Adjustment Charges, and Amortizing the Estimated Non-FAC PPA Regulatory Account			
Customer Class	Current Revenue	Proposed Revenue Increase*	Percentage Increase
Rurals	\$ 110,513,089	\$ 11,831,935	10.71%
Large Industrials	\$ 39,260,372	\$ 2,332,557	5.94%
Smelters	\$ 282,391,841	\$ 15,438,743	5.47%
Total System	\$ 432,165,302	\$ 29,603,235	6.85%

9
10

1 However, lowering the Purchased Power Base will result in an immediate, *but*
 2 *ultimately revenue neutral*, reduction of \$2,959,159, based on test-year results. The
 3 following table summarizes the net percentage increase by rate class, accounting for the
 4 increase in base rates, elimination of 50 percent of the Smelter TIER Adjustment
 5 Charges, the amortization of the Non-FAC PPA Regulatory Account through the
 6 proposed Non-Smelter Non-FAC PPA (which will be discussed below), *and* the
 7 immediate, *but ultimately revenue neutral*, reduction in billings that the Rurals and
 8 Large Industrials will experience as a result of lowering the Purchased Power Base in
 9 the Non-FAC PPA:

Net Impact of Proposed Revenue Increase			
Including Base Rate Increase, Elimination of TIER Adjustment Charges, Amortizing the Estimated Non-FAC PPA Regulatory Account, and the Short-Term Effect of Lowering the Purchased Power Base in the Non-Smelter Non-FAC PPA			
Customer Class	Current Revenue	Proposed Revenue Increase*	Percentage Increase
Rurals	\$ 110,513,089	\$ 9,686,481	8.77%
Large Industrials	\$ 39,260,372	\$ 1,518,852	3.87%
Smelters	\$ 282,391,841	\$ 15,438,743	5.47%
Total System	\$ 432,165,302	\$ 26,644,076	6.17%

1 **Q. Is the percentage increase for the Rurals representative of the impact that Big**
2 **Rivers' rate increase will have on the Members' retail rates to their members?**

3 A. No. The average impact on the Members' retail rates will result in a lower overall
4 percentage increase than what is being proposed by Big Rivers for the wholesale rates.
5 Because the Members' retail rates also include the cost of providing distribution service
6 to their members, the percentage impact of Big Rivers' rate increase will be diluted at
7 the retail level. Big Rivers estimates that its proposed increase, without considering the
8 temporary effect of the roll-in of the Non-FAC PPA, will result in an increase of
9 approximately \$6.70 per month to a retail residential customer with a monthly
10 consumption of 1,300 kWh, assuming a distribution losses of 6 percent ($\$11,831,935 /$
11 $2,428,480,630 \text{ kWh} \times 1300 \text{ kWh} \div [1.00 - 0.06] \approx \6.70). (See Exhibit Seelye-6, page
12 2.) The average net bill for a residential customer on the Big Rivers system with a
13 1,300 kWh monthly usage is approximately \$98.50 per month. Therefore, Big Rivers'
14 proposed rates will result in an increase of approximately 6.8 percent for a typical
15 residential customer with a monthly usage of 1,300 kWh ($\$6.70 \div \$98.50 = 6.8\%$).
16 Obviously, this is a very rough estimate of the impact of Big Rivers' proposed increase
17 on retail rates. The actual retail percentage increase will vary by individual distribution
18 cooperative member depending upon its individual sales characteristics. Big Rivers'
19 Members will be making their own separate filings to reflect Big Rivers' increase in
20 their rates, and in those filings the increases will be quantified with greater specificity,
21 by retail rate classification.

1 **Q. In a separate proceeding, Big Rivers is proposing to "roll in" amounts currently**
2 **billed through its Fuel Adjustment Clause ("FAC") into base rates. Have the**
3 **rates shown in Exhibit Seelye-6 been adjusted to give effect to the roll-in?**

4 A. No. In Case No. 2010-00495, Big Rivers is proposing to increase the base cost used in
5 the FAC by \$0.010212 per kWh and increase the energy charges by a corresponding
6 amount. However, at this point in time, the Commission has not approved the FAC
7 roll-in; therefore, the effect of a roll-in was not reflected in the rates shown in Exhibit
8 Seelye-6 or in the tariffs filed with the Application. However, any FAC roll-in
9 authorized in Case No. 2010-00495 must be incorporated in the final rates implemented
10 in this proceeding. Big Rivers therefore commits to incorporate any roll-in of the FAC
11 authorized in Case No. 2010-00495 in the compliance rates filed with the Commission
12 pursuant to an order in this proceeding.

13
14 **VIII. MEMBER RATE STABILITY MECHANISM AND RURAL ECONOMIC**
15 **RESERVE**

16
17 **Q. Is Big Rivers proposing changes to the Member Rate Stability Mechanism and the**
18 **Rural Economic Reserve?**

19 A. Yes. Big Rivers is proposing changes to the MRSM to specify how the mechanism will
20 operate if it remains in place beyond the original 48 months that were anticipated when
21 the mechanism was originally established. Current projections indicate that the
22 Economic Reserve is likely to last beyond the 48 month horizon originally anticipated.
23 Big Rivers is also proposing changes to the RER so that it will operate seamlessly with
24 the expiration of the MRSM.

25 **Q. What is the purpose of the MRSM?**

1 A. An Economic Reserve of \$157 million was originally established to offset the impact of
2 the FAC and Environmental Surcharge on the Non-Smelters after taking into account
3 the credits received from the Unwind Surcredit and the Rebate Adjustment. The
4 MRSM draws on the Economic Reserve to offset the monthly impacts of the FAC and
5 Environmental Surcharge on the Members' non-Smelter bills, net of the credits
6 received under the Unwind Surcredit and Rebate Adjustment. An Expense Mitigation
7 Factor was included in the MRSM to alter the speed at which the Economic Reserve
8 was to be drawn down and thereby "feather" the effect of anticipated FAC and
9 Environmental Surcharge Expenses on the Non-Smelter rates until the Economic
10 Reserve is exhausted and the full amounts of FAC and Environmental Surcharge are
11 applied without credit. (See page 4 of Supplemental Direct Testimony of William
12 Steven Seelye submitted in Case Nos. 2007-00455 and 2007-00460.)

13 **Q. Why does the MRSM need to be modified?**

14 A. In the tariff sheets for the MRSM filed in the Unwind proceeding, Expense Mitigation
15 Factors were specified for the first 48 months following the effective date of the tariff.
16 The following EMFs are currently set forth in the tariff:

17

- 18 I. \$0.000 per kWh for the first twelve (12) months following the effective
19 date of this tariff;
20
21 II. \$0.002 per kWh for months 13 through 24 following the effective date
22 of this tariff;
23
24 III. \$0.004 per kWh for months 25 through 36 following the effective date
25 of this tariff; and
26
27 IV. \$0.006 per kWh for months 37 through 48 following the effective date
28 of this tariff;
29

1 Because the Economic Reserve is not expected to be depleted until after the first 48
2 months, the MRSM needs to be modified to specify what the EMF will be after the first
3 48 months following the original effective date of the tariff.

4 **Q. How is Big Rivers proposing to change the MRSM?**

5 A. Big Rivers is proposing to add two additional EMFs that will extend beyond the first 48
6 months of the mechanism. Specifically, Big Rivers is proposing to add a fifth EMF
7 equal to \$0.007 per kWh and applicable for months 49 through 60 following the
8 effective date of the tariff and a sixth EMF equal to \$0.009 per kWh that would be
9 applicable thereafter.

10 **Q. Why is Big Rivers proposing to increase the EMF by \$0.001 per kWh between the
11 fourth and fifth periods rather than by \$0.002 per kWh as in all of the other
12 incremental changes?**

13 A. Big Rivers is proposing to increase the EMF by only \$0.001 per kWh between the
14 fourth and fifth periods in order to account for the expiration of the amortization of the
15 current Non-Smelter Non-FAC regulatory liability. The amortization of the Non-
16 Smelter Non-FAC PPA regulatory liability through the proposed Non-Smelter Non-
17 FAC PPA adjustment clause will expire in approximately August 2013. Expiration of
18 the amortization will result in the elimination of a credit of approximately \$0.001 per
19 kWh. In order to offset the elimination of the credit, Big Rivers is proposing to reduce
20 the normal \$0.002 per kWh increment by \$0.001 per kWh in the fifth EMF.

21 **Q. What is the purpose of the RER?**

22 A. In its Order in Case No. 2007-00455 dated March 6, 2009, the Commission required
23 Big Rivers to commit to establish a Rural Economic Reserve of not less than \$60.9
24 million to be used exclusively to credit the bills rendered to the Rurals over a period of
25 24 months commencing with the depletion of all funds in the Economic Reserve.

1 **Q. How is Big Rivers proposing to change the RER?**

2 A. Big Rivers is proposing to change the RER so that it operates seamlessly with the
3 MRSM. Specifically, Big Rivers is proposing that the RER operate in the same manner
4 as the MRSM, except applicable only to the Rurals, thereby offsetting the impact of the
5 FAC and Environmental Surcharge on the Rurals after taking into account the credits
6 received from the Unwind Surcredit and the Rebate Adjustment. Thus, once the
7 Economic Reserve is exhausted by the application of the MRSM, the EMFs identified
8 in the MRSM will be adopted by the RER so that there will not be a discontinuity in the
9 amounts credited to the Rurals between the two mechanisms. Therefore, the EMF
10 schedule set forth in the MRSM will continue to be used in the determination of the
11 amounts credited under the RER. For example, if the Economic Reserve expires in the
12 52nd month following the effective date of the tariff, then the RER will be billed for the
13 first time in the 53rd month using an EMF of \$0.007 per kWh. In this example, the
14 EMF of \$0.007 per kWh would then continue for another eight months (i.e., for the
15 53rd through the 60th month following the effective date of the MRSM). In the 61st
16 month, the EMF would then transition to \$0.009 per kWh and remain at that level until
17 the Rural Economic Reserve is exhausted.

18

19 **IX. NON-FAC PPA ADJUSTMENT CLAUSE FOR THE NON-SMELTERS**

20

21 **Q. Please describe the Non-FAC PPA mechanisms currently used by Big Rivers.**

22 A. Big Rivers has in place two different Non-FAC PPA mechanisms – (i) a Non-FAC PPA
23 for the Smelters, which provides for a monthly calculation of a Non-FAC PPA factor
24 that is charged or credited monthly in the Smelter bills; and (ii) a Regulatory Account
25 Charge, through which the Non-FAC PPA charges or credits applicable to the Non-

1 Smelters are recorded in a deferred asset or deferred liability account to be amortized at
2 a later date.

3 **Q. How much has been accrued in the Non-FAC PPA Regulatory Account for the**
4 **Non-Smelters?**

5 A. As of October 31, 2010, a regulatory liability balance of \$4,364,060 had been accrued
6 for the Non-Smelter Non-FAC PPA. This means that as of October 31, 2010, the
7 Rurals and Large Industrials are owed \$4,364,060.

8 **Q. How does Big Rivers propose to return the Non-FAC PPA Regulatory Account**
9 **Charges to the Rurals and Large Industrials?**

10 A. Big Rivers is proposing to establish a mechanism that would amortize the Non-FAC
11 PPA Regulatory Account balance every 12 months, instead of waiting to amortize the
12 Non-FAC PPA Regulatory Account as part of a general rate case. In the bills for
13 September service each year, Big Rivers will establish a credit (or charge) to return (or
14 collect) the Non-FAC PPA Regulatory Liability (or Asset) balance as of June 30 over
15 the upcoming 12 month period, except for the initial implementation of this mechanism
16 in 2011, which Big Rivers is proposing to return the liability as of June 30, 2010, over
17 24 months.

18 Under this mechanism, beginning with bills for September 2011, Big Rivers
19 will establish a per kWh credit which would be designed to return the Non-FAC PPA
20 Regulatory Liability balance as of June 30, 2011, over 24 months beginning with the
21 September 2011 bills. If Big Rivers' PPA expenses continue at the current level, then
22 we estimate that the Non-FAC PPA Regulatory Liability will be approximately \$6.5
23 million by June 30, 2011. This balance would then be returned to the Rurals and Large
24 Industrials through the application of a per kWh credit that would be calculated by

1 dividing the \$6.5 million balance by the estimated kWh sales to the Rurals and Large
2 Industrials for the upcoming 24 months. If the estimated sales to the Rurals and Large
3 Industrials are 6,750,000,000 kWh for the 24 month period beginning September 2011,
4 then the Rurals and Large Industrials would receive a credit of \$0.000963 per kWh
5 related to the \$6.5 million balance. The \$0.000963 per kWh credit would remain in
6 place for 24 months. After the factor has been in place for 24 months, any remaining
7 under- or over-recovery will be transferred to the Non-FAC PPA Regulatory Account
8 for the subsequent period.

9 Then with bills for September 2012, Big Rivers will establish a per kWh credit
10 or charge which would be designed to return or recover the Non-Smelter Non-FAC
11 PPA Regulatory Liability or Asset balance as of June 30, 2012, over 12 months
12 beginning with September 2012 bills. The credit or charge for the June 30, 2011,
13 regulatory account balance would remain in effect for 12 months. Because this 12
14 month period would overlap with the initial implementation of the mechanism in 2011,
15 two factors would be in effect – the first related to the June 30, 2011, balance and the
16 second related to the June 30, 2012, balance. In subsequent 12 month periods (i.e.,
17 beginning with bills for service in September 2013), only one factor would be in effect
18 at any given time.

19 **Q. Is Big Rivers proposing a new rate schedule describing the proposed Non-FAC**
20 **PPA mechanism described above?**

21 A. Yes. The rate schedule is called "Non-Smelter Non-FAC PPA" and appears on sheet
22 numbers 59 through 63 of Big Rivers' proposed tariff. See Exhibit 7 of the Application.
23 For ease of reference, a copy of the rate schedule is also included in Exhibit Seelye-7.

24 **Q. Is Big Rivers proposing to make a pro forma adjustment in this proceeding to**
25 **reflect the amortization of the Non-FAC PPA Regulatory Liability?**

1 A. No. Instead of including a pro forma adjustment to amortize the Regulatory Liability
2 and return the balance through base rates, Big Rivers is proposing to return the liability
3 through the mechanism described above. Big Rivers' Non-Smelter rate classes will
4 receive their credits beginning in the same month (in the September 2011 bills) as they
5 would otherwise receive those benefits if they were reflected in base rates by including
6 a pro forma adjustment in this proceeding to amortize the Non-Smelter Non-FAC PPA
7 regulatory liability.

8 **Q. What are the advantages of establishing the proposed mechanism compared to**
9 **including the amortization of the regulatory liability as part of base rates?**

10 A. Establishing a mechanism to clear the Regulatory Account balance every 12 months is
11 much more orderly than waiting until subsequent rate cases to clear any balances. If
12 the amortization of the Regulatory Account is included in base rates, an assumption
13 must be made regarding the amortization period, which may not accurately reflect the
14 actual period between rate cases. Setting up a credit or charge to clear the Regulatory
15 Account every 12 months, as proposed by Big Rivers, ensures that any Non-FAC PPA
16 Regulatory Account Charges are dealt with in a timely manner, rather than waiting until
17 a rate case is filed.

18 Furthermore, amortizing the Regulatory Account through a separate Non-
19 Smelter Non-FAC PPA adjustment clause *that is only applicable to the Non-Smelters*
20 helps ensure that the Smelters do not receive any additional credits or charges
21 associated with the amortization of the Non-Smelter Non-FAC PPA Regulatory
22 Account. As mentioned earlier, the Smelter Agreements include Non-FAC PPA
23 provisions that provide automatic monthly rate adjustments to the Smelters to reflect
24 changes in purchased power costs. Consequently, none of the Non-Smelter Non-FAC
25 PPA regulatory liability should be distributed to the Smelters. Unless somewhat

1 complicated precautions are undertaken, including the amortization of the Non-Smelter
2 Non-FAC PPA regulatory liability as a pro forma adjustment to operating results in this
3 proceeding would effectively assign a portion of the Non-Smelter Non-FAC PPA
4 regulatory liability to the Smelters, thus resulting a double counting of the credits.
5 Because the Smelter's Base Energy Charge is contractually linked to the Large
6 Industrials' base rate, returning the regulatory liability through base rates (i.e., through
7 a pro forma adjustment to amortize the regulatory liability) in this proceeding would
8 inappropriately result in an additional credit to the Smelters. Establishing a separate
9 Non-Smelter Non-FAC PPA adjustment clause that is only applicable to the Non-
10 Smelters is in my opinion the most straightforward way to amortize the Regulatory
11 Account to the Non-Smelters.

12
13 **X. MIDWEST ISO ATTACHMENT O TRANSMISSION FORMULA RATE**
14

15 **Q. Did the Commission approve Big Rivers' membership in the Midwest ISO?**

16 A. Yes. The Commission approved the transfer of operational control of Big Rivers'
17 transmission facilities to the Midwest ISO in Case No. 2010-00043, *In the Matter of*
18 *Application of Big Rivers Electric Corporation for Approval to Transfer Functional*
19 *Control of its Transmission System to Midwest Independent Transmission System*
20 *Operator, Inc.* in its Order dated November 1, 2010 ("Midwest ISO Order").

21 **Q. Please describe Midwest ISO Attachment O.**

22 A. Midwest ISO Attachment O is used to determine the transmission service rates under
23 the Midwest ISO Tariff. Attachment O, which is updated annually, is used to determine
24 the annual transmission revenue requirements for each transmission owner in Midwest
25 ISO. Revenue requirements are determined based on plant and expense data from the

1 utility's FERC Form 1, RUS Form 12, or EIA Form 412, as applicable, and include the
2 following components: (i) operating expenses, including operation and maintenance
3 expenses, taxes other than income tax, and depreciation expenses, (ii) return on
4 transmission net investment grossed up for income taxes, less (ii) transmission revenue
5 credits. For illustrative purposes, a copy of an updated Attachment O for the test year is
6 shown in Exhibit Seelye-8. As can be seen from the Attachment O for Big Rivers, net
7 revenue requirements are shown on page 1, line 7. Operating Expenses consist of (a)
8 total operation and maintenance expenses shown on page 3, line 8, (b) depreciation
9 expenses shown on page 3, line 12, and (c) taxes other than income taxes shown on
10 page 3, line 20. The return on transmission net investment is shown on page 3, line 28,
11 and the income tax gross up is shown on page 3, line 22. Transmission net plant is
12 shown on page 2, line 18, and adjustments to rate base are shown on line 24. Please
13 note that the updated Attachment O calculation shown in Exhibit Seelye-8 is being
14 provided solely to illustrate how the FERC-approved transmission formula rate will be
15 calculated. The actual updated Attachment O will not be implemented until the
16 Commission authorizes the use of the Attachment O formula rate in this proceeding and
17 will be developed based on cost information for the 2010 calendar year, in accordance
18 with the normal cycle for the historical-cost formula rates used by the members of the
19 Midwest ISO.

20 **Q. Is the Midwest ISO Attachment O an FERC-approved rate schedule?**

21 A. Yes, it is. The revenue requirement set forth in Midwest ISO's Attachment O for Big
22 Rivers is applicable to all loads sinking in Big Rivers' transmission pricing zone,
23 including retail load. Therefore, in the strictest sense, Schedule 9 - Network Integration
24 Service of Midwest ISO's Midwest ISO Tariff is the "filed rate" applicable to loads that
25 sink in Big Rivers' control area.

1 **Q. Has the FERC approved an interim Attachment O for Big Rivers?**

2 A. Yes. On October 14, 2010, the Midwest ISO and Big Rivers filed revisions to the
3 Midwest ISO tariff to include Big Rivers' company-specific Attachment O template
4 with the FERC in Docket No. ER11-15-000. Big Rivers and the Midwest ISO sought
5 approval for deviations from the Midwest ISO's Attachment O formula rate template,
6 on an interim basis, to use the rates that were currently contained in Big Rivers' OATT,
7 which this Commission had approved, until such time as Big Rivers obtained approval
8 from this Commission to use the Midwest ISO Attachment O formula rate. Big Rivers
9 advised the FERC that Big Rivers anticipated a filing with this Commission to adjust
10 the transmission rates to be effective no later than January 1, 2012, and noted that at
11 that time Big Rivers would seek approval from this Commission to adjust its
12 transmission rates to utilize the Midwest ISO Attachment O formula rate. Big Rivers
13 sought to utilize the existing OATT rates until such time as this Commission approved
14 an adjustment to Big Rivers' transmission rates to utilize the Midwest ISO Attachment
15 O formula rate. For convenience, a copy of that Order is attached as Exhibit Seelye-9.

16 **Q. Did the FERC issue an order in Docket No. ER11-15-000?**

17 A. Yes. FERC conditionally accepted for filing Big Rivers' Attachment O formula rate, to
18 be effective December 1, 2010, through and including December 31, 2011. FERC
19 noted in its order dated November 24, 2010, that this acceptance with an end date of
20 December 31, 2011 does not foreclose the Midwest ISO and Big Rivers from making a
21 filing at an earlier date to adopt an appropriate formula rate for Big Rivers.

22 **Q. Is Big Rivers requesting authorization to adjust its transmission rates to use the**
23 **Midwest ISO Attachment O on an ongoing basis?**

1 A. Yes. Big Rivers is requesting to use the Midwest ISO Attachment O and to update the
2 inputs used in the transmission formula rate on an annual basis.

3 **Q. If the Commission approves the use of the Midwest ISO Attachment O formula**
4 **rate, do you anticipate that a revised Attachment O rate will become effective**
5 **prior to December 31, 2011?**

6 A. Yes. In the spring of each year, Transmission-Owning members of Midwest ISO
7 ordinarily provide Attachment O data for the previous calendar year to Midwest ISO.
8 Midwest ISO then utilizes the Attachment O data for the previous calendar year when
9 updating its transmission rates to become effective June 1st of the current year. On this
10 schedule, in the spring of 2011 Big Rivers will compile Attachment O data for calendar
11 year 2010 and provide it to Midwest ISO; Midwest ISO will incorporate the 2010
12 Attachment O data for rates that become effective June 1, 2011. Thus, the Big Rivers
13 Attachment O formula rate, if authorized by this Commission to be used by Big Rivers,
14 would go into effect when the retail rates approved by the Commission in this
15 proceeding become effective, pre-empting the transmission rates that are presently
16 approved on an interim basis only until December 31, 2011.

17 **Q. Please describe the transmission costs included in Midwest ISO's FERC-approved**
18 **Attachment O formula rate?**

19 A. Schedule 7 - Long-Term Firm and Short-Term Firm Point-to-Point Transmission
20 Service, Schedule 8 - Non-Firm Point-to-Point Transmission Service, and Schedule 9 -
21 Network Integration Service of Midwest ISO's Midwest ISO Tariff are assessed for any
22 loads sinking in a transmission owner's transmission pricing zone. The charges
23 collected under these schedules are based on the rate formula contained in Attachment

1 O of the Midwest ISO Tariff. The rate formula corresponds to a revenue requirement
2 calculation that is performed annually by each Midwest ISO transmission owner. The
3 revenue requirements, including operating expenses and a return on transmission net
4 investment grossed up for income taxes, less transmission revenues (revenue credits)
5 collected pursuant to the Schedule 7, 8, and 9 of the Midwest ISO Tariff, are allocated
6 to the transmission owner.

7 **Q. Will the adoption of the Attachment O transmission formula rate affect base rates**
8 **charged to Big Rivers' members?**

9 A. No.

10
11 **XI. TEMPERATURE NORMALIZATION ADJUSTMENT**

12
13 **Q. Is Big Rivers proposing a temperature normalization adjustment for electric**
14 **operations in this proceeding?**

15 A. Yes.

16 **Q. What is the purpose of making such an adjustment in a rate case?**

17 A. In a general rate case, service rates are set at a level that will provide the utility a
18 reasonable opportunity to recover its costs on a going-forward basis. The underlying
19 principle is that when rates go into effect as a result of a general rate case, those rates
20 will represent a level of revenue that will allow the utility to recover its reasonably
21 incurred costs on a going-forward basis. This principle holds regardless of whether a
22 projected test year or a historical test year is used to set rates. When rates are based on
23 a historical test year, pro forma adjustments are made to test-year operating results so
24 that revenues and expenses will be representative on a going-forward basis. This is the

1 principle behind adjusting certain test-year operating results to reflect a going-forward
2 level of expenses and revenues for things such as annualizing revenues and expenses
3 for new customers or annualizing certain expenses (e.g., depreciation expense and
4 wages and benefits expense) to reflect the full amount on a going forward basis. In this
5 proceeding, the Company has made a number of other normalization adjustments to
6 help ensure that the historical test year will be representative of costs and revenues on a
7 going-forward basis. Only normalization adjustments that are supported by a sound
8 statistical methodology and apply clear and objective measures are used to adjust test
9 year results.

10 **Q. Why is it appropriate to make a temperature normalization adjustment in this**
11 **proceeding?**

12 A. Electric utility sales vary with temperature. As temperatures rise during the summer,
13 more electric energy is used by customers to operate the compressors on their air-
14 conditioners. Likewise, as temperatures go down in the winter, more electric energy is
15 used by customers to operate electric furnaces and other space-heating appliances.
16 Consequently, for any day during the summer or winter, Big Rivers' electric sales will
17 increase and decrease as a result of changes in temperature. Without a temperature
18 normalization adjustment, there can be no assurance that the test year level of expenses,
19 and therefore, the proposed amount of revenue will be representative on a going
20 forward basis.

21 **Q. Should revenues and expenses reflect a range of cooling and heating degree days**
22 **representative of normal conditions?**

1 A. Yes. What is considered normal can be represented in a number of statistically valid
2 ways. One methodology – the mean-value approach – is to represent normal degree
3 days by calculating a 30-year average. Another methodology would be to establish a
4 statistically determined range centered on the mean-value degree days.

5 From a statistical perspective, a 30-year mean, or average, would represent a
6 measure of the *expected value* for heating degree days. For a normally-distributed
7 probability density function, the expected value of a random variable is equal to the
8 mean value. Or stated more rigorously, the maximum likelihood estimator for a
9 normally distributed random variable is equal to the sample mean value. (For example,
10 see Robert V. Hogg and Allen T. Craig, *Introduction to Mathematical Statistics*, Third
11 Edition, 1975, at 257.) Therefore, the 30-year average heating degree days are
12 considered to be representative of a going-forward level of heating degree days for
13 purposes of determining test-year levels of revenues and sales.

14 This is a standard approach for normalizing natural gas revenues and expenses,
15 and is also used in other jurisdictions to normalize electric revenues and expenses.
16 Although it has accepted the mean-value methodology for calculating gas temperature
17 normalization adjustments for natural gas utilities for many years, the Commission has
18 expressed concerns about using the mean-value approach for electric temperature
19 normalization. In its Order in Louisville Gas and Electric's Case No. 10064, the
20 Commission stated as follows:

21 The Commission is of the opinion that there is adequate evidence to
22 suggest that a range of temperatures and not a specific mean
23 temperature is a more appropriate measure of normal temperatures.
24 As long as the temperature falls within these bounds then it is
25 inappropriate to adjust sales for temperature. However, if the

1 temperature falls outside those bounds then it is appropriate to adjust
2 sales to the nearest bound. (Order in Case No. 10064, dated July 1,
3 1988, at 39.)
4

5 Therefore, an alternative to the mean-value approach, one which was suggested by the
6 Commission's Order in Case No. 10064 and is well-grounded by statistical theory,
7 would be to determine a *range* of cooling and heating degrees days that would be
8 considered normal. Instead of normal degree days being represented by a mean value,
9 a bandwidth around the mean value could be established. Cooling degree days inside
10 the bandwidth would then be considered normal, and cooling degree days outside the
11 bandwidth – either high or low – would be considered abnormal or extraordinary,
12 requiring a normalization adjustment to bring revenues and sales to within a normal
13 range. A standard approach for establishing a *normal range* of a random variable is to
14 determine a bandwidth of two standard deviations centered on the mean. The rationale
15 for this approach is that for a normally-distributed (Gaussian) probability density
16 function, the random variable will fall within a range between one standard deviation
17 above and one standard deviation below the mean value 68 percent of the time. More
18 important for our purposes is the fact that a random variable will only exceed the two
19 standard deviation bandwidth 16 percent of the time. Assuming that cooling and
20 heating degree days are normally distributed, which is a standard supposition well-
21 grounded in empirical research, only 16 percent of the time would temperatures be
22 expected to exceed one standard deviation above or below the mean.

23 **Q. Which methodology did Big Rivers use for the Temperature Normalization**
24 **Adjustment it is proposing in this case?**

1 A. Big Rivers is proposing to use the banded methodology described above. Specifically,
2 if heating and cooling degree days during a month are *within* plus or minus one
3 standard deviation of the mean degree days for the month, then no adjustment would be
4 made during that month. If heating or cooling degree days for a month are more than
5 one standard deviation above the average for that month, then sales would be adjusted
6 upward or downward to reflect the heating or cooling degree days at the top end of the
7 range. In other words if the degree days are above the top end of the range, they are not
8 adjusted to the *average* but only to *one standard deviation above* the average.
9 Likewise if heating or cooling degree days for a month are more than one standard
10 deviation below the average for that month, then sales would be adjusted downward or
11 upward to reflect the heating or cooling degree days at the bottom end of the range.

12 This approach places constraints on the magnitude of the temperature
13 normalization adjustment when compared with an adjustment based on the mean value.
14 First, a constraint is placed on the magnitude of the total revenue and expense
15 adjustment because monthly normalization adjustments would only be made during
16 months when cooling or heating degree days fall outside a particularly wide range of
17 degree days. Second, the methodology would only adjust sales to one of the two end
18 points of the degree day range. Thus, this approach would certainly result in lower
19 revenue and expense adjustments than adjusting to the mid-point of the degree-day
20 range (the mean value).

21 The determination of Big Rivers proposed revenue and expense adjustments are
22 shown in Exhibit Seelye-10. Page 1 of the exhibit shows the calculation of the revenue
23 adjustment (\$421,610), the expense adjustment (\$295,293), and the net overall

1 adjustment of (\$126,318). Page 2 shows the calculation of the base fuel and variable
2 cost per kWh used to determine the expense adjustment. Page 3 shows the
3 determination of normalized sales and the kWh adjustment used to calculate the
4 revenue and expenses adjustments. Page 3 of the exhibit also shows the cooling degree
5 day and heating degree day bands for each month of the test year, based on one
6 standard deviation above and one standard deviation below the 30 year average for the
7 month. GDS Associates, Inc. constructed the analysis shown on page 3. GDS
8 Associates, Inc. prepared the long term forecast for Big Rivers IRP filings. Because of
9 its work in this area for Big Rivers, GDS Associates, Inc. had already compiled the data
10 necessary to perform the analysis.

11 **Q. Are there months during the year that would not be adjusted under this**
12 **methodology?**

13 A. Yes, for most months during the test year no adjustments are required. As can be seen
14 from Exhibit Seelye-10 page 3, the only heating degree day adjustments that would be
15 required are for the months of January and February. January is 32 degree days colder
16 than the top of the range; and February is 74 degree days colder than the top of the
17 range. The only cooling degree day adjustments that are necessary are for the months of
18 June and August. June is 52 degree days hotter than the top end of the range; and
19 August is 3 degree days hotter than the top end of the range.

20 **Q. After the kWh sales adjustments were determined for each class, how was the**
21 **revenue component of the adjustment calculated?**

22 A. The revenue adjustment was calculated by applying the kWh adjustment for the Rurals
23 to the applicable energy charge. No attempt was made to normalize the demand

1 charges. The proposed temperature normalization procedure normalized kWh sales and
2 not maximum individual demands. Had demands been normalized, the revenue
3 adjustment would have been larger without materially changing the expense
4 adjustment.

5 **Q. How was the expense component of the adjustment determined?**

6 A. The expense component of the temperature normalization adjustment was calculated by
7 applying the kWh sales adjustment to the variable expenses per kWh during the test
8 year. Variable expenses were determined using the FERC predominance methodology
9 that was used in the Company's embedded cost of service study.

10 **Q. Has the Commission ever considered an electric temperature normalization
11 adjustment in other proceedings?**

12 A. Yes. Electric temperature normalization adjustments were considered in Kentucky
13 Utilities Case No. 98-474 and in Case No. 8284, Case No. 8616, Case No. 8924, Case
14 No. 10064, and Case No. 98-426, which were LG&E rate proceedings. In each of these
15 proceedings, the Commission denied the adjustment, noting that the companies had
16 failed to adequately support the adjustment. The Commission however continued to
17 endorse the concept of normalization and expressed a willingness to consider
18 temperature adjustments in future rate proceedings. (See Commission's Orders in
19 Cases 8284, page 9, 8616, page 15, 98-426, page 73, and Case No. 98-474, at page 70.)

20 In Case Nos. 98-474 and 98-426, the Commission expressed concern about the
21 use of 20-year average degree days rather than a 30-year average, noting that "previous
22 electric weather normalization adjustments proposed in the LG&E rate cases were

1 based on a 30-year average. The 30-year average is typically used in gas weather
2 normalization adjustments.” (*Id.*, at 74.)

3 In Case No. 10064, the Commission expressed concern that LG&E did not
4 construct a “confidence interval” for temperature adjustment purposes. On page 38 of
5 the Order, the Commission observed that LG&E “adjusted each month’s actual billing-
6 cycle temperature-sensitive load to a mean determined temperature-sensitive load
7 instead of to a temperature-sensitive load determined by the boundaries of a range of
8 acceptable values constructed around the mean.” (Order in Case No. 10064, dated July
9 1, 1998, at 38-39.) The Commission also expressed concern about the accuracy of the
10 billing-cycle degree days used in the temperature normalization adjustment.

11 Additionally, the Commission criticized LG&E’s adjustment because it did not rely on
12 a regression model to adjust test-year sales and only analyzed one variable. (*Id.*, at 42-
13 43.)

14 The adjustments proposed by LG&E in Case Nos. 8284 and 8616 were
15 developed without relying on any sort of statistical analysis. Temperature-sensitive
16 load was estimated by first selecting a single month to calculate a base load level and
17 then all sales during the summer months above that base load level were considered to
18 be the temperature-sensitive load. The Commission rejected the methodologies
19 proposed in those proceedings for obvious reasons.

20 **Q. Do you believe that the Commission’s concerns expressed in the previous rate**
21 **cases where temperature normalization adjustments have been proposed are**
22 **adequately addressed in this filing?**

1 A. Yes. All previous concerns expressed by the Commission have been thoroughly and
2 comprehensively addressed.

3 **Q. How does this methodology address the Commissions past criticisms that any
4 temperature normalization methodology should rely on statistical analysis?**

5 A. Under the proposed methodology, GDS Associates, Inc. performed a statistical analysis
6 to develop a bandwidth for each month and to determine the relationship of temperature
7 to kWh sales to the Rurals.

8 **Q. How does this methodology address the Commissions past criticisms that
9 adjustments for temperature should not be made to a single mean value but to a
10 range of acceptable values constructed around the mean?**

11 A. Under the proposed methodology, GDS Associates, Inc. performed statistical analyses
12 to develop a band width around the 30 year average number of degree days for each
13 month. The band width was determined based on one standard deviation above and
14 below the 30 year average.

15 **Q. How does this methodology address the Commissions past criticisms that the
16 relationship between temperature and kWh sales was not determined by using a
17 regression analysis?**

18 A. GDS Associates, Inc. performed a regression analysis to determine the relationship
19 between temperature and kWh sales to the Rurals.

20 **Q. How does this methodology address the Commissions past criticisms that normal
21 temperature was based on a 20 year normal instead of a 30 year normal?**

22 A. GDS Associates, Inc. used a 30 year normal to develop the bandwidths for each month
23 of the year.

1 Q. Does the temperature normalization have the effect of decreasing test-year
2 operating income and thus increasing the Company's proposed revenue increase?

3 A. Yes. Although the net effect of the adjustment is only \$126,318, the temperature
4 normalization adjustment decreases operating income and raises the Company's
5 proposed rate increase in this filing.

6 Q. Do you recommend that this adjustment be made?

7 A. Yes. I believe that it is appropriate to make an electric temperature normalization
8 adjustment.

9

10 XII. CONCLUSION

11

12 Q. Do you have any closing comments?

13 A. Yes. Big Rivers' proposed increase in base rates is necessary so that Big Rivers can
14 meet its MFIR and maintain investment grade credit ratings, as required by its debt
15 covenants. Big Rivers' proposed rates are designed to increase base rate revenues by
16 \$39,953,965, which is necessary for Big Rivers to meet the financial requirements set
17 forth in its debt agreements and to continue to provide reliable service to its customers,
18 as discussed in Mr. Blackburn's testimony. The proposed rates are designed to narrow
19 the gap in the rates of return between the Rurals and Large Industrials.

20 Q. Does this conclude your testimony?

21 A. Yes, it does.

Exhibit Seelye-1

Qualifications of
William Steven Seelye

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 150 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility

billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

- Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.
- Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.
- FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.
- Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.
- Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.
- Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.
- Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER11-2127-000 concerning transmission rates proposed by Terra-Gen Dixie Valley, LLC.

Submitted testimony in Docket No. ER11-2779 on behalf of Southern Illinois Power Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

Submitted testimony in Docket No. ER11-2786 on behalf of Norris Electric Cooperative concerning wholesale distribution service charges proposed by Ameren Services Company.

- Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.
- Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.
- Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.
- Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.
- Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.
- Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.
- Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.
- Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas

temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Submitted testimony in Case No. 2009-00548 on behalf of Kentucky Utilities Company and in Case No. 2009-00549 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric and gas temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2010-00116 on behalf of Delta Natural Gas Company concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 10-06001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate cases.

Maryland Submitted direct testimony in PSC Case No. 9234 on behalf of Southern Maryland Electric Cooperative regarding a class cost of service study.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company’s application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company’s regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00065 on behalf of Craig-Botetourt Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Exhibit Seelye-2

Cost of Service Study

Functional Assignment and
Classification

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Plant in Service							
Intangible Plant	INTPLT	PT&D	\$ 66,895	58,634	-	-	8,261
Production Plant	PPROD	F001	\$ 1,686,796,955	1,686,796,955	-	-	-
Transmission Plant	PTRAN	F002	\$ 237,659,206	-	-	-	237,659,206
Distribution Plant	PDIST	F003	\$ -	-	-	-	-
Total Production & Transmission Plant			1,924,456,160	1,686,796,955	-	-	237,659,206
General Plant	PGP	PT&D	\$ 18,511,051	16,225,043	-	-	2,286,008
Total Plant in Service			\$ 1,943,034,107	\$ 1,703,080,632	\$ -	\$ -	\$ 239,953,475
Construction Work in Progress (CWIP)							
CWIP Production	CWIP1	PPROD	\$ 22,411,274	22,411,274	-	-	-
CWIP Transmission	CWIP2	PTRAN	\$ 7,475,859	-	-	-	7,475,859
CWIP Distribution Plant	CWIP3	PDIST	\$ -	-	-	-	-
CWIP General Plant	CWIP4	PT&D	\$ 16,915,005	14,826,100	-	-	2,088,905
Total Construction Work in Progress			\$ 46,802,138	\$ 37,237,374	\$ -	\$ -	\$ 9,564,764
Total Utility Plant			\$ 1,989,836,245	\$ 1,740,318,006	\$ -	\$ -	\$ 249,518,239

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Rate Base							
Total Utility Plant	TUP		\$ 1,989,836,245	\$ 1,740,318,006	\$ -	\$ -	\$ 249,518,239
Less: Accumulated Provision for Depreciation							
Production	ADEPREPA	PPROD	\$ 790,847,523	790,847,523	-	-	-
Transmission	ADEPRTP	PTRAN	\$ 107,564,747	-	-	-	107,564,747
Distribution	ADEPRD11	PDIST	\$ -	-	-	-	-
General & Common Plant	ADEPRD12	PT&D	\$ 6,300,770	5,222,661	-	-	778,109
Intangible, Misc. and Other Plant	ADEPRGP	PT&D	\$ -	-	-	-	-
Retirement Work in Progress	ADEPRRT	PT&D	\$ -	-	-	-	-
Total Accumulated Depreciation	TADEPR		\$ 904,713,040	\$ 796,370,184	\$ -	\$ -	\$ 108,342,855
Net Utility Plant	NTPLANT		\$ 1,085,123,206	\$ 943,947,822	\$ -	\$ -	\$ 141,175,384
Working Capital							
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	\$ 28,050,527	13,844,414	11,969,243	-	2,236,870
Materials and Supplies	M&S	TPIS	\$ 22,777,820	19,964,891	-	-	2,812,929
Fuel Stock	PREPAY	TPIS	\$ 34,326,112	30,087,036	-	-	4,239,076
Total Working Capital	TWC		\$ 85,154,459	\$ 63,896,340	\$ 11,969,243	\$ -	\$ 9,288,875
Net Rate Base	RB		\$ 1,170,277,664	\$ 1,007,844,162	\$ 11,969,243	\$ -	\$ 150,464,259

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING	OM500	PROFEX	\$ 4,974,566	4,974,566	-	-	-
501 FUEL	OM501	Energy	\$ 200,919,367	-	200,919,367	-	-
502 STEAM EXPENSES	OM502	PROFEX	\$ 34,453,882	34,453,882	-	-	-
505 ELECTRIC EXPENSES	OM505	PROFEX	\$ 5,730,122	5,730,122	-	-	-
506 MISC. STEAM POWER EXPENSES	OM506	PROFEX	\$ 7,451,302	7,451,302	-	-	-
507 RENTS	OM507	PROFEX	\$ -	-	-	-	-
509 ALLOWANCES	OM509	Energy	\$ 429,682	-	429,682	-	-
Total Steam Power Operation Expenses			\$ 253,958,921	\$ 52,609,872	\$ 201,349,049	\$ -	-
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING	OM510	Energy	\$ 3,631,867	-	3,631,867	-	-
511 MAINTENANCE OF STRUCTURES	OM511	PROFEX	\$ 3,346,806	3,346,806	-	-	-
512 MAINTENANCE OF BOILER PLANT	OM512	Energy	\$ 30,113,309	-	30,113,309	-	-
513 MAINTENANCE OF ELECTRIC PLANT	OM513	Energy	\$ 6,251,804	-	6,251,804	-	-
514 MAINTENANCE OF MISC STEAM PLANT	OM514	PROFEX	\$ 877,364	877,364	-	-	-
Total Steam Power Generation Maintenance Expense			\$ 44,221,151	\$ 4,224,170	\$ 39,996,981	\$ -	-
Total Steam Power Generation Expense			\$ 298,180,072	\$ 56,834,042	\$ 241,346,030	\$ -	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	OM546	PROFIX	-	-	-	-	-
547 FUEL	OM547	Energy	706,789	-	-	-	-
548 GENERATION EXPENSE	OM548	PROFIX	34,608	34,608	706,789	-	-
549 MISC OTHER POWER GENERATION	OM549	PROFIX	-	-	-	-	-
550 RENTS	OM550	PROFIX	-	-	-	-	-
Total Other Power Generation Expenses			\$ 741,396	\$ 34,608	\$ 706,789	\$ -	\$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	OM551	PROFIX	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	OM552	PROFIX	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	OM553	PROFIX	625,088	625,088	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	OM554	PROFIX	-	-	-	-	-
Total Other Power Generation Maintenance Expense			\$ 625,088	\$ 625,088	\$ -	\$ -	\$ -
Total Other Power Generation Expense			\$ 1,366,485	\$ 659,696	\$ 706,789	\$ -	\$ -
Total Station Expense			\$ 299,546,557	\$ 57,493,738	\$ 242,052,819	\$ -	\$ -

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Other Power Supply Expenses							
555 PURCHASED POWER Energy	OM555	OMPP	\$ 19,466,790	-	19,466,790	-	-
555 PURCHASED POWER Demand	OMD555	OMPPD	\$ 4,210,045	4,210,045	-	-	-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	\$ 58,293,374	13,175,571	45,117,803	-	-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	\$ -	-	-	-	-
555 BROKERAGE FEES	OMB555	OMPP	\$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	\$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	\$ 909,422	909,422	-	-	-
557 OTHER EXPENSES	OM557	PROFIX	\$ 20,575,465	20,575,465	-	-	-
558 DUPLICATE CHARGES	OM558	Energy	\$ -	-	-	-	-
Total Other Power Supply Expenses	TPP		\$ 103,455,096	\$ 38,870,503	\$ 64,584,593	\$ -	\$ -
Total Electric Power Generation Expenses			\$ 403,001,653	\$ 96,364,241	\$ 306,637,411	\$ -	\$ -
Transmission Expenses							
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	\$ 876,815	-	-	-	876,815
561 LOAD DISPATCHING	OM561	LBTRAN	\$ 1,454,938	-	-	-	1,454,938
562 STATION EXPENSES	OM562	PTRAN	\$ 1,163,408	-	-	-	1,163,408
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	\$ 1,090,014	-	-	-	1,090,014
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	\$ 3,065,817	-	-	-	3,065,817
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	\$ 475,381	-	-	-	475,381
567 RENTS	OM567	PTRAN	\$ 24,701	-	-	-	24,701
568 MAINTENANCE SUPERVISION AND ENG	OM568	LBTRAN	\$ 647,227	-	-	-	647,227
569 STRUCTURES	OM569	PTRAN	\$ 26,913	-	-	-	26,913
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	\$ 1,936,760	-	-	-	1,936,760
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	\$ 2,876,462	-	-	-	2,876,462
572 UNDERGROUND LINES	OM572	PTRAN	\$ -	-	-	-	-
573 MISC PLANT	OM573	PTRAN	\$ 97,880	-	-	-	97,880
Total Transmission Expenses			\$ 13,736,318	\$ -	\$ -	\$ -	\$ 13,736,318
Distribution Operation Expense							
580 OPERATION SUPERVISION AND ENGI	OM580	LBDO	\$ -	-	-	-	-
581 LOAD DISPATCHING	OM581	PDIST	\$ -	-	-	-	-
582 STATION EXPENSES	OM582	PDIST	\$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	PDIST	\$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	PDIST	\$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	PDIST	\$ -	-	-	-	-
586 METER EXPENSES	OM586	PDIST	\$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586X	PDIST	\$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	PDIST	\$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	\$ -	-	-	-	-
588 MISC DISTR EXP - MAPPIN	OM588X	PDIST	\$ -	-	-	-	-
589 RENTS	OM589	PDIST	\$ -	-	-	-	-
Total Distribution Operation Expense	OMDO		\$ -	\$ -	\$ -	\$ -	\$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Distribution Maintenance Expense							
590 MAINTENANCE SUPERVISION AND EN	OM590	LBDM	-	-	-	-	-
591 STRUCTURES	OM591	PDIST	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	PDIST	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	PDIST	-	-	-	-	-
598 MISCELLANEOUS DISTRIBUTION EXPENSES	OM598	PDIST	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		\$ -	\$ -	\$ -	\$ -	\$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-	-
Transmission and Distribution Expenses			13,736,318	-	-	-	13,736,318
Production, Transmission and Distribution Expenses	OMSUB		\$ 416,737,971	\$ 96,364,241	\$ 306,637,411	\$ -	\$ 13,736,318
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	-	-	-	-	-
902 METER READING EXPENSES	OM902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM905	F025	-	-	-	-	-
Total Customer Accounts Expense	OMCA		\$ -	\$ -	\$ -	\$ -	\$ -
Customer Service Expense							
907 SUPERVISION	OM907	TUP	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	80,486	-	-	-	-
909 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	-	70,393	-	-	10,093
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	TUP	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	OM911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	TUP	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	TUP	488,103	426,897	-	-	61,206
915 MDSE-JOBGING-CONTRACT	OM915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	-	-	-	-	-
Total Customer Service Expense	OMCS		\$ 568,589	\$ 497,290	\$ -	\$ -	\$ 71,299
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		417,306,560	96,861,532	306,637,411	-	13,807,617

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Operation and Maintenance Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	\$ 14,315,713	6,663,061	5,595,161	-	2,057,491
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	\$ 6,915,648	3,218,798	2,702,915	-	993,935
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	\$ -	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	\$ 3,954,189	1,840,425	1,545,457	-	566,306
924 PROPERTY INSURANCE	OM924	TUP	\$ -	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	\$ 179,889	83,727	70,308	-	25,854
926 EMPLOYEE BENEFITS	OM926	LBSUB9	\$ 169,663	78,967	66,311	-	24,384
927 FRANCHISE REQUIREMENTS	OM927	TUP	\$ -	-	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	\$ 1,188,958	1,039,867	-	-	149,091
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	\$ -	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	\$ 1,686,131	784,788	659,008	-	242,335
931 RENTS AND LEASES	OM931	PGP	\$ 1,933	1,694	-	-	239
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	\$ 208,156	182,450	-	-	25,706
Total Administrative and General Expense	OMAG		\$ 28,620,280	\$ 13,893,778	\$ 10,639,160	\$ -	\$ 4,087,342
Total Operation and Maintenance Expenses	TOM		\$ 445,926,840	\$ 110,755,309	\$ 317,276,572	\$ -	\$ 17,894,959
Operation and Maintenance Expenses Less Purchase Power & Fuel	OMLPP		\$ 224,404,213	\$ 110,755,309	\$ 95,753,945	\$ -	\$ 17,894,959

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses							
Steam Power Generation Operation Expenses							
500 OPERATION SUPERVISION & ENGINEERING							
501 FUEL	LB500	PROFIX	\$ 4,967,667	4,967,667	-	-	-
502 STEAM EXPENSES	LB501	Energy	\$ 3,889,944	-	3,889,944	-	-
505 ELECTRIC EXPENSES	LB502	PROFIX	\$ 9,023,322	9,023,322	-	-	-
506 MISC. STEAM POWER EXPENSES	LB505	PROFIX	\$ 4,523,897	4,523,897	-	-	-
507 RENTS	LB506	PROFIX	\$ 940,518	940,518	-	-	-
509 ALLOWANCES	LB507	PROFIX	\$ -	-	-	-	-
	LB509	Energy	\$ -	-	-	-	-
Total Steam Power Operation Expenses	LBSUB1		\$ 23,345,348	\$ 19,455,404	\$ 3,889,944	\$ -	\$ -
Steam Power Generation Maintenance Expenses							
510 MAINTENANCE SUPERVISION & ENGINEERING							
511 MAINTENANCE OF STRUCTURES	LB510	Energy	\$ 3,623,969	-	3,623,969	-	-
512 MAINTENANCE OF BOILER PLANT	LB511	PROFIX	\$ 986,831	986,831	-	-	-
513 MAINTENANCE OF ELECTRIC PLANT	LB512	Energy	\$ 8,700,235	-	8,700,235	-	-
514 MAINTENANCE OF MISC STEAM PLANT	LB513	Energy	\$ 1,595,642	-	1,595,642	-	-
	LB514	PROFIX	\$ 200,886	200,886	-	-	-
Total Steam Power Generation Maintenance Expense	LBSUB2		\$ 15,107,564	\$ 1,187,718	\$ 13,919,846	\$ -	\$ -
Total Steam Power Generation Expense			\$ 38,452,913	\$ 20,643,122	\$ 17,809,791	\$ -	\$ -

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Other Power Generation Operation Expense							
546 OPERATION SUPERVISION & ENGINEERING	LB546	PROFIX	-	-	-	-	-
547 FUEL	LB547	Energy	-	-	-	-	-
548 GENERATION EXPENSE	LB548	PROFIX	-	-	-	-	-
549 MISC OTHER POWER GENERATION	LB549	PROFIX	-	-	-	-	-
550 RENTS	LB550	PROFIX	-	-	-	-	-
Total Other Power Generation Expenses	LBSUB7		\$ -	\$ -	\$ -	\$ -	\$ -
Other Power Generation Maintenance Expense							
551 MAINTENANCE SUPERVISION & ENGINEERING	LB551	PROFIX	-	-	-	-	-
552 MAINTENANCE OF STRUCTURES	LB552	PROFIX	-	-	-	-	-
553 MAINTENANCE OF GENERATING & ELEC PLANT	LB553	PROFIX	89,555	89,555	-	-	-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	-	-	-	-	-
Total Other Power Generation Maintenance Expense	LBSUB8		\$ 89,555	\$ 89,555	\$ -	\$ -	\$ -
Total Other Power Generation Expense			\$ 89,555	\$ 89,555	\$ -	\$ -	\$ -
Total Production Expense	LPREX		\$ 38,542,468	\$ 20,732,677	\$ 17,809,791	\$ -	\$ -

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Purchased Power							
555 PURCHASED POWER Energy	LB555	OMPP	\$ -	-	-	-	-
555 PURCHASED POWER Demand	LB555	OMPP	\$ -	-	-	-	-
555 PURCHASED POWER OPTIONS	LBO555	OMPP	\$ -	-	-	-	-
555 BROKERAGE FEES	LB555	OMPP	\$ -	-	-	-	-
555 MISO TRANSMISSION EXPENSES	LB555	OMPP	\$ -	-	-	-	-
556 SYSTEM CONTROL AND LOAD DISPATCH	LB556	PROFIX	\$ -	-	-	-	-
557 OTHER EXPENSES	LB557	PROFIX	\$ -	-	-	-	-
558 DUPLICATE CHARGES	LB558	Energy	\$ -	-	-	-	-
Total Purchased Power Labor	LBPP		\$ -	\$ -	\$ -	\$ -	\$ -
Transmission Labor Expenses							
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	\$ 835,977	-	-	-	835,977
561 LOAD DISPATCHING	LB561	PTRAN	\$ 1,304,969	-	-	-	1,304,969
562 STATION EXPENSES	LB562	PTRAN	\$ 598,382	-	-	-	598,382
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	\$ 236,393	-	-	-	236,393
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	\$ -	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	\$ 312,375	-	-	-	312,375
567 RENTS	LB567	PTRAN	\$ -	-	-	-	-
568 MAINTENANCE SUPERVISION AND ENG	LB568	PTRAN	\$ 644,925	-	-	-	644,925
569 MAINTENANCE OF STRUCTURES	LB569	PTRAN	\$ 318	-	-	-	318
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	\$ 1,433,304	-	-	-	1,433,304
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	\$ 1,067,766	-	-	-	1,067,766
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	\$ 46,439	-	-	-	46,439
Total Transmission Labor Expenses	LBTRAN		\$ 6,480,848	\$ -	\$ -	\$ -	6,480,848
Distribution Operation Labor Expense							
580 OPERATION SUPERVISION AND ENG	LB580	F023	\$ -	-	-	-	-
581 LOAD DISPATCHING	LB581	PDIST	\$ -	-	-	-	-
582 STATION EXPENSES	LB582	PDIST	\$ -	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	PDIST	\$ -	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	PDIST	\$ -	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	PDIST	\$ -	-	-	-	-
586 METER EXPENSES	LB586	PDIST	\$ -	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	PDIST	\$ -	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	PDIST	\$ -	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	\$ -	-	-	-	-
589 RENTS	LB589	PDIST	\$ -	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		\$ -	\$ -	\$ -	\$ -	\$ -

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Distribution Maintenance Labor Expense							
590 MAINTENANCE SUPERVISION AND EN	LB590	F024	-	-	-	-	-
591 MAINTENANCE OF STRUCTURES	LB591	PDIST	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	PDIST	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	PDIST	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	PDIST	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	PDIST	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	PDIST	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	PDIST	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		\$ -	\$ -	\$ -	\$ -	\$ -
Total Distribution Operation and Maintenance Labor Expenses		PDIST	-	-	-	-	-
Transmission and Distribution Labor Expenses			6,480,848	-	-	-	6,480,848
Production, Transmission and Distribution Labor Expenses	LBSUB		\$ 45,023,316	\$ 20,732,677	\$ 17,809,791	\$ -	\$ 6,480,848
Customer Accounts Expense							
901 SUPERVISION/CUSTOMER ACCTS	LB901	F025	-	-	-	-	-
902 METER READING EXPENSES	LB902	F025	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F025	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F025	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB905	F025	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		\$ -	\$ -	\$ -	\$ -	\$ -
Customer Service Expense							
907 SUPERVISION	LB907	TUP	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	TUP	544,608	476,316	-	-	68,292
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	TUP	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	TUP	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	TUP	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	TUP	-	-	-	-	-
911 DEMONSTRATION AND SELLING EXP	LB911	TUP	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	TUP	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	TUP	-	-	-	-	-
915 MDSE-JOBING-CONTRACT	LB915	TUP	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	TUP	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		\$ 544,608	\$ 476,316	\$ -	\$ -	\$ 68,292
Sub-Total Labor Exp	LBSUB9		45,567,924	21,208,994	17,809,791	-	6,549,140

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Labor Expenses (Continued)							
Administrative and General Expense							
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	\$ 14,315,714	6,663,061	5,595,161	-	2,057,491
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	\$ -	-	-	-	-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	\$ -	-	-	-	-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	\$ -	-	-	-	-
924 PROPERTY INSURANCE	LB924	TUP	\$ -	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	\$ 27,509	12,804	10,752	-	3,954
926 EMPLOYEE BENEFITS	LB926	LBSUB9	\$ 17,136	7,976	6,698	-	2,463
928 REGULATORY COMMISSION FEES	LB928	TUP	\$ -	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	LBSUB9	\$ -	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	LBSUB9	\$ -	-	-	-	-
931 RENTS AND LEASES	LB931	PGP	\$ -	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	\$ 74,927	65,674	-	-	9,253
Total Administrative and General Expense	LBAG		\$ 14,435,286	\$ 6,749,515	\$ 5,612,610	\$ -	\$ 2,073,161
Total Operation and Maintenance Expenses	TLB		\$ 60,003,210	\$ 27,958,509	\$ 23,422,401	\$ -	\$ 8,622,301
Operation and Maintenance Expenses Less Purchase Power	LBLPP		\$ 60,003,210	\$ 27,958,509	\$ 23,422,401	\$ -	\$ 8,622,301

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Other Expenses							
Depreciation Expenses							
Production	DEPRDP2	PPROD	\$ 28,815,395	28,815,395	-	-	-
Transmission	DEPRDP3	PTRAN	\$ 5,182,459	-	-	-	5,182,459
Distribution	DEPRDP4	PTRAN	\$ -	-	-	-	-
General & Common Plant	DEPRDP5	PDIST	\$ -	-	-	-	-
Other Plant	DEPRDP6	PGP	\$ 238,155	208,744	-	-	29,411
	DEPROTH	TPIS	\$ -	-	-	-	-
Total Depreciation Expense	TDEPR		\$ 34,236,009	29,024,140	-	-	5,211,869
Accretion Expense							
Production	ACRTNP	F017	\$ -	-	-	-	-
Transmission	ACRTNT	PTRAN	\$ -	-	-	-	-
Distribution	ACRTND	PDIST	\$ -	-	-	-	-
Total Accretion Expense	TACRTN		\$ -	-	\$ -	\$ -	-
Property Taxes & Other	PTAX	TUP	\$ (94,563)	(82,705)	-	-	(11,858)
Amortization of Investment Tax Credit	OTAX	TUP	\$ -	-	-	-	-
Other Expenses	OT	TUP	\$ (365,864)	(319,986)	-	-	(45,878)
Interest	INTLTD	TUP	\$ 47,622,710	41,650,995	-	-	5,971,715
Other Deductions	DEDUCT	TUP	\$ 109,257	95,557	-	-	13,700
Total Other Expenses	TOE		\$ 81,507,549	70,368,000	\$ -	\$ -	11,139,549
Total Cost of Service (O&M + Other Expenses)			\$ 527,434,389	181,123,310	\$ 317,276,572	\$ -	29,034,508

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
 October 2010

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Steam Direct	Transmission Demand
Functional Vectors							
Production Plant	F001		1.000000	1.000000	0.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000	0.000000
Provar	PROVAR		1.000000	0.000000	1.000000	0.000000	0.000000
PROFIX	PROFIX		1.000000	1.000000	0.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		58,293,374	13,175,571	45,117,803	0.000000	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000	0.000000
Internally Generated Functional Vectors							
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.876506	-	-	0.123494
Total Transmission Plant		PTRAN	1.000000	-	-	-	1.000000
Operation and Maintenance Expenses Less Purchase Power		OMLPP	1.000000	0.493553	0.426703	-	0.079744
Total Plant in Service		TPIS	1.000000	0.876506	-	-	0.123494
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.465950	0.390352	-	0.143697
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.232111	0.734801	-	0.033087
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.833374	0.166626	-	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.078617	0.921383	-	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	-	1.000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.465437	0.390841	-	0.143723
Total General Plant		PGP	1.000000	0.876506	-	-	0.123494
Total Production Plant		PPROD	1.000000	1.000000	-	-	-
Total Intangible Plant		INTPLT	1.000000	0.876506	-	-	0.123494

Exhibit Seelye-3

Cost of Service Study

Class Allocation

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Plant in Service						
Power Production Plant						
Production Demand	TPIS	PLPDM	\$ 524,448,481	\$ 144,392,793	\$ 1,034,239,358	\$ 1,703,080,632
Production Energy	TPIS	PLPENG	-	-	-	-
Production - Steam Direct	TPIS	PLPSTM	-	-	-	-
Total Power Production Plant		PLPT	\$ 524,448,481	\$ 144,392,793	\$ 1,034,239,358	\$ 1,703,080,632
Transmission Plant	TPIS	PLTRN	\$ 73,891,531	\$ 20,344,047	\$ 145,717,897	\$ 239,953,475
Distribution Substation	TPIS	PLDST	-	-	-	-
Distribution Other	TPIS	PLDMC	-	-	-	-
Total		PLT	\$ 598,340,013	\$ 164,736,840	\$ 1,179,957,254	\$ 1,943,034,107

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Net Utility Plant						
Power Production Plant						
Production Demand						
Production Energy						
Production - Steam Direct						
Total Power Production Plant						
		NTPLANTNTPDMD	\$ 290,680,307	\$ 80,031,010	\$ 573,236,505	\$ 943,947,822
		NTPLANTNTPRENG	-	-	-	-
		NTPLANTNTPSTM	-	-	-	-
		NTPT	\$ 290,680,307	\$ 80,031,010	\$ 573,236,505	\$ 943,947,822
Transmission Plant						
		NTPLANTNTRN	\$ 43,473,700	\$ 11,969,315	\$ 85,732,370	\$ 141,175,384
Distribution Substation						
		NTPLANTDST	-	-	-	-
Distribution Other						
		NTPLANTDMC	-	-	-	-
Total		NTPLT	\$ 334,154,007	\$ 92,000,324	\$ 658,968,874	\$ 1,085,123,206

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Net Cost Rate Base						
Power Production Plant						
Production Demand						
Production Energy	RB	RBPDM	\$ 310,356,615	\$ 85,448,352	\$ 612,039,195	\$ 1,007,844,162
Production - Steam Direct	RB	RBPENG	\$ 2,794,152	\$ 1,059,737	\$ 8,115,354	\$ 11,969,243
Total Power Production Plant	RB	RBPSTM	\$ -	\$ -	\$ -	\$ -
	RB	RBPT	\$ 313,150,767	\$ 86,508,089	\$ 620,154,549	\$ 1,019,813,405
Transmission Plant	RB	RBTRN	\$ 46,334,126	\$ 12,756,856	\$ 91,373,277	\$ 150,464,259
Distribution Substation	RB	RBDST	\$ -	\$ -	\$ -	\$ -
Distribution Other	RB	RBDMC	\$ -	\$ -	\$ -	\$ -
Total		RBPLT	\$ 359,484,893	\$ 99,264,945	\$ 711,527,826	\$ 1,170,277,664

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
<u>Operation and Maintenance Expenses</u>						
Power Production Plant						
Production Demand	TOM	OMPDM	\$ 34,106,109	\$ 9,390,200	\$ 67,259,000	\$ 110,755,309
Production Demand Reallocation of Purchased Power			\$ 3,187,500	\$ 877,592	\$ (4,065,092)	\$ -
Production Energy	TOM	OMPENG	\$ 74,066,421	\$ 28,091,138	\$ 215,119,013	\$ 317,276,572
Production - Steam Direct	TOM	OMPSTM	\$ -	\$ -	\$ -	\$ -
Total Power Production Plant		OMPT	\$ 111,360,030	\$ 38,358,931	\$ 278,312,921	\$ 428,031,881
Transmission Plant						
	TOM	OMTRN	\$ 5,510,593	\$ 1,517,194	\$ 10,867,172	\$ 17,894,959
Distribution Substation						
	TOM	OMDST	\$ -	\$ -	\$ -	\$ -
Distribution Other						
	TOM	OMDMC	\$ -	\$ -	\$ -	\$ -
Total		OMPLT	\$ 116,870,623	\$ 39,876,124	\$ 289,180,093	\$ 445,926,840

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Labor Expenses						
Power Production Plant						
Production Demand	TLB	LBPDMD	\$ 8,609,573	\$ 2,370,415	\$ 16,978,521	\$ 27,958,509
Production Energy	TLB	LBPENG	\$ 5,467,827	\$ 2,073,780	\$ 15,880,793	\$ 23,422,401
Production - Steam Direct	TLB	LBPSTM	\$ -	\$ -	\$ -	\$ -
Total Power Production Plant		LBPT	\$ 14,077,400	\$ 4,444,195	\$ 32,859,314	\$ 51,380,909
Transmission Plant						
	TLB	LBTRN	\$ 2,655,161	\$ 731,027	\$ 5,236,113	\$ 8,622,301
Distribution Substation						
	TLB	LBDST	\$ -	\$ -	\$ -	\$ -
Distribution Other						
	TLB	LDMC	\$ -	\$ -	\$ -	\$ -
Total		LBPLT	\$ 16,732,561	\$ 5,175,222	\$ 38,095,427	\$ 60,003,210

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Depreciation Expenses						
Power Production Plant						
Production Demand	TDEPR	DPPDMD	\$ 8,937,725	\$ 2,460,762	\$ 17,625,653	\$ 29,024,140
Production Energy	TDEPR	DPPENG	-	-	-	-
Production - Steam Direct	TDEPR	DPPSTM	-	-	-	-
Total Power Production Plant		DPPT	\$ 8,937,725	\$ 2,460,762	\$ 17,625,653	\$ 29,024,140
Transmission Plant		DPTRN	\$ 1,604,949	\$ 441,879	\$ 3,165,041	\$ 5,211,869
Distribution Substation		DPDST	-	-	-	-
Distribution Other		DPDMC	-	-	-	-
Total		DPPLT	\$ 10,542,673	\$ 2,902,642	\$ 20,790,694	\$ 34,236,009

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Property and Other Taxes						
Power Production Plant						
Production Demand		PRPDMD	\$ (25,468)	(7,012)	(50,225)	(82,705)
Production Energy		PRPENG	-	-	-	-
Production - Steam Direct		PRPSTM	-	-	-	-
Total Power Production Plant		PRPT	(25,468)	(7,012)	(50,225)	(82,705)
Transmission Plant						
	PTAX	PRTRN	(3,652)	(1,005)	(7,201)	(11,858)
Distribution Substation						
	PTAX	PRDST	-	-	-	-
Distribution Other						
	PTAX	PRDMC	-	-	-	-
Total		PRPLT	(29,120)	(8,017)	(57,426)	(94,563)

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Interest Expenses						
Power Production Plant						
Production Demand		INTLTD INPDMD	\$ 12,826,052	\$ 3,531,309	\$ 25,293,634	\$ 41,650,995
Production Energy		INTLTD INPENG	-	-	-	-
Production - Steam Direct		INTLTD INPSTM	-	-	-	-
Total Power Production Plant		INPT	\$ 12,826,052	\$ 3,531,309	\$ 25,293,634	\$ 41,650,995
Transmission Plant						
		INTLTD INTRN	\$ 1,838,936	\$ 506,302	\$ 3,626,477	\$ 5,971,715
Distribution Substation						
		INTLTD INDST	-	-	-	-
Distribution Other						
		INTLTD INDMC	-	-	-	-
Total		INPLT	\$ 14,664,988	\$ 4,037,610	\$ 28,920,111	\$ 47,622,710

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Unadjusted						
Operating Revenues						
Sales to Members		REVUC	\$ 110,934,700	\$ 39,110,620	\$ 282,406,135	\$ 432,451,455
Off System Sales Revenue			\$ 12,699,303	\$ 4,615,318	\$ 59,229,055	\$ 76,543,676
Income from Leased Property Net		OTHREV	\$ 45,976	\$ 12,696	\$ 91,001	\$ 149,673
Other Operating Revenue & Income		OTHREV	\$ 4,232,543	\$ 1,168,737	\$ 8,377,466	\$ 13,778,745
Total Operating Revenues		TOR	\$ 127,912,522	\$ 44,907,371	\$ 350,103,657	\$ 522,923,549
Operating Expenses						
Operation and Maintenance Expenses			\$ 116,870,623	\$ 39,876,124	\$ 289,180,093	\$ 445,926,840
Depreciation and Amortization Expenses			\$ 10,542,673	\$ 2,902,642	\$ 20,790,694	\$ 34,236,009
Property and Other Taxes			\$ (29,120)	\$ (8,017)	\$ (57,426)	\$ (94,563)
Total Operating Expenses		TOE	\$ 127,384,177	\$ 42,770,749	\$ 309,913,361	\$ 480,068,286
Utility Operating Margin			\$ 528,345	\$ 2,136,622	\$ 40,190,296	\$ 42,855,263
Non-Operating Items						
Interest Income			\$ -	\$ -	\$ -	\$ -
Other Non-Operating Income			\$ -	\$ -	\$ -	\$ -
Other Credits			\$ -	\$ -	\$ -	\$ -
Interest on Long Term Debt			\$ -	\$ -	\$ -	\$ -
Other Interest Expense			\$ -	\$ -	\$ -	\$ -
Other Deductions			\$ -	\$ -	\$ -	\$ -
Total Non-Operating Items			\$ -	\$ -	\$ -	\$ -
Net Utility Operating Margin		TOM	\$ 528,345	\$ 2,136,622	\$ 40,190,296	\$ 42,855,263
Net Cost Rate Base			\$ 359,484,893	\$ 99,264,945	\$ 711,527,826	\$ 1,170,277,664

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma						
Operating Revenues						
Total Operating Revenue			\$ 127,912,522	\$ 44,907,371	\$ 350,103,657	\$ 522,923,549
Pro-Forma Adjustments:						
To annualize revenue for new industrial customer	2.01		\$ -	\$ 149,752	\$ -	\$ 149,752
To adjust mismatch in fuel cost recovery	2.02	FACREV	\$ (25,166,503)	\$ (9,525,471)	\$ (73,123,203)	\$ (107,815,177)
To eliminate Environmental Surcharge revenues	2.03	ESREV	\$ (5,315,462)	\$ (2,025,233)	\$ (15,493,538)	\$ (22,834,232)
To reflect temperature normalized sales volumes	2.04		\$ (421,610)	\$ -	\$ -	\$ (421,610)
To eliminate Non-FAC PPA revenues	2.05	NFPR	\$ 2,757,108	\$ 1,045,800	\$ 7,785,109	\$ 11,588,017
To eliminate WKEC Lease Expenses	2.19		\$ (45,976)	\$ (12,686)	\$ (91,001)	\$ (149,673)
To eliminate RRI Domtar Cogen Backup revenues	2.09		\$ -	\$ (1,115,159)	\$ -	\$ (1,115,159)
To adjust for Smelter TIER Adjustment Charge	2.22		\$ -	\$ -	\$ (7,128,947)	\$ (7,128,947)
Total Pro-Forma Operating Revenue			\$ 99,720,079	\$ 33,424,364	\$ 262,052,077	\$ 395,196,520

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Cost of Service Summary -- Pro-Forma						
Operating Expenses						
Depreciation and Maintenance Expenses			\$ 116,870,623	\$ 39,876,124	\$ 289,180,093	\$ 445,926,840
Property and Other Taxes			\$ 10,542,673	\$ 2,902,642	\$ 20,790,694	\$ 34,236,009
			\$ (29,120)	\$ (8,017)	\$ (57,426)	\$ (94,563)
Adjustments to Operating Expenses:						
To annualize expenses for new industrial customer	2.01		\$ -	\$ 110,607	\$ -	\$ 110,607
To adjust mismatch in fuel cost recovery	2.02		\$ (25,685,949)	\$ (9,722,081)	\$ -	\$ (35,408,030)
To eliminate Environmental Surcharge expenses	2.03		\$ (5,452,944)	\$ (2,081,425)	\$ (74,632,493)	\$ (82,166,862)
To reflect weather normalized sales volumes	2.04		\$ (295,293)	\$ -	\$ (15,923,422)	\$ (16,218,715)
To eliminate Non-FAC PPA expenses	2.05		\$ 2,858,740	\$ 1,084,350	\$ -	\$ 3,943,090
To reflect annualized depreciation expenses	2.06		\$ 1,925,448	\$ 530,120	\$ 8,072,083	\$ 10,527,651
To reflect increases in labor and labor-related costs	2.07		\$ 174,259	\$ 53,897	\$ 3,797,082	\$ 4,525,238
To reflect current interest on construction (CWIP)	2.08		\$ 158,826	\$ 43,728	\$ 396,739	\$ 599,333
To eliminate RRI Domtar Cogen Backup expenses	2.09		\$ -	\$ (2,086,416)	\$ 313,213	\$ (1,773,203)
To reflect leveled production expenses	2.10		\$ 1,743,155	\$ 479,931	\$ -	\$ 2,223,086
To reflect leveled production expenses	2.11		\$ 839,745	\$ 231,201	\$ 3,437,592	\$ 4,508,538
To reflect going forward Information Technology support services	2.12		\$ 89,756	\$ 24,784	\$ 1,656,019	\$ 1,970,559
To reflect amortization of rate case expenses	2.13		\$ 86,538	\$ 23,896	\$ 177,654	\$ 308,088
To reflect MISO related expenses	2.14		\$ 1,667,501	\$ 459,102	\$ 171,285	\$ 2,297,888
To annualize interest on long-term debt	2.15		\$ 21,628	\$ 5,972	\$ 3,288,398	\$ 3,515,998
To reflect leased property income (Soaper Building Rent)	2.16		\$ (35,797)	\$ (11,072)	\$ 42,808	\$ (4,061)
To adjust for costs related to LEM Dispatch	2.17		\$ (288,484)	\$ (79,426)	\$ (81,500)	\$ (449,410)
To adjust for costs related to APM	2.18		\$ 63,156	\$ 17,388	\$ (588,905)	\$ (508,361)
To reflect going forward level of Outside Services	2.25		\$ (725,000)	\$ (275,000)	\$ 124,546	\$ (875,454)
To eliminate costs for SFPC membership	2.20		\$ (55,530)	\$ (15,334)	\$ -	\$ (70,864)
To adjust for MISO Case-related expenses	2.21		\$ (237,459)	\$ (65,378)	\$ (109,911)	\$ (412,748)
To reflect commitment to Energy Efficiency Programs	2.26		\$ 725,000	\$ 275,000	\$ (468,281)	\$ 531,719
To eliminate promo advertising, lobbying, donation and econ dev	2.23		\$ (130,114)	\$ (45,872)	\$ -	\$ (176,000)
To reflect going forward level of income taxes	2.24		\$ 56,379	\$ 15,522	\$ (331,230)	\$ (259,329)
Total Expense Adjustments			\$ (22,506,439)	\$ (11,026,504)	\$ (70,527,141)	\$ (104,060,084)
Total Operating Expenses		TOE	\$ 104,877,738	\$ 31,744,245	\$ 239,386,220	\$ 376,008,203
Utility Operating Margins -- Pro-Forma			\$ (5,157,658)	\$ 1,680,119	\$ 22,665,857	\$ 19,188,318
Non-Operating Items			\$ -	\$ -	\$ -	\$ -
Total Non-Operating Items			\$ -	\$ -	\$ -	\$ -
Net Utility Operating Margin			\$ (5,157,658)	\$ 1,680,119	\$ 22,665,857	\$ 19,188,318
Net Cost Rate Base			\$ 359,484,893	\$ 99,264,945	\$ 711,527,826	\$ 1,170,277,664
Return on Rate Base -- Utility Operating Margin Divided by Rate Base			-1.43%	1.69%	3.19%	1.64%

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
<u>Cost of Service Summary -- Pro-Forma (Proposed Rate Increase)</u>						
Operating Revenues						
Total Operating Revenue	\$		99,720,079	33,424,364	262,052,077	395,196,520
Pro-Forma Adjustments:						
To Reflect Proposed Increase	\$		14,172,003	3,228,566	22,553,396	39,953,965
Total Pro-Forma Operating Revenue	\$		113,892,082	36,652,930	284,605,473	435,150,485
Operating Expenses						
Total Operating Expenses	\$		104,877,738	31,744,245	239,386,220	376,008,202
Utility Operating Margins -- Pro-Formed for Increase	\$		9,014,344	4,908,685	45,219,252	59,142,283
Net Cost Rate Base	\$		359,484,893	99,264,945	711,527,826	1,170,277,664
Rate of Return			2.51%	4.95%	6.36%	5.05%

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Allocation Factors						
Energy Allocation Factors						
Energy Usage by Class	E01		0.233444	0.088538	0.678017	1.000000
Customer Allocation Factors						
Rev	R01		110,934,700	39,110,620	282,406,135	432,451,455
Energy			2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
FAC Revenue Allocator		FACA	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Base Fuel Revenue Allocator		BSFL	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Fuel Expense Applicable to FAC Allocator		FACEX	2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Energy - NonSmelter		EnergyNS	1	0	-	1
Energy - Smelter only		EnergyS	-	-	1	1
Customers (Metering Points)		Cust05	3	1	2	6
Energy - Rurals only		EnergyR	1,0000	-	-	1,0000
Demand Allocators						
Steam - Direct Assignment		STMD	-	-	-	-
Substation Allocator		SUBA	-	-	-	-
Production 1 CP Demands		1CP	554,980	151,856	850,000	1,556,837
Production 2 CP Demands		2CP	1,051,963	239,829	1,700,000	2,991,792
Production 4 CP Demands		4CP	2,036,530	473,879	3,400,000	5,910,409
Production 6 CP Demands		6CP	2,979,160	721,110	5,100,000	8,800,270
Production 12 CP Demands		12CP	5,172,279	1,424,048	10,200,000	16,796,327
Production CP Allocation Method Used:		CP	0.307941	0.084783	0.607276	1.000000
Sum of Individual Class Demands			5,226,823	1,751,743	10,200,000	17,178,566
Transmission 12 CP Demand		12CPTR	5,172,279	1,424,048	10,200,000	16,796,327

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Large Industrials	Smelters	Total System
Production Energy Allocation						
Production Energy Residual Allocator	PENGA		2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
Production Energy Costs			-	-	-	-
Member Specific Assignment			-	-	-	-
Production Energy Residual	PENGT		74,066,421	28,091,138	215,119,013	317,276,572
Production Energy Total	PENG		74,066,421	28,091,138	215,119,013	317,276,572
Production Energy Total Allocator			0.233444	0.088538	0.678017	1.000000
FAC Expense Residual Allocator	FACALL		2,449,147,804	928,887,170	7,113,321,360	10,491,356,334
FAC Expense Cost			-	-	-	-
Member Specific Assignment			-	-	-	-
FAC Expense Residual	FACT		25,821	9,793	74,993	110,607
FAC Expense Total	FACAL		25,821	9,793	74,993	110,607
FAC Expense Allocator			0.233444	0.088538	0.678017	1.000000
OSS Allocated Amount	OSSRBA		313,150,767	86,508,089	-	399,658,856
Off-System Sales Allocator						
Off-System Sales Revenue			4,898,710	1,353,272	-	6,251,982
Specific Assignment			-	-	70,291,505	70,291,505
Total OSS Assignments	TOSSA		4,898,710	1,353,272	70,291,505	76,543,487
			-	-	28,015,863	28,015,863
Estimated Gross Revenues for Smelter Surplus Sales			-	-	70,291,505	70,291,505
Energy Expenses for Smelter Surplus Sales						
Surplus Sales Credit						
Less: Adjustment to Reallocate Expenses						
Off-System Sales Variable Operating Costs Allocated on kWh			(10,746,839)	(4,075,949)	(31,213,193)	(46,035,981)
Off-System Sales Variable Operating Costs Allocated on Rate Base			2,946,247	813,902	42,275,642	46,035,791
Net Expense Adjustment			(7,800,593)	(3,262,046)	11,062,450	(189)
Off-System Sales Allocator	OSSALL		12,699,303	4,615,318	59,229,055	76,543,676
Smelter Off System Sales Revenues shown in COS						
Variable Expenses Allocated for Off-System Sales to Smelters in COS						
Off-System Sales Margins Allocated to Smelters in COS						
Removal of Purchase Power Expenses Related to Surplus and Curtailed Power Recorded in Accounts 555 (Alcan) and 557 (Century)						
Purchased Power Demand Allocated to all via CP			8,341,512	2,296,611	16,449,891	27,088,015
Purchased Power Demand To Be Reallocated			-	-	(4,065,092)	(4,065,092)
Recalculated CP Allocation			0	0	-	0
Purchased Power Demand Allocation Adjustment Factor	PPDAAF		0.784115	0.215885	-	1.000000
Purchased Power Demand Allocation Adjustment			3,187,500	877,592	(4,065,092)	-

BIG RIVERS ELECTRIC CORPORATION
 Cost of Service Study
 Rate Schedule Allocation

12 Months Ended
 October 2010

Description	Ref	Name	Rurals	Industrials	Smelters	Total System
Operating Expenses						
Expenses before Adjustments						
Production Demand	\$		54,815,438	15,091,958	97,747,856	167,655,252
Production Energy	\$		68,787,409	26,088,969	199,786,613	294,662,992
Production Steam - Direct Assignment	\$		-	-	-	-
Transmission Demand	\$		9,767,051	2,689,095	19,261,126	31,717,271
Distribution Substation	\$		-	-	-	-
Distribution Other	\$		-	-	-	-
Total	\$		133,369,898	43,870,022	316,795,596	494,035,516
Expenses After Adjustments						
Production Demand	\$		54,815,438	15,091,958	97,747,856	167,655,252
Production Energy	\$		68,787,409	26,088,969	199,786,613	294,662,992
Production Steam - Direct Assignment	\$		-	-	-	-
Transmission Demand	\$		9,767,051	2,689,095	19,261,126	31,717,271
Distribution Substation	\$		-	-	-	-
Distribution Other	\$		-	-	-	-
Total	\$		133,369,898	43,870,022	316,795,596	494,035,516
Expenses After Adjustments for Rate Calculation						
Production Demand	\$		37,837,616	9,295,207	30,050,335	77,183,158
Production Energy	\$		68,787,409	26,088,969	199,786,613	294,662,992
Production Steam - Direct Assignment	\$		-	-	-	-
Transmission Demand	\$		9,767,051	2,689,095	19,261,126	31,717,271
Distribution Substation	\$		-	-	-	-
Distribution Other	\$		-	-	-	-
Total	\$		116,392,076	38,073,271	249,098,074	403,563,421
Rate Base						
Production Demand	\$		310,356,615	85,448,352	612,039,195	1,007,844,162
Production Energy	\$		2,794,152	1,059,737	8,115,354	11,969,243
Production Steam - Direct Assignment	\$		-	-	-	-
Transmission Demand	\$		46,334,126	12,756,856	91,373,277	150,464,259
Distribution Substation	\$		-	-	-	-
Distribution Other	\$		-	-	-	-
Total	\$		359,484,893	99,264,945	711,527,826	1,170,277,664

Exhibit Seelye-4

Reconciliation of Billing Determinants

Big Rivers Electric Corporation
 Reconciliation of Billing Determinants
 For the 12 Months Ended October 31, 2010

Rate	Billing Determinants	Charge	Billings
<i>Rural Delivery Point Service</i>			
Demand Charge		kW-Mo	7.37 /kW-Mo
Kenergy	2,643,407		\$ 19,481,910
Jackson Purchase	1,492,514		10,999,828
Meade County	1,091,806		8,046,610
	<u>5,227,727</u>		<u>38,528,348</u>
Energy Charge		kWh	\$ 0.02040 /kWh
Kenergy	1,255,008,258		\$ 25,602,168
Jackson Purchase	694,512,540		14,168,056
Meade County	499,627,006		10,192,391
	<u>2,449,147,804</u>		<u>49,962,615</u>
Total Demand and Energy Charges			<u>\$ 88,490,963</u>
Green Power			401.36
Fuel Adjustment Clause			25,166,503
Environmental Surcharge			5,315,462
Unwind Surcredit			(8,038,629)
Total			<u>\$ 110,934,700</u>
Revenues per Statement of Operations			\$ 110,934,700
Difference			<u>\$ (0)</u>
<i>Large Industrial Customer Delivery Point Service</i>			
Demand Charge	1,743,869	kW-Mo	10.15 /kW-Mo
			\$ 17,700,270
Energy Charge	928,887,170	kWh	\$ 0.01372 /kWh
			12,739,688
Total Demand and Energy Charges			<u>\$ 30,439,958</u>
Green Power			-
Power Factor Provision and Off-System Sales Credit			172,750
Fuel Adjustment Clause			9,525,471
Environmental Surcharge			2,025,233
Unwind Surcredit			(3,052,791)
Total			<u>\$ 39,110,620</u>
Revenues Per Statement of Operations			\$ 39,110,620
Difference			<u>\$ (0)</u>
Total			<u>\$ 150,045,320</u>

Exhibit Seelye-5

Analysis of Non-FAC PPA

BIG RIVERS ELECTRIC CORPORATION
12 Months Ended October 31, 2010

Non FAC PPA Base Calculation

	Expense Month	PP(m) \$	S(m) kWh	Monthly Rate PP(m) / S(m) \$ / kWh	Current Base PP(b) / S(b) \$ / kWh	Monthly Factor \$/ kWh
	(1)	(2)	(3)	(4)	(5)	(6)
1	Nov-09	857,210	823,074,275	0.001041	0.001750	(0.000709)
2	Dec-09	32,675	915,375,535	0.000036	0.001750	(0.001714)
3	Jan-10	1,269,343	955,577,721	0.001328	0.001750	(0.000422)
4	Feb-10	435,979	860,254,282	0.000507	0.001750	(0.001243)
5	Mar-10	434,796	872,673,993	0.000498	0.001750	(0.001252)
6	Apr-10	880,947	803,411,031	0.001097	0.001750	(0.000653)
7	May-10	996,887	852,213,743	0.001170	0.001750	(0.000580)
8	Jun-10	782,758	895,570,310	0.000874	0.001750	(0.000876)
9	Jul-10	836,859	936,197,462	0.000894	0.001750	(0.000856)
10	Aug-10	473,665	948,595,005	0.000499	0.001750	(0.001251)
11	Sep-10	503,904	838,888,879	0.000601	0.001750	(0.001149)
12	Oct-10	1,122,128	822,198,468	0.001365	0.001750	(0.000385)
13						
14	Total	8,627,151	10,524,030,704	0.000820	0.001750	(0.000930)

Exhibit Seelye-6

Summary of Revenue Increase

Big Rivers Electric Corporation
 Calculation of Proposed Rate Increase
 Based on the 12 Months Ended October 31, 2010

Proposed Rates

Class	Adjusted Revenue at Current Rates (\$)	Adjusted Revenue at Proposed Rates (\$)	Base Rate Revenue Increase (\$)	TIER Adjustment Decrease (\$)	Estimated Credits From Amortization of Non-FAC PPA Balance (\$)	Sum of Base Rate Increase, TIER Decrease and Amortization of Non-FAC PPA Balance (\$)	Sum of Base Rate Increase, TIER Decrease and Amortization of Non-FAC PPA Balance (%)	Impact of Lowering the Base Non-FAC PPA (\$)	Net Increase (\$)	Net Increase (%)
Rural	110,513,089	124,685,092	14,172,003	-	(2,340,068)	11,831,935	10.71%	(2,145,453)	9,686,481	8.77%
Large Industrial	39,260,372	42,488,938	3,228,566	-	(896,009)	2,332,557	5.94%	(813,705)	1,518,852	3.87%
Non-Smelter	149,773,461	167,174,030	17,400,569	-	(3,236,077)	14,164,492	9.46%	(2,959,159)	11,205,333	7.48%
Smelters	282,391,841	297,830,583	22,553,396	(7,114,653)	-	15,438,743	5.47%	-	15,438,743	5.47%
Total	432,165,302	465,004,614	39,953,965	(7,114,653)	(3,236,077)	29,603,235	6.85%	(2,959,159)	26,644,076	6.17%

Big Rivers Electric Corporation
 Reconciliation of Billing Determinants
 For the 12 Months Ended October 31, 2010

Rate	Billing Determinants		Current Rate		Proposed Rate before Non-FAC PPA Roll-In		Proposed Rate after Non-FAC PPA Roll-In	
	Charge	Billings	Charge	Billings	Charge	Billings	Charge	Billings
<u>Rural Delivery Point Service</u>								
Demand Charge	(current) (proposed)	NCP CP	5,227,727 5,172,279	KW-Mo KW-Mo	7.3700 7.3700	\$ 38,528,348	\$ 52,700,351	\$ 52,700,351
Energy Charge			2,448,147,804	KWh	\$ 0.02040	\$ 49,962,615	\$ 49,962,615	\$ 47,817,162
Total Demand and Energy Charges						\$ 88,490,963	\$ 102,662,966	\$ 100,517,512
Green Power						401.36	401.36	401.36
Fuel Adjustment Clause						25,166,503	25,166,503	25,166,503
Environmental Surcharge						5,315,462	5,315,462	5,315,462
Unwind Surcredit						(8,038,629)	(8,038,629)	(8,038,629)
Non-FAC PPA Accruals								2,145,453
Estimated Credits from Amort of NFPPA Balance								(2,340,068)
Temperature Normalization Adjustment								(421,610)
Total			(20,667,174)	KWh	\$ 0.02040	\$ (421,610)	\$ (421,610)	\$ (421,610)
Increase						\$ 110,513,089	\$ 122,345,024	\$ 122,345,024
Percentage Increase						\$ 11,831,935	\$ 11,831,935	\$ 11,831,935
							10.71%	10.71%
<u>Lame Industrial Customer Delivery Point Service</u>								
Demand Charge			1,743,869	KW-Mo	10.15	\$ 17,700,270	\$ 19,003,812	\$ 19,003,812
Energy Charge			928,887,170	KWh	\$ 0.013715	\$ 12,739,688	\$ 14,639,952	\$ 13,826,246
Total Demand and Energy Charges						\$ 30,439,958	\$ 33,643,764	\$ 32,830,059
Green Power								
Power Factor Provision and Off-System Sales Credit						172,750	185,472	185,472
Fuel Adjustment Clause						9,525,471	9,525,471	9,525,471
Environmental Surcharge						2,025,233	2,025,233	2,025,233
Unwind Surcredit						(3,052,791)	(3,052,791)	(3,052,791)
Non-FAC PPA Accruals								813,705
Estimated Credits from Amort of NFPPA Balance								(896,009)
Current Industrial Customer Adjustment - Demand			13,437	KW-Mo	10.15	\$ 136,384	\$ 146,428	\$ 146,428
Current Industrial Customer Adjustment - Energy			974,674	KWh	\$ 0.013715	\$ 13,368	\$ 15,362	\$ 15,362
Total			3,358,342,474	KWh		\$ 39,260,372	\$ 41,592,929	\$ 41,592,929
Increase						\$ 39,260,372	\$ 2,332,557	\$ 2,332,557
Percentage Increase							5.94%	5.94%

Exhibit Seelye-7

Non-Smelter Non-FAC PPA

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 59

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. _____

_____ SHEET NO. _____

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA

Applicability

Applicable in all territory served by Big Rivers' Member Cooperatives.

Availability

To all sales under the following Big Rivers standard rate schedules: (i) Rural Delivery Service, (ii) Large Industrial Customer, and (iii) Large Industrial Customer Expansion, but only to the extent of service priced under schedule LIC.

Definitions

Please see Section 4 for definitions common to all tariffs.

“Smelters” are the aluminum reduction facilities of Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, as further described in the Wholesale Smelter Agreements.

“Smelter Agreements” are the two Wholesale Electric Service Agreements each dated as of July 1, 2009, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

Description

The Non-Smelter Non-FAC PPA (“NSNFP”) Factor shall be calculated as a per-kWh billing credit or charge applied on a monthly basis, for each applicable rate schedule as follows:

$$\text{NSNFP Factor} = \text{RA} / \text{KWH}$$

Where

RA is the balance in the NSNFP Regulatory Account, established pursuant to the March 6, 2009 Order of the Public Service Commission in Case No. 2007-00455, as of June 30th of the current year and determined as provided below in the “Calculation of Purchased Power Expense” section;
and

KWH is the estimated Non-Smelter Applicable Sales (NSS), defined below, for the twelve month service period beginning September 1st of the current year through and including August 31st of the following year

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY _____ President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 60

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. _____

_____ SHEET NO. _____

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA contd

The NSNFP Factor shall be calculated based upon the June 30th balance and applied to bills for service beginning September 1st of the current year. The current NSNFP Factor shall remain in place for service through and including August 31st of the following year, at which time it will be updated in accordance with the formula above.

An over- or under- recovery shall be calculated using actual amounts and shall be included in the NSNFP Regulatory Account balance for recovery in the subsequent period.

Special Conditions

1) First Twelve Months

For the initial implementation of this rate mechanism, the NSNFP Factor shall be designed to return the Regulatory Liability balance as of June 30, 2011, over twenty-four (24) months beginning with the bills for September 2011 service. After this factor has been in place for twenty-four (24) months, any remaining over- or under- recovery shall be included in the Non-FAC PPA Regulatory Account balance for recovery in the subsequent period.

2) Second Twelve Months

For the service periods beginning September 1, 2012, and ending August 31, 2013, two NSNFP Factors shall be in place. The first is the credit for months thirteen (13) through month twenty-four (24) of the credit noted in the First Twelve Months section above. The second is the NSNFP Factor calculated in accordance with the standard formula:

$$\text{NSNFP Factor} = \text{RA} / \text{KWH}$$

Where

RA is the Non-FAC PPA Regulatory Account balance as of June 30, 2012 and

KWH is the estimated Non-Smelter Applicable Sales (NSS) for the twelve (12) months beginning September 1, 2012 through and including August 31, 2013.

The two NSNFP Factors will be applied simultaneously over the twelve month service period from September 1, 2012 to August 31, 2013.

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY _____ President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 61

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. _____

_____ SHEET NO. _____

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA contd.

3) Third Twelve Months and Subsequent Twelve-Month Periods

For the service periods beginning September 1, 2013, only one NSNFP Factor shall be in place, calculated in accordance with the standard formula noted herein.

Calculation of Purchase Power Expense

Purchased Power Expense:

The monthly amount of purchased power expense that is recorded in the NSNFP Regulatory Account (PP(x)) is determined as provided in this section.

Definitions:

“Account” is the specified numbered account as set forth in the Uniform System of Accounts – Electric, promulgated under Bulletin 1767B-1 by the Rural Utilities Service, an agency of the U.S. Department of Agriculture.

“SEPA” is the Southeastern Power Administration, an agency of the U.S. Department of Energy, or any successor agency.

“Wholesale Smelter Agreements” are the Alcan Wholesale Agreement and the Century Wholesale Agreement.

Determination of the PP(x):

The PP(x) shall be determined in accordance with the following formula:

$$PP(x) = (PP(m)/S(m) - PP(b)/S(b)) \times NSS(m)$$

Where PP(m) is the current Purchased Power Costs for the month; S(m) is the current Applicable Sales; PP(b) is the Purchase Power Cost for the base period; and S(b) is the sales in the base period,

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY _____ President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 62

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. _____

_____ SHEET NO. _____

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA contd

For the initial base period, PP(b)/S(b) (the "Purchased Power Base") is \$0.000874.

Purchased Power Costs (PP) shall be the sum of:

(a) The total cost of power purchased (including purchases from SEPA) that is expensed by Big Rivers to Account 555 (excluding those costs that are recovered through Big Rivers' FAC and excluding costs expensed to Account Nos. 555.150, 555.151, 555.152 and related accounts regarding Big Rivers' cost share of HMP&L's Station Two, and to Account No. 555.188 and related accounts regarding Big Rivers' purchase of back-up power for the Domtar cogenerator) including transmission and related costs that are expensed to Account 565.

(b) The total amount of any adjustments to Purchased Power Costs attributable to prior months, whether positive or negative; and

(c) The total cost of amounts credited by Big Rivers to Kenergy with respect to voluntary curtailments under Section 4.13.2 of either Smelter Wholesale Agreement to allow Big Rivers to avoid market priced purchases of power.

Less:

(d) The total cost of power purchased directly associated with sales (including related system energy losses) by Big Rivers either to non-Member purchasers of power or to Kenergy under either Wholesale Smelter Agreement for resale to either Smelter as energy products other than Base Monthly Energy, assuming SEPA power followed by the lowest cost power, whether generated or purchased, shall be allocated to Applicable Sales.

Applicable Sales (S) shall be all kilowatt-hours sold at wholesale by Big Rivers (a) to its Members under all electric rate schedules, including the Large Industrial Rate, for resale to Kentucky ratepayers (other than by Kenergy to the Smelters and to Domtar for Backup Power Service), and (b) to Kenergy as Base Monthly Energy as defined in each of the Wholesale Smelter Agreements.

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY _____ President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

For All Territory Served By
Cooperative's Transmission System
P.S.C.KY.NO. 24

Original SHEET NO. 63

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C.KY.NO. _____

_____ SHEET NO. _____

RATES, TERMS AND CONDITIONS – SECTION 2

Non-Smelter Non-FAC PPA contd

Non-Smelter Applicable Sales (NSS) shall be all kilowatt-hours sold at wholesale by Big Rivers to its Members under all electric rate schedules, including the Large Industrial Rate, for resale to Kentucky ratepayers (other than by Kenergy to the Smelters and to Domtar for Backup Power Service).

DATE OF ISSUE March 1, 2011 DATE EFFECTIVE April 1, 2011

ISSUED BY _____ President and Chief Executive Officer
Big Rivers Electric Corporation, 201 3rd St., Henderson, KY 42420

Exhibit Seelye-8

Updated Midwest ISO
Attachment O

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10
 0

Big Rivers Electric Corporation

Line No.			Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)		\$ 28,984,266
	REVENUE CREDITS	(Note T)	
2	Account No. 454	(page 4, line 30)	25,337
3	Account No. 456	(page 4, line 33)	12,981,351
4	Revenues from Grandfathered Interzonal Transactions		0
5	Revenues from service provided by the ISO at a discount		0
6	TOTAL REVENUE CREDITS (sum lines 2-5)		13,006,688
7a	Revenue Adjustment (Note W)		\$0
7	NET REVENUE REQUIREMENT (line 1 minus line 6 plus line 7a)		<u>\$ 15,977,578</u>
	DIVISOR		
8	Average of 12 coincident system peaks for requirements (RQ) service		1,399,694
9	Plus 12 CP of firm bundled sales over one year not in line 8	(Note B)	0
10	Plus 12 CP of Network Load not in line 8	(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)	(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year		0
13	Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S)		0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)		0
15	Divisor (sum lines 8-14)		<u>1,399,694</u>
16	Annual Cost (\$/kW/Yr) (line 7 / line 15)		11.415
17	Network & P-to-P Rate (\$/kW/Mo) (line 16 / 12)		0.951
		Peak Rate	Off-Peak Rate
18	Point-To-Point Rate (\$/kW/Wk) (line 16 / 52; line 16 / 52)	0.220	\$0.220
19	Point-To-Point Rate (\$/kW/Day) (line 16 / 260; line 16 / 365)	0.044 Capped at weekly rate	\$0.031
20	Point-To-Point Rate (\$/MWh) (line 16 / 4,160; line 16 / 8,760 times 1,000)	2.744 Capped at weekly and daily rates	\$1.303
21	FERC Annual Charge (\$/MWh) (Note E)	\$0.000 Short Term	\$0.000 Short Term
22		\$0.000 Long Term	\$0.000 Long Term

Midwest ISO
 IERC Electric Tariff, Fourth Revised Volume No. 1

Attachment O
 page 2 of 5

Formula Rate - Non-Levelized		Rate Formula Template Utilizing RUS Form 12 Data		For the 12 months ended 10/31/10	
Line No.	(1) RATE BASE:	(2) RUS Form 12 Reference	(3) Big Rivers Electric Corporation Company Total	(4) Allocator	(5) Transmission (Col 3 times Col 4)
GROSS PLANT IN SERVICE					
1	Production	12h A 6 e	1,686,796,955	NA	
2	Transmission	12h A. 11 e	237,659,206	TP	0.96521 229,390,235
3	Distribution	12h A. 16 e	0	NA	
4	General & Intangible	12h A 1&17 e	18,511,051	W/S	0.13894 2,571,851
5	Common		0	CE	0.13894 0
6	TOTAL GROSS PLANT (sum lines 1-5)		<u>1,942,967,212</u>	GP=	11.939% <u>231,962,086</u>
ACCUMULATED DEPRECIATION					
7	Production	12h B 1-4. f	790,847,523	NA	
8	Transmission	12h B 5 f	107,564,747	TP	0.96521 103,822,204
9	Distribution	12h B 6 f	0	NA	
10	General & Intangible	12h B 7 f	6,300,770	W/S	0.13894 875,403
11	Common		0	CE	0.13894 0
12	TOTAL ACCUM DEPRECIATION (sum lines 7-11)		<u>904,713,040</u>		<u>104,697,608</u>
NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	895,949,432		
14	Transmission	(line 2 - line 8)	130,094,459		125,568,031
15	Distribution	(line 3 - line 9)	0		
16	General & Intangible	(line 4 - line 10)	12,210,281		1,696,447
17	Common	(line 5 - line 11)	0		0
18	TOTAL NET PLANT (sum lines 13-17)		<u>1,038,254,172</u>	NP=	12.258% <u>127,264,478</u>
ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)		0		zero 0
20	Account No. 282 (enter negative)		0	NP	0.12258 0
21	Account No. 283 (enter negative)		0	NP	0.12258 0
22	Account No. 190		0	NP	0.12258 0
23	Account No. 255 (enter negative)		0	NP	0.12258 0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		<u>0</u>		<u>0</u>
25	LAND HELD FOR FUTURE USE	(Note G)	0	TP	0.96521 0
WORKING CAPITAL (Note H)					
26	CWC	calculated	4,764,063		1,685,643
27	Materials & Supplies (Note G)	12h G 4 d + 5 d	2,812,929	TE	0.86297 2,427,481
28	Prepayments	12a B 24	3,296,852	GP	0.11939 393,596
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		<u>10,873,844</u>		<u>4,506,721</u>
30	RATE BASE (sum lines 18, 24, 25, and 29)		<u><u>1,049,128,016</u></u>		<u><u>131,771,199</u></u>

Formula Rate - Non-Levelized		Rate Formula Template Utilizing RUS Form 12 Data		For the 12 months ended 10/31/10	
Line No.	(1)	(2)	Big Rivers Electric Corporation (3)	(4)	(5)
		RUS Form 12 Reference	Company Total	Allocator	Transmission (Col 3 times Col 4)
O&M					
1	Transmission	12a.A.8 b + A.16 b	13,736,318	TE	0.86297 11,854,069
2	Less Account 565	12i.A.8 a	3,065,817	TE	0.86297 2,645,717
3	A&G	12a.A.13.b + A.18 b	28,620,280	W/S	0.13894 3,976,386
4	Less FERC Annual Fees		0	W/S	0.13894 0
5	Less EPRI & Reg Comm Exp. & Non-safety Ad (Note I)		1,819,284	W/S	0.13894 252,764
5a	Plus Transmission Related Reg Comm. Exp. (Note I)		641,009	TE	0.86297 553,174
6	Common		0	CE	0.13894 0
7	Transmission Lease Payments		0	NA	1.00000 0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		<u>38,112,507</u>		<u>13,485,148</u>
DEPRECIATION EXPENSE					
9	Transmission	12h.B.5 c	5,182,459	TP	0.96521 5,002,143
10	General	12h.B.7 c	238,155	W/S	0.13894 33,088
11	Common		0	CE	0.13894 0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		<u>5,420,614</u>		<u>5,035,232</u>
TAXES OTHER THAN INCOME TAXES (Note J)					
LABOR RELATED					
13	Payroll		0	W/S	0.13894 0
14	Highway and vehicle		0	W/S	0.13894 0
PLANT RELATED					
16	Property		0	GP	0.11939 0
17	Gross Receipts		0		zero 0
18	Other		0	GP	0.11939 0
19	Payments in lieu of taxes		0	GP	0.11939 0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		<u>0</u>		<u>0</u>
INCOME TAXES (Note K)					
21	$T = 1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		0.00%	NA	
22	$CIT = (T / (1 - T)) * (1 - (WCLTD / R)) =$ where WCLTD = (page 4, line 27) and R = (page 4, line 30) and FIT, SIT & p are as given in footnote K.		0.00%		
23	$1 / (1 - T) =$ (from line 21)		0.0000		
24	Amortized Investment Tax Credit (enter negative)		0		
25	Income Tax Calculation = line 22 * line 28		0	NA	0
26	ITC adjustment (line 23 * line 24)		0	NP	0.12258 0
27	Total Income Taxes (line 25 plus line 26)		<u>0</u>		<u>0</u>
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		83,310,740	NA	10,463,886
29	REV REQUIREMENT (sum lines 8, 12, 20, 27, 28)		126,843,860		28,984,266
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note U) [Revenue requirement for facilities included on page 2, line 2, and also included in Attachment GG]		0		0
31	REV REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		<u>126,843,860</u>		<u>28,984,266</u>

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

Line No.	SUPPORTING CALCULATIONS AND NOTES			
TRANSMISSION PLANT INCLUDED IN ISO RATES				
1	Total transmission plant (page 2, line 2, column 3)			237,659,206
2	Less transmission plant excluded from ISO rates (Note M)			0
3	Less transmission plant included in OATT Ancillary Services (Note N)			8,268,970
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)			<u>229,390,235</u>
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)			0.96521
TRANSMISSION EXPENSES				
6	Total transmission expenses (page 3, line 1, column 3)			13,736,318
7	Less transmission expenses included in OATT Ancillary Services (Note L)			1,454,938
8	Included transmission expenses (line 6 less line 7)			<u>12,281,380</u>
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)			0.89408
10	Percentage of transmission plant included in ISO Rates (line 5)			0.96521
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)			0.86297
WAGES & SALARY ALLOCATOR (W&S)				
		\$	TP	Allocation
12	Production	38,542,468	0.00	0
13	Transmission	6,480,848	0.97	6,255,357
14	Distribution	0	0.00	0 W&S Allocator
15	Other	0	0.00	0 (\$ / Allocation)
16	Total (sum lines 12-15)	<u>45,023,316</u>		<u>6,255,357 = 0.13894</u>
COMMON PLANT ALLOCATOR (CE) (Note O)				
		\$	% Electric	Labor Ratio
17	Electric	1,943,034,107	(line 17 / line 2)	(line 16)
18	Gas	0	1.00000 *	0.13894 =
19	Water	0		### CE
20	Total (sum lines 17-19)	<u>1,943,034,107</u>		
RETURN (R)				
		\$		
21	Long Term Interest 12a A 22 b	<u>\$47,622,710</u>		
Cost				
		\$	%	(Note P)
22	Long Term Debt 12a B 45 + B 46 + B 51 + B 52	815,322,539	68%	0.0584
23	Proprietary Capital 12a B 38	385,705,395	32%	0.1238
24	Total (sum lines 22-23)	<u>1,201,027,934</u>	100%	0.0794 =R
25				Proprietary Capital Cost Rate = 12.38%
26				TIER = 0.74
REVENUE CREDITS				
ACCOUNT 447 (SALES FOR RESALE)				
27	a. Bundled Non-RQ Sales for Resale		(Note Q)	0
28	b. Bundled Sales for Resale included in Divisor on page 1			0
29	Total of (a)-(b)			<u>0</u>
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			\$26,250
ACCOUNT 456 (OTHER ELECTRIC REVENUES)				
31	a. Transmission charges for all transmission transactions			\$13,752,495
32	b. Transmission charges for all transmission transactions included in Divisor on page 1			\$303,198
32a	c. Transmission charges associated with Schedule 26 (Note V)			<u>\$0</u>
33	Total of (a)-(b)-(c)			<u>\$13,449,298</u>

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing RUS Form 12 Data

For the 12 months ended 10/31/10

Big Rivers Electric Corporation

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col #)

References to data from RUS Form 12 are indicated as: # x.y z (page, section, line, column)

To the extent the page references to RUS Form 12 are missing, the entity will include a "Notes" section in the RUS 12 to provide this data

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term
C	LF as defined above at time of ISO coincident monthly peaks
D	LF as defined above at time of ISO coincident monthly peaks
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory asset or liabilities related to FASB 106 or 109. Balance of
G	Transmission related only
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to
I	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state
	Inputs Required:
	FIT = 0.00%
	SIT = 0.00% (State Income Tax Rate or Composite SIT)
	p = 0.00% (percent of federal income tax deductible for state purposes)
L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be
Q	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1.
T	The revenues credited on page 1, lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff)
U	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG and recovered under Schedule 26 of the
V	Removes from revenue credits revenues that are distributed pursuant to Schedule 26 of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have
W	Line 7a reflects an adjustment to incorporate Big Rivers' existing OATT rates as approved by the Kentucky Public Service Commission (KPSC) under whose jurisdiction Big Rivers' rates

Exhibit Seelye-9

FERC Order in
Docket No. ER11-15-000

133 FERC ¶ 61,175
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Midwest Independent Transmission System Operator, Inc. and
Big Rivers Electric Corporation

Docket Nos. ER11-16-000
ER11-15-000

ORDER CONDITIONALLY ACCEPTING PROPOSED TARIFF REVISIONS

(Issued November 24, 2010)

1. In this order, we address two separate filings, Docket Nos. ER11-15-000 and ER11-16-000, submitted by Big Rivers Electric Corporation (Big Rivers) and Midwest Independent Transmission System Operator, Inc. (Midwest ISO) (collectively, Applicants) on October 4, 2010 to revise Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to facilitate Big Rivers joining Midwest ISO as a transmission-owning member on December 1, 2010.¹ With regard to Docket No. ER11-15-000, we conditionally accept for filing Big Rivers' Attachment O formula rate, to be effective December 1, 2010 through and including December 31, 2011. With regard to Docket No. ER11-16-000, we conditionally accept for filing Applicants' proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff, to be effective as of the date of Big Rivers' full integration into Midwest ISO, as requested, subject to a compliance filing as discussed below.

I. Background

2. Midwest ISO is a Commission-approved Regional Transmission Organization (RTO) that provides transmission service pursuant to rates, terms and conditions of its Tariff on file with the Commission. Among other things, Midwest ISO provides point-to-point transmission service and network integration transmission service under its Tariff. Big Rivers is a not-for-profit generation and transmission cooperative providing

¹ As the administrator of the Tariff, Midwest ISO joins Big Rivers in this filing to amend the Tariff but takes no position on the substance of the filing.

wholesale power and transmission service to its three-member distribution cooperatives in Western Kentucky. Big Rivers' three-member distribution cooperatives are: Kenergy Corporation; Jackson Purchase Energy Corporation; and Meade County Rural Electric Cooperative Corporation. Big Rivers has announced its intent to join Midwest ISO as a transmission owner and plans to integrate its facilities into Midwest ISO on December 1, 2010.

II. Description of Filings

A. Docket No. ER11-15-000

3. On October 4, 2010, Applicants filed revisions to Midwest ISO's Tariff to include Big Rivers' company-specific Attachment O template. Applicants state that Big Rivers is currently seeking approval from the Kentucky Public Service Commission (Kentucky Commission) to transfer functional control of its transmission facilities to Midwest ISO on December 1, 2010.² Applicants seek approval of deviations from Midwest ISO's Attachment O formula rate template (Non-Levelized Rate Formula Template Using Rural Utilities Service Form 12 Data). Specifically, Applicants request, on an interim basis, to use rates for firm and non-firm point-to-point and network integration transmission services currently contained in Big Rivers' safe harbor Open Access Transmission Tariff (OATT), which the Kentucky Commission has approved, until such time that Big Rivers can obtain approval from the Kentucky Commission to use Midwest ISO's Attachment O formula rate.³

4. Applicants state that the Kentucky Commission approved an "unwind" of Big River's long-term lease of its generation facilities to various subsidiaries of E.ON US LLC (Unwind Transaction), which stipulated that Big Rivers is obligated to file with the Kentucky Commission to adjust its rates, including its transmission rates, within

² Subsequent to the date of filing in this proceeding, the Kentucky Commission approved Big Rivers' request to transfer functional control of its transmission system to Midwest ISO. *In re* Application of Big Rivers Elec. Corp. for Approval to Transfer Functional Control of its Transmission System to Midwest Indep. Transmission Sys. Operator, Inc., Case No. 2010-00043, at 12 (Nov. 1, 2010).

³ Applicants state that Big Rivers filed its safe harbor OATT with the Commission on April 22, 2009 in Docket No. NJ09-3-000. The Commission conditionally accepted Big Rivers' OATT on September 17, 2009, subject to a compliance filing addressing certain non-rate terms and conditions. Applicants Transmittal Letter, Docket No. ER11-15-000, at 3-4 (citing *Big Rivers Elec. Corp.*, 128 FERC ¶ 61,264 (2009)). Applicants state that Big Rivers made the compliance filing on December 16, 2009, but that the Commission has not yet acted on the compliance filing. *Id.* at 4.

three years of the date of closing of the Unwind Transaction (July 16, 2009).⁴ Applicants state that Big Rivers anticipates submitting a filing with the Kentucky Commission to adjust its transmission rates to be effective no later than January 1, 2012.⁵ Applicants state that Big Rivers will seek approval from the Kentucky Commission at that time to adjust its transmission rates to utilize the Midwest ISO Attachment O formula rate. Until the Kentucky Commission approves such adjustments, however, Applicants state that it is necessary for Big Rivers to utilize certain limited variances from the Attachment O formula rate.⁶ Accordingly, Applicants seek to utilize Big Rivers' existing OATT rates until such time as it can obtain approval from the Kentucky Commission, as described above.

5. Specifically, Applicants propose the following deviations to Big Rivers' Attachment O:

- Revenue Adjustment, page 1, line 7a: As explained in a new Note W on page 5 to Big Rivers Attachment O, "Line 7a reflects an adjustment to incorporate Big Rivers' existing OATT rates as approved by the [Kentucky Commission] under whose jurisdiction Big Rivers' rates are subject. The rates as derived using the Midwest ISO Tariff Attachment O formul[a] will be adjusted to equal the existing rates approved by the [Kentucky Commission]." Applicants state that the Revenue Adjustment is necessary to adjust the rates up or down in order to produce the revenue requirement that is consistent with Big Rivers' current OATT rates. Applicants state that Big Rivers cannot change this revenue requirement without the approval from the Kentucky Commission.⁷
- Net Revenue Requirement, page 1, line 7: Applicants state that Big Rivers has included language to reflect that the Net Revenue Requirement includes the Revenue Adjustment.⁸

6. Applicants assert that the deviations from Midwest ISO's Attachment O formula rate are just and reasonable. In addition, Applicants argue that Big Rivers' circumstances are unique in that it will be the only Midwest ISO transmission owner whose rates under

⁴ *Id.*

⁵ *Id.*

⁶ *Id.*

⁷ *Id.*

⁸ *Id.*

Midwest ISO's Tariff are subject to state commission approval. Applicants request an effective date of December 1, 2010, and that the Commission issue an order accepting these tariff sheets no later than November 24, 2010.⁹

B. Docket No. ER11-16-000

7. Also, on October 4, 2010, Applicants filed revisions to: Schedule 7 (Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service); Schedule 8 (Non-Firm Point-to-Point Transmission Service); Schedule 9 (Network Integration Transmission Service); and Schedule 26 (Network Upgrade Charge From Transmission Expansion Plan) of Midwest ISO's Tariff to reflect the addition of Big Rivers as a pricing zone in connection with its proposed integration into Midwest ISO. The proposed revisions adopt Midwest ISO's Commission-accepted transmission formula rate template contained in Attachment O to the Tariff, with the exception of the deviations outlined above in Docket No. ER11-15-000. According to Applicants, by transitioning to Midwest ISO's Attachment O formula rate, Big Rivers will fully migrate to the Tariff and be subject to the same terms and conditions of service as are other Midwest ISO transmission owners that utilize the Attachment O formula rate.¹⁰

8. Applicants request that the Commission accept the proposed revisions, without condition or suspension, to be effective as of the date of Big Rivers' full integration into Midwest ISO, which is currently scheduled for December 1, 2010. Applicants assert that granting this request is consistent with prior Commission orders wherein the Commission addressed formula rates for transmission owners in Midwest ISO and other RTOs in which the Commission approved those rates with no more than nominal suspension periods.¹¹

III. Notice of Filing and Responsive Pleadings

9. Notice of Applicants' filings in Docket Nos. ER11-15-000 and ER11-16-000 were published in the *Federal Register*, 75 Fed. Reg. 63,457 (2010), with interventions or protests due on or before October 25, 2010.

⁹ *Id.* at 2.

¹⁰ Applicants Transmittal Letter, Docket No. ER11-16-000, at 2.

¹¹ *Id.* at 1 (citing *Va. Elec. & Power Co.*, 123 FERC ¶ 61,098 (2008); *Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284 (2007); *Michigan Elec. Transmission Co.*, 117 FERC ¶ 61,314 (2006); *Int'l Transmission Co.*, 116 FERC ¶ 61,036 (2006)).

10. American Municipal Power, Inc. and Consumers Energy Company filed timely motions to intervene in Docket Nos. ER11-15-000 and ER11-16-000. Midwest ISO Transmission Owners (Midwest ISO TOs)¹² filed a timely motion to intervene and comments in Docket Nos. ER11-15-000 and ER11-16-000. Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier) filed a timely motion to intervene and comments in Docket No. ER11-16-000. Big Rivers filed an answer to Midwest ISO TOs' comments in Docket No. ER11-15-000.

IV. Discussion

A. Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceedings in which they intervened. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Big Rivers' answer because it has provided information that assisted us in our decision-making process.

¹² Midwest ISO TOs for purposes of this filing consist of: Ameren Services Company, as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Co., and Illinois Power Company; American Transmission Company LLC; American Transmission Systems, Inc., a subsidiary of FirstEnergy Corp.; City of Columbia Water and Light Department (Columbia, Missouri); City Water, Light & Power (Springfield, Illinois); Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Michigan Electric Transmission Company, LLC; Michigan Public Power Agency; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Minnesota Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

B. Substantive Matters

1. Docket No. ER11-15-000

a. Comments

12. Midwest ISO TOs state that they do not oppose the use of Big Rivers' Attachment O, but they believe that certain aspects of the filing should be modified or clarified. Specifically, Midwest ISO TOs assert that the Commission should require Applicants to modify Big Rivers' Attachment O to state that it is being adopted on an interim basis and shall remain in effect no later than December 31, 2011. At that point, Midwest ISO TOs state, Applicants can make the necessary filings to adopt the appropriate formula rate for Big Rivers. Midwest ISO TOs express concern that while Big Rivers anticipates filing the standard Attachment O template to become effective January 1, 2012, Big Rivers makes no firm commitment to do so. Midwest ISO TOs state that although Big Rivers is making these statements in good faith, this lack of a firm end-date for the use of Big Rivers' Attachment O could mean that the rate formula remains in use indefinitely in a manner that is different from the representations made in the instant filing. Alternatively, Midwest ISO TOs request that the Commission condition its acceptance of Big Rivers' Attachment O upon Big Rivers submitting a filing to adopt an appropriate formula rate for Big Rivers, to become effective no later than January 1, 2012.¹³

13. In addition, Midwest ISO TOs assert that Applicants need to address the impact of Schedules 26 and proposed 26-A (Multi-Value Project Usage Rate)¹⁴ and the charges allocated and billed to the Big Rivers pricing zone during the interim period. Midwest ISO TOs state that Midwest ISO's Tariff contains a number of additional charges other than the base transmission charges (i.e., Schedules 7, 8, and 9), including charges under Schedule 26 and proposed Schedule 26-A. Midwest ISO TOs state that charges imposed under these schedules will be billed to and collected from Big Rivers, but it is unclear how Big Rivers will treat any charges allocated and billed to its zone under Schedule 26 and proposed Schedule 26-A. For example, Midwest ISO TOs question whether Big Rivers will treat these charges as an add-on charge that is recovered in addition to its proposed rates or, alternatively, be deemed to be part of Big Rivers' base transmission rates. Because Schedule 26 and proposed Schedule 26-A are intended to recover the

¹³ Midwest ISO TOs Comments, Docket No. ER11-15-000, at 5.

¹⁴ On July 15, 2010, Midwest ISO submitted to the Commission a new Schedule 26-A as part of a joint filing with certain Midwest ISO Transmission Owners in Docket No. ER10-1791-000. The proposed Schedule 26-A would establish a new category of transmission projects designated as Multi-Value Projects and a corresponding cost allocation methodology for such projects. This filing is pending before the Commission.

costs of new transmission facilities for every transmission owner that has revenue requirements for facilities that qualify, Midwest ISO TOs claim that these charges recover more than just Big Rivers' revenue requirements. Midwest ISO TOs contend that Applicants should be required to clarify how any Schedule 26 and proposed Schedule 26-A charges allocated and billed to the Big Rivers' zone during the interim period will be treated for purposes of Big Rivers' Attachment O.¹⁵

14. Finally, Midwest ISO TOs state that Applicants should clarify the effects of Big Rivers' Attachment O on Midwest ISO's drive-out and drive-through rates and on revenue distribution under Midwest ISO's Transmission Owners Agreement.¹⁶ Specifically, Midwest ISO TOs state that the rates for drive-out and drive-through transmission services are based on the total net revenue requirements for all transmission owners within Midwest ISO, divided by total load within Midwest ISO.¹⁷ In addition, Midwest ISO TOs state that under Midwest ISO's Transmission Owners Agreement, revenues for certain transmission services, including drive-out and drive-through transactions, are distributed to all transmission owners.¹⁸ Midwest ISO TOs argue that acceptance of Big Rivers' Attachment O should have no impact on the method used to develop the Midwest ISO drive-out and drive-through rates or the resulting revenue distribution. Regardless of whether the Commission accepts Big Rivers' Attachment O, Midwest ISO TOs state that Applicants should clarify that: (1) transmission customers taking service under the Tariff that exit the Big Rivers pricing zone will pay the drive-out and drive-through rate established pursuant to Attachment O; and (2) the distribution of revenues to the Midwest ISO Transmission Owners will include transmission revenues deriving from transmission service exiting the Big Rivers pricing zone.¹⁹

¹⁵ Midwest ISO TOs Comments, Docket No. ER11-15-000, at 6.

¹⁶ The formal name of the Transmission Owners Agreement is the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation.

¹⁷ Midwest ISO TOs Comments, Docket No. ER11-15-000, at 7 (citing Midwest ISO Tariff, FERC Electric Tariff, Third Revised Vol. No. 1, Second Revised Sheet No. 1316).

¹⁸ *Id.* (citing Midwest ISO, Transmission Owners Agreement, Appendix C, § III.A.7 and III.B).

¹⁹ *Id.*

b. Answer

15. In response to Midwest ISO TOs' concern that the interim formula rate lacks a firm end-date, Big Rivers reiterates that its transmission rates are subject to the jurisdiction of the Kentucky Commission, and cannot be changed without the Kentucky Commission's approval. Accordingly, Big Rivers states that it cannot commit to a firm end-date for the use of the proposed Big Rivers' Attachment O. However, Big Rivers does commit to submitting a filing with the Commission, to become effective no later than January 1, 2012, to propose a rate formula to be employed thereafter. In the event that Big Rivers does not receive approval from the Kentucky Commission to utilize a different rate, Big Rivers asserts that it will seek to retain the existing formula rate. However, Big Rivers states that it would not object to a Commission order that allows Big Rivers' Attachment O to remain in effect only through December 31, 2011.²⁰

16. With regard to Midwest ISO TOs' request for clarification concerning how charges under Schedule 26 and proposed Schedule 26-A will be treated, Big Rivers clarifies that it is not proposing to change Big Rivers' Attachment O to reflect any amounts that may be allocated and billed to Big Rivers' zone. Big Rivers states that the formula rate in the proposed Big Rivers' Attachment O reflects the cost of existing facilities, and it is unlikely that Big Rivers would be assessed any charges under these schedules during the interim period. Big Rivers, however, asserts that if these charges should occur, the charges will be paid, as required under Midwest ISO's Tariff, and would not result in any changes to Big Rivers' Attachment O rates.²¹

17. Finally, in response to the requested clarification concerning the impact of Big Rivers' Attachment O on Midwest ISO's drive-out and drive-through rates, Big Rivers states that its Attachment O is not intended to have any impact on the method used to develop Midwest ISO's drive-out and drive-through rates or the resulting revenue distribution under Midwest ISO's Transmission Owners Agreement.²²

c. Commission Determination

18. We will conditionally accept Big Rivers' Attachment O formula rate. As an initial matter, we find it reasonable to accept Big Rivers' non-conforming Attachment O until such time that Big Rivers receives approval from the Kentucky Commission to use the Midwest ISO Attachment O formula rate. We find that the completion of the Unwind

²⁰ Big Rivers Answer at 3.

²¹ *Id.* at 3-4.

²² *Id.* at 4.

Transaction, coupled with Big Rivers rates being subject to the Kentucky Commission authority, present unique circumstances for Big Rivers' Attachment O formula rate.²³ Thus, we find it appropriate to allow Big Rivers to adjust its revenue up or down commensurate with its state-approved transmission service rates. However, as Midwest ISO TOs point out, we are concerned that Big Rivers' non-conforming Attachment O lacks a firm end-date.²⁴ Therefore [consistent with Big Rivers' answer,] we conditionally accept Big Rivers' Attachment O formula rate to be effective December 1, 2010 through and including December 31, 2011 (Interim Period). We note, however, that this acceptance with an end-date of December 31, 2011 does not foreclose Applicants from making a filing at an earlier date to adopt an appropriate formula rate for Big Rivers.

19. With respect to Midwest ISO TOs concerns regarding Big Rivers' impact on Schedule 26 and proposed Schedule 26-A, we find that Big Rivers' answer addresses Midwest ISO TOs concern and clarifies that Big Rivers is unlikely to be assessed any charges under Schedule 26 or proposed Schedule 26-A prior to January 1, 2012 [but should that occur, the charges will be paid by the zonal load as required under the Tariff and would not result in any changes to Big Rivers' Attachment O rates].

20. Finally, with regard to Midwest ISO TOs request for clarification concerning the impact of Big Rivers' proposed Attachment O on drive-out and drive-through rates and the resulting revenue distribution pursuant to Midwest ISO's Transmission Owners Agreement, we find that Big Rivers' answer provides Midwest ISO TOs requested confirmations and therefore addresses their concerns. Big Rivers clarifies that its proposed Attachment O is not intended to have any impact on the method for calculating these rates or the associated revenue distribution. Big Rivers states that it concurs with Midwest ISO TOs clarification.

21. Accordingly, we will conditionally accept for filing Big Rivers' Attachment O formula rate, as clarified and modified in Big Rivers' answer, to be effective December 1, 2010 through and including December 31, 2011, as discussed above.

²³ We note that the Commission previously accepted Big Rivers' transmission service rates contained within its safe harbor OATT. *See supra* note 3.

²⁴ Applicants anticipate submitting a filing to the Commission to adjust its rates to utilize the Midwest ISO Attachment O formula rate to be effective no later than January 1, 2012. *See supra* P 4.

2. **Docket No. ER11-16-000**

a. **Comments**

22. Midwest ISO TOs and Hoosier request that Midwest ISO clarify which of Big Rivers' planned or proposed transmission projects will be subject to cost allocation pursuant to Attachment FF of Midwest ISO's Tariff and cost recovery pursuant to Schedule 26.²⁵ Midwest ISO TOs and Hoosier state that under the Midwest ISO Transmission Expansion Plan (MTEP) process, set forth in Attachment FF of Midwest ISO's Tariff, projects are subject to a determination of cost allocation at the time the projects are approved.²⁶ Because Big Rivers is not yet a Transmission Owner within Midwest ISO, Midwest ISO TOs and Hoosier argue that Big Rivers should have no planned or proposed projects that are subject to cost allocation under these provisions prior to the MTEP 2011 planning cycle at the earliest. Midwest ISO TOs and Hoosier note that the Commission directed Midwest ISO to provide similar clarifications in proceedings involving the integration of Dairyland Power Cooperative and MidAmerican Energy Company into Midwest ISO.²⁷ If Midwest ISO cannot or does not provide such clarification, Hoosier requests that the Commission require Applicants to provide justification for including the projects in question prior to approving the proposed revisions to the Tariff.²⁸

b. **Commission Determination**

23. We will conditionally accept the proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff to reflect the addition of Big Rivers as a pricing zone in connection with its proposed integration with Midwest ISO, to be effective as of the date of Big

²⁵ Midwest ISO TOs Comments, Docket No. ER11-16-000, at 3; Hoosier Comments at 3.

²⁶ Midwest ISO TOs Comments, Docket No. ER11-16-000, at 3 (citing Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, Second Substitute Original Sheet No. 1839C.01); Hoosier Comments at 3 (citing Midwest ISO, FERC Electric Tariff, Third Revised Vol. No. 1, Substitute Original Sheet No. 1840).

²⁷ Midwest ISO TOs Comments, Docket No. ER11-16-000, at 4 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,187, at P 14 (2010) (*Dairyland*); *Midwest Indep. Transmission Sys. Operator, Inc.*, 128 FERC ¶ 61,046, at P 61 (2009) (*MidAmerican*)).

²⁸ Hoosier Comments at 4.

Rivers' full integration into Midwest ISO, which is currently scheduled for December 1, 2010, as requested, subject to the compliance filing ordered below.

24. With respect to Midwest ISO TOs' and Hoosier's requests for Midwest ISO to clarify which of Big Rivers' projects will be subject to cost allocation pursuant to Attachment FF of Midwest ISO's Tariff and cost recovery pursuant to Schedule 26, we will require, consistent with *Dairyland* and *MidAmerican*, that Applicants provide these clarifications in a compliance filing, due within 30 days of the date of this order.

The Commission orders:

(A) Big Rivers' Attachment O formula rate is hereby conditionally accepted for filing, to be effective December 1, 2010 through and including December 31, 2011, as discussed in the body of this order.

(B) The proposed revisions to Schedules 7, 8, 9, and 26 of Midwest ISO's Tariff are hereby conditionally accepted for filing, to be effective as of the date of Big Rivers' full integration into Midwest ISO, as requested, as discussed in the body of this order.

(C) Applicants are hereby directed to make a compliance filing, due within 30 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Exhibit Seelye-10

Temperature Normalization Adjustment

Big River Electric Corporation
Temperature Normalization Adjustment
12 Months Ended October 31, 2010

#	Item	Temperature Normalization Adjustment with Banding
(1)	Normalization Adjustment - kWh	(20,667,174)
(2)	Rural Charge per kWh	\$ 0.0204
(3)	Revenue Adjustment	\$ (421,610)
(4)	Base Fuel and Variable Cost per kWh	\$ 0.01429
(5)	Expense Adjustment	\$ (295,293)
(6)	Net Adjustment	\$ (126,318)

Big River Electric Corporation
Base Fuel Cost and Variable O&M Expense
12 Months Ended October 31, 2010

Acct	Description	Test Year Expenses
	512 MAINTENANCE OF BOILER PLANT	\$ 30,113,309
	513 MAINTENANCE OF ELECTRIC PLANT	6,251,804
	514 MAINTENANCE OF MISC STEAM PLANT	877,364
	554 MAINTENANCE OF ELECTRIC PLANT - HYDRO	-
	545 MAINTENANCE OF MISC HYDRO PLANT	-
	558 DUPLICATE CHARGES	-
	Total Variable Production Expenses	\$ 37,242,478
	Total Sales (kWh)	10,436,840,268
	Variable O&M Expenses per kWh	0.00357
	FAC Base	0.01072
	Total	0.01429

Big River Electric Corporation
Determination of Adjusted kWh Sales
12 Months Ended October 31, 2010

Year	Month	Coefficient	Actual Sales	Cooling Degree Days	Heating Degree Days	Normal Cooling Degree Days beyond 1 SD	Normal Heating Degree Days beyond 1 SD	Normal Sales	Proposed Adjustment	Normal Cooling Degree Days Plus 1 SD Less 1 SD	Normal Heating Degree Days Plus 1 SD Less 1 SD
2009	11	66,685.5	165,507,760	-	435	-	-	165,507,760	0.0%	-	-
2009	12	99,133.9	237,687,050	-	918	-	-	237,687,050	0.0%	-	613
2010	1	137,685.3	263,265,220	-	1,115	32	32	258,927,129	-1.6%	-	1,010
2010	2	121,119.1	225,473,574	-	932	-	74	216,563,331	-4.0%	-	1,083
2010	3	68,216.7	179,449,879	-	533	-	-	179,449,879	0.0%	-	858
2010	4	42,939.3	141,319,505	48	140	-	-	141,319,505	0.0%	8	641
2010	5	110,630.5	170,661,972	181	47	-	-	170,661,972	0.0%	66	337
2010	6	133,344.1	231,319,542	432	-	52	-	224,439,992	-3.0%	261	110
2010	7	194,822.6	251,219,016	496	-	-	-	251,219,016	0.0%	373	-
2010	8	162,531.1	251,270,888	497	-	3	-	250,731,599	-0.2%	315	-
2010	9	129,312.1	184,587,328	218	20	-	-	184,587,328	0.0%	262	72
2010	10	33,870.3	147,386,070	29	200	-	-	147,386,070	0.0%	136	6
			2,449,147,804	1,901	4,340	55	105	2,428,480,630	0.0%	11	298
								(20,667,174)	-0.8%		

Note: This analysis was prepared by GDS Associates, Inc.